— State of —
North Dakota
Office of the Governor

Jack Dalrymple
Governor

January 2, 2013

James C. Martin
Regional Administrator
United States Environmental Protection Agency, Region 8
1595 Wynkoop Street
Denver, CO 80202-1129

Re: North Dakota's Supplemental NO_X BART Determination for Coal Creek Station Supplement No.2 to State Implementation Plan for Regional Haze

Dear Regional Administrator Martin:

Enclosed please find the State of North Dakota's Supplemental NO_X BART Determination for Coal Creek Station (Supplemental CCS NOx BART Determination). The Supplemental CCS NOx BART Determination was developed by the North Dakota Department of Health, Division of Air Quality (Department) and supplements the NO_X BART determination for the Coal Creek Station set forth in North Dakota's Regional Haze State Implementation Plan (SIP). North Dakota's SIP, which includes this Supplemental BART determination, satisfies the requirements of the Clean Air Act, complies with EPA's regulations and policy and will result in significant emission reductions while preserving the proper federal-state partnership envisioned under the Clean Air Act.

On August 17, 2006, the operator of Coal Creek Station Great River Energy (GRE) submitted its initial BART analysis to the Department. The Department provided comments to GRE's 2006 submission to which GRE responded with an updated analysis in February 2007. Between 2007 and 2010, the Department's review continued and GRE provided the Department with revised analyses as requested.

North Dakota submitted its Regional Haze SIP to the U.S. Environmental Protection Agency (EPA) on March 3, 2010. In its Regional Haze SIP, North Dakota determined that NO_X BART for the Coal Creek Station is represented by combustion controls (LNC3+) and an emission limit of 0.17 $lb/10^6$ Btu (30-day rolling average). EPA deemed North Dakota's SIP submission complete on April 30, 2010. During EPA's review of the North Dakota SIP, EPA discovered an error in GRE's submission. After the discrepancy was discovered, the Department requested that GRE submit a revised BART cost estimate to the Department. The Department provided comments to GRE's revised submission and requested additional data be submitted. GRE provided the Department with several additional submissions with the final GRE submission received June 6, 2012.

Upon review of GRE's submissions, and after conducting its own independent analysis, the Department preliminarily determined that its original NO_X BART determination for Coal Creek Station, combustion controls (LNC3+) with an emission limit of 0.17 lb/10^6 Btu (30-day rolling average), was correct and is to be reaffirmed. The Department proposed for public review and comment its proposal to reaffirm its BART determination for Coal Creek Station. The 30-day public comment period closed on October 30, 2012. None of the comments received from the public caused the Department to change its BART determination for Coal Creek Station.

As EPA is aware, EPA disapproved North Dakota's original BART determination for the Coal Creek Station. *See* 77 Federal Register 20,898 (April 6, 2012). EPA's disapproval of North Dakota's Coal Creek Station BART NO_X determination is the subject of an action for judicial review before the U.S. Court of Appeals for the Eighth Circuit. *See* North Dakota v. EPA, No. 12-1844 (8th Cir. April 6, 2012).

As set forth in the enclosed, the Supplemental CCS NO_X BART Determination is well supported and is a reasoned exercise of the State's authority and discretion under the federal Clean Air Act. As such, North Dakota requests EPA's prompt evaluation and approval of North Dakota's Supplemental CCS NO_X BART Determination.

As indicated, enclosed are one hardcopy and one electronic copy (on CD) of the Supplemental CCS NO_X BART Determination (Supplement No.2 to the Regional Haze SIP). The electronic copy is a duplicate of the hardcopy. No public hearing was held on this Supplement because no one requested one pursuant to the opportunity for such hearing indicated in the public notice.

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

Sincerely,

Jack Dalrymple

Jack Dalrymple
Governor

C: Dave Glatt, Chief, Environmental Health Section, ND Department of Health
Terry O'Clair, P.E., Director, Division of Air Quality, ND Department of Health
Gail Fallon, EPA Region 8
Carl Daly, EPA Region 8

North Dakota State Implementation Plan
for
Regional Haze
Supplement No. 2

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

North Dakota Department of Health
Adopted: 12/20/12

Division of Air Quality
Air Pollution Control Program
North Dakota Deportment of Health
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Terry Dwelle, M.D., M.P.H.T.M.
State Health Officer

Terry O'Clair, P.E.
Director

APPROVAL PAGE

North Dakota State Implementation Plan for Regional Haze
Supplement No. 2

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

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

Terry O'Clair

Terry L. O'Clair, P.E.
Director
Division of Air Quality

12/19/2012
Date

L. David Glatt, P.E.
Chief
Environmental Health Section

12/20/12
Date

Adopted for the North Dakota Department of Health

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

12/20/2012
Date

Supplement No. 2

to

North Dakota State Implementation Plan

For

Regional Haze

December 2012

North Dakota Department of Health
Division of Air Quality
Air Pollution Control Program
918 E. Divide Avenue
Bismarck, North Dakota 58501-1947

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I. Summary of Additions

Supplement No. 2 to the N.D. Regional Haze SIP provides additional information and analysis for the NO_x BART determination for Coal Creek Station Units 1 and 2. The information includes an updated analysis by GRE dated April 5, 2012 with a technical update on June 7, 2012. GRE's analysis is added as Appendix C.2.1 of the SIP. The Department's review of GRE's analysis entitled "Supplemental Evaluation of NO_x BART Determination for Coal Creek Station Units 1 and 2" and the Department's "Findings of Fact" are added to the SIP as Appendix B.2.1. Documents demonstrating the Department's consultation efforts with the Federal Land Managers and EPA are added as Appendices J.1.6 and J.3.4. Public notice documents are added as Appendices F.1.5, F.3.1 and F.4.1. The Department's Response to Public Comments is added as Appendix F.8.1

The additions to the SIP do <u>not</u> change the BART requirements for NO_x at the Coal Creek Station. The additional information supplements the original determination made by the Department that BART is a limit of 0.17 lb/10^6 Btu on a 30-day rolling average basis.

The Public Notice for this SIP Supplement offered the opportunity for a public hearing. There was no request for a public hearing so none was held. Therefore, this SIP Supplement does not contain a Certification for the Public Hearing, a transcript of the hearing or a list of attendees.

II. SIP Additions

Supplemental Evaluation
of
NO_x BART Determination
for
Coal Creek Station Units 1 and 2

September 2012

North Dakota Department of Health
Division of Air Quality
918 E Divide Avenue
Bismarck, ND 58501

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Supplemental Evaluation of
NO_x BART Determination
for
Coal Creek Station Units 1 and 2

I. Introduction

As part of the development of the State of North Dakota's Regional Haze State Implementation Plan (SIP), in March of 2010, the Department finalized and submitted to the U.S. Environmental Protection Agency (EPA) a Best Available Retrofit Technology (BART) determination for nitrogen oxides (NO_x) emitted from Coal Creek Station (CCS) Units 1 and 2. The BART determination was originally submitted to the Federal Land Manager's (FLMs) for their review (consultation) on June 2, 2008. The Department of Interior (DOI) provided comments on August 11, 2008 and the Department responded to those comments on July 16, 2009 (see Appendix J.1.2 of SIP). After making revisions and finalizing the SIP, the Department again consulted with the FLMs on the entire SIP (including the Coal Creek BART determination) in August 2009 (see Appendix J.1 of SIP). The DOI and U.S. Forest Service both provided comments in October 2009 (see Appendix J.1.3 of SIP). The Department's response to those comments was finalized in December 2009 and incorporated into the SIP (see Appendix J.1.4 of SIP). Public comment on the SIP, including the Coal Creek BART determination, was held from December 8, 2009 to January 8, 2010 with a public hearing January 7, 2010. Comments on the SIP were received from the U.S. Environmental Protection Agency (EPA), several environmental groups, concerned citizens, DOI and several of the affected sources. The comments and the Department's response to those comments are included in Appendix F.8 of the SIP.

The Coal Creek BART determination in the March 2010 SIP established a NO_x limit of 0.17 lb/10^6 Btu (30 d.r.a.) for each unit based on combustion controls. Subsequent to this submittal, EPA, during its review, discovered that Great River Energy (GRE) had used a value for ash sales based on the total sales price instead of the amount GRE would receive from the sales. After this discrepancy was discovered, EPA finalized a Federal Implementation Plan (FIP) for regional haze which established a BART limit of 0.13 lb/10^6 Btu (30 d.r.a.) based on selective non-catalytic reduction (SNCR) and combustion controls. Because of the error in GRE's analysis, the Department requested GRE submit a revised BART cost estimate to the Department. On July 15, 2011, GRE submitted its revised BART determination to the Department. Later, through telephone contact with GRE, the Department was advised that GRE planned to submit an entirely new cost estimate for selective non-catalytic reduction (SNCR) and additional information. The following is the Department's understanding of the chronology of events:

Date	Item
July 15, 2011	GRE submits revised cost estimate for SNCR
September 21, 2011	EPA proposes to approve in part and disapprove in part North Dakota's Regional Haze SIP and proposes FIP
November 3, 2011	Department letter to GRE asking that revised analysis be provided by December 21, 2011
November 14, 2011*	Department informs EPA by letter that it will reevaluate the Coal Creek Station BART determination
November 21, 2011	GRE submits revised BART analysis to the Department
December 7, 2011	Department letter to EPA advising it of GRE's submittal and Department's review
January 10, 2012	Conference call with GRE to discuss comments on November 21, 2011 submittal
January 19, 2012	Department letter to GRE with comments to the November 21, 2011 submittal
February 10, 2012	GRE submits revised analysis
February 28, 2012	Department letter to GRE with comments on February 10, 2012 submittal
April 5, 2012	GRE submits revised analysis in response to Department's February 10, 2012 comments
April 6, 2012	EPA publishes final FIP
April 11, 2012	GRE submits revised analysis which updated visibility impact tables
May 21, 2012	Conference call with GRE where Department indicated it did not agree with a baseline of 0.153 lb/10^6 Btu for Unit 2 and there was an error in the Unit 1 cost effectiveness analysis
June 6, 2012	GRE submits revised calculations of cost effectiveness and incremental cost for both units based on the May 21, 2012 comments

*The November 14, 2011 submittal, and subsequent submittals, included a site-specific evaluation of NO_x controls at Coal Creek Station by GRE's technical consultant URS. The submittal also contained an evaluation of the potential for lost ash sales due to the installation of SNCR and the cost of treating or disposing of unmarketable ash. The evaluation was prepared by Golder Associates, another consultant for GRE.

The Department's January 19, 2012 letter included comments regarding the baseline emission rate, questions about the differences between Coal Creek Station and the East Lake Station where 15% of the fly ash is untreatable due to SNCR operation, as well as identifying several calculation errors and inconsistencies. The letter also questioned the accuracy of the visibility improvement tables. GRE's February 10, 2012 resubmittal addressed many of the issues the Department had raised; however, as detailed in the Department's February 28, 2012 comments on this submittal, the Department continued to question the accuracy of the visibility modeling results and the accuracy of some calculations. The Department's February 28, 2012 letter also pointed out some discrepancies and inconsistencies in the documents.

On April 6, 2012, GRE submitted to the Department a revised analysis. However, the Department determined that the GRE analysis did not contain the revised visibility modeling results table. After informing GRE of this issue, a revised analysis with the revised visibility modeling results tables was submitted to the Department on April 11, 2012. The Department's last comments on GRE's revised NO_x BART analysis came during a conference call on May 21, 2012. On that call, the Department told GRE that it did not agree with a baseline emission rate of 0.153 lb/10^6 Btu for Unit 2. The Department also advised GRE of an error in the cost effectiveness calculations for Unit 1. In response to that call, on June 6, 2012 GRE submitted revised cost calculations based on a baseline of 0.201 lb/10^6 Btu for Unit 2 and corrected calculations of cost effectiveness for Unit 1. Based on GRE's revisions, the Department has determined the analysis is complete and the calculations are accurate.

Contained in this Supplemental Evaluation is the Department's analysis of GRE's April 11, 2012 submittal as revised on June 6, 2012.

II. BART Analysis Review

When EPA proposed the FIP, which included NO_x limits for the two units of the Coal Creek Station, they conducted their own BART analysis. The Department has identified five major issues which significantly affect the BART determination for GRE, and which EPA and GRE differ in their analysis of those issues. These issues are:

1) The baseline emission rate to be used in the analysis.
2) The NO_x control efficiency for SNCR.
3) The capital cost of SNCR.
4) The amount of urea required to be fed into the boiler to achieve the desired NO_x reduction.
5) Whether fly ash sales will be lost due to ammonia adsorption onto the ash.

The Department has reevaluated each of these five issues and independently finds and determines the following:

A. Baseline Emissions

The original BART analysis submitted by GRE (December 2007) established a baseline emission rate of 0.22 lb/10^6 Btu for each unit. In GRE's April 2012 submittal, GRE proposed a revised baseline of 0.201 lb/10^6 Btu for Unit 1 and 0.153 lb/10^6 Btu for Unit 2. GRE indicated their Dry Fining™ technology had reduced NO_x emissions to 0.201 lb/10^6 Btu at Unit 1 and LNC3+ combustion technology had further reduced emissions at Unit 2 to 0.153 lb/10^6 Btu.

Regarding GRE's proposed revision of the baseline emission rates, EPA stated in their response to comments set forth in the FIP (77 FR 20927) the following:

"We evaluate potential control options based on baseline conditions, not on ongoing revisions to a facility after the baseline period. It is not reasonable to consider controls installed after the baseline period in determining BART. Such an approach would tend to lead to higher cost effectiveness values for more effective controls and encourage sources to voluntarily install lesser controls to avoid installing more effective BART controls later."

The BART Guidelines (40 CFR 51, Appendix Y) state "The baseline emissions rate should represent a realistic depiction of **anticipated** [emphasis added] annual emissions for the source. In general, for the existing sources subject to BART, you will estimate the anticipated annual emissions based upon actual emissions from a baseline period." It is clear that the baseline emissions are future emissions, not necessarily a past emission rate. Use of past emission rates could overestimate the baseline emission rate. For example, if a source anticipated using a lower sulfur fuel in the immediate future, using past emissions to establish the baseline would clearly overstate the future emissions. Based on the BART Guidelines, the Department has evaluated future operating scenarios as part of the BART determination process (e.g. Stanton Station).

The installation of the Dry Fining™ technology was under development for many years before the Department made its BART determinations in 2010. Dry Fining™ (coal drying and other coal enhancements) along with scrubber improvements was the technology GRE listed for achieving the sulfur dioxide limit in their 2007 BART analysis. Although GRE clearly anticipated using Dry Fining™ technology, no emissions reductions were credited towards the baseline emissions rate in the Department's 2010 BART determination for NO_x. At that time, the effect on NO_x emissions was unknown. Since that time, it has been determined that Dry Fining™ reduced NO_x emissions by 0.02 lb/10^6 Btu on an annual average basis. Because the installation of the Dry Fining™ technology was anticipated as part of the technology selected for BART for sulfur dioxide, and no NO_x emissions reductions were relied on in the 2010 BART determination (the effect was unknown), it is appropriate to take the now known NO_x emissions reductions from Dry Fining™ into account when determining a new baseline emission rate.

The installation of LNC3+ combustion controls was to be installed to meet the 2010 NO_x BART limits established by the Department (SOFA + LNB Option 1). Because this technology was proposed to meet their 2010 NO_x BART limit, it is inappropriate to consider it as part of the baseline after the final BART determination.

Based on the information provided by GRE, a baseline emission rate based on 0.201 lb/10^6 Btu at each unit is appropriate. For purposes of determining the annual emissions, the last five years of data (2006 – 2010) were reviewed. Based on the average of the highest two years in the last five years, the baseline heat input was as follows:

Unit 1 = 5.0433 x 10^{13} Btu/yr
Unit 2 = 4.7965 x 10^{13} Btu/yr

The calculated baseline emissions are:

E (Unit 1) = (5.0433 x 10^{13} Btu/yr) (0.201 lb/10^6 Btu) ÷ (2000 lb/ton)
E (Unit 1) = 5,069 tons/yr

E (Unit 2) = (4.7965 x 10^{13} Btu/yr) (0.201 lb/10^6 Btu) ÷ (2000 lb/ton)
E (Unit 2) = 4,820 tons/yr

GRE established their baseline emissions at 5,080 tons per year for Unit 1 and 5,086 tons per year for Unit 2. The difference can be attributed to the Department using data from two calendar years while GRE used data from twenty-four consecutive months. GRE's estimate of baseline emissions appears to be reasonable.

The Department believes the baseline emission rate should be based on 0.201 lb/10^6 Btu because:

1) Dry Fining™ (coal drying) was being installed prior to the BART decision, although no credit was taken for potential NO_x emissions reductions at that time.

2) NO_x emissions have been reduced by 0.02 lb/10^6 Btu by Dry Fining™ which will affect "anticipated" emissions which are used for establishing the baseline.

B. SNCR Control Efficiency

GRE estimated that the control efficiency of SNCR after the installation of LNC3+ will be 20%. EPA estimated that 25% control efficiency can be attained (77 FR 20919). GRE's estimate is based on a site-specific evaluation by URS. EPA's estimate is based on data from facilities other than Coal Creek Station included in the Control Cost Manual and information from Fuel Tech, Inc. and the Institute of Clean Air Companies (ICAC).

As part of the revised BART analysis, GRE supplied an EPRI report titled "Low-Baseline NO_x Selective Non-Catalytic Reduction Demonstration". The report documents the results of SNCR testing at Electric Energy's Joppa Unit 3. The results suggest that when the NO_x concentration in the flue gas is 88 ppm (day 6) or less, the removal efficiency of SNCR would be less than 15% (see Figure 3-5). However, as the NO_x concentration increases to 155 ppm to 190 ppm, the SNCR removal efficiency increased to as much at 30+%.

GRE has indicated that when CCS is operating at 0.153 lb/10^6 Btu (with LNC3+ installed), the NO_x concentration will be approximately 88 ppm (Supplemental Best Available Retrofit Technology Refined Analysis for NO_x Emissions footnote 5, p.8). Controlling NO_x emissions to such low emission rates (0.122 lb/10^6 Btu at 20% efficiency; 0.115 lb/10^6 Btu at 25% efficiency) is not well understood. EPA's Air Pollution Control Technology Fact Sheet (EPA-452/F-03-031) states "SNCR tends to be less effective at lower levels of uncontrolled NO_x. Typical uncontrolled NO_x levels vary from 200 to 400 ppm." The EPRI report states "The current project addresses the applicability of SNCR to **these low-baseline NO_x emission rates where there is currently no full-scale experience**" [emphasis added].

The study discussed in the EPRI report represents actual stack test data for a coal-fired power plant operating at an NO_x flue gas concentration similar to that at the CCS. It is not an extrapolation of data from units of varying boiler size as EPA has done in their analysis. This extrapolation does not account for the specific design features of Coal Creek Station and does not appear to include facilities with a low uncontrolled emission rate like Coal Creek Station. The Control Cost Manual does not include data for a boiler as large as either of the units at Coal Creek Station and gives no indication of the uncontrolled emission rate. The Control Cost Manual indicated larger boilers (>3,000 Btu/hr) typically have lower NO_x removal efficiencies. The boilers at Coal Creek Station are rated at more than 6,000 x 10^6 Btu/hr. The URS analysis of the expected efficiency of SNCR is based on their experience and an on-site evaluation of CCS that takes into account the existing features of the source.

The Department believes the URS estimate of 20% removal is credible and reasonable for the following reasons:

1) The EPRI report on low (≤88 ppm) uncontrolled NO_x emission rates indicates substantially less than 25% removal. With LNC3+, the NO_x emission rate at Coal Creek Station will be approximately 88 ppm.

2) The URS estimate was based on a site specific evaluation of Coal Creek Station. EPA's estimate was not.

3) The Control Cost Manual indicates SNCR will have a lower efficiency for boilers greater than 3,000 x 10^6 Btu/hr heat (CCS boilers are approximately 6,000 x 10^6 Btu/hr).

C. Capital Cost of SNCR

GRE has estimated the Installed Capital Cost (Total Capital Investment) for SNCR to be $12.18 million dollars for each unit. EPA has estimated that the capital cost to be $5,374,000 (76 FR 58620, Table 57). GRE's (URS) estimate is based on a site specific evaluation made by URS and URS software developed from actual projects. EPA's estimate uses GRE's estimate for direct capital cost and the remaining factors in the Control Cost Manual for SNCR (77 FR 58620). The major difference between the two cost estimates is a 1.6 retrofit factor used by GRE, but disallowed by EPA.

The BART Guidelines state "Once the control technology alternatives and achievable emissions performance levels have been identified, you then develop estimates of capital and annual costs. The basis for equipment cost estimated also should be documented, either with data supplied by an equipment vendor (i.e., budget estimates or bids) or by a referenced source (such as the *OAQPS Control Cost Manual*, Fifth Edition, February 1996, EPA 453/B-96-001). In order to maintain and improve consistency, cost estimates should be based on the *OAQPS Control Cost Manual*, where possible. The Control Cost Manual addresses most control technologies in sufficient detail for a BART analysis. **The cost analysis should also take into account any site-specific design or other conditions identified above that affect the cost of a particular BART technology option."** [emphasis added] (40 CFR 51, Appendix Y, I.V.D., 4.5 Step 4)

To determine which estimate is more accurate, the EPA's Integrated Planning Model (IPM) methodology was used (IPM Model – Revisions to Cost and Performance for APC Technologies; SNCR Cost Development Methodology; August 2010 – see Appendix B). The IPM is a model used by EPA (and others) to analyze the project impact of environmental policies on the electric power industries in the 48 contiguous states and the District of Columbia. (see www.epa.gov/airmarkt/progsregs/epa-imp/). EPA has used this model to evaluate costs for the various NO_x BART options at the Coronado, Cholla and Apache Generating Stations in Arizona (77 FR 42852) and the Montana FIP (77 FR 24024). The documentation for the IPM cost methodology states "A retrofit factor that equates to difficulty in construction of the system **must be defined**" [emphasis added]. EPA has contended that a retrofit factor is not warranted even though the EPA Air Pollution Control Cost Manual states "The increased cost due to retrofit is approximately 10% to 30% of the cost of SNCR applied to a new boiler" (Chapter 1, Selective Noncatalytic Reduction, page 1-30). GRE contends that a retrofit factor of 60% (1.6) is appropriate. The total capital cost was calculated using the updated IPM methodology and retrofit factors of 1.0, 1.3 and 1.6. The results (adjusted to 2011 dollars) are:

Retrofit Factor	Total Capital Investment (per unit)
1.0	$10,300,000
1.3	$11,600,000
1.6	$12,800,000

With a retrofit factor of 1.0 (no increase for a retrofit), the IPM methodology predicts a cost that is about double EPA's estimated cost. With a retrofit factor of 1.6, the IPM estimates a cost that is about 5% higher than GRE's estimate. The GRE estimate using a 1.6 retrofit factor is within 30% of the IPM estimate with a retrofit factor of 1.0. An estimate with an accuracy of ±30% has the same accuracy as that provided by the Control Cost Manual (Background, Section 1.2, p.1-4).

EPA has also published an Air Pollution Technology Fact Sheet for SNCR (EPA-452/F-03-031). The fact sheet estimates that SNCR will have a capital cost of $9 - $25 per kilowatt (1999 dollars). Adjusting the cost to 2011 dollars using the Consumer Price Index yields a cost range of $12 - $34 per kilowatt. GRE's estimate is approximately $20 per kilowatt (2011 dollars). EPA's estimate is approximately $9 per kilowatt (2009 dollars) or approximately $9.4 per kilowatt in the 2011 dollars. EPA's estimate is well below the range specified in the Air Pollution Control Fact Sheet when adjusted to 2011 dollars while GRE's estimate is within the lower end of the range.

Based upon its review and consideration, the Department believes GRE's capital cost estimate is credible and reasonable for the following reasons:

1) EPA's estimate is based on the Control Cost Manual which is out-of-date.

2) Cost estimates using the IPM and EPA's Fact Sheet for SNCR suggests GRE's estimate is accurate (±30%).

3) The GRE estimate is a site specific estimate as suggested by the BART Guidelines. EPA's estimate is not site specific.

D. Reagent Usage

The amount of reagent necessary to achieve the desired NO_x reduction (0.153 lb/10^6 Btu to 0.122 lb/10^6 Btu) is a major operating cost and figures predominately in the annualized cost of SNCR. EPA has estimated that 770 lb/hr of urea (100%) would be required to achieve the required NO_x reduction. The URS estimate, based on their experience with SNCR systems, indicates that 1,155 lb/hr of urea (100%) would be required.

EPA's estimate of the amount of urea required was based on several assumptions and did not follow the methodology in the Control Cost Manual. EPA assumed a normalized stoichometric rate (NSR) of 1.0; however, based on Equation 1.14, the NSR is 1.335 (see Appendix C of the North Dakota SIP for calculation). EPA also fails to calculate a urea utilization factor in accordance with Equation 1.13 of the Control Cost Manual. Based on Equation 1.13, the utilization rate is expected to be only 15.2% (see Appendix C of the North Dakota SIP for calculation). Using Equation 1.15 in the Control Cost Manual, the amount of reagent actually reacted with the NO_x is 163 lb/hr (see Appendix C of the North Dakota SIP for calculation). With a utilization rate of 15.2%, the amount of urea actually required to be fed into the boiler is:

Urea Feed Rate = 163 lb/hr ÷ 0.152

Urea Feed Rate = 1,072 lb/hr

The urea feed rate predicted by the Control Cost Manual is much closer to GRE's estimate than it is to EPA's.

The Department further investigated the amount of urea usage by contacting Minnkota Power Cooperative. Minnkota operates an SNCR system on both units of the M.R. Young Station. Based on our investigation, GRE's predicted urea usage is reasonable when compared to Minnkota's actual usage (see Appendix C of the North Dakota SIP).

The Department also used the IPM to estimate the amount of urea required. The IPM uses default values of 1.0 for the NSR and a utilization of 15%. Using these defaults, IPM indicated 800 lb/hr of urea would be required. However, after adjusting the NSR rate to 1.335, the IPM estimated feed rate would be 1,068 lb/hr.

The Department finds GRE's estimate of urea usage to be reasonable for the following reasons:

1) The estimate is close to the estimates from the IPM and the Control Cost Manual.

2) Actual usage data from the M.R. Young Station indicates GRE's estimate is accurate.

3) EPA's estimate did not follow the procedures in the Control Cost Manual.

E. Lost Ash Sales

EPA believes no ash sales will be lost due to the operation of SNCR (77 FR 20920). Based on the Golder report, GRE expects a minimum of 30% lost ash sales and possibly 100% lost ash sales.

Golder Associates in their April 2, 2012 letter to Diane Stockdill of GRE (Appendix A - Supplemental Best Available Retrofit Technology Refined Analysis for NO_x - Appendix G) states "Based on available literature, the adsorption of ammonia onto fly ash from SNCR emission controls is highly variable and dependent upon factors such as SNCR operation, fuel type/fuel mix, boiler configuration, ash content, ash mineralogy, ash alkalinity, ash sulfur content, and temperature. Limited published data are available for ammonia levels in fly ash for coal-fired power plants utilizing SNCR emissions controls, with no published information being found for energy generation facilities burning lignite coal." The Department's research on this issue also indicated that the carbon content of the ash will also affect the amount of ammonia adsorbed on the ash. The Coal Creek Station is equipped with low-NO_x burners. Low-NO_x burners contribute to higher carbon levels in fly ash.[2]

EPA claims that the installation of ammonia slip monitoring will allow GRE to maintain ammonia slip at 2 ppm or less and ash sales will not be affected. Giampa[2] suggests that 2 ppm ammonia slip results in ammonia concentrations on the ash of approximately 100 ppm. Hinton[3], however, states "Typical ammonia-on-ash concentrations range from less than 30 ppmw to several hundred ppmw for systems experiencing ammonia slip concentrations of 2 to 5 ppmv. **Thus, some units operating with very low amounts of ammonia slip (< 1 ppmv) may experience ammonia on-ash concentrations of over 100 ppmw, while other units with relatively high ammonia slip may have ashes with very low levels of adsorbed ammonia (<50 ppmw)."** [emphasis added] For example, ammonia concentrations in fly ash at Tampa Electric's Big Bend Station vary from 750-3360 ppm, with an average concentration of approximately 2000 ppm, due to ammonia slip from an SCR system.[6] Brendel[7] et. al. reported ammonia concentrations in fly ash from seven different plants that ranged from 60-2020 ppm due to ammonia slip from SCR/SNCR systems. GRE has reported that the East Lake Station in Ohio must treat or blend 85% of their ash to make it marketable because of ammonia contamination. Fifteen percent of the ash has highly variable ammonia concentrations due to SNCR upset or plant load swings. This 15% of the ash is unmarketable because of the high ash ammonia content.

Golder Associates has indicated that ammonia levels of greater than 5 ppm (based on Headwaters'[a] experience this level is 35 ppm) can result in release of ammonia gases which impact either the sale or storage and disposal of fly ash. How much ammonia will be adsorbed on fly ash from a unit fired with North Dakota lignite is unknown. Golder Associates states "Definitive information is not available for the levels of ammonia that could be present in the fly ash at CCS due to SNCR ammonia slip."

Based upon the above, the Department believes that EPA's assertion that no ash sales will be lost is speculative. The number of factors that can affect the amount of ammonia adsorbed on the fly ash suggests that generalized statements about loss of fly ash sales are not scientifically sound. Any one facility can be different from any other facility in this regard. As the data presented above indicates, many sources have experienced high ammonia concentrations in their fly ash due to ammonia slip.

It cannot be determined, with any reasonable amount of certainty, the amount of ash sales lost due to ammonia adsorption on the ash from the operation of SNCR. However, it is reasonable to expect that changes in load, startup, shutdown and SNCR malfunctions will produce unmarketable ash. During these periods, the ammonia feed rate may have to be maintained to assure compliance with the BART emission limits which apply at all times. This could lead to higher ammonia slip. Whether an ammonia slip monitoring system can allow for an adjustment of the urea feed rate for these periods without loss of marketable ash is unknown.

III. BART Determination

A. Step 1 – Identify All Available Retrofit Control Technologies

For purposes of this reevaluation of BART, only SNCR, SNCR + LCN3+, and LCN3+ are considered viable options. Both the Department and EPA have previously determined that SCR (HDSCR, LDSCR and TESCR) and low temperature oxidation (LTO) are not required as BART. (Appendix B.2 of N.D. SIP and 76 FR 58622-58623).

B. Step 2 – Eliminate Technically Infeasible Options

All options are technically feasible.

[a]Headwaters is the marketer of the ash at the Coal Creek Station.

C. Step 3 – Evaluate Control Effectiveness

Alternative	Control Efficiency (%)	Controlled Emissions (tons/yr)		Controlled Emissions ($lb/10^6$ Btu)
		Unit 1	Unit 2	
SNCR + LNC3+	39.3	3,083	3,087	0.122
SNCR	24.9	3,816	3,821	0.151
LNC3+	23.9	3,867	3,871	0.153
Baseline	-	5,080	5,086	0.201

D. Step 4 – Evaluate Impacts and Document the Results

For purposes of the economic analysis, the average emissions reduction for the two units is used.

Unit 1				
Alternative	**Emissions Reductions (tons/yr)**	**Annualized Cost ($)**	**Cost Effectiveness ($/ton)**	**Incremental Cost ($/ton)**
SNCR + LNC3+				
100% Lost Ash Sales	1,998	8,879,000	4,444	10,350*
30% Lost Ash Sales	1,998	6,604,000	3,305	7,449*
0% Lost Ash Sales	1,998	4,385,000	2,195	4,619*
SNCR				
100% Lost Ash Sales	1,265	9,101,000	7,194	163,471
30% Lost Ash Sales	1,265	6,826,000	5,396	118,863
0% Lost Ash Sales	1,265	4,608,000	3,643	75,373
LNC3+	1,214	764,000	629	

* Incremental cost between SNCR + LNC3+ and LNC3+.
Note: Unit 2 costs for SNCR + LNC3+ would be the same as Unit 1.

The Department is unable to determine the amount of ash that will be unmarketable because of ammonia contamination due to operation of an SNCR system. The Department believes that at least some ash sales will be lost due to startups, shutdowns, malfunctions and load changes. Recycling as much ash as possible is a goal of the Department. The use of SNCR may severely limit the achievement of that goal. The disposal of fly ash in a landfill will increase costs to prevent non-air quality environmental impacts and eliminate useful land. In addition, greenhouse gas emissions will increase due to production of Portland cement to replace the fly ash that is not recycled. The operation of SNCR will also lead to the emission of ammonia to the atmosphere due to ammonia slip.

There are no other non-air quality environmental concerns that would preclude the use of any of the technologies evaluated.

E. Step 5 – Evaluate Visibility Impacts

GRE has conducted dispersion modeling to assess the potential improvement from the use of SNCR + LNC3+ and just LNC3+. The modeling was conducted in accordance with the Department's Protocol for BART-Related Visibility Impairment Modeling Analysis in North Dakota (November 2006). The Department has verified the results (see Appendix D to North Dakota's SIP). The results of that analysis are as follows:

Coal Creek Station Unit 1 or 2 (Individually) Delta Deciview 98th Percentile				
Year	**Unit**	**LNC3+**	**SNCR + LNC3+**	**Difference**
2000	TRNP-SU	0.472	0.431	0.041
2001	TRNP-SU	0.477	0.438	0.039
2002	TRNP-SU	1.040	0.936	0.104
Average	TRNP-SU	0.663	0.602	0.061
2000	TRNP-NU	0.354	0.315	0.039
2001	TRNP-NU	0.452	0.419	0.033
2002	TRNP-NU	0.910	0.804	0.106
Average	TRNP-NU	0.572	0.513	0.059
2000	TRNP-Elkhorn	0.311	0.280	0.031
2001	TRNP-Elkhorn	0.449	0.395	0.054
2002	TRNP-Elkhorn	0.795	0.711	0.084
Average	TRNP-Elkhorn	0.518	0.462	0.056
2000	Lostwood W.A.	0.428	0.415	0.013
2001	Lostwood W.A.	0.943	0.892	0.051
2002	Lostwood W.A.	0.763	0.683	0.080
Average	Lostwood W.A.	0.711	0.663	0.048
Overall Average		0.616	0.560	0.056

Coal Creek Station Unit 1 or 2 (Individually) Delta Deciview 90th Percentile				
Year	**Unit**	**LNC3+**	**SNCR + LNC3+**	**Difference**
2000	TRNP-SU	0.117	0.110	0.007
2001	TRNP-SU	0.096	0.090	0.006
2002	TRNP-SU	0.202	0.189	0.013
Average	TRNP-SU	0.138	0.130	0.008
2000	TRNP-NU	0.115	0.111	0.004
2001	TRNP-NU	0.126	0.125	0.001
2002	TRNP-NU	0.144	0.138	0.006
Average	TRNP-NU	0.128	0.125	0.003
2000	TRNP-Elkhorn	0.084	0.076	0.008
2001	TRNP-Elkhorn	0.075	0.071	0.004
2002	TRNP-Elkhorn	0.132	0.117	0.015
Average	TRNP-Elkhorn	0.097	0.088	0.009
2000	Lostwood W.A.	0.207	0.187	0.020
2001	Lostwood W.A.	0.211	0.193	0.018
2002	Lostwood W.A.	0.139	0.134	0.005
Average	Lostwood W.A.	0.186	0.171	0.015
Overall Average		0.129	0.137	0.009

The installation of SNCR will also have little effect on the number of days with a delta-deciview value above 0.5. In any year modeled (2000-2002), the number of days will decrease no more than 2 days per year at any Class I area for a single unit at Coal Creek Station and no more than 4 days per year when the two units at the station are combined.

The Department received a public comment that suggested that the LCALGRD setting in CALMET should be “True” instead of the “False” setting the Department has been using. The Department conducted modeling to evaluate the difference in the results using these two settings. The results indicate the “True” setting produces less improvement in visibility for the various control options (see Appendix D). The results shown above indicate the larger visibility improvement associated with the two LCALGRD options (LCALGRD = F).

F. Step 6 – Select BART

In making previous BART determinations, the Department gave very little weight to the single source BART-type modeling results for visibility improvement. The Department believes this type of modeling overpredicts the amount of visibility improvement by a factor of 5 to 7. Specifically, the Department’s technical evaluations led it to believe that the BART type modeling overpredicts because it uses a clean background for the improvement calculation and does not account for other sources that impact visibility impairment (see North Dakota’s SIP Section 7.4.2 and State of North Dakota, Comments on United States Environmental

Protection Agency Region 8, Approval and Promulgation of Implementation Plans; North Dakota Regional Haze State Implementation Plan; Federal Implementation Plan for Integrated Transport of Pollution Affecting Visibility and Regional Haze). In the case of NO_x for M.R. Young 1 and 2 and Leland Olds 2, the Department conducted cumulative type modeling and considered those results in the BART determination. Visibility results were considered in those determinations because 1) the cost effectiveness and/or incremental cost was near or slightly above the Department's cost threshold, 2) there was a wide cost effectiveness and incremental cost range, 3) the Department was aware that EPA had a different opinion on the appropriate BART (p.37 – 38, State of North Dakota, Comments on United States Environmental Protection Agency Region 8, Approval and Promulgation of Implementation Plans; North Dakota Regional Haze State Implementation Plan; Federal Implementation Plan for Integrated Transport of Pollution Affecting Visibility and Regional Haze). The Department has determined that all three of these criteria apply to the Coal Creek NO_x BART determination.

The visibility results indicate a maximum improvement in visibility of 0.106 deciviews (98th percentile) at any one Class 1 area by the use of SNCR + LNC3+ versus LNC3+. The average improvement will only be 0.056 deciviews (98th percentile). These results show there will be very little improvement in visibility. Based on the 5-7 overprediction factor previously cited, the Department believes the true visibility improvement will be 0.01 – 0.02 deciviews for the added expense associated with SNCR. Both the BART type modeling results and the estimated cumulative type modeling results indicate the amount of improvement is insignificant. This factor is not affected by the loss of ash sales. The amount of improvement in visibility, even based on the BART Guideline type modeling results, does not warrant the installation of SNCR.

When the Department began the development of the Regional Haze program in 2006, a cost threshold was established for BART controls. Any cost effectiveness above $3,650/ton or incremental cost above $6,500/ton (2006 dollars) was considered excessive (see Appendix E). If these values are adjusted to 2011 dollars based on the Consumer Price Index, any cost effectiveness above $4,100/ton or incremental cost above $7,300/ton would be considered excessive.

The Department believes that SNCR, when used alone, is clearly an inferior option to LNC3+ based on the least cost envelope analysis and the incremental cost between the two options. The incremental cost between these two options is excessive no matter whether ash sales are lost or not. The two remaining options are LNC3+ and SNCR plus LNC3+. If no ash sales are lost, the cost effectiveness and incremental cost of SNCR plus LNC3+ would be considered reasonable. However, while the Department expects some ash sales will be lost, the exact amount cannot be determined. If 30% of the ash sales are lost, the incremental cost between SNCR plus LNC3+ and LNC3+ would be considered excessive.

When EPA proposed in the FIP to disapprove the Department's BART determination for CCS, EPA's analysis of SCR at the facility indicated a cost effectiveness of $4,166/ton, an incremental cost of $6,653/ton and a visibility improvement of 0.253 deciviews (98th percentile-total for two units). EPA stated "Given the anticipated visibility improvement, and the incremental cost effectiveness of $6,653, we are not prepared to impose this option as BART." The most visibility will improve by using SNCR plus LNC3+ on both units versus LNC3+ is 0.205 deciviews (total for 2 units); which is less than the amount EPA cited as a reason for rejecting SCR as BART. The Department believes that some ash sales will be lost due to startup, shutdown, malfunctions and load swings. Normal operations of SNCR can also produce high concentrations in the fly ash as noted previously. If 30% of ash sales are lost due to ammonia contamination from SNCR, the cost effectiveness will be $3,305/ton with an incremental cost of $7,449 per ton. Again, the incremental cost of SNCR plus LNC3+ versus LNC3+ is higher than SCR + SOFA + LNB versus SNCR + SOFA + LNB which EPA cited as a reason for rejecting SCR as BART.

Recycling the ash and keeping this material out of a landfill is important to the Department. The use of LNC3+ will assure that as much fly ash as possible will be recycled. The use of SNCR may prevent the recycling of any fly ash. The Department must consider the possibility of the loss of ash recycling. The loss of ash recycling is a non-air quality environmental impact that can be considered in making the BART determination (see 40 CFR 51, Appendix Y, IV.D.4 Step 4i.). Pollution by coal ash is a significant concern of the Department and EPA. On June 21, 2010, EPA proposed a specific rule for the disposal of combustion residuals (including fly ash) from electric utilities (75 FR 35128 – 35264).

Over $31 million has been invested at Coal Creek Station for the management and sale of fly ash. Although EPA has indicated that this "sunk" cost cannot be taken into account in the economic analysis, the Department believes it represents an irretrievable commitment of resources for fly ash recycling that presents other environmental impacts such as the loss of useful land. The BART Guidelines states "you may consider the extent to which the alternative emission control systems may involve a trade-off between short-term environmental gains at the expense of long-term environmental losses and the extent to which the alternative systems may result in irreversible or irretrievable commitment of resources (for example, use of scarce water resources)." If 100% of fly ash sales are lost, 31 million dollars of ash recycling equipment would be rendered useless without much chance of retrieving the resources that may prevent non-air quality environmental impacts.

In summary, the Department's NO_x BART Determination for the Coal Creek Station relies upon the following:

1) The amount of visibility improvement for SNCR + LNC3+ versus LNC3+ is very small and considered negligible. The amount of visibility improvement does not warrant the use of SNCR.

2) There is evidence that suggests to the Department that at least some ash sales will be lost and that it is reasonably possible that all ash sales will be lost. The incremental cost of SNCR + LNC3+ versus LNC3+ is excessive if 30% of fly ash sales are lost.

3) The annualized cost of SNCR + LNC3+ is excessive if 100% of ash sales are lost. The incremental cost is also excessive.

4) The loss of ash sales means landfilling of the ash which can cause other non-air quality environmental effects such as the loss of useful land.

5) The loss of ash sales will render 31 million dollars of equipment useless with likely no opportunity to retrieve the resources invested.

Because the amount of fly ash sales that will be lost cannot be exactly determined, the cost effectiveness of SNCR cannot be precisely determined. Therefore, the Department has chosen to weight the visibility impact heavily in this determination. The impact on visibility is not affected by the amount of ash sales. Therefore, the Department gave greater consideration to the fact that the use of the more expensive SNCR at CCS provides only a small amount of improvement in visibility results. Accordingly, the use of SNCR at CCS is not warranted based on the small amount of improvement in visibility that could result from its use. Additionally, the Department believes that some ash sales will be lost with the installation of SNCR, which further supports the Department's determination that SNCR at CCS is not warranted. And as detailed in this Supplemental Evaluation, there is also the potential for adverse environmental effects if ash sales are lost and that ash must be landfilled.

Based upon the analysis set forth in this Supplemental Evaluation, the Department accordingly reaffirms its decision that NO_x BART for the GRE CCS is represented by combustion controls with a BART limit of 0.17 lb/10^6 Btu on a 30-day rolling average basis.

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Appendix A
GRE BART Analysis

Appendix B
IPM Documentation and Results

Appendix C
Memo to Regional Haze File
Reagent Usage

Appendix D
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Appendix E
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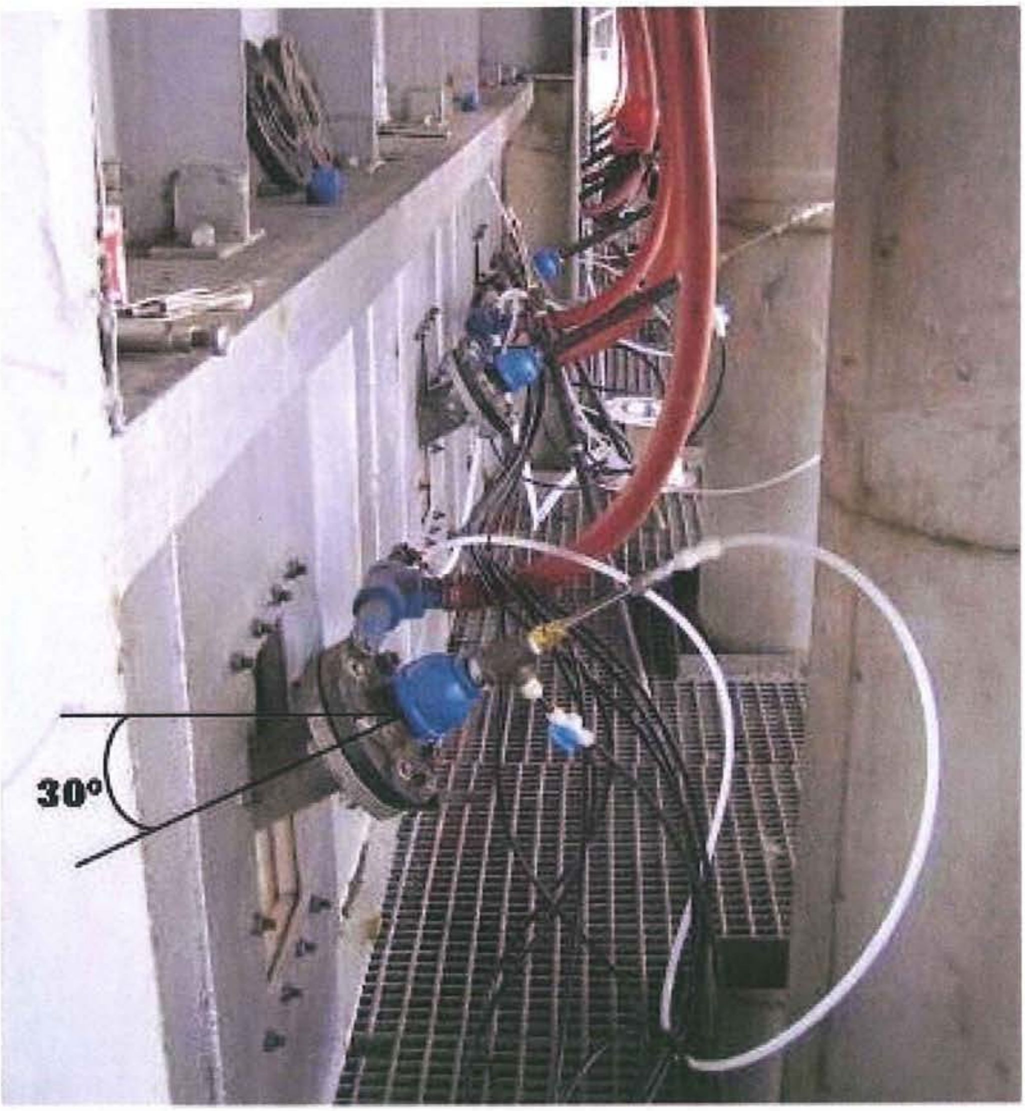
Appendix F
Correspondence Regarding
BART Determination

Confidential Business Information

ELECTRIC POWER RESEARCH INSTITUTE

Low-Baseline NOx Selective Non-Catalytic Reduction Demonstration

Joppa Unit 3



Low-Baseline NOx Selective Non-Catalytic Reduction Demonstration

Joppa Unit 3

1018665

Final Report, March 2009

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PRODUCT DESCRIPTION

Increased NO_x reduction mandates are affecting some coal-fired units with NO_x emissions less than 0.12 lb/MBtu. EPRI has previously shown that a post-combustion technique—selective non-catalytic reduction (SNCR) technology—can be economically applied to a broad range of coal-fired boilers with baseline NO_x emissions in excess of 0.15 lb/MBtu. SNCR also can provide incremental NO_x reductions that can defer or eliminate the need for some selective catalytic reduction (SCR) retrofits. The current project addresses the applicability of SNCR to low-baseline NO_x emission units less than 0.12 lb/MBtu where there is currently no full-scale experience. A short-term SNCR demonstration project was conducted in Joppa, Illinois, at Electric Energy's Joppa Unit 3 with baseline NO_x emissions of nominally 70 ppm.

Results and Findings

SNCR performance appears to be significantly degraded at baseline NO_x emission levels less than 100 ppm. Increased ammonia slip levels experienced during the last day of testing indicates reagent was present at the optimum SNCR temperature window. Overall performance is likely constrained due to imperfect mixing achieved within the boiler using low-energy reagent injectors. Increased NO_x reductions with increasing urea flow rate supports the overall SNCR results at Joppa 3 being mixing-constrained at low baseline NO_x levels.

Challenges and Objective(s)

The primary objective of this short-term demonstration project was to assess the maximum NO_x reduction capabilities of a single-level, urea-based SNCR system at Joppa Unit 3 using existing ports above the nose of the boiler with baseline NO_x emission levels on the order of 0.10 lb/MBtu.

Applications, Values, and Use

Agencies at federal, state, and local levels are mandating increased reductions in NO_x emissions from fossil-fueled power plants. Available NO_x control technologies include combustion modifications and post-combustion techniques. Combustion modifications such as overfire air (OFA) and low-NO_x burners are limited in the level of NO_x reductions they can achieve by increases in either carbon monoxide or fly ash unburned carbon levels. As regulations become stricter, post-combustion processes such as SNCR and SCR must be considered.

EPRI Perspective

While the SNCR results using an identified optimum reagent injection configuration with mechanical atomizers showed unacceptable ammonia slip values, air atomized injectors may provide finer droplet size distribution "tuning capability". Based on documented differences of SNCR performance as a function of NO_x emission level, however, overall SNCR performance capabilities at baseline NO_x emission levels of 70 ppm will likely be constrained within a NO_x reduction range of 8 – 12%.

Approach

While the current project required modest NO_x reductions from SNCR, the project team did not know what actual level of SNCR performance to anticipate due to the lack of any SNCR operating experience at low-baseline NO_x levels. To determine actual SNCR NO_x reduction capability, the team conducted a comprehensive program at Joppa Unit 3 to evaluate SNCR performance at baseline NO_x levels of nominally 0.10 lb/MBtu (70 ppm) using a single-level, urea-based SNCR system. The project included O_2, CO, NO_x and ammonia slip measurements at the air heater inlet and temperature measurements at the furnace exit. The team performed testing at loads ranging from 150 to 180 MWg over a 6-day period. Several parameters were varied, including urea injection rate, atomizer type, baseline NO_x levels, and baseline CO levels.

To assess the cost-effectiveness of a SNCR system applied to a low-baseline NO_x unit, the team generated a capital cost estimate using an approach described in *SNCR Guidelines Update* (EPRI report 1004727, December 2004).

Keywords

NO_x control
Selective non-catalytic reduction
SNCR

ABSTRACT

Increasing NO_x reduction mandates are affecting a broad range of coal-fired boilers, including those of small capacity or limited remaining life where selective catalytic reduction (SCR) solutions are typically uneconomical. EPRI has shown that selective non-catalytic reduction (SNCR) Trim technology can be economically applied to a broad range of coal-fired boilers with baseline NO_x emissions in excess of 0.15 lb/MBtu and provide incremental NO_x reductions that can defer or eliminate the need for some SCR retrofits. Increased NO_x reduction mandates are recently affecting some coal-fired units with NO_x emissions less than 0.12 lb/MBtu. Additional NO_x controls beyond combustion modifications are still required. The current project addresses the applicability of SNCR to these low-baseline NO_x emission units where there is currently no full-scale experience. To this end, a short-term SNCR demonstration project was conducted at Joppa Unit 3 with baseline NO_x emissions of nominally 75 ppm. The project investigated the influence of baseline NO_x emissions, CO levels, as well as reagent injector parameters.

ACKNOWLEDGEMENTS

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1 INTRODUCTION

Background

Agencies at federal, state and local levels are requiring further reductions in NO_x emissions from fossil-fueled power plants. Available NO_x control technologies include combustion modifications and post-combustion techniques. Combustion modifications such as overfire air (OFA) and low-NO_x burners are limited in the ultimate level of NO_x reductions that they can achieve. As regulations become stricter, post-combustion processes such as Selective Non-Catalytic Reduction (SNCR), and Selective Catalytic Reduction (SCR) must be considered.

SNCR Process Description

SNCR is a post-combustion technique developed to reduce NO_x emissions from fossil-fuel combustion systems. This process typically involves injection of a urea solution where the flue gas temperature is between 1,800°F – 2,200°F (982°C – 1,204°C). The urea solution evaporates and decomposes to react selectively with NO_x in the presence of oxygen, forming primarily nitrogen and water. An overview of the reactions for urea is shown in Figure 1-1. For this project, a 40% by weight urea solution was selected to avoid heat tracing of transport lines since the precipitation temperature for this weight percent urea solution is 33°F (0.6°C). Numerous factors can alter the effectiveness of the SNCR process, which include temperature, residence time, CO levels, as well as the baseline NO_x concentration.

As seen in Figure 1-2, temperature variations and residence time can significantly impact the efficiency of the SNCR process. For urea, the optimal injection temperature is around 1,850°F (1,010°C) under well-mixed laboratory conditions. Optimal reaction efficiencies are also obtained with nominal residence times of 250 milliseconds at the optimal temperature. The relatively narrow temperature window that is associated with the SNCR processes is due to the competition between key oxidation steps and NO reduction steps and their dependence on gas temperature. The key reactions leading to NO reduction are:

$$NH_2 + NO \rightarrow NNH + OH \quad (1)$$

$$NH_2 + NO \rightarrow N_2 + H_2O \quad (2)$$

$$NCO + NO \rightarrow N_2O + CO \quad (3)$$

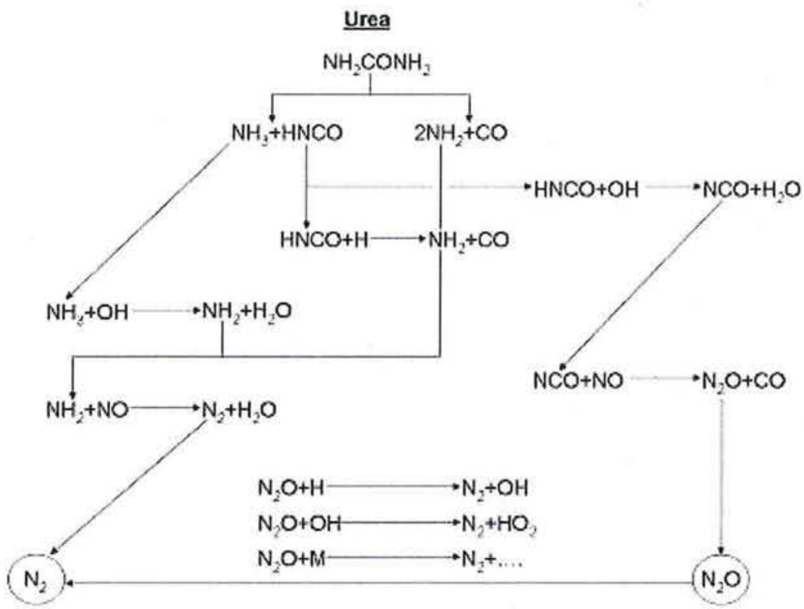


Figure 1-1
SNCR Process Reactions

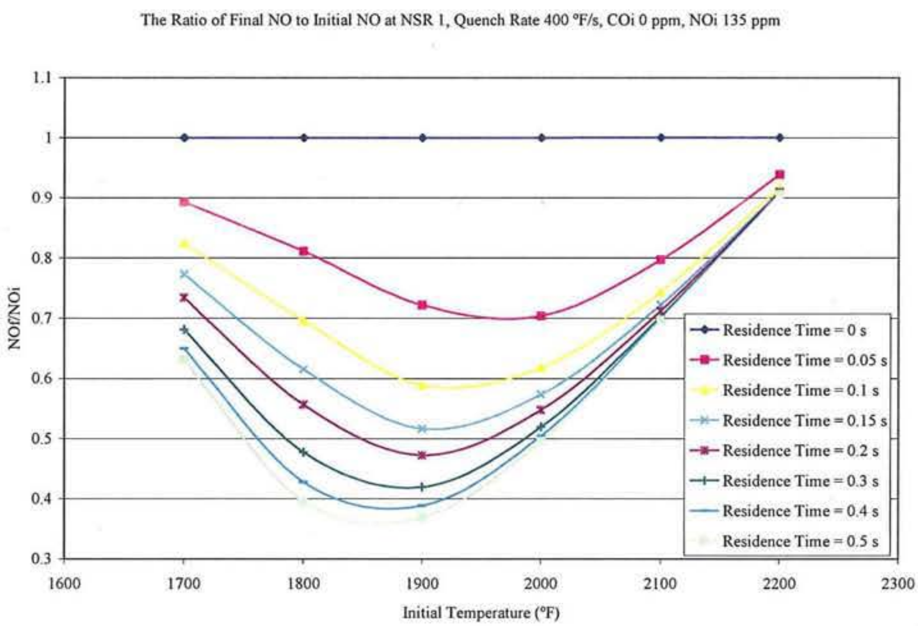


Figure 1-2
CFD Model Predictions Showing Impact of Gas Temperature and Residence Time on NO_x Reduction under Baseline Conditions (NSR=1, Quench Rate = 400°F/s [204°C/s], Initial NO = 135 ppmv, SR = 1.15) (EPRI 1004729, 2003)

In order to sustain reactions 1 – 3, there needs to be a continuous supply of O and OH radicals. These species are produced through the following key routes:

$$H + O_2 \rightarrow OH + O \quad (4)$$

$$O + H_2O \rightarrow OH + OH \quad (5)$$

At the low temperature end of the effective temperature range, the NO reduction is limited by the rates of chain termination reactions (2 and 3) that compete with chain branching reactions (4 and 5). As temperatures increase, the rate of formation of the chain carriers (i.e., O, OH) is large enough to sustain the chain termination steps. As temperatures increase above the optimal temperature range, then oxidation reactions begin to dominate and start to contribute to net NO formation. Important steps in this process include:

$$NH_2 + O \rightarrow HNO + H \quad (6)$$

$$HNO + M \rightarrow H + NO + M \quad (7)$$

$$NH_2 + OH \rightarrow NH + H_2O \quad (8)$$

$$NH + O_2 \rightarrow NO + OH \quad (9)$$

$$NCO + O \rightarrow NO + CO \quad (10)$$

The presence of CO can also alter the effectiveness of the process. As seen in Figure 1-3, greater amounts of CO will typically decrease the NO reduction levels. However, as a beneficial aspect, higher CO levels will also tend to broaden the SNCR process temperature window. CO contributes to the formation of chain carriers (OH) which are necessary to sustain the SNCR chemistry. At lower gas temperatures, the increased rate of chain branching caused by the CO addition is favorable to the SNCR process. However, at higher temperatures it is detrimental since the pathways for oxidation of the reagent begin to compete unfavorably with the NO reduction pathways. Key reactions are:

$$CO + OH \rightarrow CO_2 + H \quad (11)$$

$$H + O_2 \rightarrow OH + O \quad (4)$$

$$O + H_2O \rightarrow OH + OH \quad (5)$$

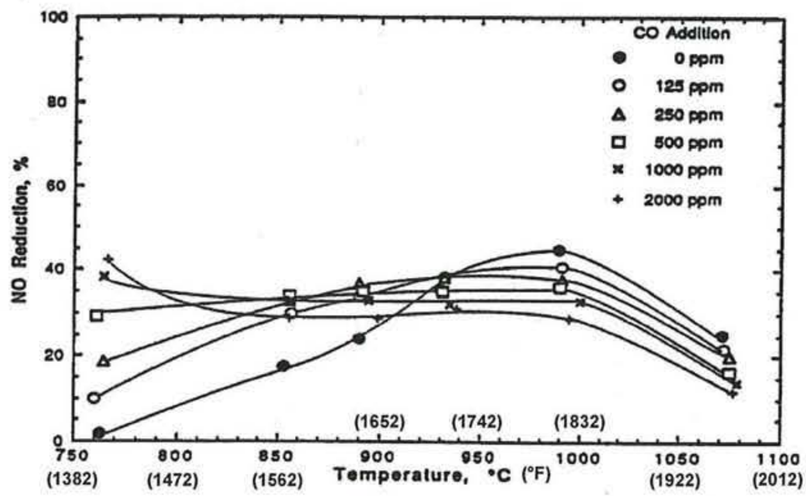


Figure 1-3
Effect of CO Levels on SNCR Performance with Urea Injection; Initial NO = 125 ppm, NSR = 2.0 (AFRC/JFRC International Conference on Environmental Control of Combustion Process, October 1991)

Concentrations of different gaseous components can also impact the process. Figure 1-4 shows the predicted effect initial NO levels have on the SNCR process, along with temperature based on CFD modeling. The more NO present in the flue gas, the greater the potential for NO reduction.

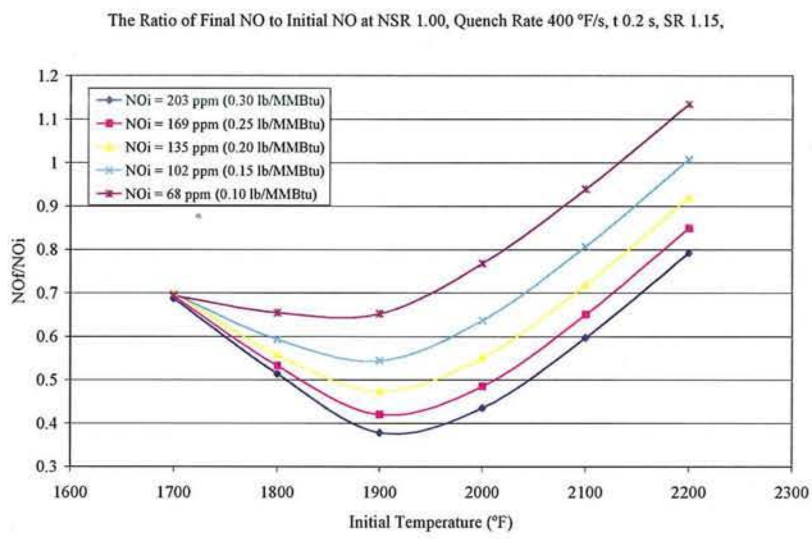


Figure 1-4
Impact of Initial NO Concentration on NO Reduction under Baseline Conditions (NSR=1, Quench Rate = 400°F/s [204°C/sec], SR = 1.15) (EPRI 1004729, 2003)

Project Objectives

The primary objective of the short-term demonstration project was to assess the maximum NO_x reduction capabilities of a single-level, urea-based SNCR system at Joppa Unit 3 using existing ports at Elevation 470 feet. The following key parameters were investigated during the optimization process:

- Urea injection rate (NSR – Normalized Stoichiometric Ratio)
- Urea dilution and drop size
- Load/temperature effects
- NO_x concentration impacts
- Carbon monoxide impacts

At optimized conditions, other objectives included evaluating ammonia slip as a function of NSR and NO_x reduction, and measuring ammonia retention on fly ash.

Project Approach

High velocity thermocouple (HVT) measurements were taken in early September 2008 under a separate contract with Innovative Combustion Technologies (ICT). HVT measurements were performed at Elevation 470 feet and 457 feet to document the temperature distribution at the point of urea injection. During this effort furnace exit gas temperatures as well as gaseous species concentrations were characterized.

In November 2008, a temporary urea storage, handling and injection system was set up for the demonstration. Urea was injected using existing ports at Elevation 470 feet, and gaseous species concentrations (O_2, CO, NO_x and NH_3) were monitored at the air heater inlet. NO_x reduction performance was optimized and documented as a function of NSR and ammonia slip at full load. Furnace exit temperatures were continuously monitored at Elevation 457 feet using optical instruments.

A detailed description of the measurement methods can be found in Appendix A.

2
UNIT DESCRIPTION

Joppa Unit 3 is a Combustion Engineering, tangential-fired furnace rated at 181 MWg. The unit currently burns Powder River Basin (PRB) coal, and utilizes close-coupled overfire air (CCOFA) and separated overfire air (SOFA) for NO_x reduction. The furnace cross section is 40 feet (12.2 meters) wide by 28 feet (8.5 meters) deep at the burner elevations. Figure 2-1 shows an elevation view of the unit identifying the urea injection and test measurement locations.

The furnace exit sootblowers were in automatic operation during the test program. The neural net boiler optimization system was turned off.

Joppa Units 3 and 4 have a common stack, so independent CEMS data for Unit 3 were not available. Plant NO_x and CO monitors are located at the Unit 3 ID fan outlet. The plant NO_x reading was useful for monitoring changes in the raw NO_x value during the SNCR tests. However, the raw NO_x values could not be directly compared to FERCo measurements since there was no means for dilution correction. At full load and normal OFA conditions, baseline NO_x values measured at the air heater inlet were as low as 70 ppmc (0.10 lb/MBtu).

High velocity thermocouple (HVT) measurements were conducted separately just prior to the current SNCR demonstration tests. Furnace exit gas temperature measurements at full load averaged 2,080°F (1,138°C). CO levels at the furnace exit averaged 10,900 ppm, and ranged between 240 to 32,000 ppm.

SNCR Demonstration Configuration

The layout of the temporary SNCR system used at Joppa Unit 3 is shown in Figure 2-2. Photos of individual components of the SNCR system are shown in Figures 2-3 through 2-7. A metering pump was used to move urea solution (40% by weight) from a 5,000 gallon (18,900 liter) tank trailer at ground level (Elevation 350 feet) up to Elevation 457 feet. After dilution water was added, the solution was pumped through a distribution header and up to the injection ports at Elevation 470 feet (oriented at a 30° downward angle). Valves and rotameters were used to adjust the amount of solution flow to each of the eight injection lances. The tip of each lance was placed flush with the furnace wall. Although each injection lance was cooled by the solution, plant air was utilized to provide further cooling and to prevent fly ash from depositing on the lances.

The system flow ranges are listed below:

- 40% by weight Urea: 0 - 2 gpm (0 - 7.6 lpm)

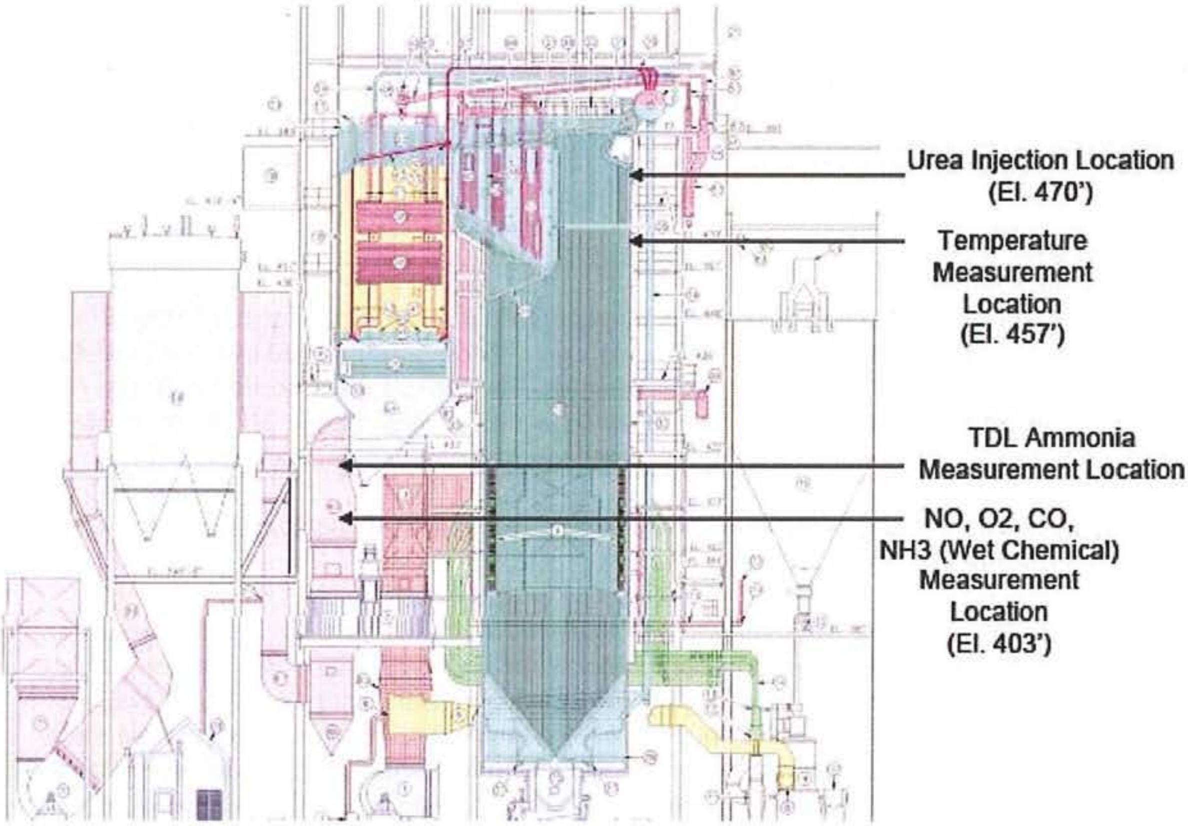


Figure 2-1
Joppa Unit 3 Elevation View

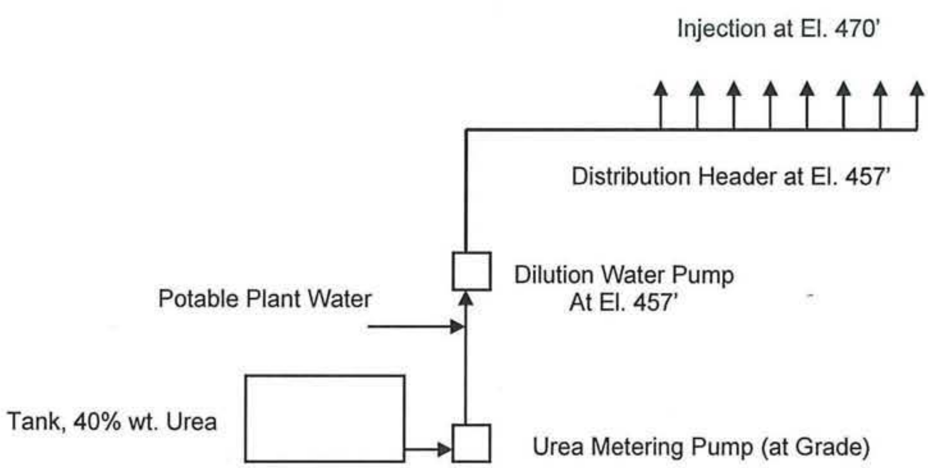


Figure 2-2
SNCR Flow System Schematic

Figure 2-3
Urea Metering Pump Attached to Urea Tanker

Figure 2-4
Dilution/Booster Pumps at Elevation 457 Feet

Figure 2-5
Distribution Header at Elevation 457 Feet

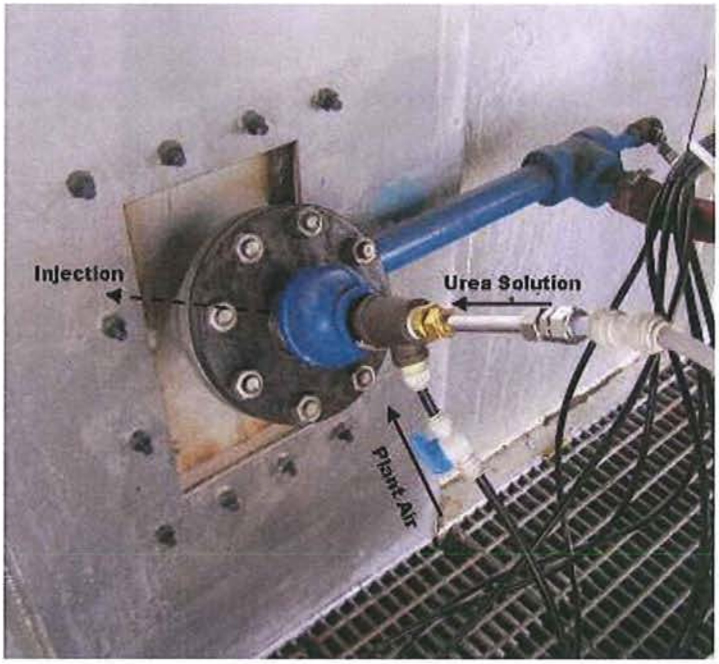


Figure 2-6
Injector Configuration on Elevation 470 Feet

Figure 2-7
Side View of Injection Configuration

- Dilution Water: 0 - 10 gpm (0 – 38.0 lpm)
- Flow per Injector: 0 - 1.5 gpm (0 – 5.7 lpm)

The system P&ID is provided in Appendix D.

Pressure Atomizer Description

The following flat-fan pressure atomizers were utilized during the field tests:

- Spraying Systems 15-055 Nozzle (0.55 gpm @ 40 psig, 15°Spray Angle)
  (2.0 lpm @ 2.7 bars)
- Spraying Systems 25-08 Nozzle (0.8 gpm @ 40 psig, 25°Spray Angle)
  (3.0 lpm @ 2.7 bars)
- McMaster Carr 0.5 gpm Nozzle (0.5 gpm @ 40 psig, 30°Spray Angle)
  (1.9 lpm @ 2.7 bars)
- McMaster Carr 1.5 gpm Nozzle (1.5 gpm @ 40 psig, 30°Spray Angle)
  (5.7 lpm @ 2.7 bars)
- McMaster Carr 3.0 gpm Nozzle (3.0 gpm @ 40 psig, 50°Spray Angle)
  (11.3 lpm @ 2.7 bars)

- Field-Modified Nozzle with 5/64 inch (0.2 cm) hole (Inconsistent Flow and Spray Angle)

Figure 2-8 shows the relationship between droplet size and pressure for a typical pressure atomizer of similar design. In general, larger droplets (i.e., lower pressures) are more effective for regions on the higher side of the SNCR temperature window due to their longer evaporation times.

In some cases, spray angle can help fine-tune SNCR performance. Smaller angles provide less side-to-side coverage and better penetration inside the furnace, and the opposite is true for larger injector spray angles.

For the purposes of the Joppa Unit 3 tests, the middle six injectors were aligned with a horizontal flat-fan spray relative to the injection port downward angle. The outside injectors near the side walls were aligned vertically to avoid tube wall impingement.

Gaseous Measurement Location

As shown in Figure 2-1, gaseous species concentrations (O_2, CO, NO_x and NH_3) were measured at the air heater inlet near Elevation 403 feet. Figure 2-9 shows a plan view arrangement of the ductwork and probe grid at this location. The air heater inlet consisted of two separate ducts. Each duct contained a four-wide by two-deep probe array, or 8 probes in each duct for a total of 16 probes. Composite and point-by-point measurements of O_2, CO, and NO_x were performed using the gas sampling grid.

As described in Figure 2-9, wet chemical ammonia slip measurements were made at the same elevation, but at different ports. Composite samples were obtained for each duct. The ammonia TDL instrument was mounted in a port on the south duct at a slightly higher elevation.

The methods for the gaseous species measurements are described in detail in Appendix A.

Temperature Measurement Locations

Measurements of the furnace exit gas temperatures during the test program were conducted at Elevation 457 feet through three observation ports. Two InfraView® optical instruments, one placed on the north wall and the other on the south, measured gaseous temperatures in the front corner along the front wall of the boiler. A SpectraTemp® optical instrument was placed in the middle of the front wall, measuring gas temperatures down the boiler centerline. The method of operation for these devices is described in Appendix A. Figure 2-10 shows the instrument locations, Figure 2-11 shows a photo of the observation port used for the North InfraView®, and Figure 2-12 shows a photo of the SpectraTemp®.

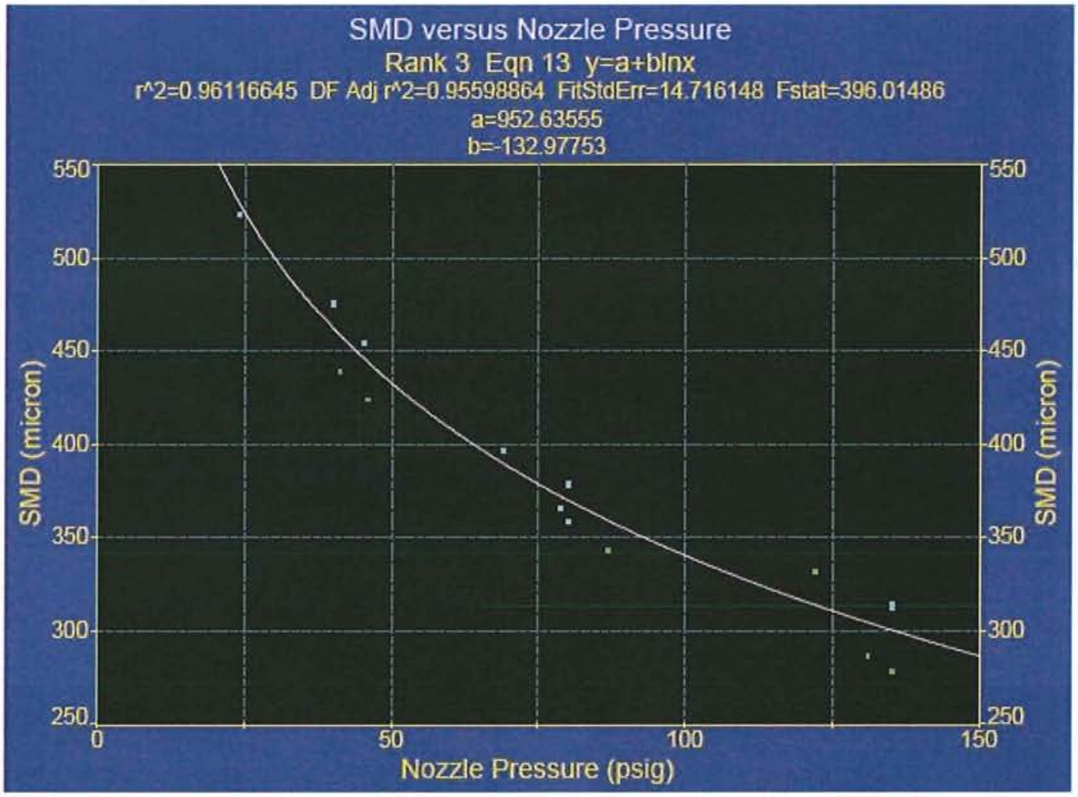


Figure 2-8
Droplet Size as a Function of Nozzle Pressure (Typical Pressure Atomizer)

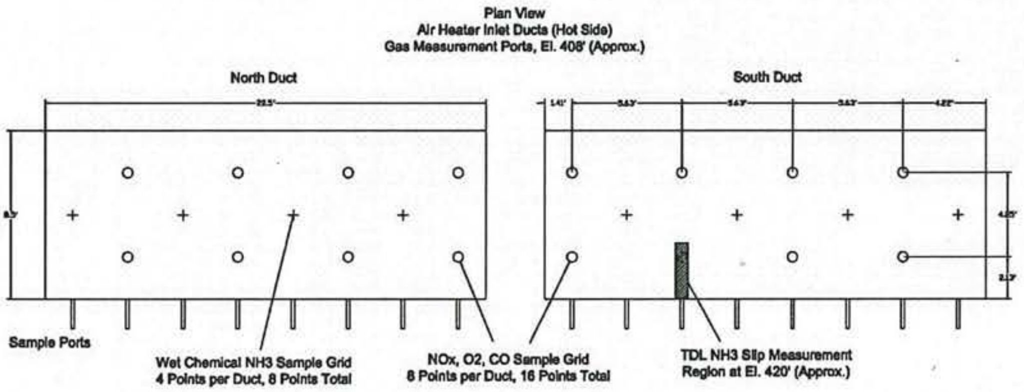


Figure 2-9
Air Heater Inlet Gaseous Probe Locations

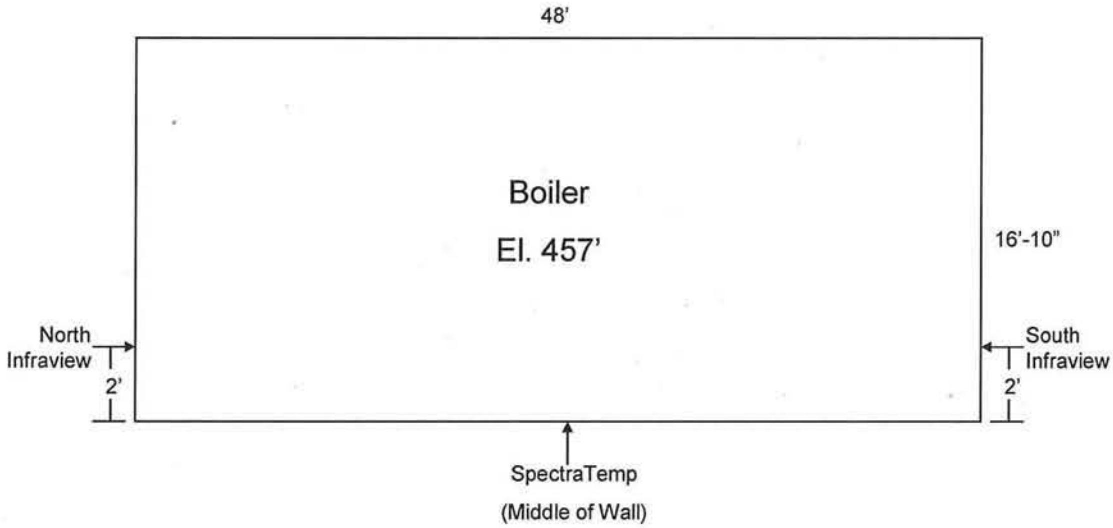


Figure 2-10
Temperature Measurement Locations

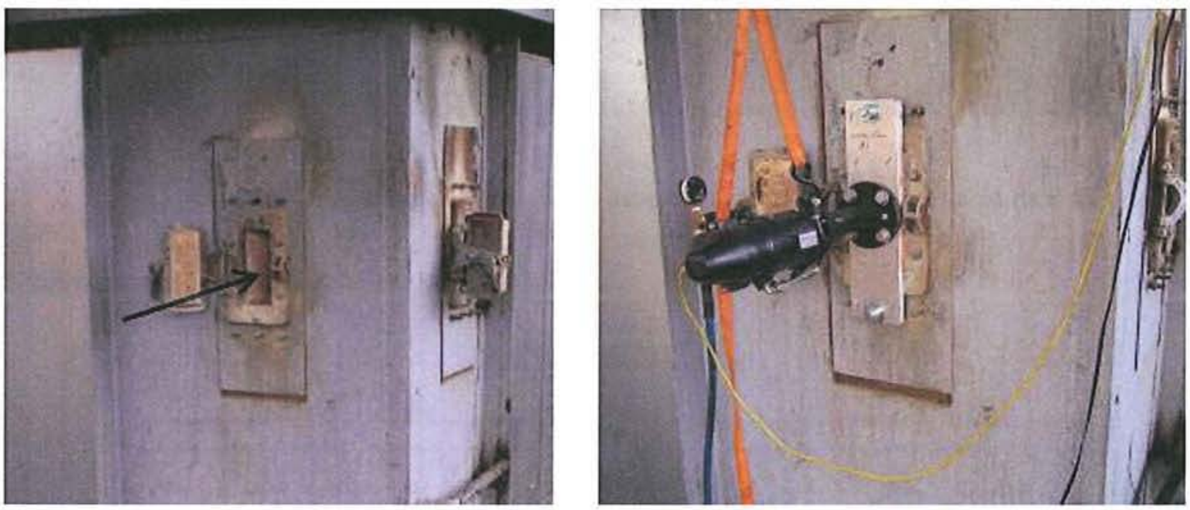


Figure 2-11
North Infraview® Observation Port

Figure 2-12
SpectraTemp® Observation Port

3
TEST RESULTS

Temperature Measurements

ICT performed furnace exit HVT measurements at Joppa Unit 3 on September 4, 2008. Table 3-1 provides a summary of the temperature data collected at Elevations 457 feet and 470 feet. Figure 3-1 shows contour plots of the temperature data. The average temperatures were on the high side of the urea temperature window. The temperature profile at Elevation 457 feet was at the nose of the boiler, showing a relatively uniform temperature distribution with the exception of the cold region in the southwest corner. At Elevation 470 feet, it is important to note that the temperature profile data was collected using the same ports for urea injection (angled downward at 30°). The cold region in the southwest corner was also evident in the 470 feet profile. Temperatures exceeded 2250°F (1,231°C) in the central region of the boiler.

Table 3-1
HVT Temperature Measurement Summary

Elevation	Minimum	Average	Maximum (°F)
457 feet	1,641°F (894°C)	2,095°F (1,146°C)	2,246°F (1,230°C)
470 feet	1,629 °F (887°C)	2,068°F (1,131°C)	2,293°F (1,256°C)

During the SNCR tests conducted in November 2008, continuous temperature measurements were made using InfraView® and SpectraTemp® optical instruments at Elevation 457 feet. Figure 3-2 shows a representation of the instrument locations, as well as their average readings compared to the HVT measurements made in September 2008. The values shown for the HVT measurements were averages of the data obtained at the same ports utilized by the optical instruments. The optical and HVT measurements show reasonable agreement, both indicating hotter temperatures in the middle of the furnace and lower temperatures in the southwest corner.

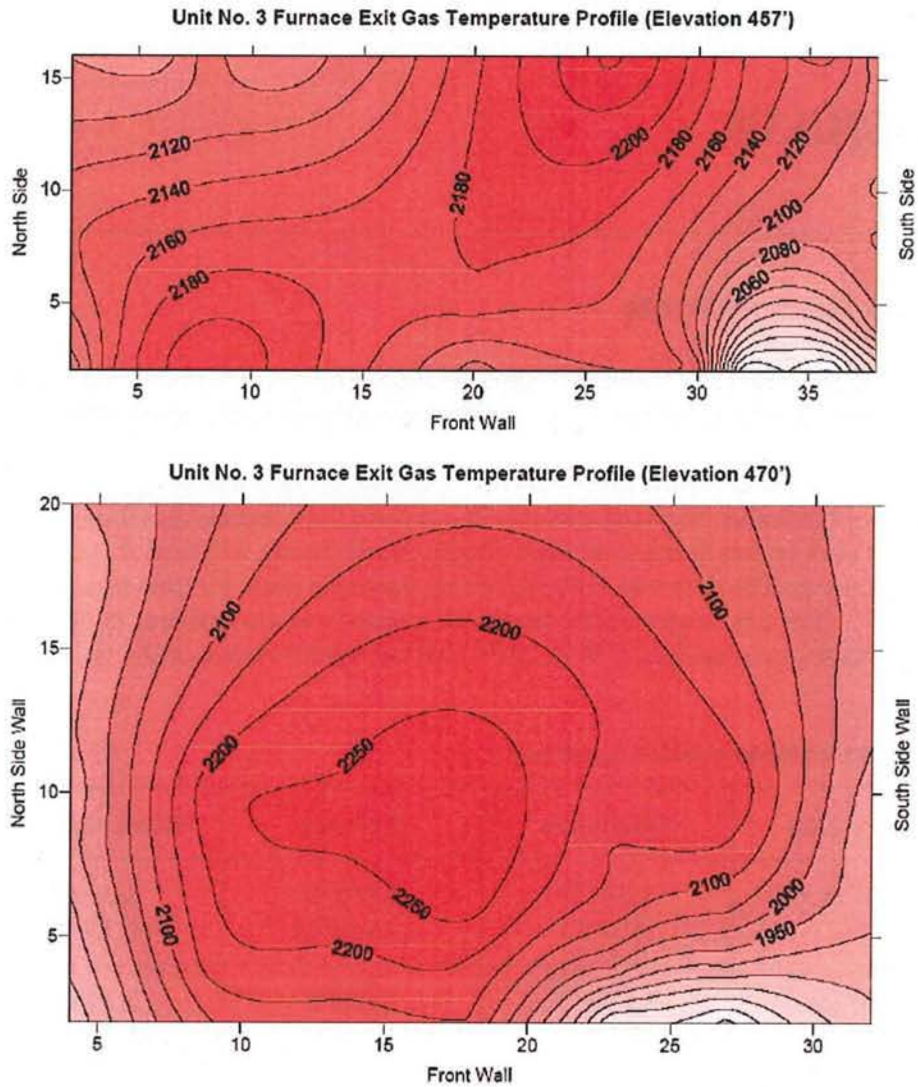
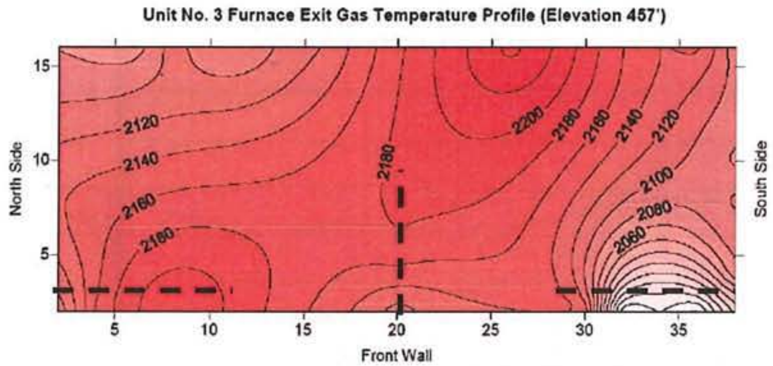


Figure 3-1
Full Load HVT Measurements (September 4, 2008)



North Infraview®

Line of Sight

Middle Spectratemp®

Line of Sight

South Infraview®

Line of Sight

Figure 3-2
Continuous Temperature Measurements Compared with HVT Temperature Measurements

Baseline NO_x Variations

Plant DCS data from November 14th and November 21st (the days just before and after the SNCR test program) were analyzed to evaluate typical baseline NO_x variations (i.e., "noise") during full-load with normal OFA operation. Figures 3-3 and 3-4 show the boiler NO_x (raw), O_2 and load for these two days. The NO_x standard deviation was nominally 1.8 ppm, or 2.8% of the average value. As a result, any NO_x variations during the SNCR test program within this range were considered to be within the normal range of variation.

SNCR Test Results

Urea injection tests were performed from November 15 through 20, 2008. A summary of NO_x reduction performance for each test day is provided in Figure 3-5. NO_x reduction was calculated in most cases by averaging the baseline NO_x values obtained before and after a urea injection test. During some tests the baseline value drifted or bumped significantly due to coal supply upsets. In these cases only the baseline value before the upset was used. Tabulated data with test descriptions, unit conditions, urea injection settings and gas concentrations are provided in Appendix B.

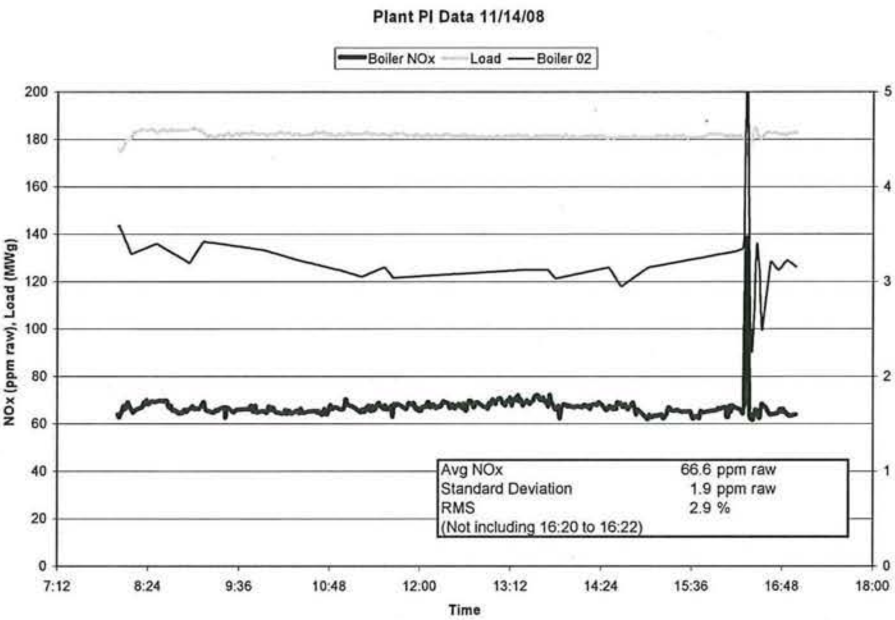


Figure 3-3
Plant Load, NO_x and O_2 Data from November 14, 2008

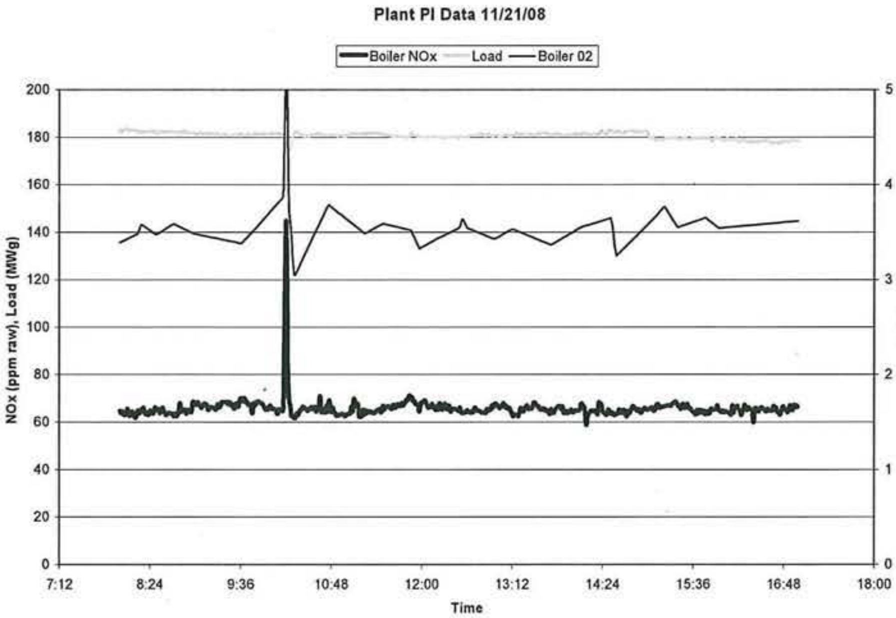


Figure 3-4
Plant Load, NO_x and O_2 Data from November 21, 2008

Gas profile plots for selected baseline and urea injection tests are provided in Appendix E. These plots include O_2, CO, NO_x and NO_x reduction profiles measured at the air heater inlet.

The following subsections will describe the day-to-day test conditions and results:

- Day 1 – Full load baseline tests
- Day 2 – Larger droplet and reduced load tests
- Day 3 – High and intermediate baseline NO_x tests with modified nozzles
- Day 4 – Higher capacity nozzle tests
- Day 5 – High baseline NO_x tests with higher capacity nozzles
- Day 6 – Extended optimum SNCR configuration tests

Day 1 (11-15-08)

The first day of testing was done at full load and normal OFA conditions. Normal OFA conditions were defined by the positioning of the OFA, auxiliary air, and fuel air dampers before testing began:

- CCOFA dampers closed
- SOFA dampers at ~ 20%, 94% and 94% open
- Aux Air damper AAS at ~ 83% open, ABS-DES holding fairly steady at 20% open
- Fuel Air dampers at 35% - 49% open on average

The baseline NO_x level was measured at 74 ppmc with an O_2 level of 3.9%. Testing was completed using the 15-055 and 25-08 nozzles. The Spraying Systems nozzle number references the fan spray angle and the flow capacity in gallons per minute at 40 psig (2.7 atmospheres) nozzle pressure. The first test utilized all eight injectors, but was not effective, so it was decided to remove the outside injectors to eliminate any possible wall impingement. Six injectors were utilized with both the 15-055 nozzles as well as the 25-08 nozzles. Pressure was varied from 10 psig to 80 psig, which varied the urea concentration from 20% to 5% respectively, due to the different dilution water flow rates. The NSR of urea to NO_x was maintained at 1.5 for each test with constant urea flow.

Figure 3-6 shows select unit data for the day, along with shaded bars representing test times and arrows designating when urea was turned on or off. The full gray bars are injection tests, while the hashed bars are baseline tests. NO_x removals were less than 5% for all tests. The highest capacity injectors achieved limited NO_x reductions, and a higher atomization pressure actually produced higher NO_x levels. This was likely the result of the furnace exit gas temperature being on the higher side of the SNCR temperature window. If SNCR performance was to be improved, higher capacity nozzles would be needed to produce a more dilute urea solution, as well as a larger drop size distribution. Low load testing during Day 2 was used to confirm this assessment.

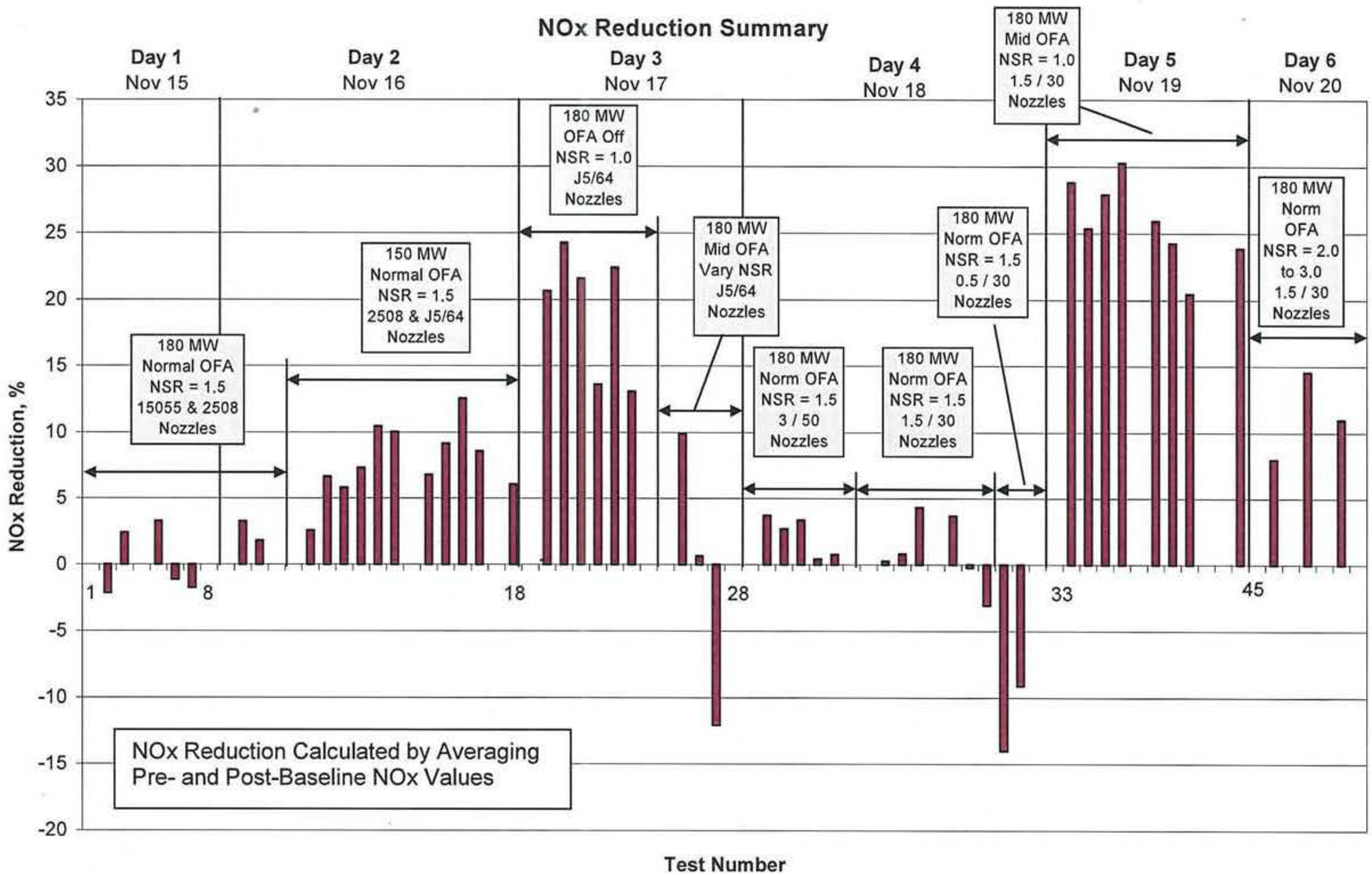


Figure 3-5
Overall Summary of NO_x Reduction Performance

Confidential Business Information

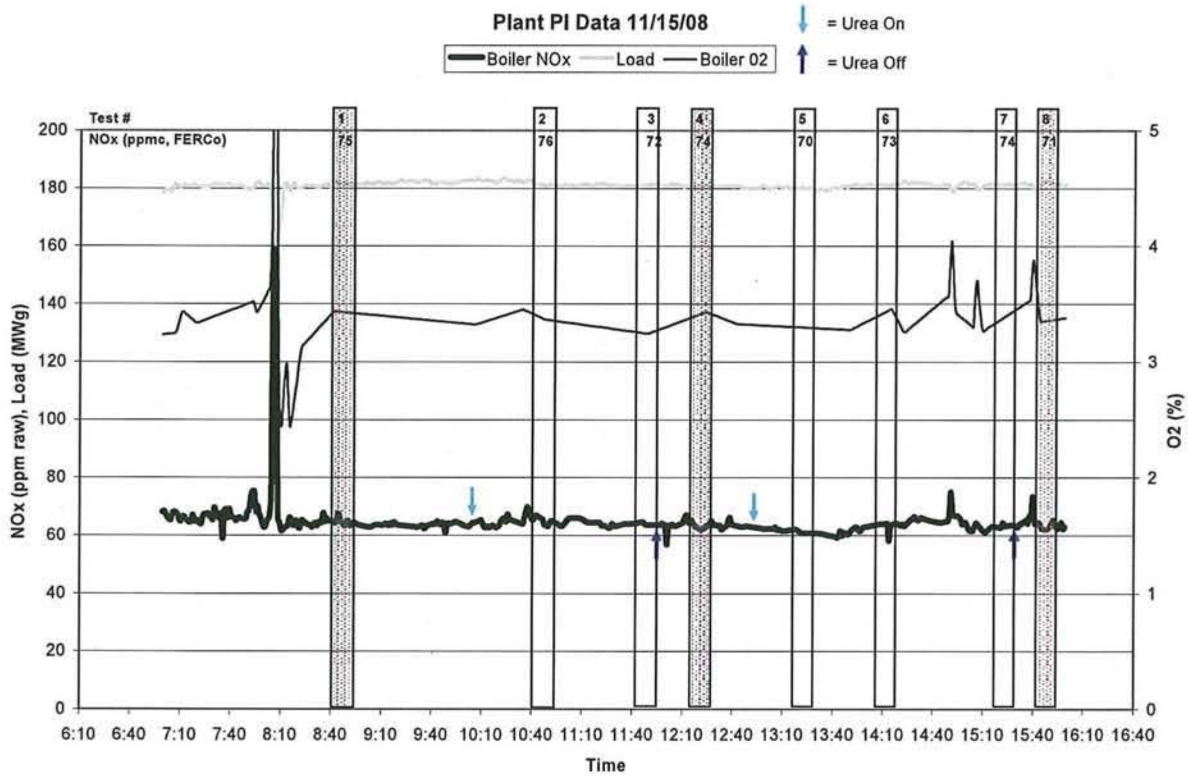


Figure 3-6
Day 1 Unit Load, NO_x, and O_2 Data with Test Numbers and Times

Day 2 (11-16-08)

On the second day of testing, several tests were initially performed at full load to verify the results from Day 1. The middle six injectors were utilized with 25-08 nozzles at low atomization pressures to produce a large droplet size. NO_x removal was again less than 5% at an NSR of 1.5, and the TDL ammonia monitor showed NH_3 slip less than 10 ppm. Both of these results suggest droplet time-temperature profiles that are inoptimum and on the hot side of the SNCR process temperature window.

The load was then reduced to 150 MWg with all mills in service while keeping normal OFA conditions (see Figure 3-7). Baseline NO_x was measured at 65 ppmc, while O_2 levels remained at 3.9%. The nozzle configuration was kept the same, while nozzle pressure was varied from 15 psig to 40 psig (2.7 atmospheres). NO_x removals were 5 to 10 % at an NSR of 1.5, with higher removals at the lowest nozzle pressure, as can be seen in Figure 3-8.

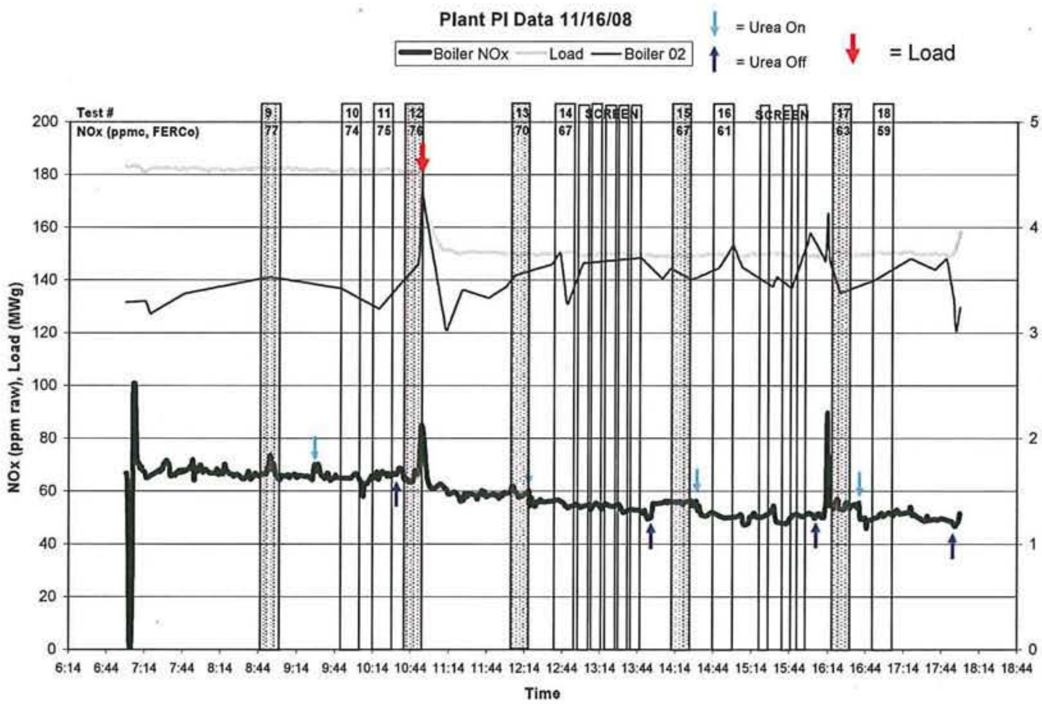


Figure 3-7
Day 2 Unit Load, NO_x, and O_2 Data with Test Numbers and Times

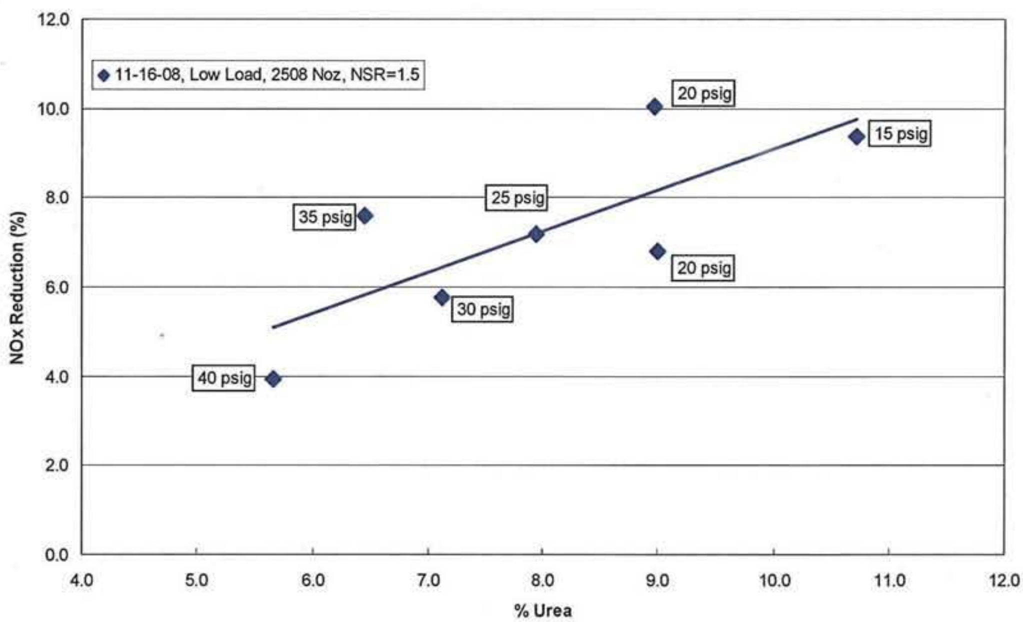


Figure 3-8
Reduced Load Test Results with Varying Nozzle Pressure

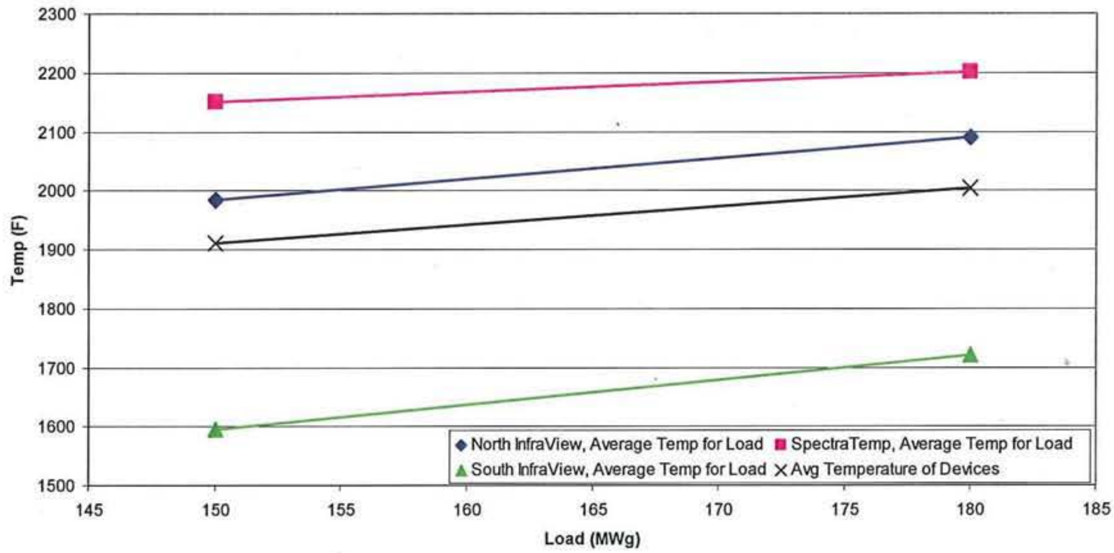


Figure 3-9
Average Upper Furnace Gas Temperature as a Function of Load Change

The improved SNCR performance was attributed to the lower temperatures (90°F (32°C) drop, as shown in Figure 3-9) and increased residence time at reduced load. This result suggested that larger drop sizes and/or more dilute urea solution would be beneficial. Larger capacity nozzles were ordered, but would not be available until Day 4. In the interim, plant personnel modified some of the existing nozzles by enlarging the holes to 5/64 inch. These nozzles provided higher capacity, but generated inconsistent flows and spray angles. With these nozzles placed on the middle six injectors, NO_x removal was 6 to 13% at an NSR of 1.5. Ammonia slip (wet chemical method) was measured at 10 ppm for a composite sample across the south duct.

Day 3 (11-17-08)

In order to assess the potential impact of the low baseline NO_x levels on SNCR performance, Day 3 testing was performed at full load with a high baseline NO_x condition. With the CCOFA and SOFA dampers closed, the baseline NO_x level was measured at nominally 190 ppmc, with excess O_2 levels around 3.5%. The six middle injectors were utilized, with the 5/64 inch modified nozzles. Nozzle pressure was varied from 20 psig to 30 psig, and NSR was varied from 0.5 to 1.4. NO_x removal for these conditions ranged from 13 to 24%, while wet chemical ammonia measurements showed slip levels below 10 ppm.

SOFA dampers were then opened slightly to provide a full-load, intermediate baseline NO_x condition (see Figure 3-10). Under this condition baseline NO_x was 95 ppmc. Again, the middle six injectors were utilized with the modified 5/64 inch nozzles, and NSR varied from 0.5 to 1.5. Measured NO_x removals ranged from -12% to 10%, with wet chemical NH_3 slip less than 10 ppm.

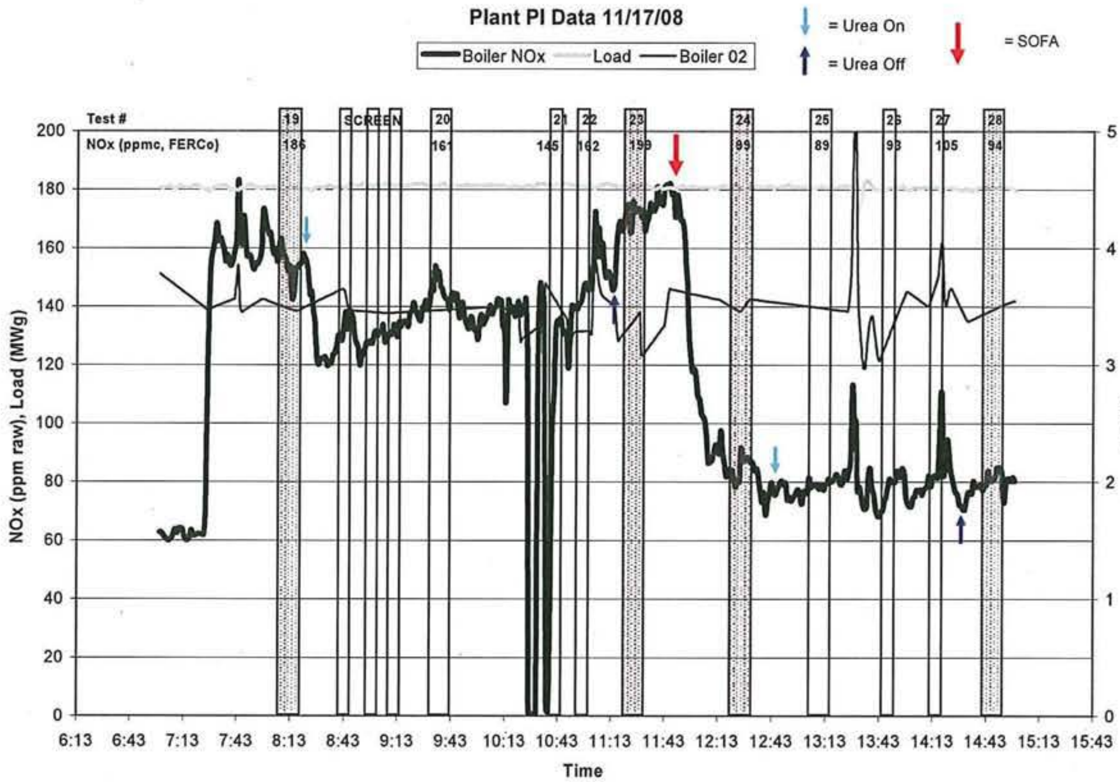


Figure 3-10
Day 3 Unit Load, NO_x, and O_2 Data with Test Numbers and Times

These tests demonstrated typical SNCR NO_x reduction capabilities on the order of 25% at the higher baseline NO_x levels. Contour plots consistently showed better removals on the south side of the boiler (see Appendix E). This could be attributable to either the cooler flue gas temperatures present, or due to inconsistent nozzle performance. The results also demonstrated that reducing the NO_x baseline yields diminished SNCR performance.

Day 4 (11-18-08)

Day 4 testing was performed at full load and normal OFA conditions (Figure 3-11). It was noted that aux air damper positions ABS-DES were more variable, floating between 15 to 20% open. Baseline NO_x levels were 70 ppmc, and O_2 levels remained fairly steady at 3.9%. The higher capacity nozzles had arrived earlier in the day and tests were performed using two different sets (3 gpm (11.4 lpm)/50° fan and 1.5 gpm (5.7 lpm)/30° fan). A smaller third set was also tested (0.5 gpm (1.9 lpm)/30° fan).

Nozzle pressure was varied between 10 psig to 40 psig, which varied the urea solution concentration from 28 to 3%, depending on the nozzle flow capacity curve. Nozzle orientation was also varied (vertical fan spray vs. horizontal fan spray), which exhibited no impact. NO_x

removals for all tests were less than 5% at an NSR of 1.5, with ammonia slip levels using a tunable diode laser monitor measured below 10 ppm.

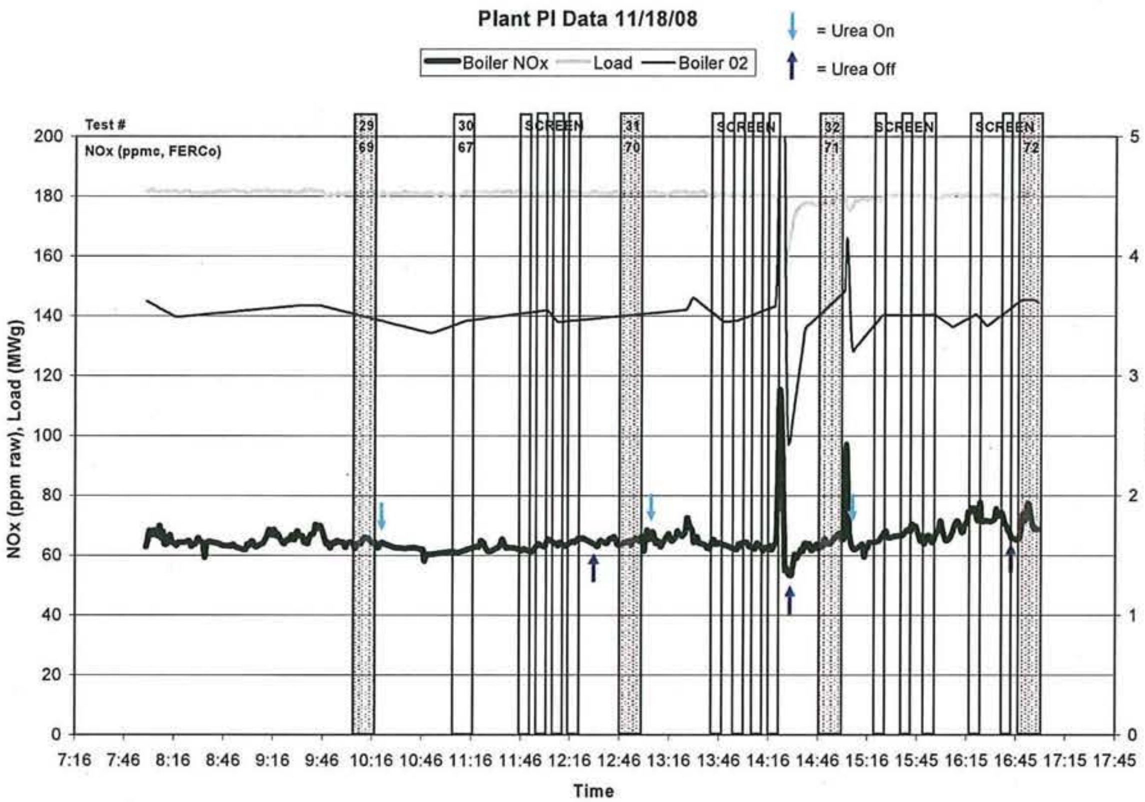


Figure 3-11
Day 4 Unit Load, NO_x, and O_2 Data with Test Numbers and Times

Tests with the higher capacity nozzles yielded NO_x removals of less than 5%. The smaller 0.5 gpm nozzles actually increased NO_x, which could be attributed to the smaller droplets and faster evaporation under unfavorable flue gas temperatures. It was decided to do more testing at higher baseline NO_x levels to determine an optimized set-up, and to test the effect of varying the CO level.

Day 5 (11-19-08)

Day 5 testing was done at full load at an intermediate OFA condition, which provided a baseline NO_x of 155 ppmc, and a 3.8% O_2 level (see Figure 3-12). The auxiliary air dampers ABS-DES were not steady, ranging from 40 to 85% open. As a result, the baseline NO_x varied continuously throughout the day, diminishing the consistency of the results. During this series of tests all eight reagent injectors were utilized, with the outside injectors using the smaller 25-08 nozzles (aligned vertically to avoid wall impingement), and 1.5 gpm (5.7 lpm)/30° fan nozzles for the middle six injectors.

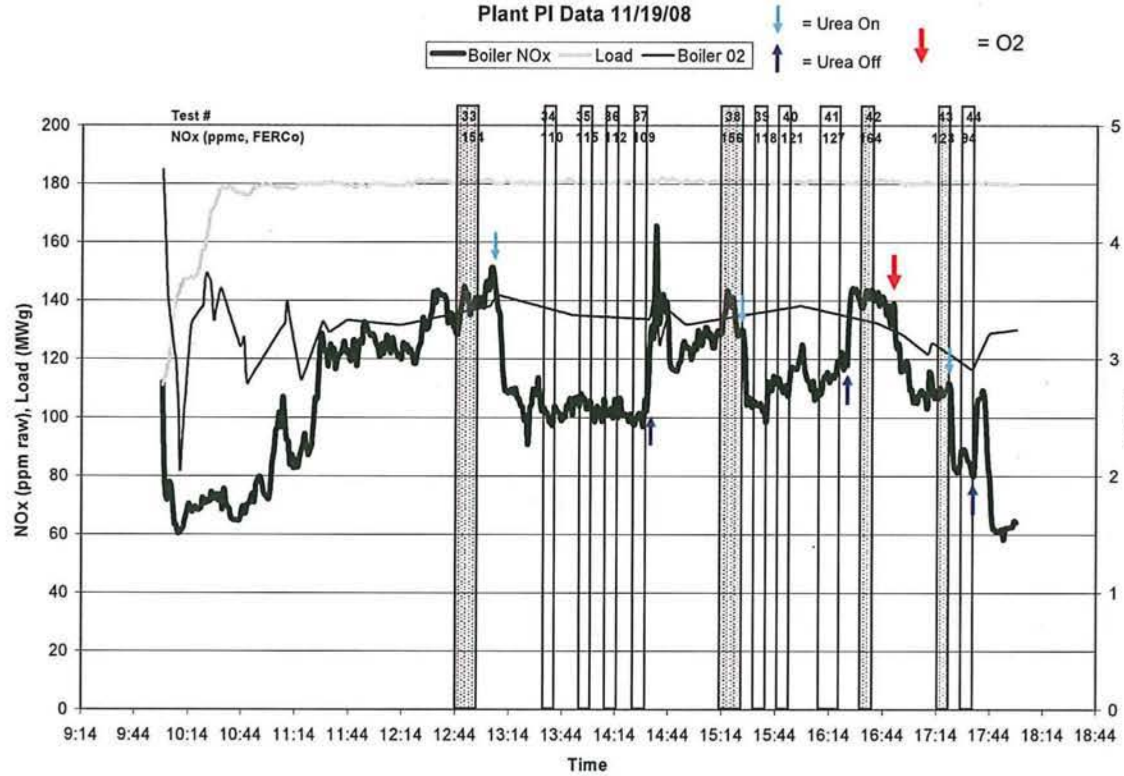


Figure 3-12
Day 5 Unit Load, NO_x, and O_2 Data with Test Numbers and Times

Nozzle pressure was varied from 20 psig (1.4 atmospheres) to 35 psig (2.4 atmospheres), while keeping the NSR constant at 1.0. Injector biasing was also tested by shutting off flow to individual lances, but this had little impact. NO_x removals ranged from 25 to 30%, while ammonia slip levels measured with the ammonia monitor on the south duct were below 10 ppm.

Excess O_2 was then lowered to increase CO levels. Baseline gaseous values for this condition were 123 ppmc for NO_x, and 3.4% O_2. The baseline CO level, as measured at the economizer outlet, was increased from 60 ppm to 400 ppm. Utilizing the same injection configuration at an NSR of 1.2 resulted in 24% NO_x removal, with ammonia slip values below 5 ppm.

Increasing the NO_x baseline and utilizing higher capacity nozzles yielded SNCR performance at the upper ranges (25-30%), with a slight trend of increasing removals with larger drop sizes. The increase in CO did not appear to significantly impact SNCR performance (Figure 3-13), with differences in NO_x reduction performance with the overall range in variability.

In sum, SNCR results demonstrated that typical SNCR NO_x reductions were achievable at higher baseline NO_x levels (e.g., greater than 120 ppm). Thus, results obtained at low baseline NO_x levels were not constrained by the reagent injectors or injector configuration that was implemented.

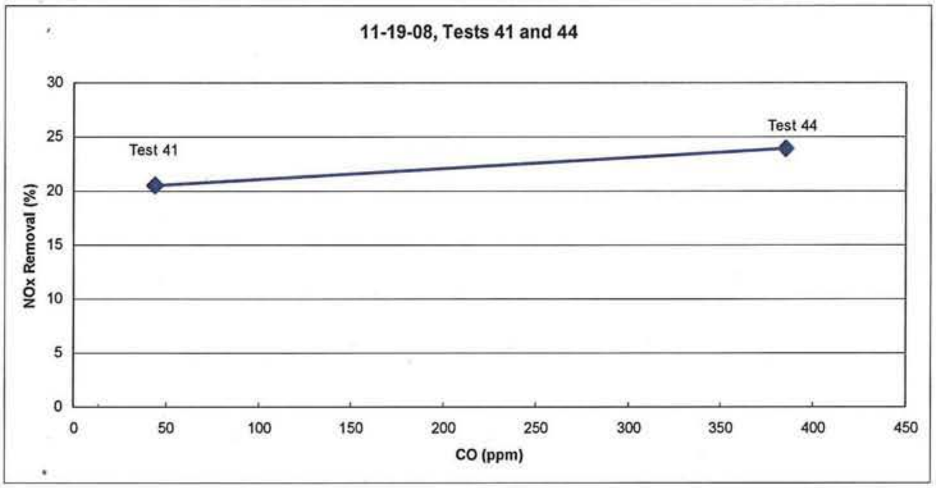


Figure 3-13
Effect of CO Level on SNCR Performance

Day 6 (11-20-08)

Day 6 testing was performed at full load and normal OFA conditions (see Figure 3-14). The dampers for auxiliary air ABS-DES were unsteady, ranging from 18 to 35%. Throughout the day the unit was experiencing mill problems, which lead to inconsistent baseline readings. Baseline NO_x values ranged from 74 to 88 ppmc, while O_2 levels were relatively consistent at 3.9 to 4.1%. These tests were designed to provide an extended operational performance assessment with the same injection configuration as Day 5.

Tests were run at NSR values of 2.0, 2.5, and 3.0, which gave NO_x removals of 8%, 11% and 14%, respectively. Again, movement of the NO_x baseline affected the calculated percent NO_x reduction removal results. Wet chemical ammonia slip values from this day varied from 19 to 24 ppm, while ammonia monitor slip values ranged from 8 to 19 ppm. The ammonia slip ppm levels during these tests were greater than the reduced NO_x levels.

During the final Day 6 test (NSR = 2.5), plant personnel collected a fly ash sample using a CEGRIT Sampler at the ESP inlet. Fly ash baseline samples were also collected prior to the test program on November 5 and 11. Analysis of the baseline samples showed nominally 5 ppm ammonia on the ash (weight basis). Analysis of the Day 6 sample showed 9 ppm ammonia (weight basis). This result indicates very little ammonia adsorption on the ash, possibly the result of the high alkalinity of the PRB ash.

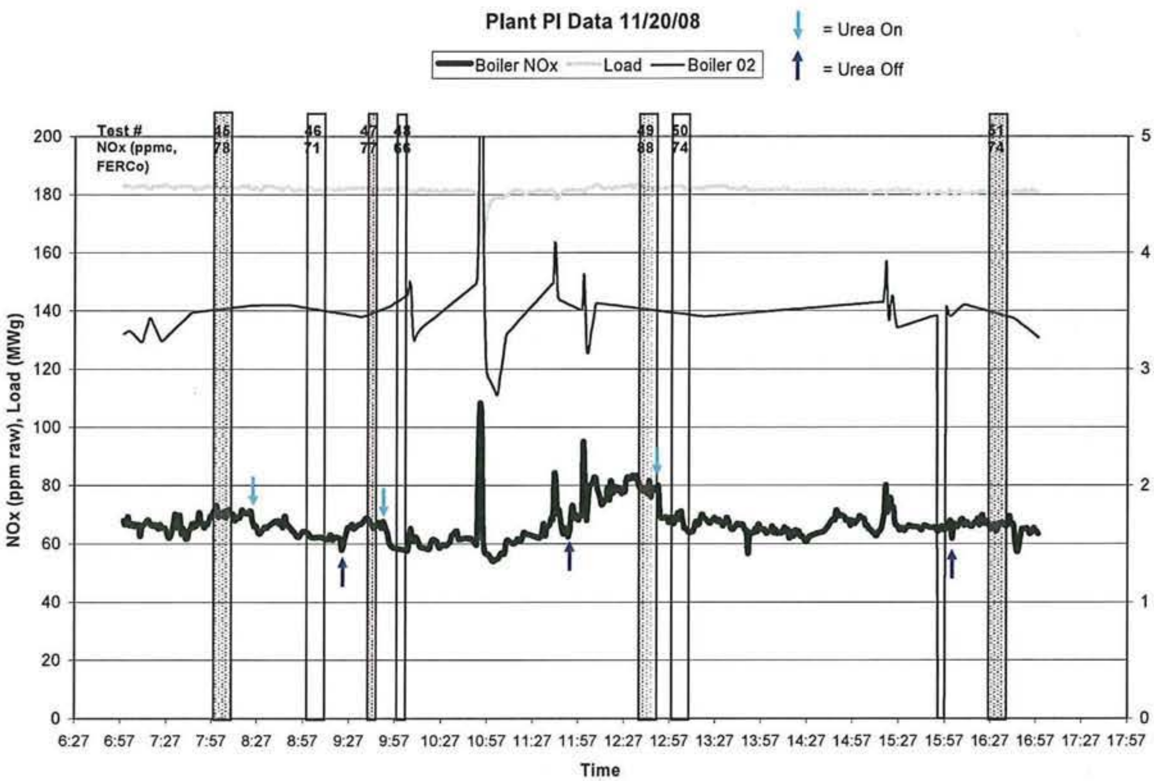


Figure 3-14
Day 6 Unit Load, NO_x, and O_2 Data with Test Numbers and Times

Higher NSR values improved NO_x reduction but also lead to higher NH_3 slip values. Although the baseline NO_x was inconsistent, SNCR reductions showed 8 to 15% reduction over the range of NSRs from 2.0 to 3.0. Further SNCR optimization may be possible, but improvement would likely only be second order at these low baseline NO_x levels. Estimates of optimized NO_x reduction at slip levels below 10 ppm would be 8 to 12%.

Baseline NO_x Level Impacts

Lower baseline NO_x levels limited SNCR performance during the test program. This is illustrated Figure 3-14 using all of the data at full load. Figure 3-15 isolates data for a specific nozzle type (1.5 gpm (5.7 lpm)/30°).

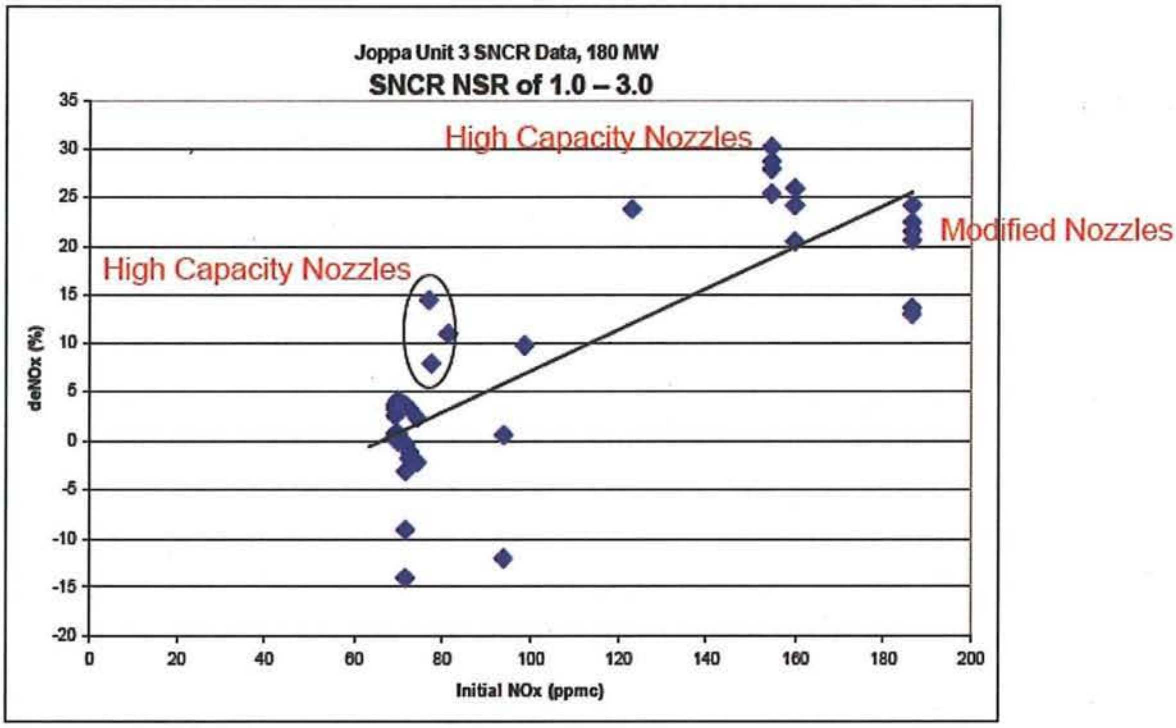


Figure 3-15
Full Load NO_x Reduction Plotted with Initial NO_x

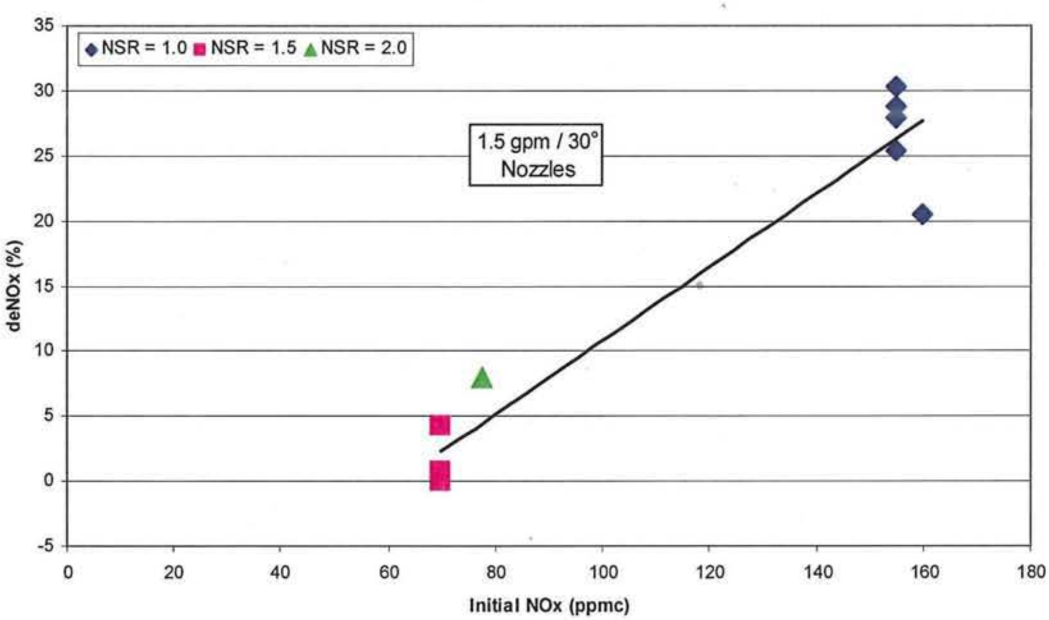


Figure 3-16
Full Load NO_x Reduction Plotted with Initial NO_x (1.5 gpm/ 30º Nozzles)

4
ECONOMIC ASSESSMENT

In order to assess the cost effectiveness of a SNCR system applied to a low baseline NO_x unit, a capital cost estimate was generated from a previously described approach (1004727, December 2004) and reproduced in Table 4-1. The approach estimates a capital cost of nominally \$2.5 million, which yields an annualized levelized cost of \$436,000 with a capital cost recovery factor of 17.5%. On a relative basis, SNCR is a variable cost oriented technology, with the urea solution being the principle variable cost component. For a 180 MW unit with a baseline NO_x level of 0.115 lb/MBtu, the hourly consumption of 50% urea solution at an average NSR of 1.2 is less than 0.6 gpm (2.3 lpm). Assuming an 80% capacity factor, and a delivered 50% urea reagent cost of \$1.40 per gallon, annual reagent costs are on the order \$334,000. As shown in Table 4-2, with an average SNCR performance of 10% NO_x reductions, nominally 73 tons of NO_x would be reduced each year. With annualized capital costs of \$436,000 and reagent costs of \$334,000 for a total of \$770,000, the cost effectiveness per ton of NO_x removed is \$10,620. The variable operating cost for 50% urea reagent alone is \$4,600 per ton NO_x removed. Increasing the NO_x reduction performance to 15% would reduce the overall cost effectiveness to \$7,080 per ton NO_x removed with operating costs for urea reagent being reduced to \$3,070 per ton NO_x removed due to the increased reagent utilization.

Table 4-1
SNCR Capital Cost Estimate

SNCR Trim Capital Cost Estimate

			SNCR
Boiler Capacity (MW)			180
Boiler Width (ft)			40
Baseline NOx (lb/MBtu)			0.115
HVT Testing / Modeling			$80,000
Startup & Testing			$150,000
Storage Requirements (30 days)		24,517 gallons	
Storage Requirements (14 days)		11,441 gallons	
Reagent Storage			$200,000
Injection System		#Inj	
	MNL Lances	0	$0
	Upper Level Inj	8	$330,000
	Mid Level Inj	0	
	Lower Level Inj w/Retracts	0	
Compressors			$200,000
Continuous Ammonia Monitor (4 path)		2	$175,000
Continuous FEGT Monitor		6	$100,000
Installation			$438,000
Total Process Capital (TPC)			$1,673,000
Taxes		6%	$100,380
Engineering & Procurement		10%	$167,300
Field Supervision & Indirects		8%	$133,840
Project Contingency		10%	$167,300
Vendor Markups		15%	$250,950
Total Estimated Capital			$2,492,770
$/kW			13.85

Table 4-2
Low Baseline NO_x Cost Effectiveness

Unit Capacity	180	
Capacity Factor	80%	
Baseline Nox (lb/Mbtu)	0.115	0.104
Heat Input (Mbtu/hr)	1,800	
NOx Removal		10%
Tons NOx Removed		
Annual (tons Nox)	725	73
Capital Cost Recovery Factor	17.5%	
Capital Cost		$2,492,770
Annual Levelized Capital Cost		$436,235
Urea Reagent Cost		$334,088
Annual Cost Estimate		$770,323
Annual SNCR Levelized Costs	$/ton NOx	$10,620
Urea Operating Costs	$/ton NOx	$4,606
Urea Cost ($gal)	$ 1.40	

It should be noted that there are a number of factors that would impact the cost estimates generated herein. Among these factors is the scope of the retrofit, process control system implemented, and the cost of urea solution, which is proportional to the price of its natural gas feedstock. However, the cost estimates do place into context the elevated cost per ton NO_x removed. This elevated cost is attributable to both the low baseline NO_x levels, and relatively low number of tons NO_x removed on an annual basis, as well as the reduced SNCR operational efficiencies at low NO_x levels.

5 CONCLUSIONS

While several SNCR demonstrations have been conducted through EPRI over the previous decade to document the achievable NO_x reduction performance with a single level of reagent injectors, they have all been performed on units with full load baseline NO_x levels ranging between 0.17 lb/MBtu – 0.35 lb/MBtu. As each demonstration used existing boiler access, typically provided by observation doors, there was a range of injector spacing used at each demonstration site. Figure 5-1 provides a first level assessment of the impact of injector spacing and unit size on SNCR NO_x reduction performance. As noted in Figure 5-1, each of these demonstration projects achieved short term SNCR NO_x reduction performance between 20-30%. Injector spacing appears to have a first order impact on SNCR performance while unit capacity appeared to exhibit a lesser impact on SNCR performance that was more pronounced for units greater than 500 MW in capacity.

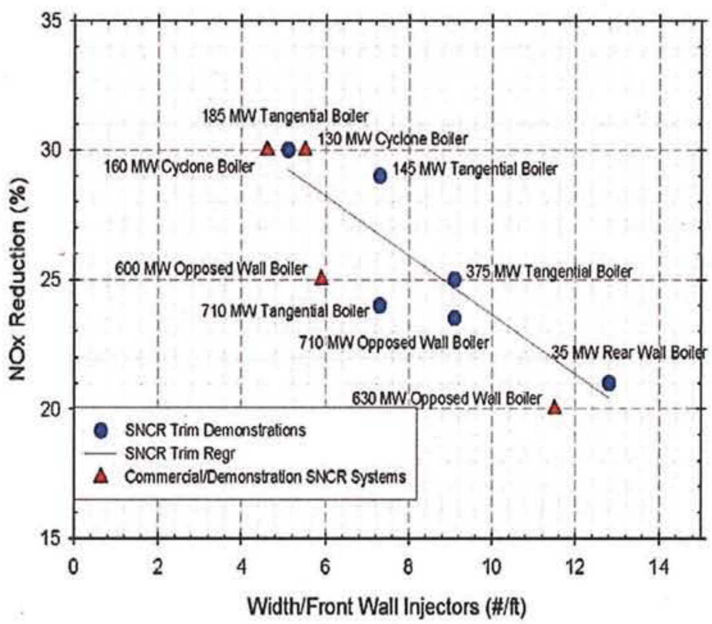


Figure 5-1
Full Load SNCR Trim Demonstration Performance at NSR = 1 and Baseline NO_x Levels Greater Than 0.15 lb/MBtu

As shown in Figure 1-4, however, CFD modeling has shown that SNCR performance can degrade significantly at baseline NO_x levels of 100 ppm and below. While the current project only required modest NO_x reductions from SNCR, it was not known what actual level of SNCR performance might be anticipated. Toward this end, a comprehensive program was conducted at Joppa Unit 3 to evaluate SNCR performance at baseline NO_x levels of nominally 0.10 lb/MBtu (70 ppm) using a single-level, urea-based SNCR system. The project included O_2, CO, NO_x and ammonia slip measurements at the air heater inlet, and temperature measurements at the furnace exit. Testing was performed at loads ranging from 150 to 180 MWg over a six-day period. Several parameters were varied, including NSR, atomizer type, baseline NO_x levels, and baseline CO levels.

While initial assessments of furnace exit gas temperatures (FEGT) suggested smaller drops might be required to minimize ammonia slip levels, the limited heat transfer surface area in the upper furnace actually necessitated larger droplets and a more dilute urea solution. With reagent injectors along the front wall, injected urea droplets needed to traverse the boiler depth prior to reaching the convective pass entrance where the flue gas was begun to be cooled down toward the SNCR process temperature of 1,850°F (1,010°C). As a result, droplets generated from the injectors had insufficient residence time prior to their evaporation and yielded minimal NO_x reduction levels (i.e., <5%). While larger capacity nozzles were ordered, reduced load testing on the second day supported these preliminary conclusions. Lower FEGT and increased residence times at comparable baseline NO_x levels yielded improved SNCR NO_x reduction performance that ranged between 5 – 10%, depending upon the injection conditions. Nozzles modified to provide larger droplets and flow rate increased the overall SNCR NO_x reduction performance between 8 – 12% at a NSR of 1.5 while maintaining ammonia slip levels as measured on the south duct at 10 ppm. A plot of the NO_x reduction performance as a function of atomization pressure (Figure 3-8) demonstrated the effect of evaporation rate, with larger droplets (lower atomization pressure) yielding higher NO_x reduction levels.

As overall SNCR NO_x reduction performance at this stage of the demonstration project was less than 15%, however, there were questions regarding the impact of the baseline NO_x level as well as the reagent injection location and resultant mixing and reagent release. To address this important question, tests on the third day destaged the unit to create a higher baseline NO_x level that was on the order of 190 ppm. While using modified injectors which created distribution gradients within the boiler, overall NO_x reduction levels improved to 20 – 24%. These results suggested that the reagent injection location was not constraining the overall SNCR performance, and that the low baseline NO_x levels represented a significant factor that was potentially limiting SNCR performance.

These results were supported further on the fifth day of testing when larger capacity commercial pressure atomizers were tested at increased baseline NO_x levels of around 155 ppm. These tests yielded a range of NO_x reduction performance between 25 – 30% at a NSR of 1.0. Further tests that altered the excess oxygen level in order to reduce CO levels, indicated a limited effect by CO on observed SNCR performance.

To minimize the impact of reducing both the NO_x and urea within the boiler by keeping a constant NSR, tests on the sixth day set up the boiler with a typical baseline NO_x level that ranged from 74 – 88 ppm over the course of the day. Instead of maintaining a NSR of 1.0, the same amount of urea was injected into the boiler as on Day 5 so as to minimize any mixing impacts on SNCR performance (e.g. similar urea distribution/concentrations across the flue gas). Overall NO_x reduction levels, however, were diminished to levels just under 10%. Increasing the

NSR further to values of 2.5 and 3.0 increased the SNCR NO_x reduction performance to 11% and 14% respectively, but ammonia slip levels also increased to levels on the order of 20 ppm.

In sum, SNCR performance appears to be significantly degraded at baseline NO_x emission levels less than 100 ppm. The increased ammonia slip levels experienced during the testing on Day 6 indicates that there was reagent present at the optimum SNCR temperature window. The overall performance is likely constrained due to imperfect mixing that is achieved within the boiler with the low energy reagent injectors. As the NSR was increased from 2.0 – 3.0 on Day 6, the overall NO_x reduction performance also increased (Table 5-1). The increased NO_x reductions with increasing urea flow rate is supportive of the overall SNCR results at Joppa 3 being mixing constrained at low baseline NO_x levels. While the results on Day 6 experienced unacceptable ammonia slip values between 15 – 20 ppm, air atomized injectors may provide finer droplet size distribution 'tuning capability' at a constant liquid flow rate than that achievable with the mechanically atomized injectors used during this project. Overall SNCR performance capabilities at baseline NO_x emission levels of 75 ppm, however, will likely be constrained within a NOx reduction range of 8 – 12%. It should be noted that at the baseline NOx levels cited, this range in SNCR performance represents a difference of 3 ppmv.

Table 5-1
SNCR NOx Reduction Performance on Day 6 as a Function of NSR

NSR	ΔNO_x
2.0	8.0%
2.8	11.0%
3.0	14.5%

A
PARAMETRIC TEST METHODS

Continuous Gas Monitoring

Gaseous species concentrations of NO, CO, O_2, and CO_2 were measured using an extractive continuous emissions monitoring (CEM) package contained in a mobile emissions laboratory. A schematic of the sample handling system is presented in Figure A-1. The system is comprised of three basic subsystems, including: 1) sample acquisition and conditioning system, 2) calibration gas system, and 3) analyzers. Each of these subsystems is described in the following paragraphs.

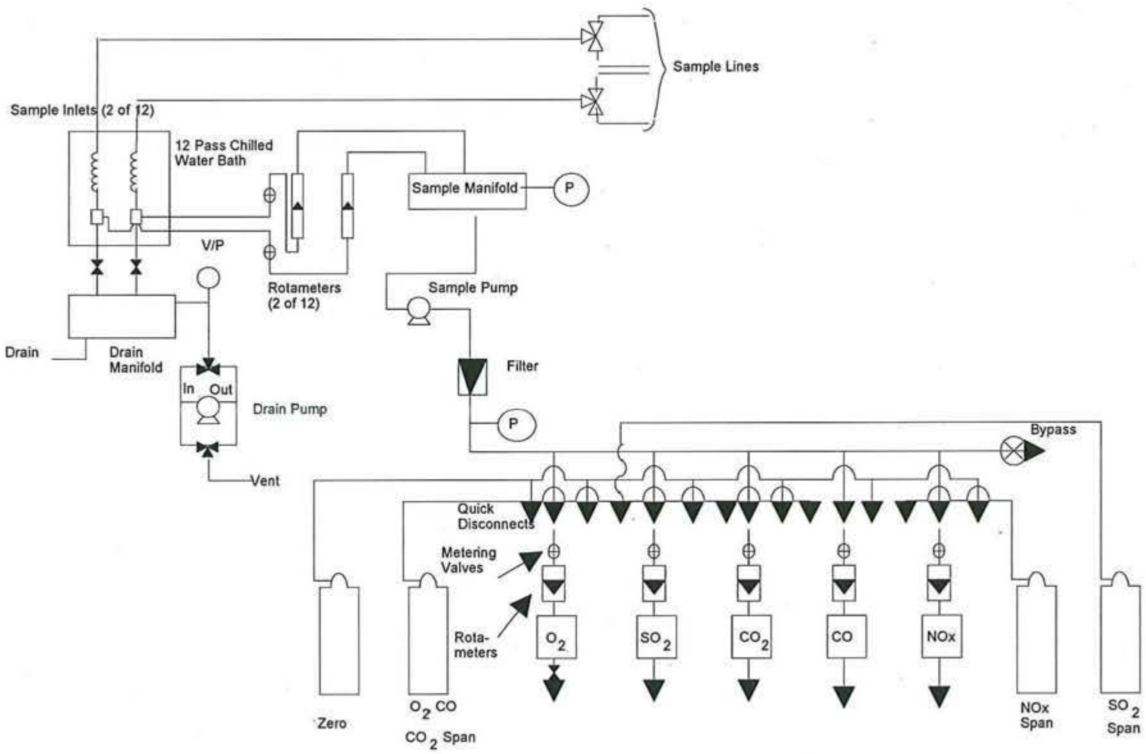


Figure A-1
Gas Sample Handling System

The sample acquisition and conditioning system contains components to extract a representative gas sample, transport the sample to the analyzers, and remove moisture and particulate material from the sample. In addition to performing these tasks, the system preserves the measured species and delivers them intact for analysis. For the program, the economizer exit ducts were fitted with a grid of 16 gas sample probes. The economizer exit consists of two separate ducts. Each duct contained a four wide by two deep probe array, 8 probes in each duct for a total of 16 probes. Figure A-2 shows the arrangement of the probe grid and the locations of the continuous NH_3 analyzer. The overall duct dimensions at this sample location are 45 feet (13.7m) wide by 8.5 feet (2.6m) deep.

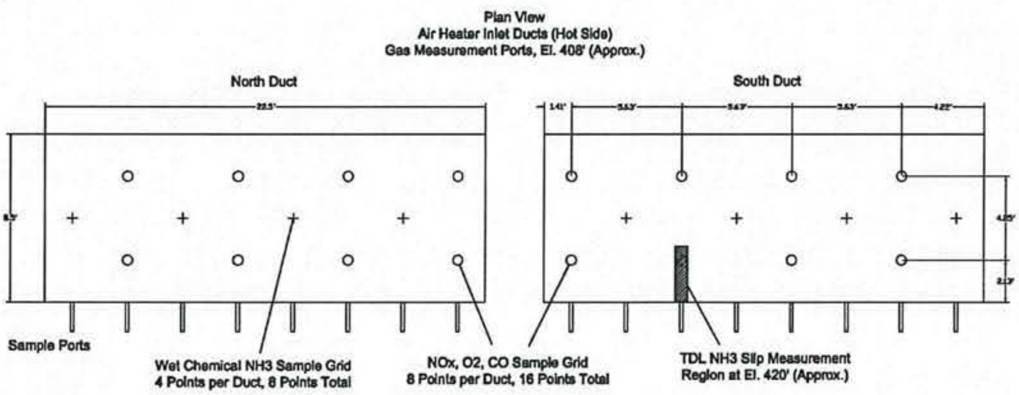


Figure A-2
Economizer Exit Probe Locations

Gaseous samples were extracted through stainless steel probes; external filters were used at the outlet of each probe to reduce particulate loading. The samples were then drawn through inert polyethylene sample lines into a refrigerated (38°F, 3°C) dryer for moisture removal. The sample then entered the dual head, diaphragm pump. All sample-wetted components of the pump are stainless steel or Teflon. The pressurized sample leaving the pump flows to the analyzers. Excess sample is vented through a back-pressure regulator, maintaining a constant pressure of 5 to 6 psig to the analyzers.

The analyzers were calibrated with gases certified to ±1% calibration by the manufacturer to comply with reference method requirements. The cylinders are equipped with pressure regulators which supply the calibration gas to the analyzers at the same pressure and flow rate as the sample. The selection of zero, span, or sample gas directed to each analyzer is accomplished by operation of the sample/calibration selector valves.

Table A-1 lists the analyzers used for this test program.

Table A-1
Continuous Gas Analyzers

Species	Analyzers	Measurement Principle
NO/NO_x	TECO 10A	Chemiluminescent
O_2	Siemens Oxymat 5E	Paramagnetic
CO	ZRH	NDIR
CO_2	ZRH	NDIR

NO/O_2/CO Profiles

An important aspect of SNCR optimization is the assessment of chemical distribution and the resulting stratification of NO_x removal and NH_3 slip. The NO_x removal and NH_3 slip will vary not only due to non-uniform chemical distribution, but also with temperature variations at the injection plane. To assess local NO_x reductions and slip, point-by-point measurements need to be made at the exit of the economizer (i.e., it is possible that one localized low temperature region, or small region with excess chemical, can be contributing a majority of the measured NH_3 slip).

To simplify these point-by-point measurements, FERCo has developed an NO/O_2/CO monitoring system that is capable of simultaneously monitoring the NO, O_2, and CO levels for up to twelve separate sample points in the economizer exit duct. This analyzer system allows the duct emissions profiles to be characterized in a matter of minutes, as opposed to hours for traditional duct emission traverse techniques. Data from twelve sample lines are taken every ten seconds and a contour plot of O_2, NO and CO is shown in "real time" on the computer screen. Figure A-3 shows a general arrangement of this system.

Wet Chemical NH_3 Slip Measurements

Ammonia slip measurements were made using a batch wet chemical technique. This method involves sampling a measured portion of the flue gas and collecting the condensed ammonia vapors in a wet chemical sampling train. The ammonia content of the samples was then determined using an ammonia ion-specific electrode. This method allows same-day turnaround of ammonia samples while in the field.

The ammonia sample was taken from ports located at the air heater inlet. Four ports were sampled from, and combined to get an average number for each duct. The sample was withdrawn using a low flow rate sample pump (e.g., 15-20 scfh [0.4-0.6 m^3/hr]). The flue gas sample was then passed through three impingers. The first two impingers contained 0.02 N sulfuric acid (H_2SO_4) and the final impinger was dry. Nominally two cubic feet of flue gas are passed through the impinger train during each test at a rate of about 0.2 ft^3 per minute [0.3 m^3 per hour].

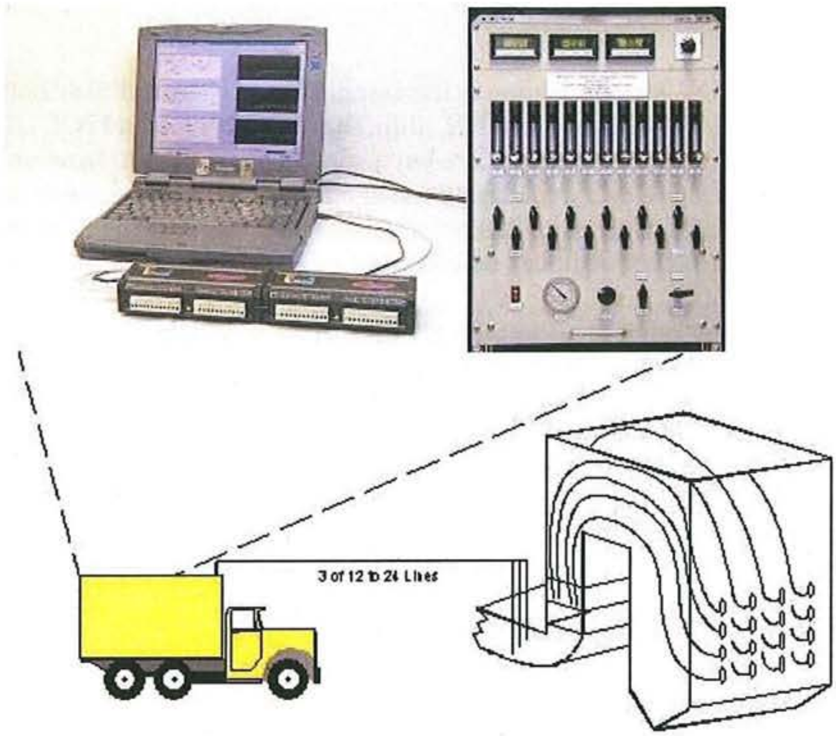


Figure A-3
Multipoint Multigas Combustion Diagnostic Analyzer

Following each sample run, the sample probe, Teflon line and sampling train glassware were washed with dilute H_2SO_4 into the bottle containing the impinger solution. Figure A-4 shows the sample train schematic.

The samples were analyzed using an ammonia ion-specific electrode. The electrode is gas sensitive, and uses a hydrophobic, gas permeable membrane to separate the sample solution from the electrode internal solution. Dissolved ammonia in the sample diffuses through the membrane until the partial pressure of ammonia is equal on both sides of the membrane. In any sample, the partial pressure of the ammonia is proportional to its concentration. The ion-specific electrode was calibrated daily with NH4Cl solutions of known concentration.

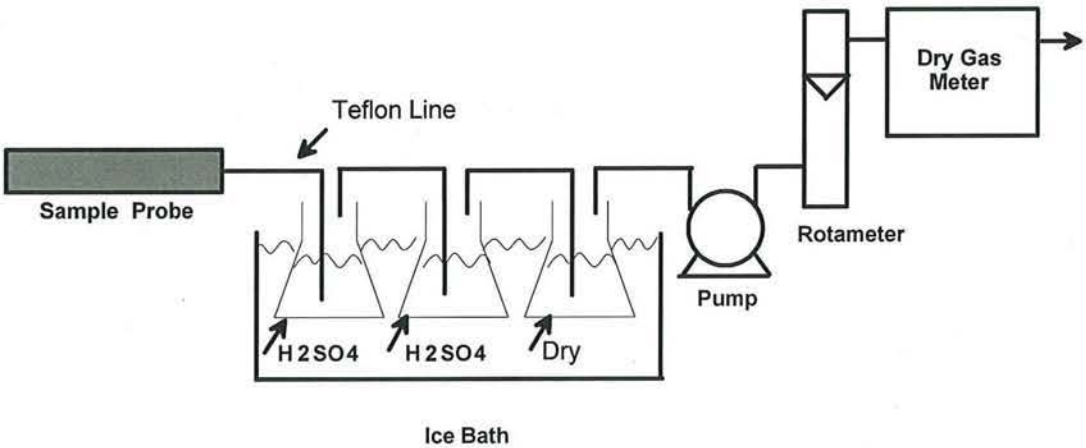


Figure A-4
Ammonia Sampling Train Schematic

Continuous Ammonia Monitor

For this test program, EPRI made available an *in situ* continuous ammonia monitor that was installed in the air heater inlet duct. This instrument utilizes a tunable diode laser which is mounted on a thermoelectric cooler to maintain a stable temperature environment. The laser is coupled to a fiber-optic cable, which is in turn coupled to a fiber-optic beam splitter where the beam is divided into a number of equal outputs when in the 'multiplexer' mode of operation.

For the current system, three outputs using an optical multiplexer from the fiber-optic beam splitter are sent to the back of the analyzer where they provide the laser emission for the signal measurements for each of the measurement targets. One output from the beam splitter provides the laser emission for the reference channel. The laser emission on the reference channel passes through a small reference cell containing a high concentration of NH_3 that is used to lock the laser wavelength onto the absorption feature, as well as to serve as a secondary calibration standard.

Calibrations are done to the instrument by way of introducing a known amount of ammonia into a small audit cell inside the LasIR analyzer. The audit cell is located just above the reference cell. This configuration, in principle, is exactly the same as having a known amount of NH_3 blowing through the probe, as it does not matter where the molecules of ammonia are so long as they are somewhere directly in the light path. The net result is a convenient calibration procedure which obviates the need for cylinders of calibration gases at the site since the ammonia concentration in the audit cell is relatively stable.

Furnace Temperature Monitors

The project utilized two furnace temperature monitors. Both the SpectraTemp® and InfraView® instruments incorporate optical pyrometry techniques to measure temperature in real time. The technique is based on Planck's blackbody, which is an ideal surface that acts as a perfect radiation emitter and absorber.

In a commercial SNCR system, the optical temperature measurements can be either integrated into the SNCR control system, or used by the operators to control soot blowing in order to maintain near constant temperatures in the upper furnace. For the current project, the instrument was used solely to monitor the upper furnace temperature.

The InfraView® measures infrared emissions from CO_2 within the gas, while the SpectraTemp® measures emissions within the visible spectrum from ash particles entrained in the combustion gas. Both instruments are prone to inference from wall infrared emissions, however, calculations show that within certain bandwidths it may not be significant. These instruments are fine-tuned to measure wavelengths from the appropriate sources, only installation and monitoring of the devices was necessary during the test program.

B
PARAMETRIC TEST RESULTS

Parametric Test Results

Test	Date	Time	Description * = A-B Comp	Load MW	OFA Condition	Heat Rate Btu/KW-hr
1	15-Nov	8:40	Baseline	180	Normal OFA	10000
2	15-Nov	10:40	15055 Injectors, Outsides Off, NSR = 1.5	180	Normal OFA	10000
3	15-Nov	11:45	2508 Injector with NSR = 1.5	180	Normal OFA	10000
4	15-Nov	12:14	Baseline	180	Normal OFA	10000
5	15-Nov	13:15	2508 Injector, 20 psi, NSR = 1.5	180	Normal OFA	10000
6	15-Nov	14:03	2508 Injector, 80 psi, NSR = 1.5	180	Normal OFA	10000
7	15-Nov	15:16	2508 Injector, 10 psi, NSR = 1.5	180	Normal OFA	10000
8	15-Nov	15:41	Baseline	180	Normal OFA	10000
9	16-Nov	8:45	Baseline	180	Normal OFA	10000
10	16-Nov	9:47	2508, 10 psi North, 20 psi South, NSR=1.5	180	Normal OFA	10000
11	16-Nov	10:15	2508, 15 psi North, 25 psi South, NSR=1.5	180	Normal OFA	10000
12	16-Nov	10:40	Baseline	180	Normal OFA	10000
13	16-Nov	12:06	Baseline, Low Load	150	Normal OFA	10000
14	16-Nov	12:33	Low Load, 2508, 40 psi uniform, NSR = 1.5	150	Normal OFA	10000
SCREEN	16-Nov	12:54	Low Load, 2508, 35 psi uniform, NSR = 1.5*	150	Normal OFA	10000
SCREEN	16-Nov	13:06	Low Load, 2508, 30 psi uniform, NSR = 1.5*	150	Normal OFA	10000
SCREEN	16-Nov	13:17	Low Load, 2508, 25 psi uniform, NSR = 1.5*	150	Normal OFA	10000
SCREEN	16-Nov	13:29	Low Load, 2508, 20 psi uniform, NSR = 1.5*	150	Normal OFA	10000
SCREEN	16-Nov	13:41	Low Load, 2508, 15 psi uniform, NSR = 1.5*	150	Normal OFA	10000
15	16-Nov	14:12	Baseline, Low Load	150	Normal OFA	10000
16	16-Nov	14:45	Low Load, 2508, 20 psi uniform, NSR = 1.5	150	Normal OFA	10000
SCREEN	16-Nov	15:23	Low Load, J5/64, 20 psi uniform, NSR = 1.5*	150	Normal OFA	10000
SCREEN	16-Nov	15:36	Low Load, J5/64, 25 psi uniform, NSR = 1.5*	150	Normal OFA	10000
SCREEN	16-Nov	15:54	Low Load, J5/64, max pressure, NSR = 1.5*	150	Normal OFA	10000
17	16-Nov	16:23	Baseline	150	Normal OFA	10000
18	16-Nov	16:52	Low Load, J5/64, 25 psi uniform, NSR = 1.5	150	Normal OFA	10000
19	17-Nov	8:04	Baseline, High NOx	180	OFA Off	10000
SCREEN	17-Nov	8:40	High NOx, J5/64, 25 psi uniform, NSR = 1*	180	OFA Off	10000
SCREEN	17-Nov	8:53	High NOx, J5/64, 20 psi uniform, NSR = 1*	180	OFA Off	10000
SCREEN	17-Nov	9:06	High NOx, J5/64, 30 psi uniform, NSR = 1*	180	OFA Off	10000
20	17-Nov	9:28	High NOx, J5/64, 20 psi uniform, NSR = 1	180	OFA Off	10000
21	17-Nov	10:35	High NOx, J5/64, 20 psi uniform, NSR = 1.4*	180	OFA Off	10000
22	17-Nov	10:53	High NOx, J5/64, 20 psi uniform, NSR = 0.5*	180	OFA Off	10000
23	17-Nov	11:23	Baseline, High NOx	180	OFA Off	10000
24	17-Nov	12:22	Baseline, Mid OFA	180	Middle OFA	10000
25	17-Nov	13:02	Mid OFA, J5/64, 20 psi uniform, NSR = 1	180	Middle OFA	10000
26	17-Nov	13:48	Mid OFA, J5/64, 20 psi uniform, NSR = 1.5*	180	Middle OFA	10000
27	17-Nov	14:12	Mid OFA, J5/64, 20 psi uniform, NSR = 0.5*	180	Middle OFA	10000
28	17-Nov	14:41	Baseline, Mid OFA	180	Middle OFA	10000
29	18-Nov	10:05	Baseline, Full Load	180	Normal OFA	10000
30	18-Nov	11:02	3/50 Vert Orientation, 30 psi uniform, NSR = 1.5	180	Normal OFA	10000
SCREEN	18-Nov	11:45	3/50, 30 psi uniform, NSR = 1.5*	180	Normal OFA	10000
SCREEN	18-Nov	11:55	3/50, 35 psi uniform, NSR = 1.5*	180	Normal OFA	10000
SCREEN	18-Nov	12:05	3/50, 40 psi uniform, NSR = 1.5*	180	Normal OFA	10000
SCREEN	18-Nov	12:15	3/50, 20 psi uniform, NSR = 1.5*	180	Normal OFA	10000
31	18-Nov	12:47	Baseline	180	Normal OFA	10000
SCREEN	18-Nov	13:40	1.5/30, 40 psi uniform, NSR = 1.5*	180	Normal OFA	10000
SCREEN	18-Nov	13:54	1.5/30, 35 psi uniform, NSR = 1.5*	180	Normal OFA	10000
SCREEN	18-Nov	14:06	1.5/30, 30 psi uniform, NSR = 1.5*	180	Normal OFA	10000
SCREEN	18-Nov	14:18	1.5/30, 25 psi uniform, NSR = 1.5*	180	Normal OFA	10000
32	18-Nov	14:48	Baseline	180	Normal OFA	10000
SCREEN	18-Nov	15:20	1.5/30, 25 psi uniform, NSR = 1.5*	180	Normal OFA	10000
SCREEN	18-Nov	15:37	1.5/30, 20 psi uniform, NSR = 1.5*	180	Normal OFA	10000
SCREEN	18-Nov	15:50	1.5/30, 10 psi uniform, NSR = 1.5*	180	Normal OFA	10000
SCREEN	18-Nov	16:20	0.5/30, 10 psi uniform, NSR = 1.5*	180	Normal OFA	10000
SCREEN	18-Nov	16:32	0.5/30, 40 psi uniform, NSR = 1.5*	180	Normal OFA	10000
SCREEN	18-Nov	16:45	Baseline	180	Normal OFA	10000
33	19-Nov	12:43	Baseline, Mid OFA (20%/0%), All 8 Injection Ports in Service	180	Middle OFA	10000
34	19-Nov	13:35	Mid OFA, Outside 2508 @ 20 psi, Middle 1.5/30 @ 30 psi, NSR = 1.0*	180	Middle OFA	10000
35	19-Nov	13:55	Mid OFA, Outside 2508 @ 20 psi, Middle 1.5/30 @ 35 psi, NSR = 1.0*	180	Middle OFA	10000
36	19-Nov	14:10	Mid OFA, Outside 2508 @ 20 psi, Middle 1.5/30 @ 25 psi, NSR = 1.0*	180	Middle OFA	10000
37	19-Nov	14:25	Mid OFA, Outside 2508 @ 20 psi, Middle 1.5/30 @ 20 psi, NSR = 1.0*	180	Middle OFA	10000
38	19-Nov	15:13	Baseline, Mid OFA	180	Middle OFA	10000
39	19-Nov	15:30	Mid OFA, Outside 2508 @ 20 psi, Middle 1.5/30 @ 30 psi (4, 5 OFF), NSR = 1.0*	180	Middle OFA	10000
40	19-Nov	15:45	Mid OFA, Outside 2508 OFF, Middle 1.5/30 @ 30 psi, NSR = 1.0*	180	Middle OFA	10000
41	19-Nov	16:09	Mid OFA, Outside 2508 @ 20 psi, Middle 1.5/30 @ 30 psi, NSR = 1.0	180	Middle OFA	10000
42	19-Nov	16:35	Baseline, Mid OFA*	180	Middle OFA	10000
43	19-Nov	17:15	Baseline, O2 Adj*	180	Middle OFA	10000
44	19-Nov	17:30	O2 Adj, Outside 2508 @ 20 psi, Middle 1.5/30 @ 30 psi, NSR = 1.25*	180	Middle OFA	10000
45	20-Nov	7:57	Baseline, Full Load	180	Normal OFA	10000
46	20-Nov	9:00	Outside 2508 @ 20 psi, Middle 1.5/30 @ 30 psi, NSR = 2.0	180	Normal OFA	10000
47	20-Nov	9:40	Baseline*	180	Normal OFA	10000
48	20-Nov	10:00	Outside 2508 @ 20 psi, Middle 1.5/30 @ 30 psi, NSR = 3.0	180	Normal OFA	10000
49	20-Nov	12:37	Baseline	180	Normal OFA	10000
50	20-Nov	13:00	Outside 2508 @ 20 psi, Middle 1.5/30 @ 30 psi, NSR = 2.5	180	Normal OFA	10000
51	20-Nov	16:27	Baseline	180	Normal OFA	10000

Test	Water Flow gpm	Urea Flow gpm	Metering Pump Setting	Water+Urea gpm	[Urea] %
1	4	0	Off	-	-
2	3.99	0.81	33	4.8	7.4
3	3.99	0.81	33	4.8	7.4
4	4	0	Off	-	-
5	2.19	0.81	33	3	11.6
6	5.89	0.81	33	6.7	5.3
7	0.99	0.81	33	1.8	19.0
8	1	0	Off	-	-
9	1.6	0	Off	-	-
10	1.59	0.81	33	2.4	14.4
11	2.19	0.81	33	3	11.6
12	2.2	0	Off	-	-
13	2.2	0	Off	-	-
14	4.18	0.62	26	4.8	5.7
SCREEN	3.58	0.62	26	4.2	6.4
SCREEN	3.18	0.62	26	3.8	7.1
SCREEN	2.78	0.62	26	3.4	7.9
SCREEN	2.38	0.62	26	3	9.0
SCREEN	1.88	0.62	26	2.5	10.7
15	1.9	0	Off	-	-
16	2.38	0.62	26	3	9.0
SCREEN	6.08	0.62	26	6.7	4.1
SCREEN	7.08	0.62	26	7.7	3.5
SCREEN	8.38	0.62	26	9	3.0
17	8.4	0	Off	-	-
18	6.88	0.62	26	7.5	3.6
19	6.9	0	Off	-	-
SCREEN	6	1.4	55	7.4	8.2
SCREEN	5.1	1.4	55	6.5	9.3
SCREEN	7.1	1.4	55	8.5	7.2
20	5.1	1.4	55	6.5	9.3
21	4.65	1.85	72	6.5	12.3
22	5.8	0.7	29	6.5	4.7
23	5.8	0	Off	-	-
24	5.8	0	Off	-	-
25	5.8	0.7	29	6.5	4.7
26	5.43	1.07	43	6.5	7.2
27	6.14	0.36	16	6.5	2.4
28	6.1	0	Off	-	-
29	6.1	0	Off	-	-
30	Overscale	0.74	30	Overscale	-
SCREEN	Overscale	0.74	30	Overscale	-
SCREEN	Overscale	0.74	30	Overscale	-
SCREEN	Overscale	0.74	30	Overscale	-
SCREEN	Overscale	0.74	30	Overscale	-
31	7.8	0	Off	-	-
SCREEN	7.76	0.74	30	8.5	3.8
SCREEN	6.76	0.74	30	7.5	4.3
SCREEN	6.26	0.74	30	7	4.6
SCREEN	5.26	0.74	30	6	5.4
32	5.3	0	Off	-	-
SCREEN	5.26	0.74	30	6	5.4
SCREEN	4.76	0.74	30	5.5	5.9
SCREEN	2.56	0.74	30	3.3	9.7
SCREEN	0.36	0.74	30	1.1	27.8
SCREEN	2.26	0.74	30	3	10.7
SCREEN	2.3	0	Off	-	-
33	6.9	0	Off	-	-
34	6.9	1.1	44	8	6.0
35	7.6	1.1	44	8.7	5.5
36	6.4	1.1	44	7.5	6.4
37	5.4	1.1	44	6.5	7.4
38	5.4	0	Off	-	-
39	4.7	1.1	44	5.8	8.2
40	5.8	1.1	44	6.9	7.0
41	6.7	1.1	44	7.8	6.2
42	6.7	0	Off	-	-
43	6.7	0	Off	-	-
44	6.7	1.1	44	7.8	6.2
45	6.7	0	Off	-	-
46	6.9	1.1	44	8	6.0
47	6.9	0	Off	-	-
48	6.55	1.65	65	8.2	8.7
49	6.6	0	Off	-	-
50	6.6	1.65	65	8.2	8.7
51	6.6	0	Off	-	-

Parametric Test Results

Test	Inj #1	Inj #2	Inj #3	Inj #4	Inj #5	Inj #6	Inj #7	Inj #8
1	15055 V	15055 H	15055 H	15055 H	15055 H	15055 H	15055 H	15055V
2	Off	15055H	15055 H	15055 H	15055 H	15055 H	15055 H	Off
3	Off	2508H	2508H	2508H	2508H	2508H	2508H	Off
4	Off	2508H	2508H	2508H	2508H	2508H	2508H	Off
5	Off	2508H	2508H	2508H	2508H	2508H	2508H	Off
6	Off	2508H	2508H	2508H	2508H	2508H	2508H	Off
7	Off	2508H	2508H	2508H	2508H	2508H	2508H	Off
8	Off	2508H	2508H	2508H	2508H	2508H	2508H	Off
9	Off	2508H	2508H	2508H	2508H	2508H	2508H	Off
10	Off	2508H	2508H	2508H	2508H	2508H	2508H	Off
11	Off	2508H	2508H	2508H	2508H	2508H	2508H	Off
12	Off	2508H	2508H	2508H	2508H	2508H	2508H	Off
13	Off	2508H	2508H	2508H	2508H	2508H	2508H	Off
14	Off	2508H	2508H	2508H	2508H	2508H	2508H	Off
SCREEN	Off	2508H	2508H	2508H	2508H	2508H	2508H	Off
SCREEN	Off	2508H	2508H	2508H	2508H	2508H	2508H	Off
SCREEN	Off	2508H	2508H	2508H	2508H	2508H	2508H	Off
SCREEN	Off	2508H	2508H	2508H	2508H	2508H	2508H	Off
SCREEN	Off	2508H	2508H	2508H	2508H	2508H	2508H	Off
15	Off	2508H	2508H	2508H	2508H	2508H	2508H	Off
16	Off	2508H	2508H	2508H	2508H	2508H	2508H	Off
SCREEN	Off	J 5/64	J 5/64	J 5/64	J 5/64	J 5/64	J 5/64	Off
SCREEN	Off	J 5/64	J 5/64	J 5/64	J 5/64	J 5/64	J 5/64	Off
SCREEN	Off	J 5/64	J 5/64	J 5/64	J 5/64	J 5/64	J 5/64	Off
17	Off	J 5/64	J 5/64	J 5/64	J 5/64	J 5/64	J 5/64	Off
18	Off	J 5/64	J 5/64	J 5/64	J 5/64	J 5/64	J 5/64	Off
19	Off	J 5/64	J 5/64	J 5/64	J 5/64	J 5/64	J 5/64	Off
SCREEN	Off	J 5/64	J 5/64	J 5/64	J 5/64	J 5/64	J 5/64	Off
SCREEN	Off	J 5/64	J 5/64	J 5/64	J 5/64	J 5/64	J 5/64	Off
SCREEN	Off	J 5/64	J 5/64	J 5/64	J 5/64	J 5/64	J 5/64	Off
20	Off	J 5/64	J 5/64	J 5/64	J 5/64	J 5/64	J 5/64	Off
21	Off	J 5/64	J 5/64	J 5/64	J 5/64	J 5/64	J 5/64	Off
22	Off	J 5/64	J 5/64	J 5/64	J 5/64	J 5/64	J 5/64	Off
23	Off	J 5/64	J 5/64	J 5/64	J 5/64	J 5/64	J 5/64	Off
24	Off	J 5/64	J 5/64	J 5/64	J 5/64	J 5/64	J 5/64	Off
25	Off	J 5/64	J 5/64	J 5/64	J 5/64	J 5/64	J 5/64	Off
26	Off	J 5/64	J 5/64	J 5/64	J 5/64	J 5/64	J 5/64	Off
27	Off	J 5/64	J 5/64	J 5/64	J 5/64	J 5/64	J 5/64	Off
28	Off	J 5/64	J 5/64	J 5/64	J 5/64	J 5/64	J 5/64	Off
29	Off	3 gpm/ 50	3 gpm/ 50	3 gpm/ 50	3 gpm/ 50	3 gpm/ 50	3 gpm/ 50	Off
30	Off	3 gpm/ 50V	3 gpm/ 50V	3 gpm/ 50V	3 gpm/ 50V	3 gpm/ 50V	3 gpm/ 50V	Off
SCREEN	Off	3 gpm/ 50	3 gpm/ 50	3 gpm/ 50	3 gpm/ 50	3 gpm/ 50	3 gpm/ 50	Off
SCREEN	Off	3 gpm/ 50	3 gpm/ 50	3 gpm/ 50	3 gpm/ 50	3 gpm/ 50	3 gpm/ 50	Off
SCREEN	Off	3 gpm/ 50	3 gpm/ 50	3 gpm/ 50	3 gpm/ 50	3 gpm/ 50	3 gpm/ 50	Off
SCREEN	Off	3 gpm/ 50	3 gpm/ 50	3 gpm/ 50	3 gpm/ 50	3 gpm/ 50	3 gpm/ 50	Off
31	Off	3 gpm/ 50	3 gpm/ 50	3 gpm/ 50	3 gpm/ 50	3 gpm/ 50	3 gpm/ 50	Off
SCREEN	Off	1.5 gpm/ 30	1.5 gpm/ 30	1.5 gpm/ 30	1.5 gpm/ 30	1.5 gpm/ 30	1.5 gpm/ 30	Off
SCREEN	Off	1.5 gpm/ 30	1.5 gpm/ 30	1.5 gpm/ 30	1.5 gpm/ 30	1.5 gpm/ 30	1.5 gpm/ 30	Off
SCREEN	Off	1.5 gpm/ 30	1.5 gpm/ 30	1.5 gpm/ 30	1.5 gpm/ 30	1.5 gpm/ 30	1.5 gpm/ 30	Off
SCREEN	Off	1.5 gpm/ 30	1.5 gpm/ 30	1.5 gpm/ 30	1.5 gpm/ 30	1.5 gpm/ 30	1.5 gpm/ 30	Off
32	Off	1.5 gpm/ 30	1.5 gpm/ 30	1.5 gpm/ 30	1.5 gpm/ 30	1.5 gpm/ 30	1.5 gpm/ 30	Off
SCREEN	Off	1.5 gpm/ 30	1.5 gpm/ 30	1.5 gpm/ 30	1.5 gpm/ 30	1.5 gpm/ 30	1.5 gpm/ 30	Off
SCREEN	Off	1.5 gpm/ 30	1.5 gpm/ 30	1.5 gpm/ 30	1.5 gpm/ 30	1.5 gpm/ 30	1.5 gpm/ 30	Off
SCREEN	Off	1.5 gpm/ 30	1.5 gpm/ 30	1.5 gpm/ 30	1.5 gpm/ 30	1.5 gpm/ 30	1.5 gpm/ 30	Off
SCREEN	Off	0.5 gpm/ 30	0.5 gpm/ 30	0.5 gpm/ 30	0.5 gpm/ 30	0.5 gpm/ 30	0.5 gpm/ 30	Off
SCREEN	Off	0.5 gpm/ 30	0.5 gpm/ 30	0.5 gpm/ 30	0.5 gpm/ 30	0.5 gpm/ 30	0.5 gpm/ 30	Off
SCREEN	Off	0.5 gpm/ 30	0.5 gpm/ 30	0.5 gpm/ 30	0.5 gpm/ 30	0.5 gpm/ 30	0.5 gpm/ 30	Off
33	2805V	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	2805V
34	2805V	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	2805V
35	2805V	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	2805V
36	2805V	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	2805V
37	2805V	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	2805V
38	2805V	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	2805V
39	2805V	1.5 gpm/30	1.5 gpm/30	Off	Off	1.5 gpm/30	1.5 gpm/30	2805V
40	Off	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	Off
41	2805V	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	2805V
42	2805V	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	2805V
43	2805V	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	2805V
44	2805V	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	2805V
45	2805V	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	2805V
46	2805V	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	2805V
47	2805V	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	2805V
48	2805V	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	2805V
49	2805V	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	2805V
50	2805V	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	2805V
51	2805V	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	2805V

Test	Inj #1 gph	Inj #2 gph	Inj #3 gph	Inj #4 gph	Inj #5 gph	Inj #6 gph	Inj #7 gph	Inj #8 gph
1	35	35	35	35	35	35	35	35
2	Off	48	48	47	48	48	48	Off
3	Off	48	48	48	48	48	48	Off
4	Off	44	44	44	44	44	44	Off
5	Off	32	32	32	32	32	32	Off
6	Off	76	76	76	76	76	76	Off
7	Off	20	20	20	20	20	18	Off
8	Off	20	20	20	20	20	20	Off
9	Off	20	20	20	20	20	20	Off
10	Off	20	20	20	33	33	33	Off
11	Off	29	29	29	38	38	38	Off
12	Off	29	29	29	38	38	38	Off
13	Off	47	47	47	47	47	47	Off
14	Off	47	47	47	47	47	47	Off
SCREEN	Off	42	42	42	42	42	42	Off
SCREEN	Off	39	39	39	39	39	39	Off
SCREEN	Off	35	35	35	35	35	35	Off
SCREEN	Off	32	32	32	32	32	32	Off
SCREEN	Off	27	27	27	27	27	27	Off
15	Off	27	27	27	27	27	27	Off
16	Off	32	32	32	32	32	32	Off
SCREEN	Off	76	72	50	64	62	74	Off
SCREEN	Off	86	81	55	72	69	81	Off
SCREEN	Off	90	90	87	90	90	90	Off
17	Off	90	90	87	90	90	90	Off
18	Off	88	82	55	69	69	81	Off
19	Off	88	82	55	69	69	81	Off
SCREEN	Off	88	70	55	70	66	84	Off
SCREEN	Off	76	60	46	60	58	72	Off
SCREEN	Off	95	78	60	80	74	92	Off
20	Off	76	60	47	61	58	71	Off
21	Off	76	60	47	61	58	71	Off
22	Off	76	60	47	61	58	71	Off
23	Off	76	60	47	61	58	71	Off
24	Off	76	60	47	61	58	71	Off
25	Off	76	60	47	61	58	71	Off
26	Off	76	60	47	61	58	71	Off
27	Off	76	60	47	61	58	71	Off
28	Off	76	60	47	61	58	71	Off
29	Off	76	60	47	61	58	71	Off
30	Off	Overscale	Overscale	Overscale	Overscale	Overscale	Overscale	Off
SCREEN	Off	Overscale	Overscale	Overscale	Overscale	Overscale	Overscale	Off
SCREEN	Off	Overscale	Overscale	Overscale	Overscale	Overscale	Overscale	Off
SCREEN	Off	Overscale	Overscale	Overscale	Overscale	Overscale	Overscale	Off
SCREEN	Off	Overscale	Overscale	Overscale	Overscale	Overscale	Overscale	Off
31	Off	Overscale	Overscale	Overscale	Overscale	Overscale	Overscale	Off
SCREEN	Off	82	82	82	82	82	82	Off
SCREEN	Off	75	75	75	75	75	75	Off
SCREEN	Off	68	68	68	68	68	68	Off
SCREEN	Off	62	62	62	62	62	62	Off
32	Off	62	62	62	62	62	62	Off
SCREEN	Off	62	62	62	62	62	62	Off
SCREEN	Off	54	54	54	54	54	54	Off
SCREEN	Off	33	33	33	33	33	33	Off
SCREEN	Off	11	11	11	11	11	11	Off
SCREEN	Off	30	30	30	30	30	30	Off
SCREEN	Off	30	30	30	30	30	30	Off
33	31	68	68	68	68	68	68	31
34	31	68	68	68	68	68	68	31
35	32	76	76	76	76	76	76	32
36	32	62	62	62	62	62	62	32
37	32	57	57	57	57	57	57	32
38	32	57	57	57	57	57	57	32
39	31	69	69	Off	Off	69	69	31
40	Off	69	69	69	69	69	69	Off
41	31	69	69	69	69	69	69	31
42	31	69	69	69	69	69	69	31
43	31	69	69	69	69	69	69	31
44	31	69	69	69	69	69	69	31
45	31	69	69	69	69	69	69	31
46	31	69	69	69	69	69	69	31
47	31	69	69	69	69	69	69	31
48	31	69	69	69	69	69	69	31
49	31	69	69	69	69	69	69	31
50	31	69	69	69	69	69	69	31
51	31	69	69	69	69	69	69	31

Parametric Test Results

Test	Inj #1	Inj #2	Inj #3	Inj #4	Inj #5	Inj #6	Inj #7	Inj #8
	psi	psi	psi	psi	psi	psi	psi	psi
1	46	46	46	46	46	46	46	46
2	Off	86	87	86	86	87	85	Off
3	Off	44	44	44	44	44	44	Off
4	Off	38	38	38	38	38	38	Off
5	Off	20	20	20	20	20	20	Off
6	Off	80	80	80	80	80	80	Off
7	Off	10	10	10	10	10	10	Off
8	Off	10	10	10	10	10	10	Off
9	Off	10	10	10	10	10	10	Off
10	Off	10	10	10	20	20	20	Off
11	Off	15	15	15	25	25	25	Off
12	Off	15	15	15	25	25	25	Off
13	Off	40	40	40	40	40	40	Off
14	Off	42	42	42	42	42	42	Off
SCREEN	Off	35	35	35	35	35	35	Off
SCREEN	Off	30	30	30	30	30	30	Off
SCREEN	Off	25	25	25	25	25	25	Off
SCREEN	Off	20	20	20	20	20	20	Off
SCREEN	Off	15	15	15	15	15	15	Off
15	Off	15	15	15	15	15	15	Off
16	Off	20	20	20	20	20	20	Off
SCREEN	Off	20	20	20	20	20	20	Off
SCREEN	Off	25	25	25	25	25	25	Off
SCREEN	Off	28	30	55	37	38	30	Off
17	Off	28	30	55	37	38	30	Off
18	Off	25	25	25	25	25	25	Off
19	Off	25	25	25	25	25	25	Off
SCREEN	Off	25	25	25	25	25	25	Off
SCREEN	Off	20	20	20	20	20	20	Off
SCREEN	Off	30	30	30	30	30	30	Off
20	Off	20	20	20	20	20	20	Off
21	Off	20	20	20	20	20	20	Off
22	Off	20	20	20	20	20	20	Off
23	Off	20	20	20	20	20	20	Off
24	Off	20	20	20	20	20	20	Off
25	Off	20	20	20	20	20	20	Off
26	Off	20	20	20	20	20	20	Off
27	Off	20	20	20	20	20	20	Off
28	Off	20	20	20	20	20	20	Off
29	Off	20	20	20	20	20	20	Off
30	Off	30	30	30	30	30	30	Off
SCREEN	Off	30	30	30	30	30	30	Off
SCREEN	Off	35	35	35	35	35	35	Off
SCREEN	Off	40	40	40	40	40	40	Off
SCREEN	Off	45	45	45	45	45	45	Off
31	Off	45	45	45	45	45	45	Off
SCREEN	Off	40	40	40	40	40	40	Off
SCREEN	Off	35	35	35	35	35	35	Off
SCREEN	Off	30	30	30	30	30	30	Off
SCREEN	Off	25	25	25	25	25	25	Off
32	Off	25	25	25	25	25	25	Off
SCREEN	Off	25	25	25	25	25	25	Off
SCREEN	Off	20	20	20	20	20	20	Off
SCREEN	Off	10	10	10	10	10	10	Off
SCREEN	Off	10	10	10	10	10	10	Off
SCREEN	Off	40	40	40	40	40	40	Off
SCREEN	Off	40	40	40	40	40	40	Off
33	20	30	30	30	30	30	30	20
34	20	30	30	30	30	30	30	20
35	20	35	35	35	35	35	35	20
36	20	25	25	25	25	25	25	20
37	20	20	20	20	20	20	20	20
38	20	20	20	20	20	20	20	20
39	20	30	30	Off	Off	30	30	20
40	Off	30	30	30	30	30	30	Off
41	20	30	30	30	30	30	30	20
42	20	30	30	30	30	30	30	20
43	20	30	30	30	30	30	30	20
44	20	30	30	30	30	30	30	20
45	20	30	30	30	30	30	30	20
46	20	30	30	30	30	30	30	20
47	20	30	30	30	30	30	30	20
48	20	30	30	30	30	30	30	20
49	20	30	30	30	30	30	30	20
50	20	30	30	30	30	30	30	20
51	20	30	30	30	30	30	30	20

Test	NSR	O2 % dry	O2 % wet	CO ppm	NOx ppm	NOxc ppmc	NOx-Baseline ppmc	NOx lb/MMBtu	NOx-Baseline lb/MMBtu	dNOx %
1	-	3.90	3.43	317	71.0	74.8		0.102		-
2	1.5	3.88	3.41	455	72.0	75.7	74.1	0.103	0.101	-2.1
3	1.5	3.83	3.37	345	69.0	72.4	74.1	0.099	0.101	2.4
4	-	3.86	3.40	434	70.0	73.5		0.101		-
5	1.5	4.02	3.54	299	66.0	70.0	72.4	0.096	0.099	3.3
6	1.5	4.02	3.54	387	69.0	73.2	72.4	0.100	0.099	-1.1
7	1.5	4.12	3.63	197	69.0	73.6	72.4	0.101	0.099	-1.7
8	-	3.55	3.12	590	69.0	71.2		0.097		-
9	-	3.88	3.41	342	73.0	76.8		0.105		-
10	1.5	3.94	3.47	116	70.0	73.9	76.4	0.101	0.104	3.2
11	1.5	3.95	3.48	289	71.0	75.0	76.4	0.102	0.104	1.8
12	-	3.93	3.46	307	72.0	75.9		0.104		-
13	-	3.96	3.48	312	66.0	69.7		0.095		-
14	1.5	4.23	3.72	181	62.0	66.6	68.3	0.091	0.093	2.6
SCREEN	1.5	4.01	3.53		60.2	63.8	68.3	0.087	0.093	6.6
SCREEN	1.5	3.99	3.51		60.8	64.4	68.3	0.088	0.093	5.8
SCREEN	1.5	4.00	3.52		59.8	63.3	68.3	0.087	0.093	7.3
SCREEN	1.5	3.99	3.51		57.8	61.2	68.3	0.084	0.093	10.5
SCREEN	1.5	4.10	3.61		57.7	61.5	68.3	0.084	0.093	10.0
15	-	4.05	3.56	220	63.0	66.9		0.091		-
16	1.6	4.08	3.59	244	57.0	60.7	65.1	0.083	0.089	6.8
SCREEN	1.6	3.91	3.44		56.1	59.1	65.1	0.081	0.089	9.2
SCREEN	1.6	3.69	3.25		54.7	56.9	65.1	0.078	0.089	12.6
SCREEN	1.6	4.35	3.83		55.0	59.5	65.1	0.081	0.089	8.6
17	-	3.91	3.44	358	60.0	63.2		0.086		-
18	1.6	4.02	3.54	279	56.0	59.4	63.2	0.081	0.086	6.1
19	-	4.00	3.52	15	176.0	186.4		0.255		-
SCREEN	1.0	3.80	3.34	15	141.3	147.9	186.4	0.202	0.255	20.7
SCREEN	1.0	3.68	3.24	18.9	135.8	141.2	186.4	0.193	0.255	24.3
SCREEN	1.0	3.74	3.29	18.3	140.1	146.1	186.4	0.200	0.255	21.6
20	1.0	4.00	3.52	15	152.0	161.0	186.4	0.220	0.255	13.6
21	1.4	3.69	3.25	35	139.0	144.6	186.4	0.198	0.255	22.4
22	0.5	3.55	3.12	35	157.0	162.0	186.4	0.221	0.255	13.1
23	-	3.93	3.46	66	189.0	199.4		0.272		-
24	-	4.21	3.70	105	92.0	98.7		0.135		-
25	1.0	3.99	3.51	168	84.0	88.9	98.7	0.122	0.135	9.9
26	1.6	4.01	3.53	123	88.0	93.3	93.9	0.127	0.128	0.7
27	0.5	4.22	3.71	88	98.0	105.2	93.9	0.144	0.128	-12.0
28	-	4.12	3.63	118	88.0	93.9		0.128		-
29	-	3.93	3.46	378	65.0	68.6		0.094		-
30	1.5	3.98	3.50	407	63.0	66.6	69.2	0.091	0.095	3.7
SCREEN	1.5	3.81	3.35	290	64.3	67.3	69.2	0.092	0.095	2.7
SCREEN	1.5	3.72	3.27	334	64.2	66.9	69.2	0.091	0.095	3.4
SCREEN	1.5	3.78	3.33	354	65.9	68.9	69.2	0.094	0.095	0.4
SCREEN	1.5	3.83	3.37	425	65.5	68.7	69.2	0.094	0.095	0.8
31	-	3.99	3.51	396	66.0	69.9		0.095		-
SCREEN	1.5	3.81	3.35	441	66.7	69.9	69.9	0.095	0.095	0.0
SCREEN	1.5	3.89	3.42	314	66.2	69.7	69.9	0.095	0.095	0.3
SCREEN	1.5	3.90	3.43	408	65.8	69.3	69.9	0.095	0.095	0.8
SCREEN	1.5	3.71	3.26	371	64.2	66.9	69.9	0.091	0.095	4.3
32	-	4.10	3.61	269	67.0	71.4		0.098		-
SCREEN	1.4	3.74	3.29	340	66.0	68.8	71.5	0.094	0.098	3.7
SCREEN	1.4	3.71	3.26	317	68.8	71.6	71.5	0.098	0.098	-0.2
SCREEN	1.4	3.79	3.34	241	70.4	73.7	71.5	0.101	0.098	-3.0
SCREEN	1.4	3.85	3.39	239	77.6	81.5	71.5	0.111	0.098	-14.0
SCREEN	1.4	3.71	3.26	282	74.9	78.0	71.5	0.107	0.098	-9.1
SCREEN	-	3.74	3.29	242	68.6	71.6		0.098		-
33	-	3.89	3.42	62	147.0	154.7		0.211		-
34	1.0	3.67	3.23	81	106.0	110.1	154.7	0.151	0.211	28.8
35	1.0	3.69	3.25	67	111.0	115.5	154.7	0.158	0.211	25.4
36	1.0	3.73	3.28	56	107.0	111.5	154.7	0.152	0.211	27.9
37	1.0	3.64	3.20	81	104.0	107.9	154.7	0.147	0.211	30.3
38	-	4.08	3.59	31	146.0	155.4		0.212		-
39	1.0	3.66	3.22	58	114.0	118.4	159.8	0.162	0.218	25.9
40	1.0	3.59	3.16	50	117.0	121.0	159.8	0.165	0.218	24.3
41	1.0	3.85	3.39	44	121.0	127.0	159.8	0.174	0.218	20.5
42	-	3.45	3.04	43	160.0	164.1		0.224		-
43	-	3.42	3.01	422	120.0	122.9		0.168		-
44	1.2	3.49	3.07	385	91.0	93.6	122.9	0.128	0.168	23.9
45	-	3.90	3.43	330	74.0	77.9		0.106		-
46	2.0	4.06	3.57	361	67.0	71.2	77.4	0.097	0.106	8.0
47	-	4.13	3.63	308	72.0	76.9		0.105		-
48	3.0	4.00	3.52	380	62.0	65.7	76.9	0.090	0.105	14.6
49	-	4.06	3.57	162	83.0	88.2		0.121		-
50	2.8	3.95	3.48	212	68.5	72.3	81.3	0.099	0.111	11.0
51	-	4.04	3.56	249	70.0	74.3		0.102		-

Parametric Test Results

Test	North InfraView °F	SpectraTemp °F	South InfraView °F	South Duct, Int. TDL Ammonia Slip ppmc	Wet Chem. Ammonia Slip (ppmc) North	South
1	2045	2155	1700			
2	2050	2186	1770			
3	2060	2177	1760			
4	2030	2175	1720			
5	2070	2166	1740			
6	2050	2177	1710			
7	2070	2180	1800			
8	2060	2200	1700			
9				0.7		
10	2090	2205	1690	4.8		
11	2090	2200	1750	6.3		
12				0.5		
13	1980	2140	1580	0.7		
14	1950	2150	1625	2.5		
SCREEN						
SCREEN						
SCREEN						
SCREEN						
SCREEN						
15						
16	1960	2145	1600			
SCREEN						
SCREEN						
SCREEN	2010	2160	1580			
17						
18	2020	2160	1590			9.5
19						
SCREEN	1950	2295	1600			
SCREEN	1950	2305	1660			
SCREEN	1980	2320	1660			
20	1940	2315	1660		4.8	9.8
21	1920	2305	1640			
22	1940	2305	1650			
23						
24						
25	2040	2245	1680		3.4	5.2
26						
27	1990	2215	1740			
28						
29				0.6		
30	2100	2200	1680	6.1		
SCREEN				3.8		
SCREEN				3.5		
SCREEN	2125	2193	1680	2.8		
SCREEN				1.8		
31				0.8		
SCREEN	2100	2220	1600	2.3		
SCREEN				1.8		
SCREEN				2.3		
SCREEN				1.1		
32				0.3		
SCREEN						
SCREEN	2130	2194	1760			
SCREEN						
SCREEN	2120	2190	1750			
SCREEN						
SCREEN						
33				0.8		
34	1860	2255	1560	2.8		
35	1858	2265	1585	5.4		
36	1875	2266	1540	5.1		
37	1890	2267	1585	2.1		
38				0.8		
39	1900	2276	1590	1.8		
40	1910	2276	1630	2.8		
41	1900	2275	1580	2.7		
42				0.4		
43				0.8		
44	1920	2271	1620	2.1		
45				0.5		
46	2060	2194		2.3		
47				0.3		
48	2010	2180		19.1	24.4	19.9
49				0.8		
50	2070	2205		7.8	18.5	22.4
51				0.7		

C
COAL ANALYSIS

SGS

January 02, 2009

Fossil Energy Research
23342 C South Pointe
Laguna Hills, CA 92653
USA

Client Sample ID:	11-20-08-B32-2101	**P. O. #:**	08-578-2101
Date Received:	12/23/2008	**Sample Type:**	-8 Mesh Moist
Matrix:	Coal		
Net Sample Weight:	1230.90		

SGS Sample ID: 072-36941-001

		As Received	Dry	MAF
% Moisture, Total	[ASTM D 3302)	29.13		
% Ash	[ASTM D 3174/5142]	5.12	7.22	
% Volatile Matter	[ASTM D 5142]	30.39	42.89	46.23
% Fixed Carbon	[ASTM D 3172]	35.36	49.89	53.77
Gross Calorific Value (Btu/lb)	[ASTM D 5865]	8486	11978	12910
% Sulfur	[ASTM D 4239]	0.27	0.38	
% Carbon	[ASTM D 5373]	49.23	69.47	
% Hydrogen	[ASTM D 5373]	3.17	4.47	
% Nitrogen	[ASTM D 5373]	0.70	0.99	
% Oxygen (Calc)	[ASTM D 3176]	12.38	17.47	

Analyte	Result	Method
Pounds of Ash/mm Btu	6.03 lb	ASTM D 5865
Pounds of Sulfur/mm Btu	0.32 lb	ASTM D 5865
Pounds of SO2/mm Btu	0.64 lb	ASTM D 5865

Respectfully submitted,
SGS NORTH AMERICA INC.

Denver Laboratory

Page 1 of 1

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4665 Paris Street, Suite B-200, Denver, CO 80239 t (303) 373-4772 f (303) 373-4791 www.us.sgs.com/minerals

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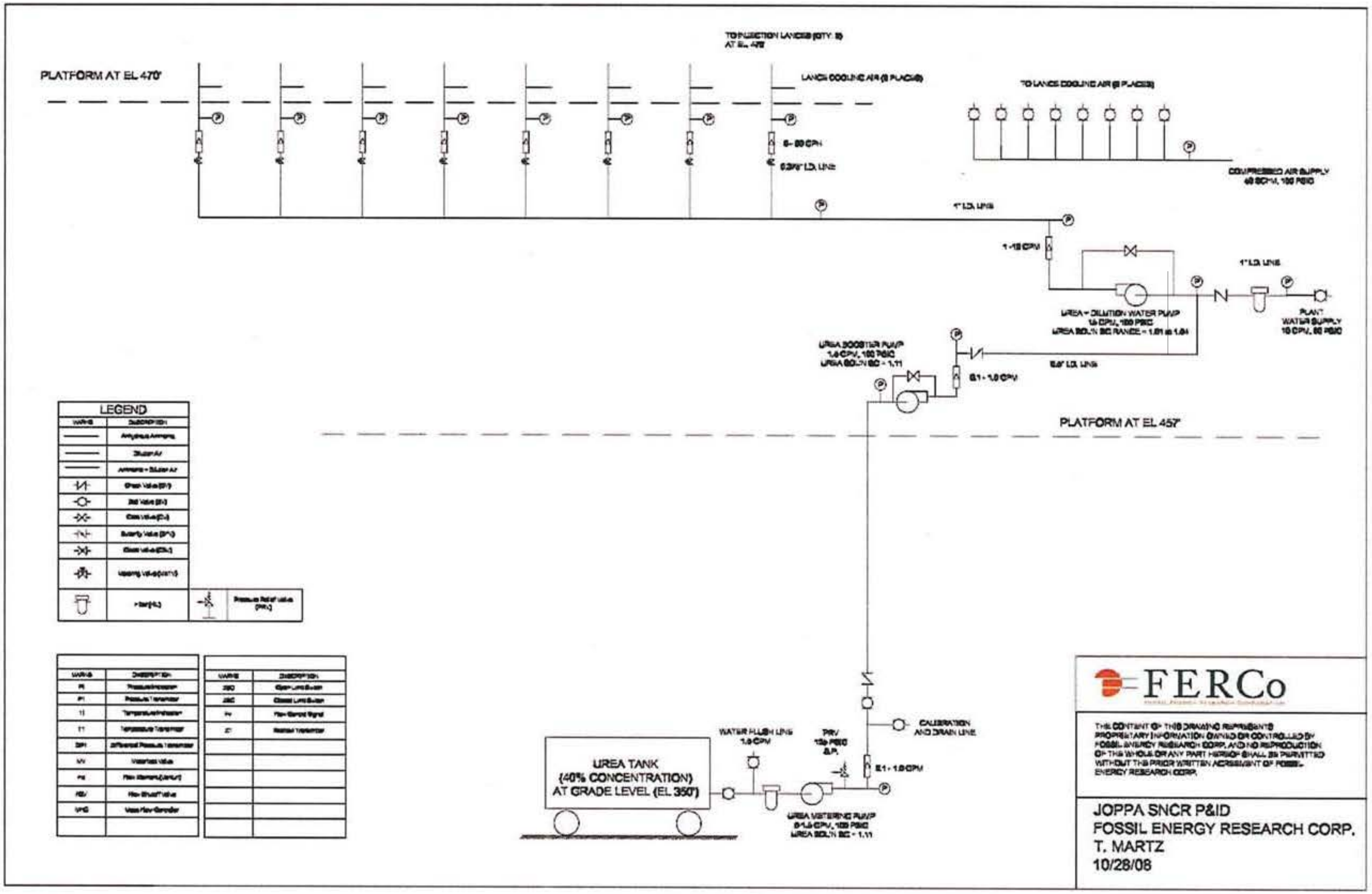
D
SNCR P&ID



Confidential Business Information

E
CONTOUR PLOTS

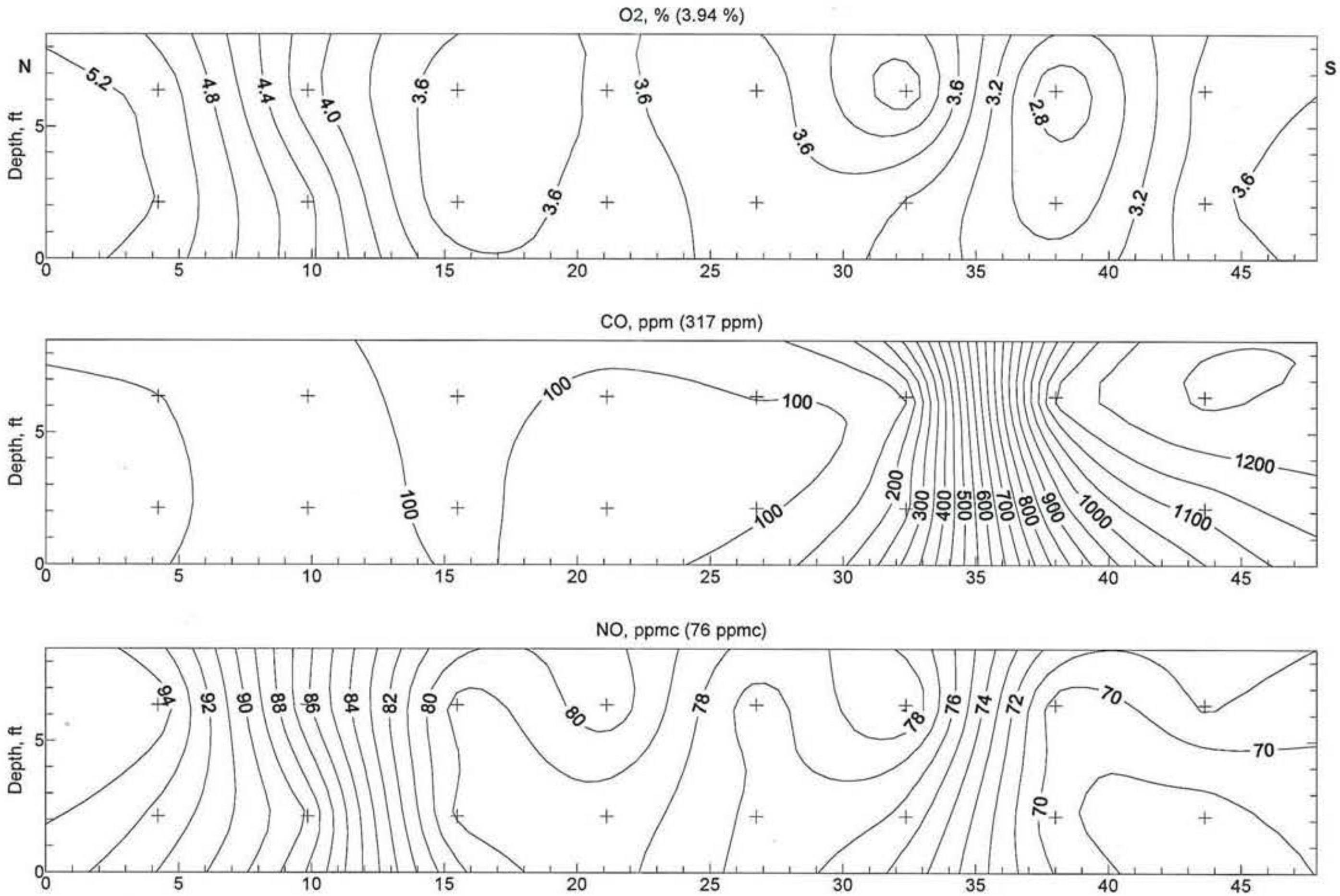


Figure E-1
Test 1, Full Load Baseline, Day 1 (11/15/08)

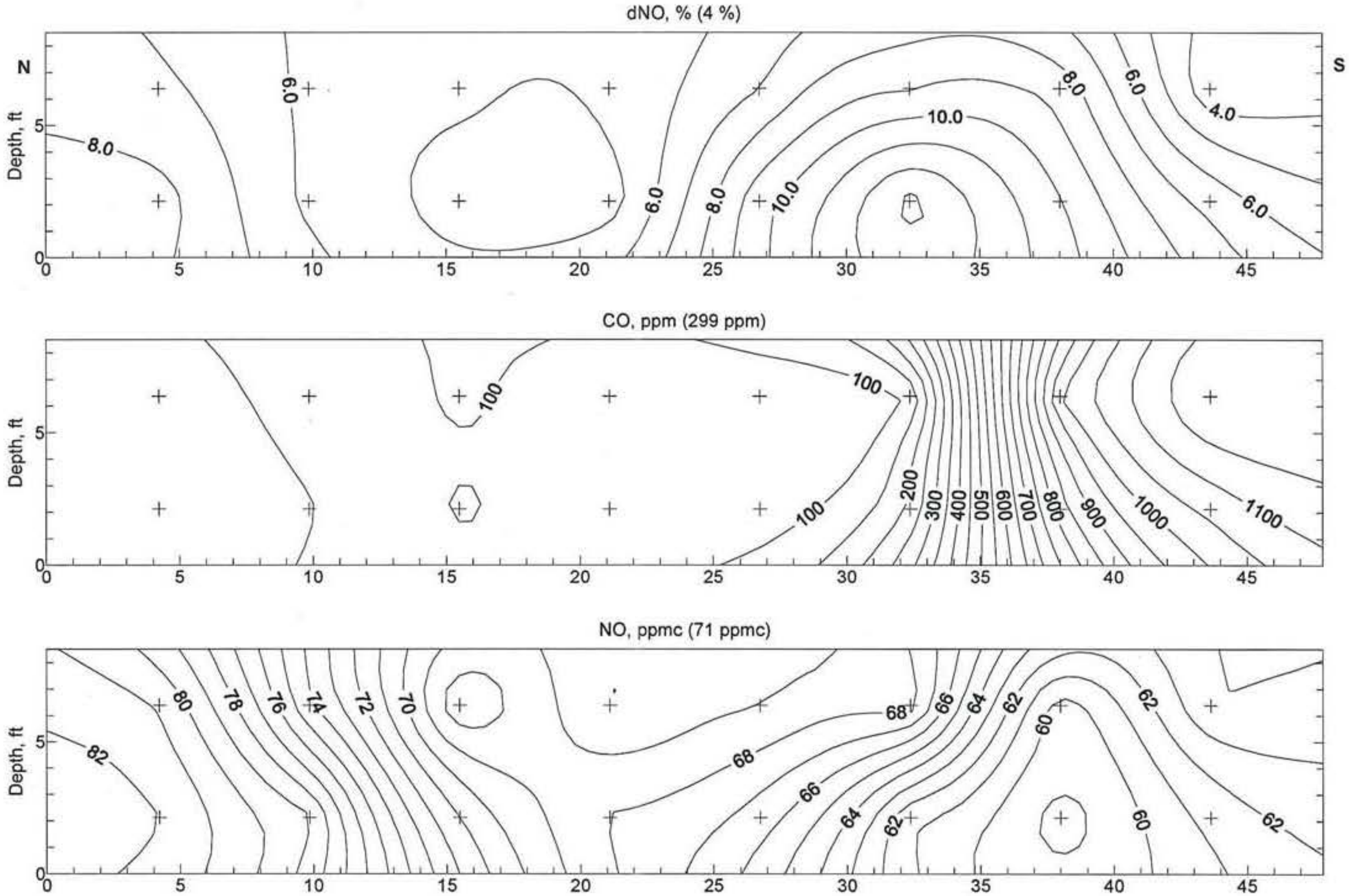


Figure E-2
Test 5, SNCR Injection Test, Day 1 (11/15/08)

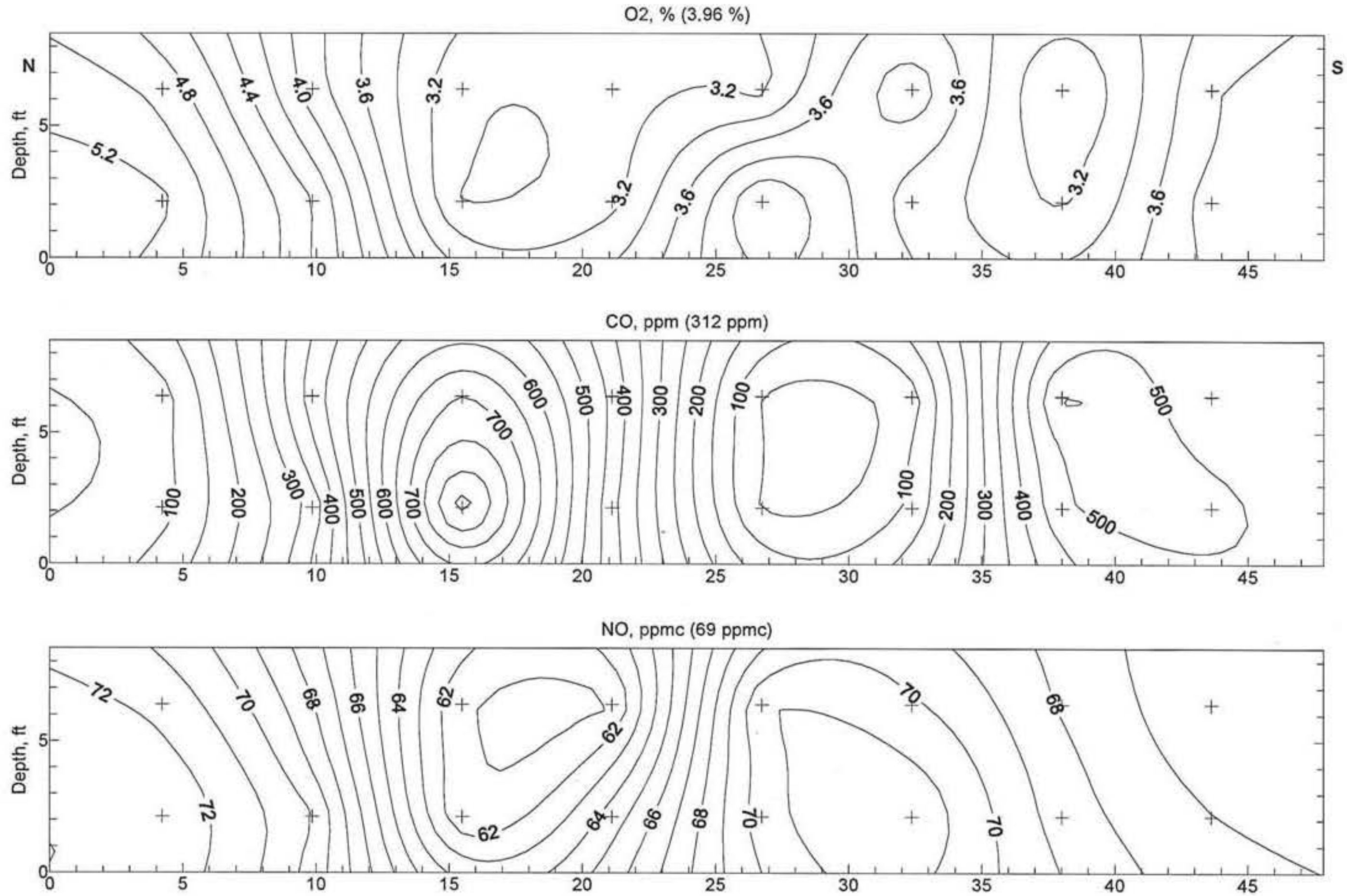


Figure E-3
Test 13, 150 MWg Baseline, Day 2 (11/16/08)

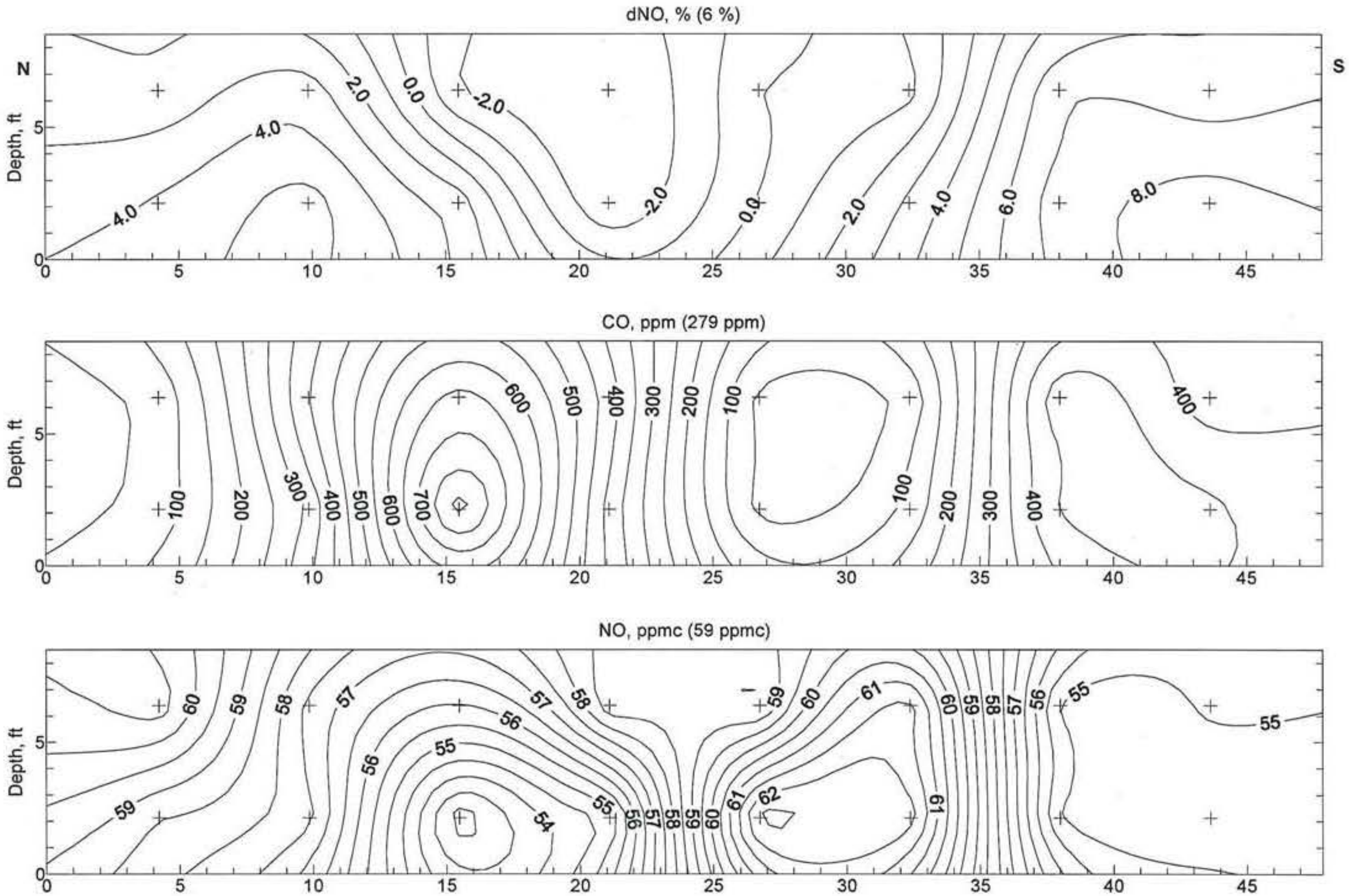


Figure E-4
Test 18, SNCR Injection Test, Day 2 (11/16/08)

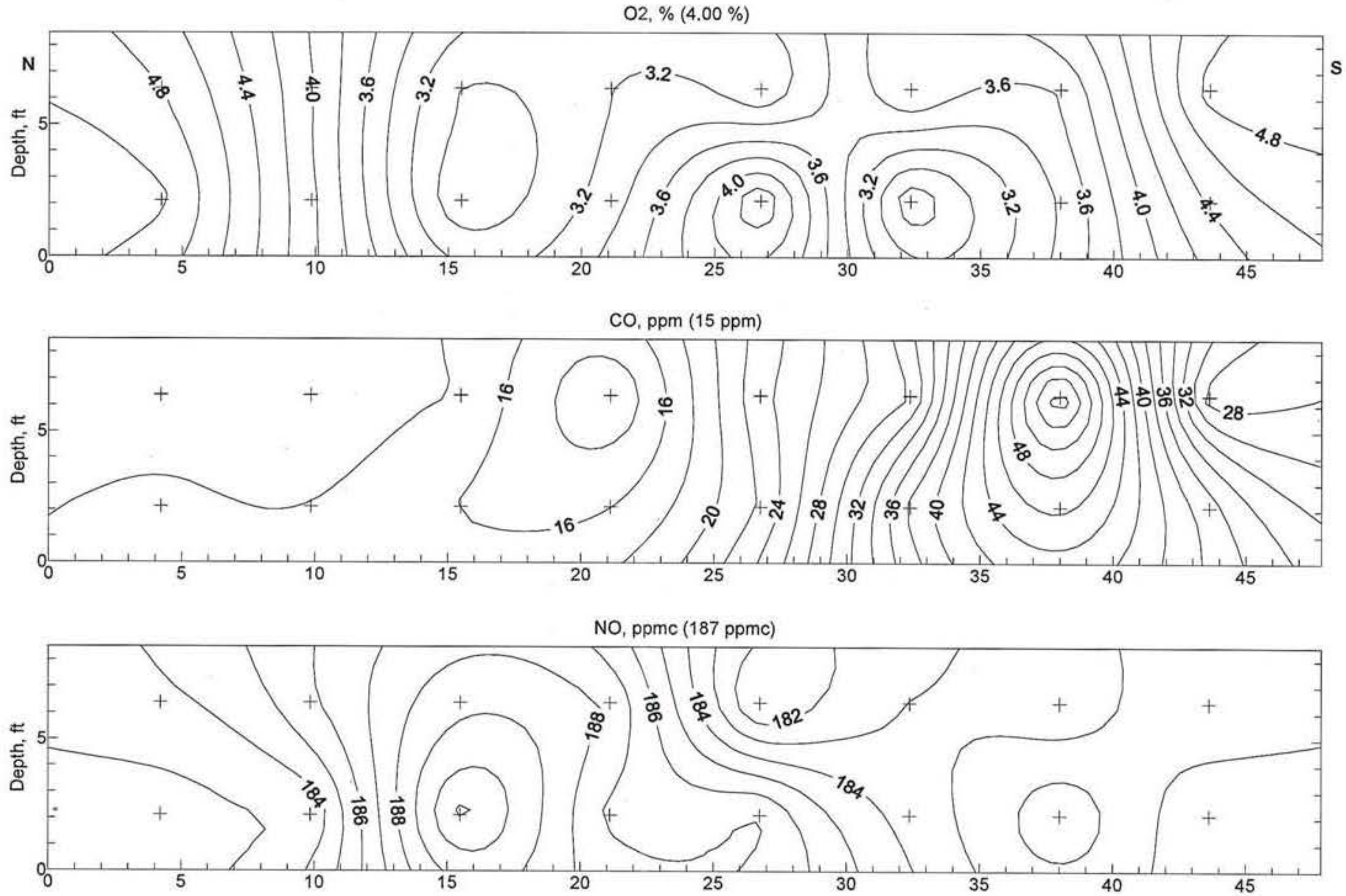


Figure E-5
Test 19, SOFA Off Baseline, Day 3 (11/17/08)

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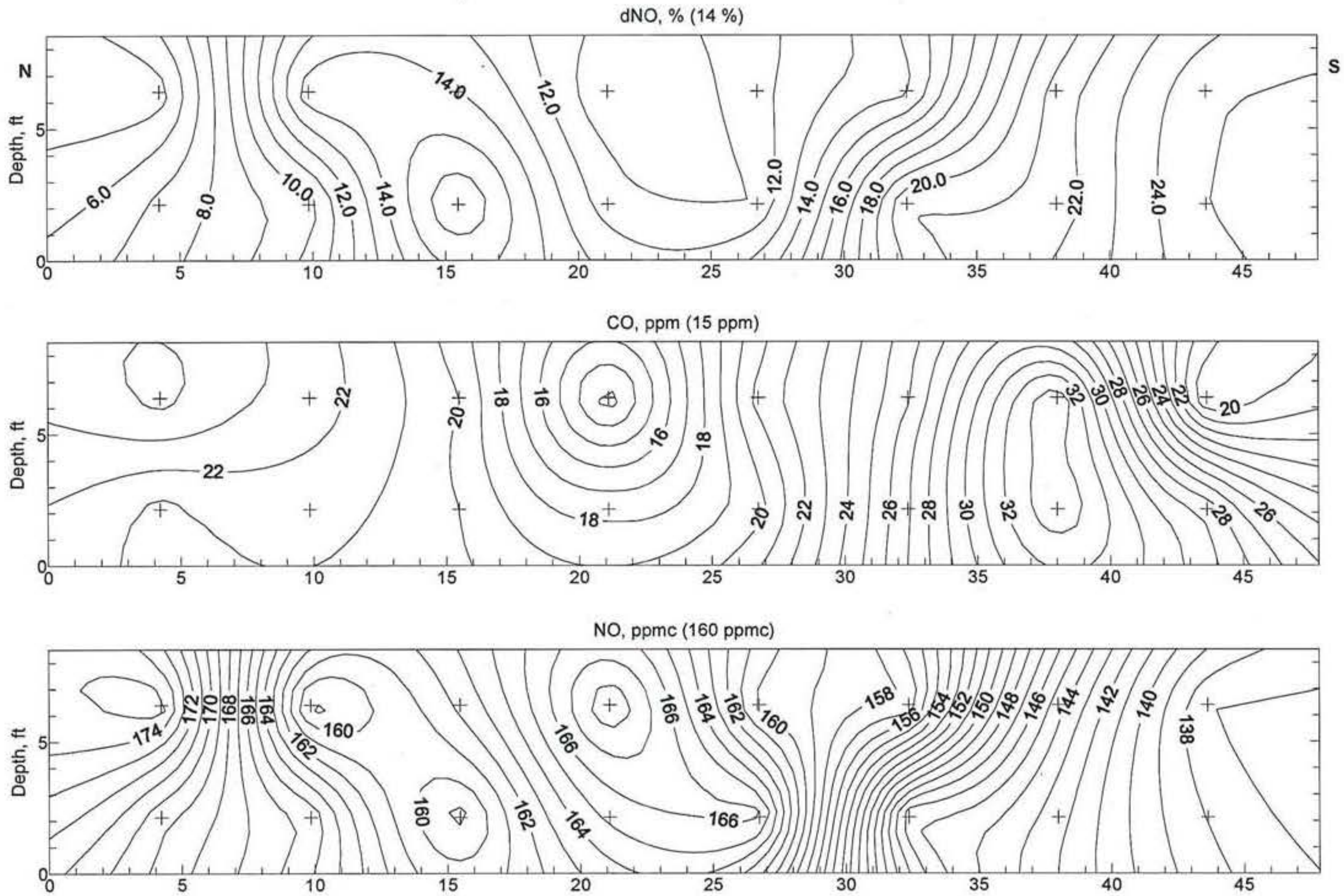

Figure E-6
Test 20, SNCR Injection Test, Day 3 (11/17/08)

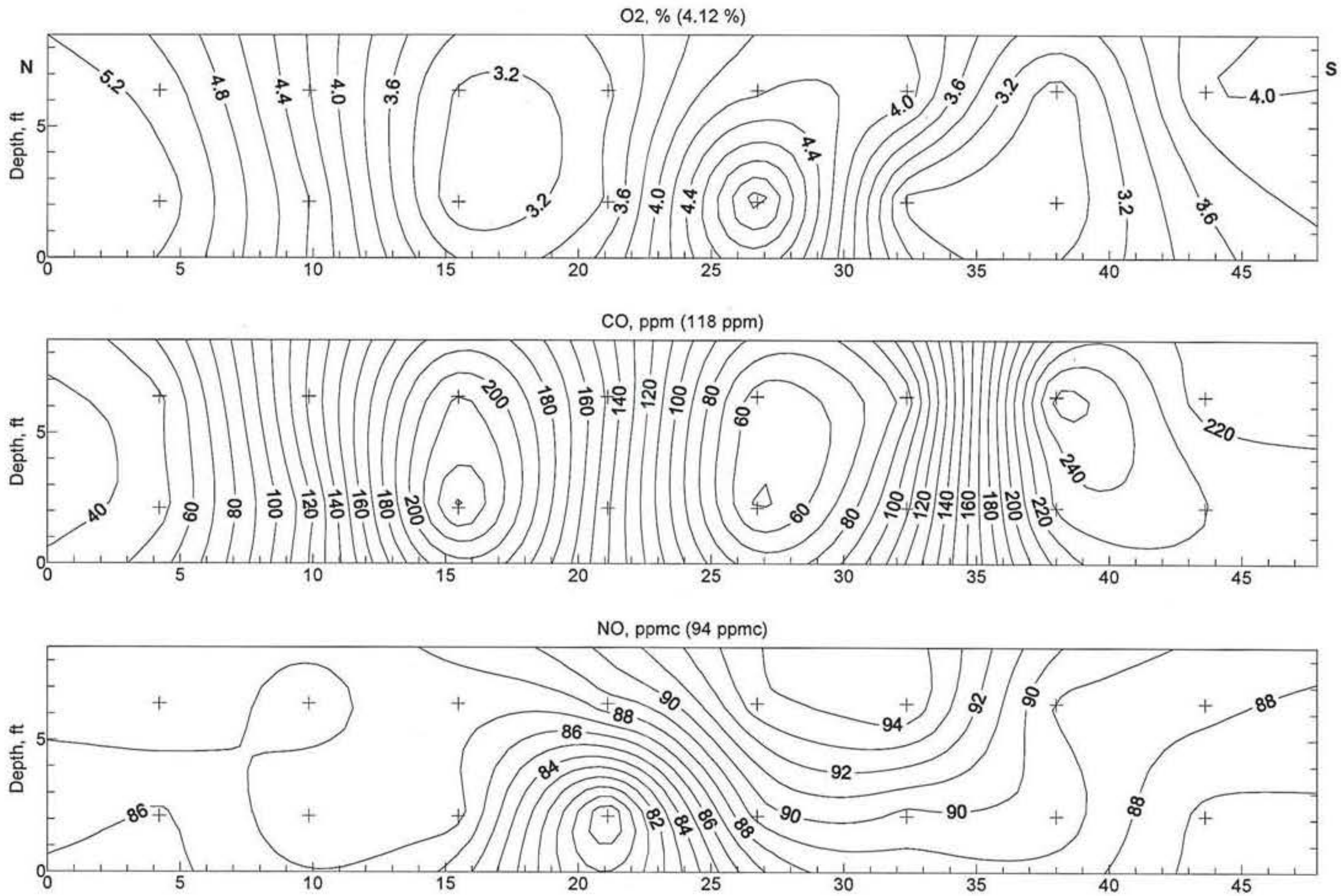

Figure E-7
Test 28, Middle SOFA Baseline, Day 3 (11/17/08)

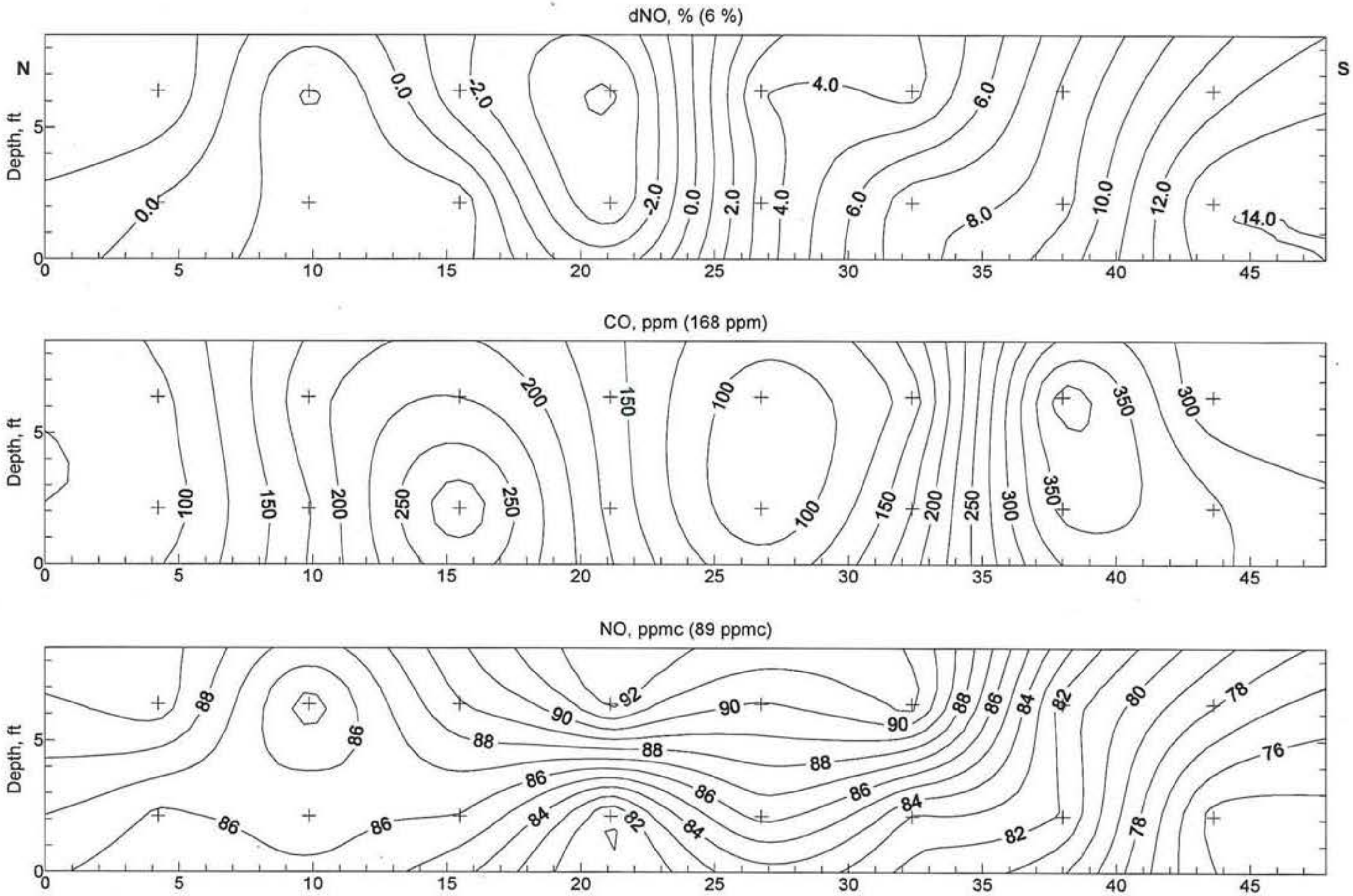

Figure E-8
Test 25, SNCR Injection Test, Day 3 (11/17/08)

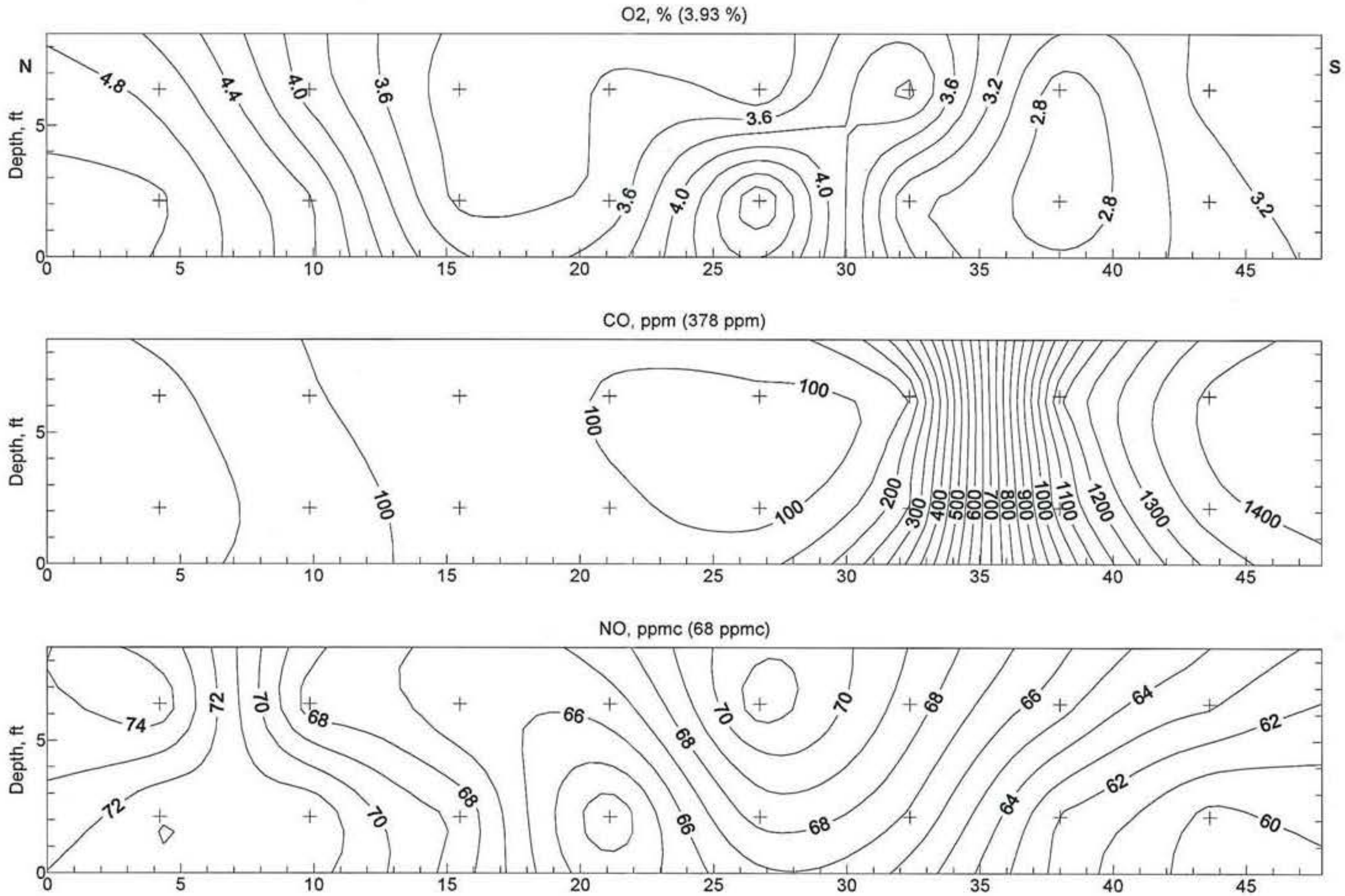

Figure E-9
Test 29, Full Load Baseline, Day 4 (11/18/08)

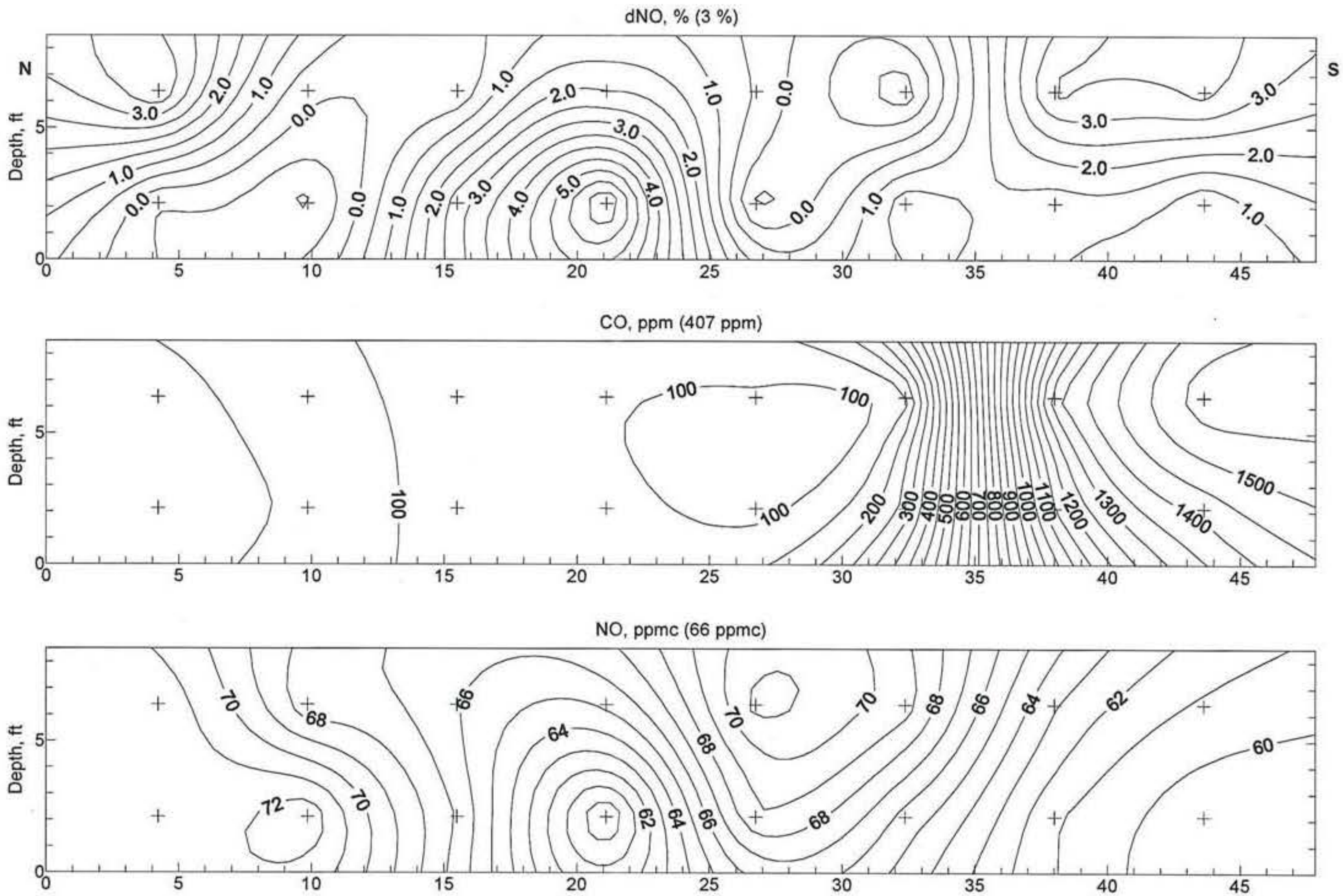

Figure E-10
Test 30, SNCR Injection Test, Day 4 (11/18/08)

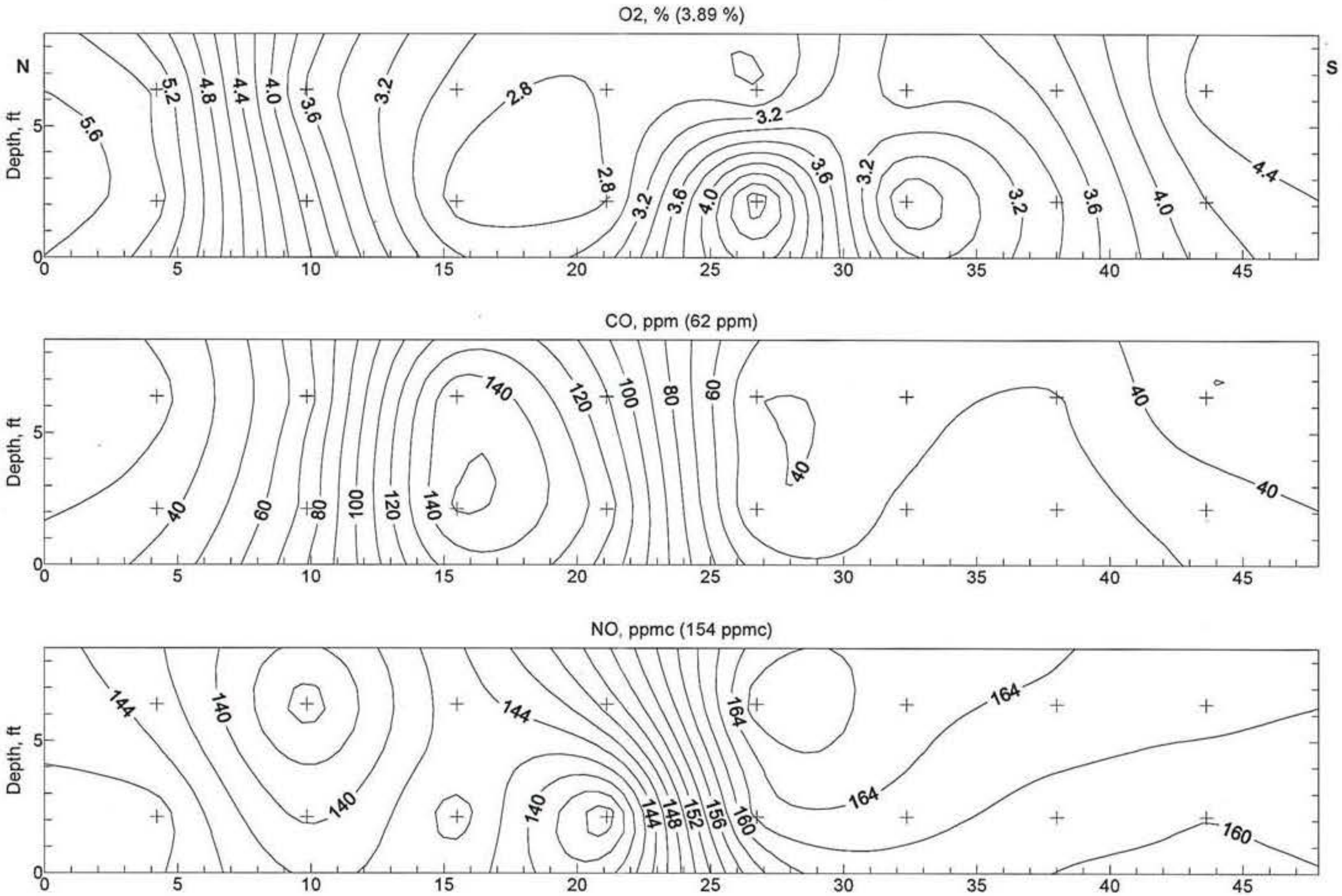

Figure E-11
Test 33, Middle SOFA Baseline, Day 5 (11/19/08)

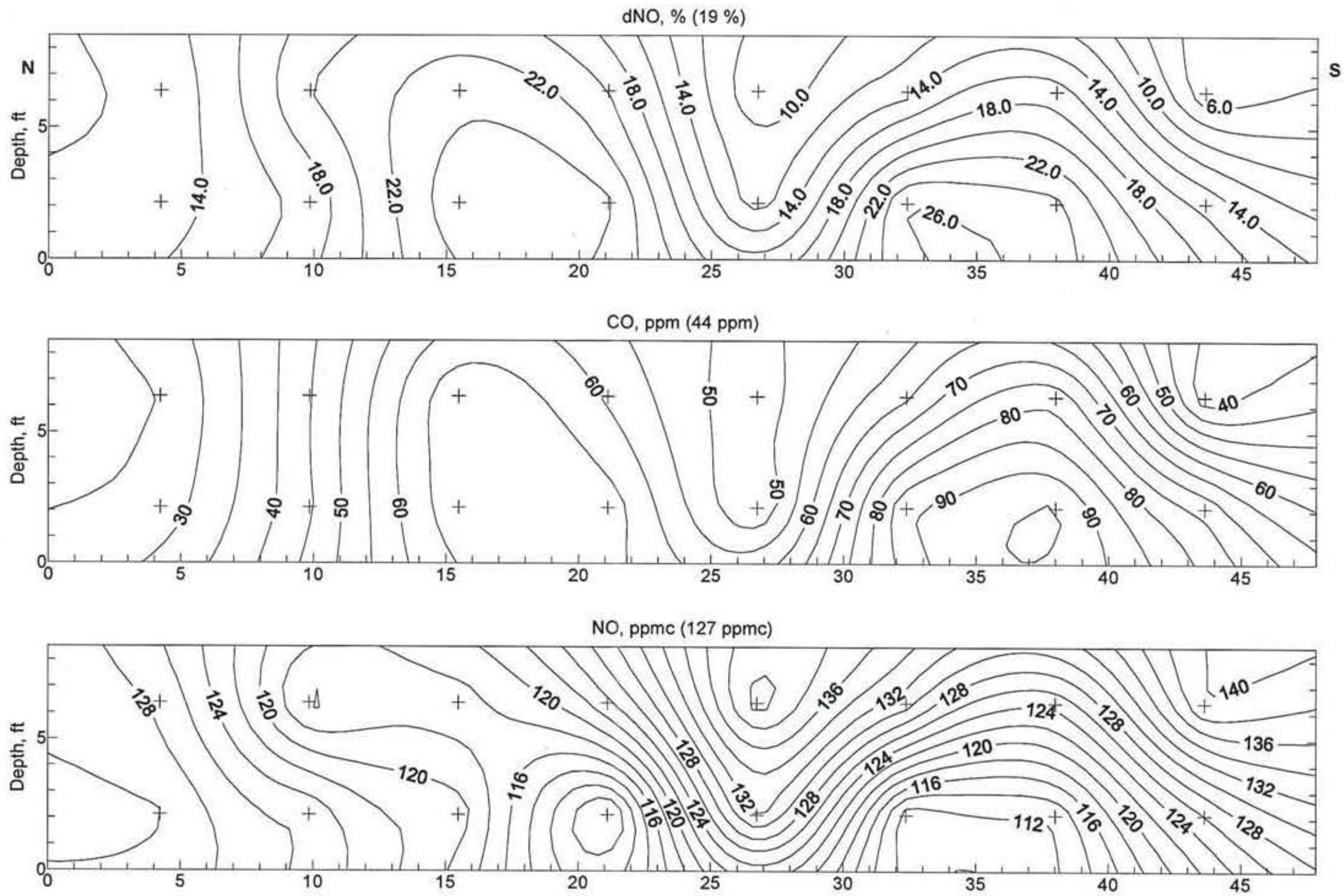

Figure E-12
Test 41, SNCR Injection Test, Day 5 (11/19/08)

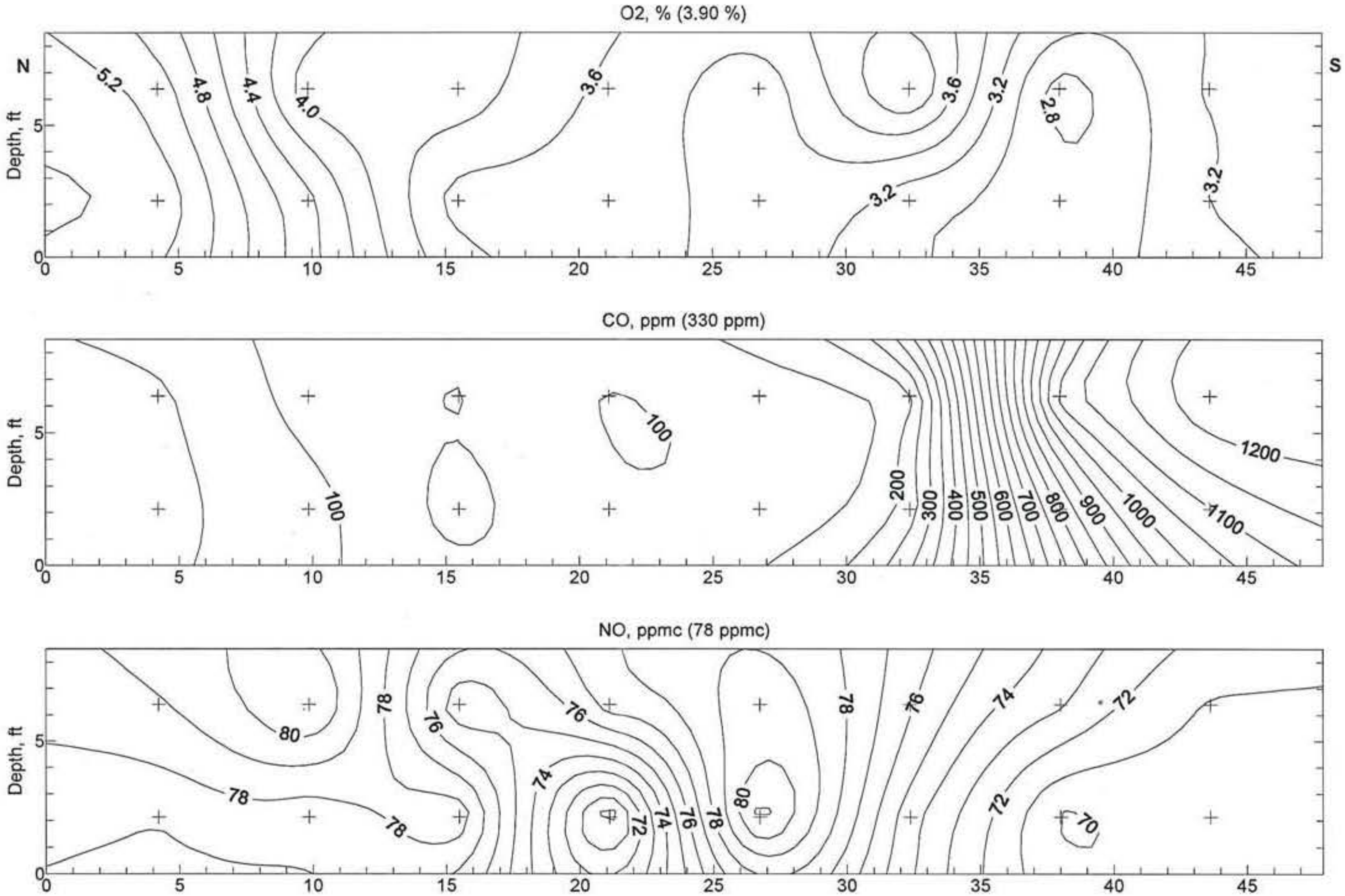

Figure E-13
Test 45, Full Load Baseline, Day 6 (11/20/08)

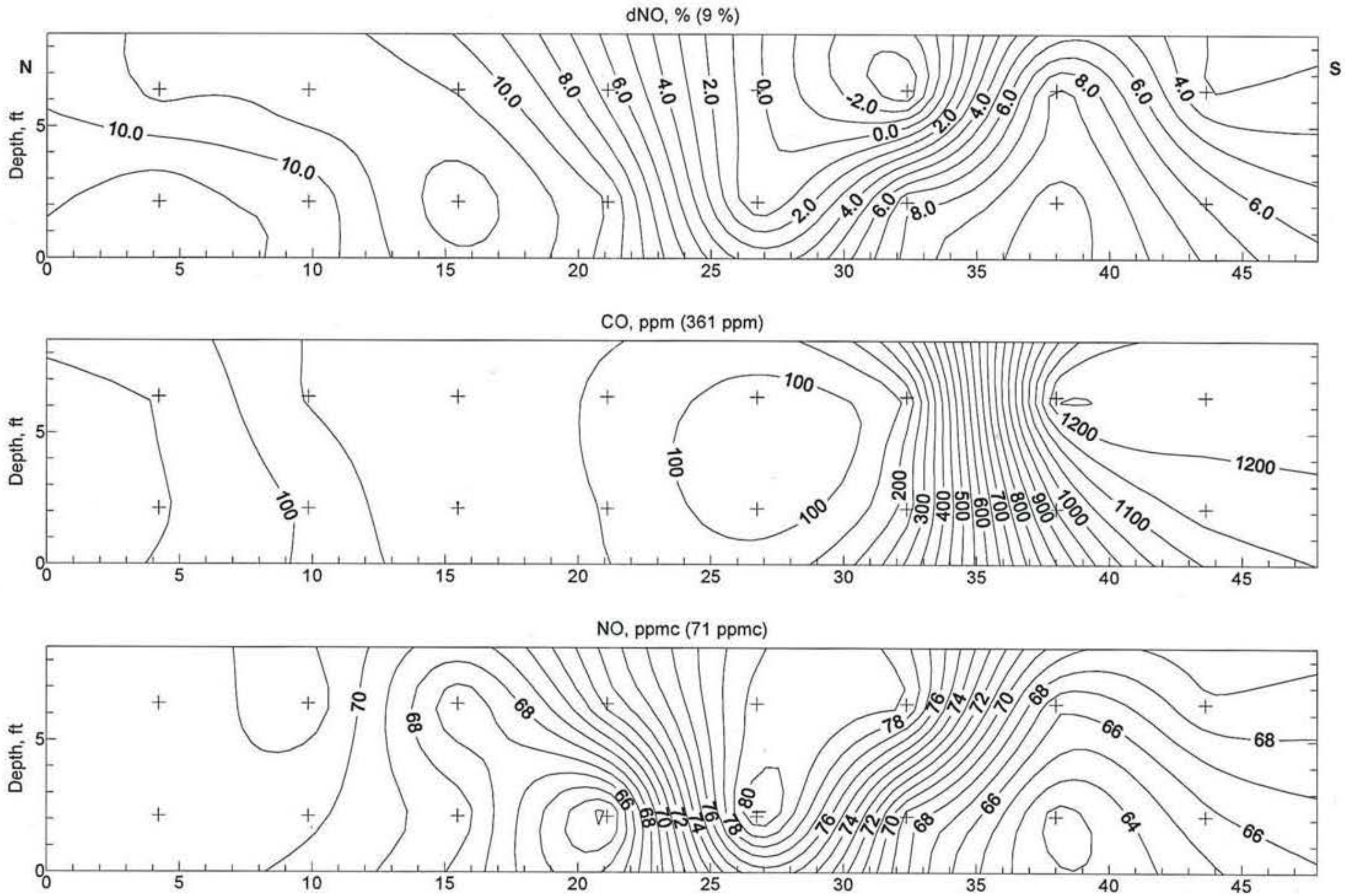

Figure E-14
Test 46, SNCR Injection Test, Day 6 (11/20/08)

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Memorandum

To: William Bumpers, Baker Botts L.L.P.
From: Andrew Skoglund
Subject: CALPUFF Visibility Impact Variations
Date: 4/4/2012
Project: 34280013.01
c: Mary Jo Roth, Debra Nelson - GRE; Joel Trinkle, Laura Brennan - Barr

CALPUFF is the USEPA's preferred model for assessing visibility impacts at Class I Areas resulting from long range (50 – 300 km) plume transport. CALPUFF is a multi-source model which accounts for plume advection and atmospheric chemical reactions to estimate the concentrations of primary chemical species (ammonium nitrate, ammonium sulfate, elemental carbon, organic carbon, fine particulate and soil) known to cause haze (i.e., visibility impairment). Plumes in CALPUFF are transported using sophisticated meteorological data and plume transformations from atmospheric chemical reactions occur due to interactions of plume pollutants, background atmospheric pollutants (ozone and ammonia) and meteorological variables – most importantly water vapor as represented by relative humidity.

Visibility impairment is calculated as a function of the light scattering properties of atmospheric particles and gases. An increase in light scattering particles decreases the visual range as measured in deciviews. The EPA estimates that a sensitive observer may be able to detect a variation of 0.5 deciviews, with 1.0 deciviews being a more accepted threshold for distinguishable difference in visual impairment. Modeled visibility impacts of 0.1 deciviews are therefore indistinguishable to the human eye.

Calpuff modeled visibility impacts are reported in the model output files to thousandths of deciviews. However, this level of sensitivity overstates the potential accuracy of the model when compared to real-world observations. Assessments of the CALPUFF modeling suite versus real-world monitoring data demonstrate the potential for significant differences between modeled and actual concentrations. There are many model inputs which play a role in impact variability, ranging from background chemistry data to emissions data entered into the model.

Visibility calculations are directly affected by the background chemistry input to the model. While ozone is input to the model based on hourly observations from available monitoring locations within the modeling domain, ammonia inputs are calculated monthly average values. The use of monthly ammonia background concentrations in the model, allows for consistency between modeling runs, but is a simplification of the actual conditions and impacts to visibility. Variation in ammonia background can have a measurable effect on the chemical transformations in the model, and in turn on modeled visibility impacts. The background values for visibility impairing pollutants (ammonium nitrate, ammonium sulfate, elemental carbon, organic carbon, fine particulate, and soil.) are based on projected values of pristine or natural conditions. These also are input as monthly average background levels. Variability in actual backgrounds, while demonstrating definite seasonal changes, is not limited to changing by calendar month.

Additionally, the fixed nature of the modeled emissions utilized in BART analyses does not reflect actual operations of a facility. Few facilities will operate at their maximum 24-hour rate 365 days per year. The emission rates and parameters for the potential modeled scenarios use assumed emissions and fixed stack parameters (e.g. exhaust temperature, airflow) for scenarios not already in operation at a facility. Final design may yield variations in these parameters, an additional source of impact variability. There is the possibility for considerable variation in actual emissions versus the modeled maximum rates used for BART analysis. It could be expected that small changes to the source parameter assumptions would result in small changes to the model results. Therefore, if the assumed stack flow rate or temperature for the EPA BART controls were misrepresented by 10 - 20% from potential as-built values, it could be possible that the deciview difference would be on the order of 0.1 deciviews – i.e., within the sensitivity of the model.

Inasmuch as the BART modeling analysis methodology is proscriptive (e.g., model each facility individually, use background monthly ammonia values, etc…), the CALPUFF results from one model run to the next can be useful in a relative sense and not in an absolute sense (i.e., the CALPUFF model results are not expected to reflect observed values). However, the difference in results from any two modeling runs needs to be understood in context of the parameter estimated. For the BART analysis, the parameter of interest is deciviews and the human perceptibility threshold is 0.5 deciviews. On this basis, differences in model run results of less than 0.5 deciviews are not significant.

For the CCS modeling analysis, the model run differences are 1) baseline – current controls compared to 2) baseline – EPA BART controls. In both cases, the relative model results (baseline – controls) show a fairly large difference (up to 2 deciviews), giving some confidence in the modeling results that controls would result in perceptible improvements to visibility. However, the EPA's contention that the 0.1 deciview difference between 1) and 2) is actionable based on modeling, ignores the fact that 0.1 is the difference between two large numbers.

Given the many sources of variability of input to CALPUFF's visibility analysis versus actual impacts, a difference of 0.1 deciviews between options may reflect no real difference at all.

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BARR

TRANSMITTAL LETTER

To:	Mary Jo Roth (GRE)	**Date:**	April 5, 2012
c:	Deb Nelson (GRE), Diane Stockdill (GRE), Joel Trinkle (Barr)		
Project #:	34280013.01	**Re:**	GRE CCS Supplemental NOx Analysis
Sent by:	Laura Brennan	**Phone:**	952.832.2615

We are sending you:

	Correspondence	X	Reports		Plans
	Copy of Letter		Specifications		Other:

These are transmitted as checked below:

	For approval	X	As requested		Other:
	For your use		For review and comment:		

Description:

This report is a revised version of the original November 2011 report titled "Best Available Retrofit Technology Refined Analysis for NOx Emissions" submitted by GRE to the NDDH. The report reflects the collaborative effort of Barr and GRE with assistance from other technical consultants to develop an appropriate control strategy for Coal Creek's Units 1 and 2. Barr assisted with the development and update of cost estimates for various control scenarios, incorporating GRE's work with URS and Golder into the technical discussion at GRE's direction.

The Refined NOx Analysis is prepared in response to comments from the NDDH provided in letters dated January 19, 2012 and February 28, 2012. The conclusions and text of the analysis are not markedly changed in responding to NDDH's comments. The changes in this report primarily focus on updated modeling results and clarifications to cost calculations, as described below.

In response to an anomaly identified in Appendix D of GRE's submittal, GRE has revised the visibility tables that were presented in that submittal. A review of the modeling output files for the year 2000 SNCR run in question concluded that the values presented in the original table were consistent with the output files. The original modeling runs had been conducted in 2006 and 2007 for the initial BART evaluation, and the intermediate data files were no longer available to identify whether the apparent error was the result of an incomplete annual model run or some other contributing factor. In order to be responsive to NDDH's request for clarification of the data, the model was re-run. The modeling files had not previously been reopened for the NOx refined analysis efforts in 2011 and 2012. Accordingly, GRE also took the opportunity to more closely

realign the NOx emission rates and stack-related modeling input parameters with the scenarios described in the report for all scenarios in all years as opposed to the approximations from previously modeled scenarios shown in the November 2011 tables.

The new results more closely align with the expected reductions for each control scenario and follow the trend originally illustrated in the year 2001 and 2002 tables for the February 10, 2012 submittal. The revised modeling runs support the conclusions presented in the GRE NOx analysis, and have only resulted in minor revisions to Table 3.3.1 and Appendix D.

In this revised report, NDDH also provides several comments with respect to alignment of calculations and clarity of documentation provided in the Appendix A cost calculations. Footnotes and documentation are appropriately updated. Additionally, the calculation alignment is clarified through the inclusion of additional significant digits. Neither of these updates result in changes to the final cost tables included within the report text.

Should you have any questions regarding this transmittal or the revisions herein, please contact Laura Brennan at 952.832.2615.

GREAT RIVER ENERGY®

A Touchstone Energy® Cooperative

Coal Creek Station Units 1 and 2

Supplemental Best Available Retrofit Technology Refined Analysis for NOx Emissions

November 2011; Updated April 5, 2012

Coal Creek Station Supplemental BART Refined Analysis for NOx Emissions

November 2011; Updated April 5, 2012

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1.0 Introduction

In December 2007, GRE submitted its final Best Available Retrofit Technology (BART) evaluation for Regional Haze controls to the North Dakota Department of Health (NDDH). The NDDH incorporated the proposed emission limitations for Coal Creek Station (CCS) Units 1 and 2 into their proposed State Implementation Plan (SIP), and issued a draft Permit-to-Construct (PTC) for these BART limits. As part of their review on North Dakota's draft and final SIP, EPA requested supplemental data and documentation on Coal Creek's BART controls. These requests started in February 2010, and continued through June 2011 and July 2011. GRE provided the requested information.

On September 21, 2011, EPA proposed a Federal Implementation Plan (FIP), which would override certain NDDH determinations, particularly with respect to required NOx controls for certain coal-fired utility units. On November 3, 2011, NDDH requested that GRE provide a supplemental BART analysis that is focused on NOx control options at Coal Creek Station. In particular, GRE has performed more refined analyses on selective non-catalytic reduction (SNCR) cost assumptions, achievable control levels and the overall impacts to ash re-use on Coal Creek's Units 1 and 2. This supplemental analysis is being provided to address questions from the NDDH per its letters of January 19, 2012 and February 28, 2012.

Based on the supplemental analyses, Great River Energy still asserts that use of its state-of-the-art coal drying technology, DryFining™, in conjunction with second generation combustion control low NOx burners with separated overfire air (LNC3+), meets EPA's presumptive BART NOx limit of 0.17 lb/MMBtu, and is consistent with cost effective thresholds as set by North Dakota and ultimately approved by EPA through their partial approval of the North Dakota SIP. When all factors are adequately considered, including ammoniated ash impacts, SNCR is not considered cost effective for Coal Creek and would not result in perceptible visibility improvements in the affected Class I areas.

This supplemental analysis summarizes updated SNCR cost and emission assessments and supplemental information provided by URS Energy and Construction (URS). It also provides an updated ash implication assessment and supplemental information as provided by Golder Associates (Golder). (see Appendices F and G, respectively) The updated ash implications are then integrated with the updated SNCR cost and emission estimates to more accurately demonstrate that SNCR is not cost effective, by either EPA established thresholds or NDDH established thresholds.

1.1 Initial BART Analysis and EPA Guidance

In preparing the initial BART analysis and subsequent revisions, Great River Energy developed a combination of detailed engineering and screening level analyses, which were ultimately used by NDDH to make their BART determinations. From the BART preamble, EPA sets presumptive levels based on their cost effective assessments and deciview reductions, and essentially rule out post combustion NOx controls for electric generating units greater than 750MW, subject to the state's determination. Great River Energy's screening level analyses on SNCR and ash impacts initially supported EPA's presumptive determination. Great River Energy continues to concur with EPA's establishment of a presumptive NOx emission limit at 0.17 lb/MMBtu.

Specifically, in its final rule publication of 40 CFR Part 51, Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations, EPA establishes presumptive NOx levels based on combustion controls, and not SNCR:

> *In today's action, EPA is setting presumptive NOx limits for EGUs larger than 750 MW. EPA's analysis indicates that the large majority of the units can meet these presumptive limits at relatively low costs. Because of differences in individual boilers, however, there may be situations where the use of such controls would not be technically feasible and/or cost-effective. For example, certain boilers may lack adequate space between the burners and before the furnace exit to allow for the installation of over-fire air controls. Our presumption accordingly may not be appropriate for all sources. As noted, the NOx limits set forth here today are presumptions only in making a BART determination, <u>States have the ability to consider the specific characteristics of the source at issue and to find that the presumptive limits would not be appropriate for that source.</u>* (emphasis added)
>
> *For all types of boilers other than cyclone units, the limits in Table 2 are based on the use of current combustion control technology. Current combustion control technology is generally, but not always, more cost-effective than post-combustion controls such as SCRs. For cyclone boilers, SCRs were found to be more cost-effective than current combustion control technology; thus the NOx limits for cyclone units are set based on using SCRs. SNCRs are generally not cost-effective except in very limited applications and therefore were not included in EPA's analysis. The types of current combustion control technology options assumed include low NOx burners, over-fire air, and coal reburning.*

> *We are establishing presumptive NOx limits in the guidelines that we have determined are cost-effective for most units for the different categories of units below, based on our analysis of the expected costs and performance of controls on BART-eligible units greater than 200 MW. We assumed that coal-fired EGUs would have space available to install separated over-fire air. Based on the large number of units of various boiler designs that have installed separated over-fire air, we believe this assumption to be reasonable. It is possible, however, that some EGUs may not have adequate space available. In such cases, other NOx combustion control technologies could be considered such as Rotating Opposed Fire Air (''ROFA''). The limits provided were chosen at levels that approximately 75 percent of the units could achieve with current combustion control technology. The costs of such controls in most cases range from just over $100 to $1000 per ton. Based on our analysis, however, we concluded that approximately 25 percent of the units could not meet these limits with current combustion control technology. However, our analysis indicates that all but a very few of these units could meet the presumptive limits using advanced combustion controls such as rotating opposed fire air (''ROFA''), which has already been demonstrated on a variety of coal-fired units. <u>Based on the data before us, the costs of such controls in most cases are less than $1500 per ton.</u>* (emphasis added)
>
> *The advanced combustion control technology we used in our analysis, ROFA, is recently available and has been demonstrated on a variety of unit types. It can achieve significantly lower NOx emission rates than conventional over-fire air and has been installed on a variety of coal-fired units including T-fired and wall-fired units. We expect that not only will sources have gained experience with and improved the performance of the ROFA technology by the time units are required to comply with any BART requirements, but that more refinements in combustion control technologies will likely have been developed by that time. <u>As a result, we believe our analysis and conclusions regarding NOx limits are conservative. For those units that cannot meet the presumptive limits using current combustion control technology, States should carefully consider the use of advanced combustion controls such as ROFA in their BART determination</u>* (emphasis added).[1]

There are several key concepts from EPA's preamble. First, Coal Creek is unique in that it has installed DryFining™ as a novel multi-pollutant control technology. This is important because it enhances the effectiveness of the NOx combustion controls. Second, Coal Creek re-uses the vast

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[1] Federal Register / Vol. 70, No. 128 / Wednesday, July 6, 2005 / Page 39134-39135.

majority of its fly ash rather than disposing of it. Any negative impacts to fly ash, such as adding ammonia, will have both operational risks and cost implications for Great River Energy that must be included in any cost-effectiveness determination. Third, EPA has made its cost-effectiveness determination in setting presumptive BART NOx levels and has given states the authority to determine if more stringent requirements are needed based on their review.

In reviewing EPA's preamble discussion, it was clear to GRE that the EPA did not expect BART control scenarios for tangentially-fired units, such as Coal Creek Station's Units 1 and 2, to include post combustion add-on controls such as selective catalytic reduction (SCR) and SNCR. As such, in the initial BART evaluation, GRE focused on supporting this determination through the use of screening level cost data, and comparing those screening costs to cost effectiveness thresholds.

Based on the direction provided in the BART preamble and guidance, along with an analysis of cost effectiveness thresholds implemented in other EPA regulatory programs,[2] GRE proposed a cost effectiveness range of $1,300 to $1,800 (2006$) per ton of NOx removed. Guidance provided by NDDH presented higher cost per ton thresholds than EPA's in setting the presumptive level.

GRE's BART NOx determination for CCS Units 1 and 2 was consistent with EPA's preamble and confirmed that advanced combustion controls and an emission limit of 0.17 lb/MMBtu represented BART. SNCR was found to be cost <u>in</u>effective based on screening level analysis, and presented additional operational and non-environmental impacts that were not exhaustively discussed in the December 2007 BART analysis but are provided herein.

[2] http://www.ndhealth.gov/AQ/RegionalHaze/Regional%20Haze%20Link%20Documents/Appendix%20C/Coal%20Creek/Coal%20Creek%20BART%20Analysis.pdf (Appendix B).

2.0 Refined NOx Control Evaluation at CCS

This section will first establish that Coal Creek is unique, such that site specific evaluations are more appropriate than relying on general screening level assumptions to determine emission reductions and associated costs. It will then summarize the evaluation of site specific SNCR NOx reductions by URS, as well as ash impacts from the ammonia associated with this control.

2.1 Unique Aspects of Unit 1 and 2 NOx Controls

As discussed in the following sections, Coal Creek Station is neither average nor typical. EPA Guidelines, provided to States in identifying appropriate Regional Haze control requirements and provided in EPA's Pollution Control Cost Manual (2002), are developed in order to assist State authorities in making regulatory determinations. These guidelines are not to be viewed as regulatory requirements. They are best suited for evaluating average or typical installations. Units 1 and 2 are uniquely designed and employ a state-of-the-art lignite fuel enhancement technology, or DryFining™. This means that any accurate analysis of add-on NOx controls must be site specific and not rely upon general guidelines, which might apply to a normal facility.

2.1.1 DryFining™ Technology

GRE has a long track record of being innovative and going beyond minimum environmental requirements. DryFining™ is a $270 million, multi-pollutant technology. It reduces coal moisture and impurities while increasing the heat content of Fort Union lignite, which has the highest moisture of any coal in the US. The operation of DryFining™ has afforded CCS Units 1 and 2 significant reductions across the spectrum of emissions. Sulfur dioxide and mercury emissions have been reduced by more than 40%. Carbon dioxide emissions have been reduced by 4%. NOx emissions – the subject of the EPA FIP and this evaluation – have been reduced by more than 20%.

GRE expected that some additional NOx reductions would result from the implementation of DryFining™. It was estimated that the reduction in coal moisture, and corresponding increase in coal heat content, would result in less coal into the furnace, and more air available elsewhere in the furnace, which can be utilized to reduce NOx emissions. However, this NOx reduction benefit was not quantified in the original BART analysis. At the time of the final BART analysis (December 2007), DryFining™ had not yet operated, and the exact degree of control was unknown for this innovative strategy. Because DryFining™ has been in place for nearly two years, NOx emissions are

reduced. Consequently, current (baseline) NOx emissions that are used in Section 3.1 have been updated to reflect the URS control cost analysis and are inclusive of DryFining™, with low NOx burner technology as applicable.

2.1.2 NOx Combustion Control Considerations

GRE's proposed BART NOx control strategy includes the use of DryFining™ along with advanced combustion controls. As a result of the installation of the proposed advanced combustion controls on Unit 2, GRE has gained a better understanding of anticipated NOx control levels and costs.

The size and arrangement of the furnace box on CCS Units 1 and 2 is unique. It is literally a one-of-a-kind furnace box, sized specifically for the high moisture Fort Union lignite. Given a larger firebox, relative to other lower-moisture, higher-heat-content coal-fired units, there is a correspondingly higher complexity and higher cost to NOx combustion controls. There is a greater distance across the furnace through which the air must penetrate, thus increasing the size and type of wall nozzles, along with increased nozzle staging complexity throughout the wall sections. When an advanced combustion air system is added to a larger firebox, it requires additional wall openings, and redesign to wall water tubes, further increasing costs.

Since the time of the initial BART submittal, GRE has gained direct operational experience on the performance of these advanced combustion controls and DryFining™. Prior to the installation of DryFining™, most of the available primary air was needed to convey, grind, and dry the coal in the pulverizers due to the high moisture in the coal. Consequently, the maximum performance for the LNC3+ control installed on Unit 2 could not be fully realized upon initial installation. The Unit 2 LNC3+ installation includes larger registers to increase available primary air. Since a significant amount of that primary air was used to dry and pulverize the "unrefined" high moisture coal, there was not sufficient air available for the larger registers to act as a form of overfire air. With DryFining™, there is additional air available to be routed to the larger registers, which reduces NOx emissions. As a result, Units 1 and 2 currently operate with annual average NOx emissions of 0.200 and 0.153 lb/MMBtu, respectively. Unit 2's lower annual average NOx emission rate is directly attributable to the larger registers, which are tentatively anticipated for Unit 1 in 2014.

2.1.3 Site Specific SNCR Expected Control Levels

Portions of Coal Creek Station's December 2007 submittal of the NOx BART analysis were based on screening level data presented in the EPA Pollution Control Cost Manual (2002). Since EPA has proposed to reject North Dakota's SIP largely on their assessment of SNCR's screening level, cost

effectiveness, it is imperative to more accurately portray SNCR costs. With respect to SNCR specifically, EPA acknowledges in its cost manual:

> *SNCR system design is a proprietary technology. Extensive details of the theory and correlations that can be used to estimate design parameters such as the required [normal stoichiometric ratio] NSR are not published in the technical literature. Furthermore, the design is highly site-specific. In light of these complexities, SNCR system design is generally undertaken by providing all of the plant- and boiler-specific data to the SNCR system supplier, who specifies the required NSR and other design parameters based on prior experience and computational fluid dynamics and chemical kinetic modeling.*[3](emphasis added)

As discussed above, GRE has established that Coal Creek is unique due to its boiler size, DryFining™, and existing NOx combustion controls. Therefore, only a site specific evaluation, by a competent engineering and construction company (URS) familiar with SNCR engineering and installation costs, should be used to estimate emission reductions and associated costs. URS is a leading engineering consultant, with significant experience in installing SNCR technology, having managed the design and installation of several dozen SNCR pollution control systems throughout the world. This experience qualifies URS to make site-specific recommendations on SNCR design.

URS completed a site inspection, evaluated the unique aspects of Coal Creek, and provided their refined analysis (see Appendix B).

URS has determined that the removal efficiency for Coal Creek Unit 1 with an inlet NOx concentration of 0.22 lb/MMBtu would not be 50% as anticipated from the EPA Pollution Control Cost Manual (2002), and as used in GRE's original BART analysis. Rather, URS estimates a removal rate of approximately 30% removal for Unit 1. With respect to Unit 2, and an inlet concentration of 0.15 to 0.16 lb/MMBtu, URS estimates the removal efficiency would be approximately 20%.

EPA has raised concerns with respect to utilizing a new baseline period in determining the removal efficiencies for SNCR vs. DryFining™ with LNC3+. At the time of the 2007 BART analysis, GRE had no experience with the DryFining™ technology and was unable to determine the removal efficiencies possible with the LNC3+ and DryFining™ projects combined relative to NOx emissions.

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[3] EPA Pollution Control Cost Manual (2002); Section 4.2 Chapter 1.3.

In an effort to evaluate existing installed technologies, GRE incorporated actual DryFining^{TM} operating experience and performance subsequent to the 2007 analysis. This information must be considered in the revised analysis in order to capture the actual realized removal efficiencies of the DryFining^{TM} and LNC3+ technologies as existing installed pollution control technologies. GRE notes that since the submittal of the 2007 BART analysis, GRE has lowered its Unit 2 NOx emissions from the baseline level of 0.22 lb/MMBtu to 0.153 lb/MMBtu on an annual average basis. This equates to an emissions reduction of 30.5% from the previously utilized 2007 baseline.

In addition to GRE's experience operating CCS with LNC3+ in combination with the DryFining^{TM} technology, resulting in lower NOx emission levels, a relatively new study has been completed for a facility with low-baseline NOx emissions[4] (Appendix E). This EPRI study addressed applicability of and anticipated removal efficiencies for SNCR for units with low-baseline NOx emissions. The study's findings suggest that SNCR performance is significantly decreased at baseline NOx emission levels less than 100 ppm[5]. The demonstrated low removal efficiencies (~10% reduction) are much lower than GRE's suggested removal efficiency for the SNCR technology (20%) applied in this analysis. Similarly, the low removal efficiencies are also much lower that the removal efficiency of 25%+ suggested in EPA's proposed FIP.

The study concludes that for low-baseline NOx applications, at levels around 75 ppm4, anticipated removal efficiency for SNCR is in the range of 8%-12%. If GRE takes into account the data from this study in place of the removal efficiency recommended by URS, the cost effectiveness would be well outside the range deemed cost effective. GRE's anticipated SNCR removal efficiency of 20% is likely higher than the technology will be able to achieve starting from a baseline of 0.153 lb NOx/MMBtu or 88 ppm (DryFining^{TM} with LNC3+ installed). GRE continues to use a removal efficiency of 20% in its analysis based on the SNCR technology evaluation conducted by URS, but notes that this value may in fact be conservatively optimistic.

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[4] *Low-Baseline NOx Selective Non-Catalytic Reduction Demonstration*: *Joppa Unit 3*. EPRI, Palo Alto, CA: 2009, 1018665. GRE asserts a business confidentiality claim and asserts this report is confidential business information subject to the protections set forth in Air Pollution Control Rules for the State of North Dakota at 33-15-01-16 and 40 CFR Part 2.

[5] Current NOx concentrations for CCS Unit 1 and Unit 2 are 110 ppm and 88 ppm, respectively (determined on a 12-month rolling average basis).

Given these lower projected emission rates, and the lower "baseline" emission rates from installed controls, the cost evaluation has been revised, accordingly, in Section 3.1.

Rather than relying on the original screening level analyses, GRE finds it imperative to provide this updated information to North Dakota to make their well-informed cost effectiveness determinations.

2.2 Revision of Baseline NOx Emissions

The BART Guidelines (40 CFR 51, Appendix Y) state "The baseline emissions rate should represent a realistic depiction of anticipated annual emissions for the source. In general, for the existing sources subject to BART, you will estimate the anticipated annual emissions based upon actual emissions from a baseline period." To accurately depict the anticipated annual emissions for the units at CCS a new baseline must be established taking into consideration the DryFining™ technology and installed combustion controls in Unit 2 (LNC3+). The DryFining™ process is designed to remove moisture and segregate dense material from the coal prior to introduction of the coal into the final stage of grinding and conveyance into the boiler. DryFining™ having been funded under a DOE collaborative agreement (DE-FC26-04NT41763) was required to conduct performance tests which demonstrated a heat input reduction of approx. 2-3%. Having removed the moisture prior to the introduction into the pulverizers lends to less primary air required to "dry" and convey the coal through the pulverizers, making air available for staging (Over-fired air NOx control) in other areas in the boiler. This drier coal will not require the same amount of heat input into the boiler because wet coal expends some of its heat input to vaporize the moisture in the coal and its heating value has increased per pound so fewer pounds are needed. Thus a drier coal will not require that additional coal typically lost to vaporizing the moisture and reduced heating value. DryFining™ is currently obtaining a moisture reduction in the coal of approximately 8%. Future tuning is continuing and will meet a required reduction of 12% by 2016, which is needed for the SO_2 BART analysis to achieve full scrubbing.

In order to make its cost effectiveness determination, North Dakota must not only have site specific control cost, but also accurate emission reduction estimates. Clearly, with the installation of both LNC3, LNC3+, and DryFining™, Coal Creek's NOx emissions are greatly reduced with respect to "baseline" values previously provided. In this section, in light of recently refined analysis, GRE will update baseline emissions to be used in making the cost effectiveness determination.

Based on the timing of the original analysis, the initial BART evaluation used baseline emission rates for approximately the same time period that was used to determine the visibility baseline, which was

a 5-year period of emission inventory data from 2000 to 2004. It is necessary to update the baseline emissions for Units 1 and 2 for this technology evaluation in order to reflect current conditions and unit performance. Both units utilize “low NOx coal-and-air nozzles with close-coupled and separated overfire air,” which is referred to as LNC3. Since the time of the initial evaluation, NOx controls in the form of larger registers,[6] advancing the LNC3 controls (LNC3+),[7] have been added to Unit 2, which means that the two units have different baselines for the purpose of estimating future emission reductions. For Unit 1, the revised baseline is 0.200 lb/MMBtu, as an annual average. For Unit 2, the revised baseline is 0.153 lb/MMBtu, as an annual average, as also described in Section 2.1.2. These new “baseline” emission rates are lower than the initial BART baseline of 0.22 lb/MMBtu.

2.2.1 Circumferential Cracking in Boiler Tubes

Following the installation of LNC3+ technology at Unit 2, CCS has determined that an emission rate of 0.15 lb/MMBtu for LNC3+ is not a sustainable 30-day rolling average control level due to circumferential cracking. In other words, the 0.15 lb/MMBtu on a 30-day rolling basis is at the edge of this technology’s capabilities. While GRE may intermittently achieve this rate on a monthly or perhaps more easily as an annual average, it is not the basis for a 30-day rolling limit.

As background, in 2008 GRE lowered NOx emissions from Unit 2 by expanding the OFA registers. This diverted more of the combustion air from the burners of the boiler to an area about 30 feet higher in the boiler. In doing so, the flame temperatures were lowered, which reduced the production of NOx generated by the combination of oxygen and nitrogen gas burned under high temperatures. NOx emissions were lowered, but there was an unexpected side effect. This low NOx emission rate caused circumferential cracks in the boiler tubes between the burner front and the over-fired air registers.

The phenomenon of circumferential cracking has several interrelated contributing factors including high surface temperatures (>900°F bare tubes, >1100°F weld overlays) (which exposes the boiler tubes to high wall temperatures and high temperature fluctuations, which produces numerous thermal fatigue cracks in the boiler walls), frequent and severe thermal spikes (>100°F), and corrosive

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[6] Larger registers allow for a greater ability to tune combustion staging and thus control NOx emissions.

[7] LNC3 is the acronym used by EPA to describe a specific type of restrictive combustion control. To differentiate between the controls installed on Unit 1 and the additional controls installed on Unit 2 (both are versions of LNC3), the acronyms LNC3 and LNC3+ are used for each unit, respectively.

conditions/deposits. Low NOx burner systems with overfire air ports produce longer flames and increase the chance of flame impingement and local overheating of the boiler walls.

In 2009, Coal Creek Station began to experience unscheduled outages on Unit 2 due to failures from the circumferential cracking described above. To understand and correct this problem, Great River Energy engaged the Electric Power Research Institute (EPRI) to assist in evaluating the causes and potential remedies for this problem. To date, corrective actions have included detailed examinations of the boiler tubes to detect the extent of the cracking, the installations of additional temperature monitors to determine boiler wall temperatures, the replacement of damaged boiler tubes, and continued tuning of the boiler to minimize the circumferential cracking in the zone of concern. While not eliminating the problem, these efforts have greatly reduced the problem of unscheduled outages caused by circumferential cracking. Based on our analysis, it is not clear how to completely and consistently eliminate this problem, while operating at or near 0.15 lb/MMBtu on a 30-day rolling basis. Efforts continue to further reduce this circumferential cracking problem while balancing our desire to operate at lower NOx emission levels.

The only examples of tangentially-fired units with emissions lower than the 0.17 lb/MMBtu NOx presumptive level are facilities with post combustion NOx controls, such as SNCR. Further, a majority of these SNCR controlled sources operate well above the 0.17 lb/MMBtu, as annual averages, as detailed in the Cross State Air Pollution Rule and illustrated in Figure 2.2. Consequently, GRE presumes it cannot safely and consistently operate below 0.17 lb/MMBtu as a 30-day rolling limit, without installing SNCR.

2.2.2 Load Variability

In addition to circumferential cracking, this assessment must also consider load variability and its impacts on NOx emissions. The NOx emission limits proposed in the original BART evaluation for Units 1 and 2 did not consider that Coal Creek's units would experience significant load variability. GRE has historically operated as a baseload unit, without much load swinging. In May 2011, Midwest Independent Transmission System Operator (MISO) began cycling CCS in the real-time market. In September 2011, GRE greatly increased the cycling range of CCS in response to current market prices in the MISO market. This is important because load swinging significantly impacts expected NOx control performance. While base load NOx emissions can be tuned due to relatively stable load, the swinging load cannot be finely tuned but must still be accounted for when assessing compliance with emission limits.

Table 2.1 illustrates the variability experienced during recent load swinging. It is different on Units 1 and 2, due to different NOx controls. Based on changing market conditions, load variability is expected to continue as an operational scenario for Units 1 and 2 for the foreseeable future. As such, any emission limit must account for this additional variability in emissions. It is clear from Table 2.1 that the BART NOx presumptive emission rate of 0.17 lb/MMBtu is achievable, including load variability, and also reflecting the maximum NOx emission reductions from LNC3+ and DryFining™, as demonstrated through Unit 2.

Table 2.1 Coal Creek Station NOx Emission Rates During Load Variability

Scenario Description		NOx Emissions (lb/MMBtu)			
		Unit 1		Unit 2	
		Min	Max	Min	Max
Overall - Nov. 2010 to Nov. 2011	30-day Rolling	0.179	0.219	0.14	0.169
Load Variability – May – November 2011	30-day Rolling	0.186	0.219	0.146	0.166
	Hourly Average	0.206		0.16	
Load Variability – September – November 2011	30-day Rolling	**0.207**	**0.219**	**0.163**	**0.166**
	Hourly Average	0.218		0.17	

In addition, GRE provides a chart (Figure 2.1) showing Unit 2's 30-day rolling average NOx emission rate, with notes on tuning emphasis and load variability, as further support of the 0.17 lb/MMBtu emission limit.

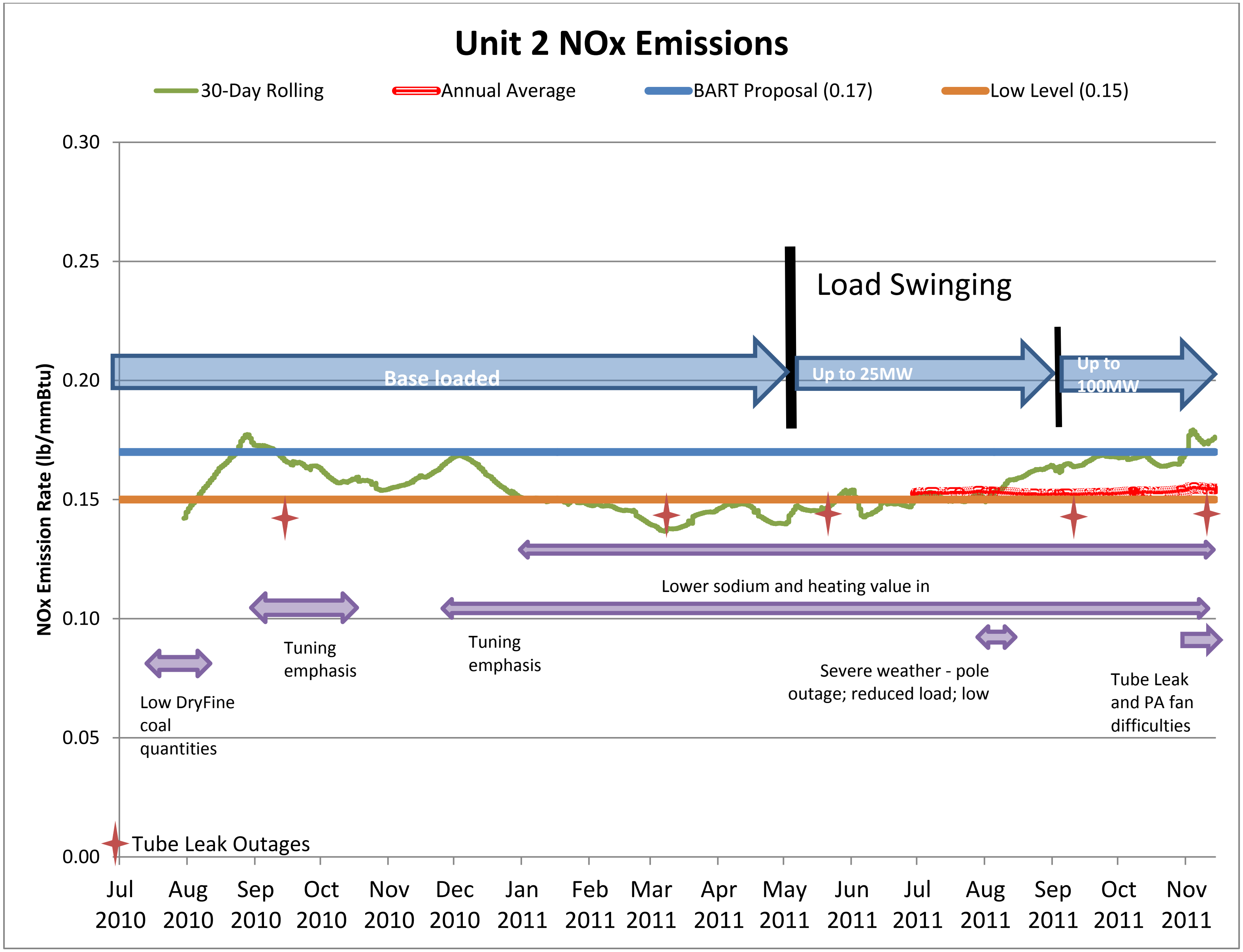

Figure 2.1 **Unit 2 30-Day Rolling NOx Emission Averages**

2.2.3 Evaluation of SNCR Effectiveness in CSAPR

Interestingly, the Coal Creek presumptive NOx BART emission rates are consistent with annual average emissions as modeled by EPA in CSAPR. By reviewing existing units of similar design, data from the docket for the proposed Cross State Air Pollution Rule (Docket ID EPA-HQ-OAR-2009-0491) illustrates that there are currently no tangentially-fired utility electricity generating units with LNC3 combustion controls and SNCR post combustion controls that operate at or below the presumptive BART limit of 0.17 lb/MMBtu for NOx (Figure 2.2), as annual averages. If the data set is expanded to include LNC3 ("low NOx coal-and-air nozzles with separated overfire air (LNC2[8])") and "low NOx burners and overfire air (OFA)" as illustrated in Figure 2.3, only four supercritical[9] emission units operate below the presumptive NOx limit of 0.17 lb/MMBtu. None of the facilities included in the CSAPR database operate at or below the proposed FIP limit of 0.12 lb/MMBtu. All of the facilities analyzed use SNCR to effectively achieve the Coal Creek presumptive NOx emission limit of 0.17 lb/MMBtu. To state it differently, Coal Creek effectively achieves presumptive BART with DryFining™ rather than SNCR.

[8] LNC2 and LNC3 are various types of low NOx burner design.

LNC2 = Low NOx burner with separated OFA

LNC3 = Low NOx burner with close-coupled and separated OFA

[9] For a subcritical boiler (standard operational design consistent with CCS Units 1 and 2), steam to power the turbine is derived by heating liquid water to its saturation point and then isothermally heating of the system causing the phase change from liquid water to steam (boiling). In contrast, a supercritical steam generating unit operates at such a high pressure that liquid water does not boil and is instead converted to a supercritical fluid, an intermediate fluid having properties of both liquid water and steam. Operation of supercritical units is typically more thermally efficient than operation of subcritical units, resulting in less fuel combusted for the same energy output and, consequently, lower emissions.

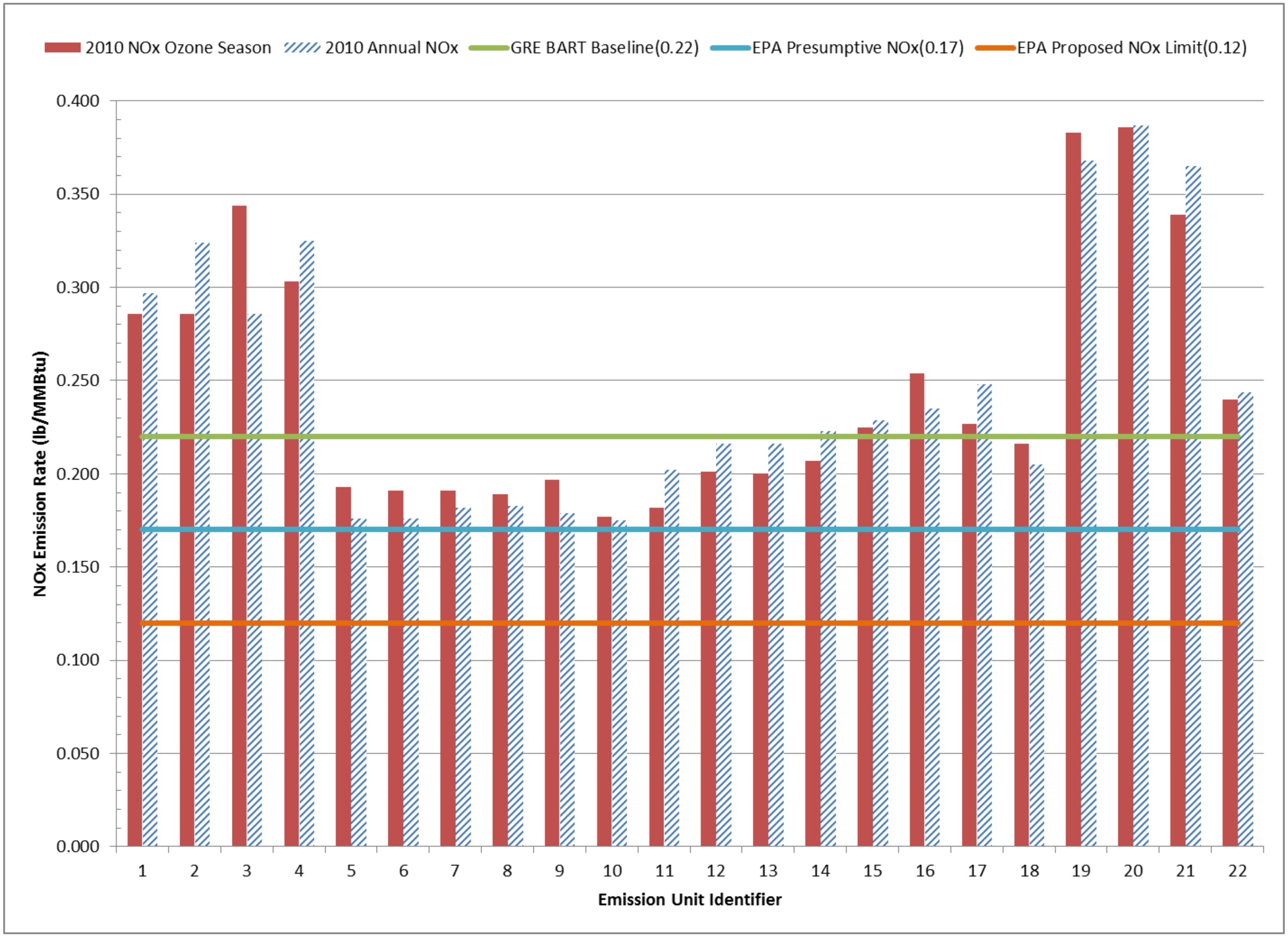

Figure 2.2 2010 NOx Emission Rates from CSAPR Rule Data for Units with SNCR and LNC3/OFA NOx Control

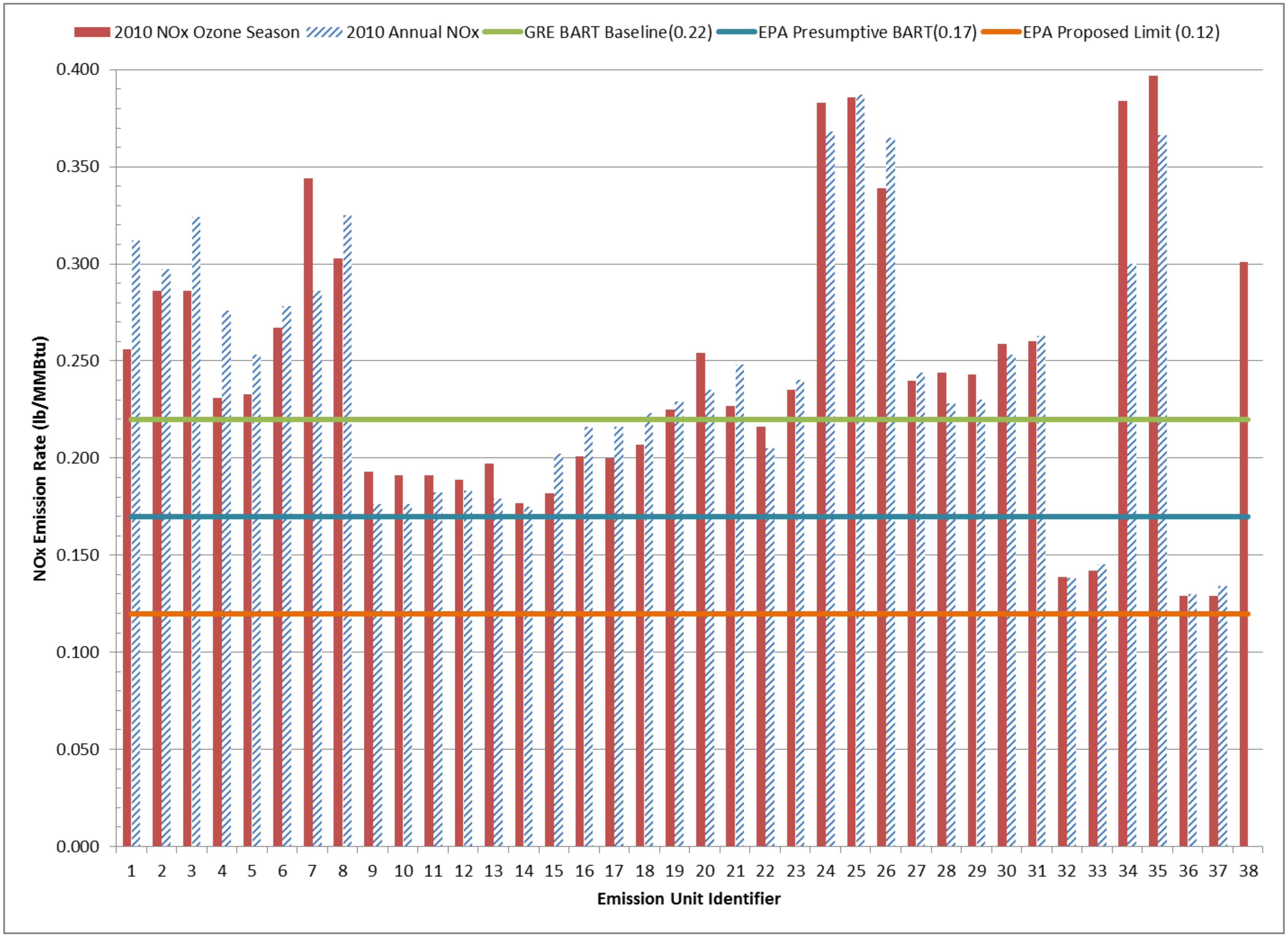

Figure 2.3 2010 NOx Emission Rates from CSAPR Rule Data for Units with SNCR and LNC2/LNC3/OFA NOx Control

2.2.4 Ash Cost Considerations

The EPA indicated in its proposed FIP that GRE fly ash sales and disposal values provided in previous submittals were in error and, when corrected, resulted in SNCR being cost effective. Great River Energy had previously submitted two estimates: $5/ton and $36/ton (2006$). Contrary to our Summer 2011 submittal, these values were not necessarily in error, but instead represented different assumptions on economic impacts of lost ash sales and associated disposal costs. Therefore, rather than rely upon these screening level values as previously submitted, GRE contracted with Golder Associates to provide a more refined analysis of ash impacts associated with the installation of SNCR. The following discussion and attached "Fly Ash Storage and Ammonia Slip Mitigation Technology Evaluation" (Appendix C) provides a more comprehensive assessment of ash implications associated with SNCR installation.

To provide some additional background on the previously submitted values, the $36/ton value represented the total freight on board (FOB) Coal Creek Station price that was paid by the end user. The $5/ton dollar per ton figure represented what GRE received as a portion of the FOB price prior to December 1, 2011.

Both of the values ($5/ton and $36/ton) attempted to capture lost revenue from decreased ash sales. In each case, an additional $5/ton cost was added as GRE's cost to dispose of the unsalable ash. This additional $5/ton disposal value was the result of a screening level analysis and had not taken into account all of the internal costs associated with ash disposal. This disposal value also had not accounted for anticipated cost increases based on changing ash disposal regulations, nor did it take into account various ash disposal levels as could be anticipated due to lost fly ash sales.

GRE and Headwaters Resources, Inc (HRI), GRE's strategic partner in the sales and distribution of fly ash, have invested heavily into fly ash sales infrastructure including terminals and storage facilities, conveying equipment, scales and train car shuttles. HRI financed GRE's portion of the infrastructure through a per ton payment on fly ash sales. The current ash sales contract requires payments to GRE that total 30% of the $41 (2011$) FOB price or $12.30 per ton (2011$) of ash that is delivered.

Considerable effort has been taken to clarify the impacts that SNCR installation will have on GRE's ash management methods, overall disposal costs and reduction in ash sales revenues. In short, Great River Energy firmly believes, and EPA acknowledges in its proposed FIP, that SNCR may have a detrimental impact to ash sales. The Golder analysis represents these risk ranging from a worst case

100% lost fly ash sales, to an optimistic 30% lost sales, as shown in their Scenarios B and C, respectively. For the sole purpose of defining a baseline, a hypothetical Scenario A "No Ash Impacts," has also been included as a reference point.

2.2.5 SNCR's Impact on Ash Management Options

Fly ash from CCS is used throughout the Upper Midwest to replace a portion of Portland cement in concrete production, making the concrete more durable and longer lasting. Ash generated at Coal Creek Station has chemical and physical properties that make it an extremely desirable ash in the concrete market. Coal Creek Station currently generates approximately 525,000 tons of fly ash per year. Approximately 415,000 tons of that ash is sold as a Portland cement replacement. Coal Creek fly ash has been used in many large-scale projects such as construction of the new Interstate-35W Bridge after its collapse.

The beneficial use of fly ash also has a strong positive economic benefit to Great River Energy, and the regional economy. We started selling fly ash nearly three decades ago. In that time, we have grown this activity into a sizable annual revenue stream. The addition of SNCR will have a negative impact on the marketability, value and perception of Coal Creek Station's fly ash. The addition of ammonia into the combustion process leaves an ammonia residue on the ash that can cause aesthetic and worker safety issues during the use of the ash. The residual ammonia in the ash eventually off-gases and creates odors which are offensive, are potentially dangerous to human health, and can even pose an explosion risk. Section 1-2 of EPA's Pollution Control Cost Manual recognizes this fact and states the following:

> *Ammonia sulfates also deposit on the fly ash that is collected by particulate removal equipment. The ammonia sulfates are stable until introduced into an aqueous environment with an elevated pH levels. Under these conditions, ammonia gas can release into the atmosphere. These results in an odor problem or, in extreme instances, a health and safety concern. Plants that burn alkali coal or mix the fly ash with alkali materials can have fly ash with high pH. In general, fly ash is either disposed of as waste or sold as a byproduct for use in processes such as concrete admixture. Ammonia content in the fly ash greater than 5 ppm can result in off-gassing which would impact the*

salability of the ash as a byproduct and the storage and disposal of the ash by landfill.[10](emphasis added)

The range of residual ammonia left with the fly ash can vary with each installation of SNCR. Ammonia slip of only 5 ppm, generally accepted as the minimum that can be achieved with SNCR, can render fly ash unmarketable. (URS, Appendix B) Even in those systems where residual ammonia is generally low, there will be times of increased ammonia slip based on plant operations. As the plant output varies due to market demand or startup/shutdown activity, varying levels of ammonia will be used to control NOx and, consequently, the levels in the ash will change. Variable ammonia levels in the ash create additional complexity to both sales and/or treatment, and will result in increased disposal.

2.2.6 Ammonia Mitigation Technology

Great River Energy is committed to ash re-use due to its economic and environmental benefits. Therefore, we anticipate additional capital and operating costs to treat the ash in order to ideally preserve a percentage of ash sales. With respect to ammoniated ash treatment, Ammonia Slip Mitigation (ASM) technology refers to a variety of technologies that have been designed to improve the marketability of ammoniated ash. These technologies fall into two rough categories, combustion or carbon burn out (CBO) and chemical treatment. CBO is the process of running the ash through an additional combustion unit that would combust and burn out the residual carbon and ammonia that is with the ash. This is a capital intensive technology that also has high operating costs. The second category of ASM technology is generally referred to as chemical treatment. These treatment technologies involve creating a chemical or physical reaction that results in the off-gassing of the residual ammonia. These treatment technologies are generally less costly than CBO. For purposes of this more refined analysis, GRE contracted with Golder Associates to provide a detailed cost estimate of one particular chemical treatment technology as a potentially cost effective option. The detailed cost estimate can be found in Appendix C.

Even with a cost effective ASM technology installed, there will be times when the residual ammonia levels in the ash are too high to treat. Ammonia injection rates will vary during periods of startup and shutdown, in addition to variable load operation, in order to maintain compliance with the BART limits. Variable ammonia injection rates and associated changes in ash concentrations will result in

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frequent testing and periodic rejection of ash for on-site disposal. Further, variable ammoniated ash levels will put GRE's generated ash in a very vulnerable position with respect to competitors in the fly ash marketplace, reducing ash sales and increasing on-site disposal.

2.2.7 Ash Disposal Scenario Cost Summaries

Appendix C contains a technical assessment and cost analysis of ammonia slip mitigation technology and ash disposal under RCRA Subtitle D design standards. To address the uncertainty regarding costs associated with ammoniated ash management and disposal, a range of costs is presented. These costs are based on three scenarios described below. Table 2.2 shows the volumes of ash produced, sold and disposed of in each scenario. For a more detailed description please see Appendix C.

Scenario A (current ash sales levels) – This scenario is the base case with fly ash sales equal to the average sales over the past few years. The scenario assumes that fly ash will be disposed of in a new landfill with a design based on RCRA Subtitle D practices, and has a 20-year disposal capacity. No post processing of the fly ash is required to maintain 100% marketability. (Golder 2011) This hypothetical scenario is not considered to be a possible option for future ash management costs but serves as a point of reference for understanding future impacts.

Scenario B (No ash sales) – This "worst case" scenario assumes that the ammonia slip impact of SNCR makes fly ash at CCS completely unsalable. The scenario also assumes that fly ash will be disposed of in a new landfill with a design based on RCRA Subtitle D practices, and has a 20-year disposal capacity. (Golder 2011)

***Scenario C* (30% sales reduction, ASM costs)** – This "realistic" scenario assumes that Headwater's ASM technology will be viable for ammonia-impacted fly ash at CCS. However, sales will be reduced from current sales levels due to load swing impacts on ammonia slip, market conditions, and other factors previously identified. The scenario also assumes that fly ash will be disposed of in a new landfill with a design based on RCRA Subtitle D practices, and has a 20-year disposal capacity. (Golder 2011)

Table 2.2 Fly Ash Sales and Disposal Tons

	Scenario A (Current Sales)	Scenario B (No Sales)	Scenario C (Reduced Sales, ASM)
Fly Ash Produced (ton/yr)	525,000	525,000	525,000
Fly Ash Sold (ton/yr)	415,000	0	290,500
Fly Ash Disposed (ton/yr)	110,000	525,000	234,500

It is clear in EPA's proposed FIP that the installation of SNCR may negatively impact ash sales[11].

Our knowledge of the ash marketplace, SNCR systems, and treatment technologies confirm that the installation of SNCR will have a detrimental impact on the salability of fly ash. GRE believes that Scenario A, which represents no impact to ash sales, is extremely unlikely. Nevertheless, we present it as a point of reference for better quantifying the ash impacts from SNCR installation.

GRE believes that scenario B (zero ash sales) is a likely outcome, but we hope that through investment in ASM technology we will be able to preserve some of the ash sales. To model partial ash sales, we created Scenario C. Scenario C assumes an investment in ASM technology and a reduction of ash sales by 30%.

It is not possible to determine exactly what percent of ash sales would be lost based on the installation of the SNCR and ammonia mitigation technologies at Coal Creek Station. There are no plants in the country with both of these technologies operating together on a lignite-fired unit. In fact, the vendor responsible for the ammonia mitigation technology will not guarantee the technology's performance at Coal Creek Station.

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[11] Federal Register / Vol. 76, No. 183 / Wednesday, September 21, 2011 / Page 58620.

"Regarding this value for fly ash sales, North Dakota concluded that SCR and SNCR use at Coal Creek would likely result in NH_3 in the fly ash due to NH_3 slip which would negatively affect fly ash salability. According to Great River Energy and North Dakota, fly ash that is currently beneficially used in the production of concrete would, instead, be landfilled. While we have opted to agree that fly ash will not be saleable for the SNCR and SCR options for purposes of our cost analyses, we are seeking comment on this issue, particularly related to the levels of NH_3 that fly ash marketers deem problematic, and the availability, applicability, and cost of applying NH_3 mitigation techniques to fly ash derived from lignite coal."

Across the country there are examples of plants that have SCR or SNCR and sell most of their ash, however, there are also others that sell none of their ash. It is a very site-specific scenario and depends on the type of coal, type of combustion, type of ash collection, plant operation (cycling % load), type of ammonia mitigation technology (if any), and how the SNCR or SCR system has been designed, installed and implemented. Each and every site is very different.

For the sake of modeling the costs related to lost ash sales we determined it was important to model a middle ground between 0% lost ash sales and 100% lost ash sales. There is a strong possibility that all ash sales will be lost and a zero chance that 100% ash sales will be maintained; some middle option needed to be considered. We looked across the industry to determine the best scenario for a moderate outcome. The 30% lost ash sales figure reflects a reasonable and optimistic (i.e., conservative) outcome that can be justified based on our understanding of plant operations and the ash markets in which we compete for sales.

The only plant (Eastlake) in the U.S. operating with the discussed ammonia mitigation technology operates under a very different scenario. This plant mixes the ammoniated ash with a non-ammoniated ash prior to sales. Thus, Eastlake is able to sell up to approximately 85% of its ash. However, Coal Creek Station is unlike the Eastlake plant. Increased load variation at CCS, adjusting plant output to match the MISO market in which we operate, can lead to upsets in the SNCR system and higher levels of ammonia in the ash.

The addition of ammonia mitigation technology and additional handling and processing steps will also increase the cost of ash to the end users. As our price point in the market increases, we will face increased competition and will lose some sales to competing ash sources.

In addition, consistency is a prized trait for a fly ash that is marketed to the cement industry. The addition of SNCR will have a detrimental impact on the consistency of the market product. Decreased consistency will lead to lower demand for the ash and will result in some lost sales to competing ash sources.

Predicting exactly what impact all of these factors will have on our ash sales is not possible. Based on our investigation and knowledge, and that of the experts we consulted, we concluded it is very likely that we will lose 50% or more of our ash sales. We chose to model 30% loss in sales as a conservative scenario that likely underestimates the real impact of this technology on ash sales.

Furthermore, in our modeling scenarios, we assumed that the future regulation of coal ash would not be subject to RCRA Subtitle C requirements. Consistent with our comments to EPA's docket during its Coal Combustion Residuals rulemaking, we believe Subtitle C regulation of coal ash is unwarranted and unnecessary. Nevertheless, EPA has proposed it as one option for a final rule. Subtitle C regulation of coal ash would significantly increase our cost to handle and dispose of our ash. Subtitle C regulation has not been included in our scenarios.

In summary, we consider a 30% scenario to be a very optimistic view of the future that relies on the successful implementation of a technology that cannot currently be guaranteed by the vendor and has never been installed on lignite-fired units. This scenario also quantifies increased disposal costs, in addition to some GRE-specific economic benefit from preserved ash sales. None of the scenarios attempt to capture economic impacts to GRE's strategic partners or other regional entities, but these impacts are mentioned in Section 3.2 and should also be taken into consideration when making a final BART determination.

2.2.8 Ash Management Costs

There are three major cost categories to be considered in each of these scenarios;

- Fly ash disposal cost estimates,
- Ammonia slip mitigation costs, and
- Lost fly ash sales revenue

Each cost area is summarized below. For a more detailed assessment, see Appendix C.

2.2.9 Fly Ash Disposal Cost Estimates

Given significant uncertainty with pending regulatory requirements such as RCRA Subtitles C and D, with ammonia slip treatment technologies, and with market reactions to ammoniated ash, Great River Energy has developed essentially three scenarios that attempt to capture a range of possibilities associated with SNCR installation. For all three scenarios, a 20-year disposal capacity and a RCRA Subtitle D design is assumed. It is also assumed that the landfill will be built on property not currently owned by GRE, as GRE does not currently have a suitable location for siting a Subtitle D landfill. For this cost estimate, it is assumed that property just west of the plant property would be purchased for the new facility. Landfill size is based on a 20-year fly ash disposal capacity. For the three scenarios, this varies between 2.2 million and 10.5 million tons of capacity. For each scenario, Golder developed a simplified landfill footprint that would provide the 20-year fly ash disposal capacity.

The cost estimate includes costs for the life of the disposal facility including engineering, design, and permitting; construction; and operations and maintenance, including closure and post-closure care. Golder used actual costs from similar projects at CCS, local contractor rates, RS Means manuals (RS Means 2010), and professional judgment to develop this cost estimate. Sources and assumptions are documented. Some general assumptions for the cost estimate include:

- All costs are estimated in 2011 dollars.
- Capital costs are annualized based on a 20-year life and 5.5% interest rate.
- Existing fly ash processing equipment (silos, unloaders, etc.) is not included. Disposal costs begin once the haul trucks are loaded with fly ash.
- Existing fly ash sales infrastructure (silos, scales, rail facilities) and operations and maintenance are not included.
- Disposal costs only include fly ash disposal and not facility airspace or operations and maintenance for other coal combustion products produced at CCS. (Golder 2011)

Table 2.3 Disposal Cost Summary (2011$)

	Scenario A (Current Sales)	Scenario B (No Sales)	Scenario C (Reduced Sales, ASM)
Fly Ash Disposed (ton/yr)	110,000	525,000	234,500
Total Disposal Cost ($/ton)	$18.06	$11.18	$13.91
Annual Disposal Cost ($/yr)	$1,987,000	$5,870,000	$3,262,000
Annual Increase in Disposal Cost Compared to Scenario A ($/yr)	-	$3,883,000	$1,275,000
Incremental Increase in Disposal Cost Compared to Scenario A ($/ton) *	-	$7.40	$5.44

*These values are used in the BART analysis as they represent the only the incremental costs above the baseline costs which would be incurred with or without the installation of SNCR.

2.2.10 Ammonia Slip Mitigation Costs

Post-processing of ammonia slip impacted fly ash by Headwater's ASM technology is proposed as an option to maintain fly ash sales. This post-processing is only being applied to the sold fly ash tonnage in Scenario C. Depending upon the plant power profile and how the fly ash distribution system is setup, it is likely that additional tons of fly ash will be treated and disposed, but these potential cost impacts are not included. The cost impact for ASM post-processing is shown in Table 2.4. (Golder 2011)

Table 2.4 ASM Post-Processing Costs (Golder 2011)

	Scenario A (Current Sales)	Scenario B (No Sales)	Scenario C (Reduced Sales, ASM)
ASM Unit Rate Capital and O&M ($/ton sold)	$0.00	$0.00	$5.61
ASM Annual Capital and O&M ($/yr)	$0	$0	$1,629,000

2.2.11 Lost Fly Ash Sales Revenue

The current fly ash sales are supported by a large investment in capital infrastructure as well as a large operations and maintenance contingency. Changes to the quantity of fly ash marketed and sold will have a direct impact on fly ash management costs, as the revenue currently used to offset fly ash management will be lost. The lost fly ash sales revenue is based on the 2010 average price per ton FOB of $41.00; with 30% of the sale price going to GRE as revenue. The cost impact of the potential loss in fly ash sales in shown in Table 2.5. (Golder 2011)

Table 2.5 Lost Fly Ash Sales (Golder 2011)

	Scenario A (Current Sales)	Scenario B (No Sales)	Scenario C (Reduced Sales, ASM)
Lost Fly Ash Sales Revenue ($/ton lost sales)	$12.30	$12.30	$12.30
Annual Lost Fly Ash Sales Revenue ($/yr)	$0	$5,105,000	$1,531,000

2.2.12 Total Fly Ash Management Costs

The combination of the ASM post-processing, fly ash disposal, and lost fly ash sales revenue is shown in Table 2.6. This table represents the total economic impact of SNCR installation on GRE's fly ash management in two likely scenarios; a total loss of ash sales and a 30% reduction in ash sales.

Table 2.6 Total Fly Ash Management Costs (Golder 2011)

	Scenario A (Current Sales)	Scenario B (No Sales)	Scenario C (Reduced Sales, ASM)
Total (Disposal + Post Processing + Lost Sales)			
Annual Cost ($/yr)	$1,987,000	$10,975,000	$6,422,000
Unit Cost ($/ton produced)	$3.79	$20.91	$12.23
Additional Cost (Scenario B/C - Scenario A)			
Fly Ash Management Cost ($/yr)	-	$8,988,000	$4,435,000
Fly Ash Management Cost ($/ton produced)	-	$17.12	$8.45

2.2.13 BART Analysis Ash Disposal Cost Summary[12]

While the exact impacts to Coal Creek Station's ash are unknown, mandating SNCR will leave GRE in a vulnerable position where we would expect to incur significantly higher costs from lost ash sales and increased landfilling. Based on the detailed technical review discussed above and included as Appendix C, GRE proposes a range of ash disposal costs and lost ash sales revenue figures in the BART analysis. None of the scenarios consider the significant cost impact of potential RCRA Subtitle C regulation in the future.

Scenario B represents the highest cost scenario with a total annual additional cost of $8,988,000. The total cost includes lost ash sales revenue of $5,105,000 (Table 2.5) and an additional annual ash disposal cost of $3,883,000 or $7.40 per ton disposed (Table 2.3).

Scenario C represents an optimistically low cost scenario with a total annual additional cost of $4,435,000. The total cost includes lost ash sales revenue of $1,531,000 (Table 2.5) and an additional annual ash disposal cost of $1,275,000 or $5.44 per ton disposed (Table 2.3). Scenario C also includes a Ammonia Slip Mitigation cost of $5.61 per ton of ash reused for an additional annual cost of $1,629,000 (Table 2.4).

[12] All costs within this section are presented in 2011$.

3.0 Integrated NOx Control and Ash Impact Impacts Analyses

This section will integrate the revised baseline emissions, the refined URS SNCR Analysis and the Golder Ash Impact Analysis. It will then provide a summary table with associated cost per ton and incremental cost per ton values.

3.1 SNCR Control Cost Analysis

As discussed in Section 2.1.3, baseline NOx emissions are adjusted to reflect existing controls. Based on the updated baseline, Table 3.1 summarizes the anticipated control costs for additional NOx controls. It includes more refined SNCR costs for CCS Units 1 and 2 (See URS Report Appendix B). It also includes cost scenarios from the Golder Associates Fly Ash Storage and Ammonia Slip Mitigation Technology Evaluation (See Appendix C). It should be noted that the controlled NOx emission concentrations and mass rates have been evaluated on an annual average basis and are not representative of anticipated operation on a shorter scale averaging period (30-day rolling or 24-hour rolling), consistent with BART guidance that costs be normalized to the expected annual emissions reduction. The 30-day rolling limits are intended to be inclusive of unit startup and shutdown as well as variability in load. Consequently, associated BART limits must be higher than stated annual averages used for estimating cost effectiveness (e.g., LNC3+ is evaluated at 0.153 lb NOx/MMBtu on an annual average basis with an anticipated 30-day rolling limit of 0.17 lb NOx/MMBtu). Costs are valued on a present (2011) dollars basis.

Considerable effort has been taken to clarify the impacts that SNCR installation will have on GRE's ash management methods, overall disposal costs and reduction in ash sales revenues. In short, Great River Energy firmly believes, and EPA acknowledges in its proposed FIP, that SNCR may have a detrimental impact to ash sales. The Golder analysis represents these risk ranging from a worst case 100% lost fly ash sales, to an optimistic 30% lost sales, as shown in their Scenarios B and C, respectively. For the sole purpose of defining a baseline, a hypothetical Scenario A "No Ash Impacts," has also been included as a reference point.

Table 3.1 Control Cost Summary (2011$)

<table>
<tr><th>Unit ID</th><th>Control Description</th><th>NOx Emissions (lb/MMBtu)</th><th>Control Eff. From Baseline (%)</th><th>Emission Reduction from Baseline (T/yr)</th><th>Installed Capital Cost ($MM)</th><th>Annualized Operating Cost ($MM)</th><th>Pollution Control Cost ($/ton)</th><th>Incremental Cost $/ton</th></tr>
<tr><td rowspan="8">Unit 1</td><td>SNCR, LNC3+, 100% Lost Ash Sales (Scenario B)</td><td rowspan="3">0.122</td><td rowspan="3">33%</td><td rowspan="3">1,525.2</td><td rowspan="3">$17.873</td><td>$8.878</td><td>$5,821</td><td>$19,125</td></tr>
<tr><td>SNCR, LNC3+, 30% Lost Ash Sales (Scenario C)</td><td>$6.602</td><td>$4,329</td><td>$13,762</td></tr>
<tr><td>SNCR, LNC3+, No Ash Impacts (Scenario A)</td><td>$4.384</td><td>$2,875</td><td>$8,534</td></tr>
<tr><td>SNCR, 100% Lost Ash Sales (Scenario B)</td><td rowspan="3">0.150</td><td rowspan="3">25%</td><td rowspan="3">1,152.8</td><td rowspan="3">$12.176</td><td>$8.795</td><td>$7,629</td><td rowspan="3">NA – Inferior Control</td></tr>
<tr><td>SNCR, 30% Lost Ash Sales (Scenario C)</td><td>$6.519</td><td>$5,655</td></tr>
<tr><td>SNCR, No Ash Impacts (Scenario A)</td><td>$4.301</td><td>$3,731</td></tr>
<tr><td>LNC3+</td><td>0.153</td><td>24%</td><td>1,100.9</td><td>$6.079</td><td>$0.763</td><td>$693</td><td>$693</td></tr>
<tr><td>Baseline (LNC3)</td><td>0.200</td><td>NA-Base</td><td>NA-Base</td><td>NA-Base</td><td>NA-Base</td><td>NA-Base</td><td>NA-Base</td></tr>
<tr><td rowspan="4">Unit 2</td><td>SNCR, 100% Lost Ash Sales (Scenario B)</td><td rowspan="3">0.122</td><td rowspan="3">20%</td><td rowspan="3">772.5</td><td rowspan="3">$11.794</td><td>$8.115</td><td>$10,505</td><td>$10,505</td></tr>
<tr><td>SNCR, 30% Lost Ash Sales (Scenario C)</td><td>$5.839</td><td>$7,559</td><td>$7,559</td></tr>
<tr><td>SNCR, No Ash Impacts (Scenario A)</td><td>$3.621</td><td>$4,688</td><td>$4,688</td></tr>
<tr><td>Baseline – LNC3+</td><td>0.153</td><td>NA-Base</td><td>NA-Base</td><td>NA-Base</td><td>NA-Base</td><td>NA-Base</td><td>NA-Base</td></tr>
</table>

Scenario A (No Ash Impacts) is provided for reference only and does not represent a feasible control option.

Below is provided the least cost envelope illustrated graphically. Only dominant controls falling within the least cost envelope were further analyzed for incremental feasibility. Inferior technologies are deemed not cost effective.

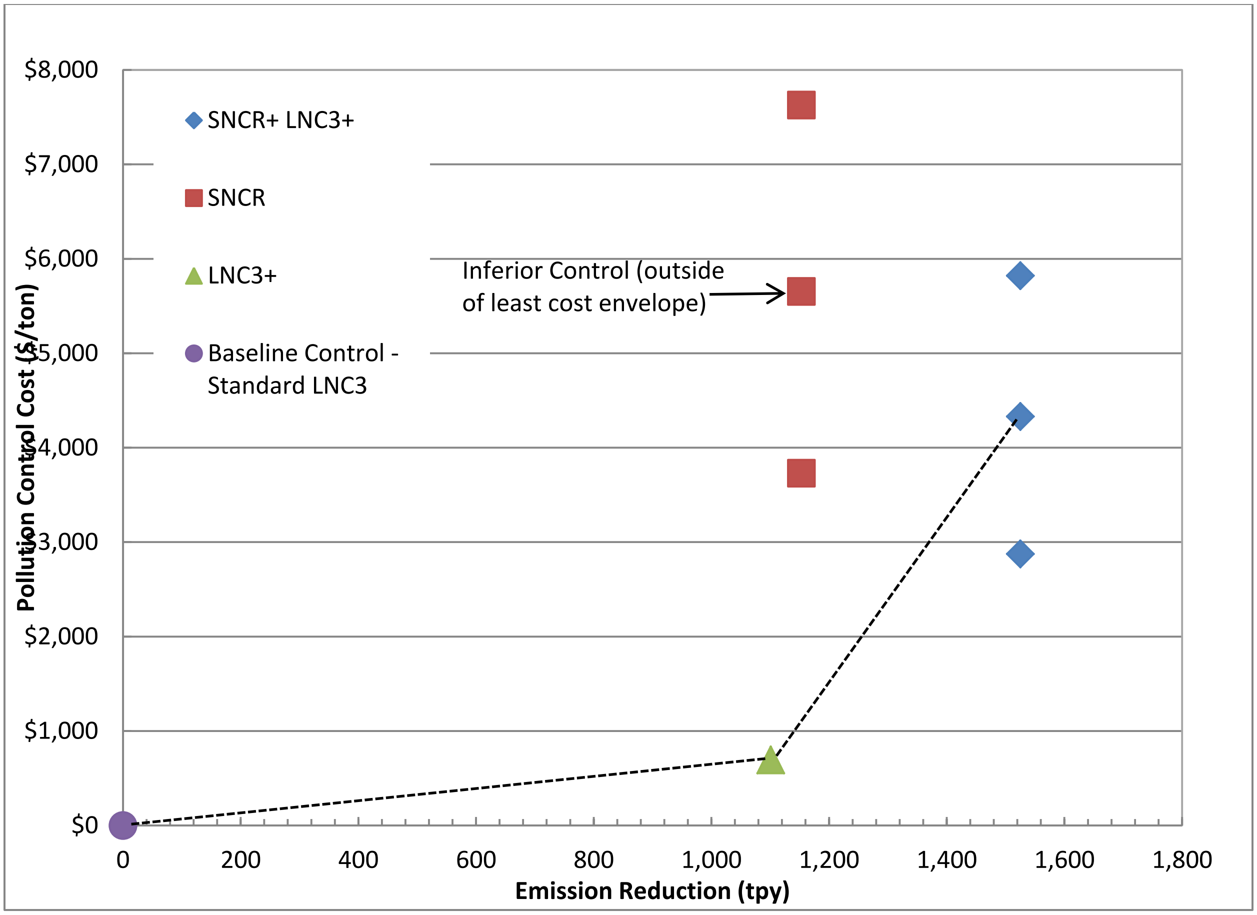

Figure 3.1 **Incremental NOx Analysis**

The remaining feasible technologies are illustrated on the basis of annualized emission reduction in tons per year and total annualized cost in millions of dollars per year.

This refined economic impacts analysis confirms GRE's original conclusion that SNCR is not a cost effective NOx control option. From Table 3.1, it would appear as if Unit 1 SNCR – No Ash Impacts would be cost effect on a dollar per ton basis according to the State of ND thresholds, but in understanding that this scenario is considered hypothetical since some level of ash impacts are expected, and the incremental cost per ton is an order of magnitude higher than anything deemed cost effective. The disparity in the incremental costs occurs due to the fact that the DryFining™ with LNC3+ technology could achieve the associated emissions reduction indicated for the SNCR technology. As highlighted, the "most realistic" or optimistic scenario is 30% lost ash sales, with cost exceeding $4,000 (2011$) per ton of NOx controlled. This value is higher than EPA's determination of economic infeasibility for SCR for CCS at around $4,000/ton (2011$) of NOx removed stated in the FIP.

Although not directly incorporated into GRE's capital and operating control costs presented above, NDDH must also consider additional impacts, such as indirect and stranded cost components discussed in Section 3.2 and Section 3.3.

3.2 Additional Impacts

GRE provides these additional impact considerations not found in the original BART analysis as important to North Dakota in making its final BART determination.

1. The use of DryFining™ technology that has already been implemented for use at both units at a cost of $270 million. GRE has made a significant investment to achieve multi-pollutant emission reductions and visibility improvements in the region.

2. At the time of this submittal, GRE has already installed LNC3+ combustion controls at Unit 2. In 2011 dollars, this was at a cost of over $6 million and has already resulted in NOx reductions. The same system is currently tentatively scheduled to be installed on Unit 1 during the 2014 outage.

3. Ash infrastructure investments of over $31 million have been made to date for management and sale of Coal Creek Station's ash. Over $7 million of the total investment have been made by GRE, directly.

4. The DryFining™ technology provides a dual emission improvement for the total BART analysis. In order to achieve 100% scrubbing for the SO_2 analysis GRE must reduce the moisture, related air flow and therefore the total mass of flue gas travelling through the absorbers in the scrubber. DryFining™ will be implemented to its fullest extent by the BART compliance deadline.

3.2.1 Regional Impact from Ash Sales Revenue

The BART analysis does not take into account additional regional economic impacts resulting from the reduction or elimination of CCS ash sales. In order to estimate these regional impacts, one can use the freight on board (FOB) price of the ash at $41 (2011$), and subtract GRE's share of that revenue at $12.30 (2011$). Therefore, SNCR installation would reduce or eliminate ash sales, eliminating an additional $28.70/ton (2011$) from the local and regional economy. This could result in a loss of as much as $11,910,500 (2011$) per year from the local and regional economy. In addition to these regional economic impacts, there are other impacts that must also be considered.

3.2.2 Fly Ash is Important to the National Economy

Fly ash is an important part of the regional and national economy. The National Association of Manufacturers reported in 2010 that Coal Combustion Residuals (CCRs) contribute $6-11 billion annually to the U.S. economy through revenues from sales for beneficial use, avoided cost of disposal, and savings from use as a sustainable building material.[13] The beneficial use of fly ash and other CCRs are directly responsible for a large number of jobs throughout the country. A 2011 report by Veritas found that "Approximately 10.6 million tons of coal combustion residuals were used in concrete-related products during 2009. Those products provided employment for 240,100 manufacturing workers, 78,480 foundation, structure, and building exterior workers and many of the 102,350 nonresidential building construction workers during 2010." (Veritas 2011[14])

3.2.3 Fly Ash is Important to Regional and National Infrastructure

The American Road and Transportation Builders Association[15] completed a report in 2011 that highlighted the importance of fly ash as a component of road and bridge construction across the country. Their research found that the elimination of fly ash as a construction material would increase the average annual cost of building roads, runways and bridges in the United States by nearly $5.23 billion. This total includes $2.5 billion in materials price increases, $930 million in additional repair work and $1.8 billion in bridge work. The additional costs would total $104.6 billion over 20 years.

3.2.4 Environmental Benefits of Ash Reuse

The use of fly ash as a replacement for cement has many environmental benefits. As a result of the increased use of fly ash, less land is disturbed for quarrying raw materials, less land is taken out of production for landfills, and less carbon dioxide (CO_2) is emitted into the atmosphere to make cement. Using one ton of fly ash instead of Portland cement reduces up to one ton of greenhouse gas emissions. Inversely, by contaminating the ash with ammonia, and increasing ash disposal, there will be a corresponding 1-to-1 ton increase in CO_2 emissions from using more Portland cement. These CO_2 emissions are not trivial.

[13]Report available at: http://www.regulations.gov/#!documentDetail;D=EPA-HQ-RCRA-2009-0640-6992.

[14] Available at: http://www.recyclingfirst.org/pdfs/101.pdf.

[15] Available at: http://www.artba.org/mediafiles/study2011flyash.pdf.

3.2.5 Additional Ash Management Cost Considerations

The ash management costs detailed in this report are considered to be conservative figures from reasonable assumptions that most likely underestimate GRE's future expenditures on ash management.

The ash analysis envisions that all future disposal facilities will be designed and constructed to RCRA subtitle D standards. EPA is currently proceeding with an ash disposal rulemaking that will create uniform national disposal standards under RCRA subtitle D, the far more stringent Subtitle C (Hazardous Waste), or some hybrid approach that takes some requirements from each Subtitle D and C. The cost of complying with a Subtitle C rule would vastly exceed the amounts discussed in this report. This analysis reasonably assumes Subtitle D.

The ash disposal costs discussed above are portrayed as three scenario costs: a baseline which represents current ash sales figures; a scenario where all ash must be disposed of; and a scenario where ash sales are reduced by 30% from the baseline. There is significant uncertainty regarding specific impacts to beneficial reuse if SNCR were installed. The zero ash sales scenario (Scenario B) is very possible and is an outcome that we hope to avoid. Scenario C captures a "hybrid" estimate of the future where some ash is beneficially used and some additional ash must be disposed. For the hybrid scenario, we chose a 30% reduction in sales. This 30% estimate is an optimistic figure of preserved ash sales at 70%. It is quite possible that the amount of ash requiring disposal could easily represent a 50%, 70% or larger reduction in fly ash sales. For this reason, Scenario C is likely to produce ash management costs that are lower than will actually be encountered.

As discussed above, there are a variety of different Ammonia Slip Mitigation (ASM) technologies available. Most of these technologies have only been installed at a small number of generating units and, to GRE's knowledge, no lignite-fired unit is currently operating SNCR and ASM technology.[16] Of all ASM technologies that were investigated, the Headwaters technology was the least expensive. If the Headwaters ASM technology fails to function properly on lignite, it is likely that we would incur significantly larger costs to preserve the beneficial reuse of some portion of our fly ash.

[16] It is important to note that Headwaters ASM technical staff have stated that this technology has not been tested on a lignite unit and they would not guarantee any level of performance if installed at CCS.

The EPA Pollution Control Cost Manual (2002) does not allow GRE to include in our BART analysis the value of previously purchased assets that would be rendered useless by the elimination or reduction of fly ash sales. GRE and its strategic partner, Headwaters Resources, have invested $31 million on ash storage, transportation and distribution infrastructure.

3.3 SNCR Visibility Impacts

It is known that NOx contributes to ammonium nitrate formation, which is predominantly a winter "haze" contributor. For purposes of valuing the welfare effects of recreational visibility, it is important to consider that the North Dakota national parks are generally not in high use during the winter season. If required to install SNCR, GRE will pay an extreme price per deciview resulting in imperceptible improvements for a time of year when the parks are generally not used.

To satisfy EPA's proposed Federal Implementation Plan, Coal Creek Station would need to install SNCR technology to reach a NOx emissions level that is 29% lower than EPA's presumptive BART. Yet, the extensive modeling performed as part of the BART analysis concludes that the installation of SNCR, at an emission rate of 0.12 lb/mmBtu, will have an imperceptible improvement in visibility, ranging from 0.05 deciview (dV) to 0.18 dV in the Class I areas near the facility. This is far less than one-half of what EPA has determined to be perceptible to the human eye (0.50 dV)[17]. As such, it is not justifiable for GRE to incur the added cost of SNCR without any appreciable improvement in visibility.

It is worth noting that SNCR will result in ammonia emissions to the atmosphere. Ammonia is a listed state toxic in North Dakota, and is viewed as a contributor to regional haze because it can bond with sulfur dioxide and nitrogen oxides to form ammonium sulfate and ammonium nitrate aerosols Consequently, GRE does not believe that SNCR is a cost effective technology for improving visibility.

3.3.1 CCS Modeled Visibility Impacts

Under EPA's modeling guidelines, it is necessary to develop a 24-hour maximum anticipated emission rate for each control technology in order to assess visibility impacts. GRE assumes that on a 30-day rolling basis, combustion and post-combustion NOx controls can experience emissions that

[17] Federal Register / Vol. 76, No. 183 / Wednesday, September 21, 2011.
FR discusses State's ability to consider potential impacts for VOC and ammonia although full analyses may not be required.

are approximately 10% higher than their annual design basis. Similarly, for assessing a 24-hour maximum emission rate, GRE assumes emissions will be up to 20% higher than the annual design rate for a given control.

GRE presented a full evaluation of anticipated cost per unit visibility impairment (Δ-dV) in its final BART analysis (Dec 2007). Pollutant interaction has an impact on modeled visibility impairment and, as such, GRE believes that modeling changes to NOx emission rates alone will not provide visibility modeling results that are representative of actual emission controls. This may overstate visibility improvement as compared to modeling NOx, SO_2 and fine PM together. However, for the purpose of illustrating the relative visibility impacts of SNCR and LNC3+, an analysis of the difference in modeled impacts is presented in Table 3.2.

An incremental cost per deciview analysis is also included in Table 3.2. This comparison relies on the annualized operating costs presented in Table 3.1, and represents the difference in annualized capital costs between the two controls compared to the change in average visibility impairment for the 98th percentile over the three modeled years for the same controls.

Table 3.2 Difference in Impairment and Incremental Cost for LNC3+ with Tuning and SNCR with LNC3+

Unit ID	2000 (dV)	2001 (dV)	2002 (dV)	Average (dV)	Incremental Cost per dV (MM$/dV)[1]
Unit 1	0.031	0.044	0.093	0.056	$103.81
Unit 1 & 2	0.062	0.083	0.172	0.106	$110.26

[1] Incremental cost comparison (2011$) of LNC3+ with SNCR with LNC3+ at 30% lost ash sales.

The visibility analysis demonstrates that SNCR will not result in actual improvement to visibility in North Dakota's affected Class I areas, and potential modeled improvements will come at a prohibitive incremental cost exceeding $100 million (2011$) per deciview. Utilities in North Dakota only contribute ~6% to total NOx emissions in the State. Consequently, any additional utility NOx reductions will not have an appreciable effect on visibility improvement. Additional details regarding modeling inputs and visibility impairment is presented in Appendix D.

4.0 Conclusions

Great River Energy provided BART Determinations utilizing the 5 step process in 2007. Until now, Great River Energy has provided screening level analyses and assumptions with respect to SNCR installation. Due to EPA's proposed FIP, and its assertion that SNCR is cost effective for Coal Creek Station, Great River Energy responds with more refined analyses in three primary areas. This refined analysis reevaluates the last two steps of the BART Determination process for LNC3+ and SNCR technology at Coal Creek Station.

First, URS provides a site specific evaluation of SNCR effectiveness at Coal Creek Station, which results in lower projected emissions reductions from this control. These emission estimates clearly change the basis for any cost effective determination. Consideration for startup and shutdown emissions, circumferential cracking and load variations should also factor into this determination as discussed in Section 2.2.

Second, URS reviewed and updated both capital and operating costs for SNCR, based on their expertise and site specific investigation. These values were relatively consistent with values presented to EPA in June and July 2011, but are somewhat higher than the screening values presented in the original BART analysis.

Third, Golder Associates conducted a detail ash impact analysis associated with a range of costs from contaminating the fly ash with ammonia from SNCR. While the exact impacts to Coal Creek Station's ash management and sales are unknown, mandating SNCR will leave GRE in a vulnerable position where we would expect to incur significantly higher costs from lost ash sales and increased landfilling. Based on a detailed technical review GRE would expect to incur additional ash annual costs somewhere between $4,435,000 and $8,988,000 (2011$).

The final two steps of the BART Determination include Step 4 - "Evaluate Impacts and Document Results" and Step 5 – "Evaluate Visibility Impacts". In evaluating the impacts of Unit 1's technologies it was concluded that installation of SNCR alone (without LNC3+) is an economic inferior technology and therefore is not further evaluated incrementally. When the SNCR and LNC3+ technologies were evaluated together for Unit 1 and Unit 2 they were deemed not cost effective on an incremental basis and therefore not an appropriate BART technology. GRE included the visibility tables for the associated LNC3+, and SNCR cases presented in Table 3.1. The final conclusion for the visibility impacts is that based on our refined analysis the state Class I areas would not see any

perceptible improvement in visibility by requiring a level of NOx control above LNC3+ for CCS, and additional reductions would be cost prohibitive on a dollar per deciview basis (Table 3.2).

When the three refined analyses of the final two steps of the BART Determination process are combined and evaluated, it clearly demonstrates that the presumptive NOx limit of 0.17 lb/mmBtu is both cost effective and results in significant visibility improvements in North Dakota's Class I areas.

On strictly a cost effective basis, SNCR can be ruled not cost effective for Unit 2, especially when the GRE specific risks and costs associated with this technology are included. On an incremental cost effectiveness basis, SNCR can be ruled not cost effective for Unit 1, also considering the GRE specific risks and costs associated with this technology. As noted, there are additional economic and visibility impacts associated with SNCR that further preclude it from consideration.

Appendix A

Pollution Control Cost Evaluations

Great River Energy Coal Creek Station
BART Supplement - NOx Emission Control Cost Analysis

Table A-1: Cost Summary

NO_x Control Cost Summary - Unit 1

Case	Control Technology [1]	Annual Designed Emissions lb/MMBtu	Control Eff % from Baseline [3]	Controlled Emissions T/yr	Emission Reduction T/yr	Installed Capital Cost MM$	Annualized Control Cost MM$/yr	Pollution Control Cost $/ton	Annual Incremental Cost $/ton [4]	See Table XX for additional information
3 [2]	SNCR + LNC3+ - 100% Lost Ash Sales	0.122	33%	3,086.2	1,525.2	$17.873	$8.878	$5,821	$19,125	A-4, A-10
	SNCR + LNC3+ - 30% Lost Ash Sales						$6.602	$4,329	$13,762	A-4, A-9
	SNCR + LNC3+ - No Ash Impacts						*$4.384*	*$2,875*	*$8,534*	*A-4, A-8*
2	SNCR - 100% Lost Ash Sales	0.150	25%	3,458.5	1,152.8	$12.176	$8.795	$7,629	NA - Inferior Control	A-7
	SNCR - 30% Lost Ash Sales						$6.519	$5,655	NA - Inferior Control	A-6
	SNCR - No Ash Impacts						*$4.301*	*$3,731*	*NA - Inferior Control*	*A-5*
1	LNC3+	0.153	24%	3,510.5	1,100.9	$6.079	$0.763	$693	$693	A-4
0	Baseline Control - Standard LNC3	0.200	NA-Base	4,611.4	NA-Base	NA-Base	NA-Base	NA-Base	NA-Base	A-3

NO_x Control Cost Summary - Unit 2

Case	Control Technology [1]	Annual Designed Emissions lb/MMBtu	Control Eff % from Baseline [3]	Controlled Emissions T/yr	Emission Reduction T/yr	Installed Capital Cost MM$	Annualized Control Cost MM$/yr	Pollution Control Cost $/ton	Annual Incremental Cost $/ton [4]	See Table XX for additional information
1	SNCR - 100% Lost Ash Sales	0.122	20%	3,089.8	772.5	$11.794	$8.115	$10,505	$10,505	A-10
	SNCR - 30% Lost Ash Sales					$11.794	$5.839	$7,559	$7,559	A-9
	SNCR - No Ash Impacts					*$11.794*	*$3.621*	*$4,688*	*$4,688*	*A-8*
0	Baseline Control - LNC3+	0.153	NA-Base	3,862.3	NA-Base	NA-Base	NA-Base	NA-Base	NA-Base	A-3

[1] Ash impact scenarios align with November 2011 Golder report.
No Ash Impacts - Golder Scenario A; *Scenario provided for reference only and does not represent a feasible outcome*
30% Lost Ash Sales - Golder Scenario C
100% Lost Ash Sales - Golder Scenario B

[2] Capital costs for combined control scenario on Unit 1 are calculated using LNC3+ costs for Unit 1 (scenario 1) and SNCR costs for Unit 2, as unit 2 presently has LNC3+ installed.

[3] Calculated on a mass basis.

[4] Incremental costs calculated as the difference in annualized operating cost divided by the difference in emission reduction for the next lowest level of dominant control.

Great River Energy Coal Creek Station

BART Supplement - NOx Emission Control Cost Analysis

Table A-2: Emission Inventory Data / Baseline Emission Rate for BART Control Cost Analysis

Equipment Information: GRE Coal Creek Unit I				6015	MMBtu/hr
Year (12-Month Avg. Period)	Jul 2010 - Jun 2011	Aug 2010 - Jul 2011	Sep 2010 - Aug 2011	Oct 2010 - Sep 2011	Nov 2010 -Oct 2011
Hours of Operation	7,700	7,700	7,635	7,599	7,629
Fuels Used:					
Quanity of Lignite - Tons	3,356,248	3,352,605	3,296,938	3,268,966	3,282,270
Percent Sulfur in Coal (Average)	0.64%	0.65%	0.65%	0.66%	0.61%
BTU per Unit of Coal (Average)	6,415	6,448	6,482	6,517	6,003
Heat Input	4.410E+07	4.422E+07	4.356E+07	4.320E+07	4.346E+07
MMBtu/hr	5,727	5,743	5,705	5,685	5,697
% of Capacity	95.2%	95.5%	94.8%	94.5%	94.7%
NOx lb/MMBtu	0.200	0.200	0.199	0.200	0.203
Total Stack Emissions:					
NOx Emitted Tons Per Year:	4,416.3	4,412.0	4,333.1	4,330.2	4,402.3
NOx Emitted Lb Per Hour:	1,204.8	1,200.3	1,196.7	1,205.8	1,218.5
Stack Emissions --- Lignite:					
NOX CEM Annual Average lb/MMBtu	0.201	0.200	0.200	0.201	0.203

Baseline Emis	
Unit 1	**Unit 2**
7,653	8,410
3,311,405	3,688,805
0.64%	0.64%
6,373	6,373
43,708,554	47,761,077
5,712	5,679
95.0%	94.3%
0.200	0.153
4,378.8	3,642.5
1205.2	918.5
0.201	0.153

Equipment Information: GRE Coal Creek Unit II				6022	MMBtu/hr
Year	Jul 2010 - Jun 2011	Aug 2010 - Jul 2011	Sep 2010 - Aug 2011	Oct 2010 - Sep 2011	Nov 2010 -Oct 2011
Hours of Operation	8,430	8,430	8,397	8,401	8,390
Fuels Used:					
Quanity of Lignite - Tons	3,730,674	3,718,253	3,676,481	3,672,436	3,646,178
Percent Sulfur in Coal (Average)	0.64%	0.65%	0.65%	0.66%	0.61%
BTU per Unit of Coal (Average)	6,415	6,448	6,482	6,517	6,003
Heat Input	4.810E+07	4.799E+07	4.757E+07	4.764E+07	4.751E+07
MMBtu/hr	5,706	5,692	5,665	5,671	5,662
% of Capacity	94.9%	94.6%	94.2%	94.3%	94.1%
NOx lb/MMBtu	0.152	0.153	0.152	0.152	0.153
Total Stack Emissions:					
NOx Emitted Tons Per Year:	3,662.4	3,666.8	3,610.4	3,626.8	3,646.1
Stack Emissions --- Lignite:					
NOX CEM Annual Average lb/MMBtu	0.152	0.153	0.152	0.153	0.154

Great River Energy Coal Creek Station

BART Supplement - NOx Emission Control Cost Analysis

Table A-3: Summary of Utility, Chemical and Supply Costs

Operating Unit: Unit 1 or 2 **Study Year** 2011

From Golder Report

Item	Unit Cost	Units	Reference Cost	Year	Data Source	Notes
Operating Labor	37.00	$/hr	25.86	2002	Stone & Webster 2002 Cost Estimate; confirmed by GRE	
Maintenance Labor	37.00	$/hr	26.25	2002	Stone & Webster 2002 Cost Estimate; confirmed by GRE	
Electricity	0.0604	$/kwh	0.049	2004	DOE Average Retail Price of Industrial Electricity, 2004	http://www.eia.doe.gov/emeu/aer/txt/ptb0810.html
Water	0.31	$/kgal	0.79	2002	Stone & Webster 2002 Cost Estimate; confirmed by GRE	
Cooling Water	0.32	$kgal	0.23	1999	EPA Air Pollution Control Cost Manual, 6th ed. Section 3.1 Ch 1	Ch 1 Carbon Adsorbers, 1999 $0.15 - $0.30 Avg of 22.5 and 7 yrs and 3% inflation
Compressed Air	0.37	$/kscf	0.25	1998	EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1	Example problem; Dried & Filtered, Ch 1.6 '98 cost adjusted for 3% inflation
Wastewater Disposal Neutralization	1.96	$/kgal	1.50	2002	EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 2 Chapter 2.5.5.5	Section 2 lists $1- $2/1000 gal. Cost adjusted for 3% inflation Sec 6 Ch 3 lists $1.30 - $2.15/1,000 gal
Wastewater Disposal Bio-Treat	4.96	$/kgal	3.80	2002	EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 5.2 Chapter 1	Ch 1 lists $1.00 - $6.00 for municipal treatment, $3.80 is average. Cost adjusted for 3% inflation
Solid Waste Disposal - No Impact	0.000	$/ton	0.00	2011	Assume no chang in GRE landfill cost for ash	Fly ash disposal of 0 net tons
Solid Waste Disposal - 30% Lost	5.438	$/ton	5.438	2011	Golder Fly Ash Management Evaluation - Nov. 2011	Cost per ton of $13.91/ ton for 234,500 tons less existing cost of $18.06/tons for 110,000 tons
Solid Waste Disposal - 100% Lost	7.396	$/ton	7.396	2011	Golder Fly Ash Management Evaluation - Nov. 2011	Cost per ton of $11.18/ ton for 525,000 tons less existing cost of $18.06/tons for 110,000 tons
Hazardous Waste Disposal	326.19	$/ton	250.00	2002	EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 2 Chapter 2.5.5.5	Section 2 lists $200 - $300/ton Used $250/ton. Cost adjusted for 3% inflation
Waste Transport	0.65	$/ton-mi	0.500	2002	EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 3	Example problem. Cost adjusted for 3% inflation
Ash Sales	12.300	$/ton	12.300	2011	Golder Fly Ash Management Evaluation - Nov. 2011	$/ton received for sale of ash; this amount is lost if ash cannot be sold
Ammonia Mitigation	5.610	$/ton	5.610	2011	Golder Fly Ash Management Evaluation - Nov. 2011	
Chemicals & Supplies						
Lime	90.00	$/ton	72.19	2005	GRE per Diane Stockdill 12/6/05 email	Cost adjusted for 3% inflation
Caustic	364	$/ton	305.21	2005	GRE per Diane Stockdill 12/6/05 email	Cost adjusted for 3% inflation
Urea	500	$/ton	500	2011	URS SNCR Report - November 2011	
Oxygen	17.91	kscf	15.00	2005	Get cost from Air Prod Website	Cost adjusted for 3% inflation
EPA Urea	179.1	$/ton				
Ammonia	1	$/lb	0.92	2005	GRE per Diane Stockdill	Cost adjusted for 3% inflation
Other						
Sales Tax	0	%			GRE per Diane Stockdill 12/6/05 email	
Interest Rate	5.50%	%			GRE per Diane Stockdill 12/6/05 email	Estimated prime rate plus 3%

Please note, for units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal

Future Operating Scenario for BART Cost Analysis

Operating Information	Unit 1	Unit 2			Data Source	Notes
Annual Op. Hrs	7,652.6	8,409.6	Hours		July 2010 to October 2011 Coal Creek Emission Data	
Utilization Rate	100.0%	100.0%			GRE per Diane Stockdill 12/6/05 email	
Equipment Life	20	20	yrs			Engineering Estimate
Coal Ash	11.70	11.70	wt % ash		2010 Coal Creek Emission Inventory	
Coal Sulfur	0.64	0.64	% Coal Sulfur Content		July 2010 to October 2011 Coal Creek Emission Data	
Coal Heating Value	6,373	6,373	Btu/lb of coal		July 2010 to October 2011 Coal Creek Emission Data	
Design Capacity	6,015	6,022	MMBtu/hr			
ID Fan Flow Rates	Assumes coal drying with DryFining™					
Standardized Flow Rate	866293.7	866293.7	scfm @ 32º F			
Temperature	330.0	330.0	Deg F		GRE per G. Riveland 4/5/06 email	
Moisture Content	13.3%	13.3%			GRE per G. Riveland 4/5/06 email	
Actual Flow Rate	2,234,300	2,234,300	acfm		GRE per G. Riveland 4/5/06 email	
Standardized Flow Rate	1,391,000	1,391,000	scfm @ 330º F		GRE per G. Riveland 4/5/06 email	
Dry Std Flow Rate	1,205,997	1,205,997	dscfm @ 330º F			
NOx Pollutant Data						
Max Emis (lb/hr)	1,205.2	918.5			July 2010 to October 2011 Coal Creek Emission Data	
Max Emis (tpy)	4,611.4	3,862.3				
Baseline Emiss (lb/MMBtu)	0.200	0.153				

Great River Energy Coal Creek Station

BART Supplement - NOx Emission Control Cost Analysis

Table A-4: Unit 1 NOx Control - Foster Wheeler LNC3+

Operating Unit: **Unit 1**

Emission Unit Number	EU-1		Stack/Vent Number	SV-1		CEPCI	
Desgin Capacity	6,015	MMBtu/hr	Standardized Flow Rate	866,294	scfm @ 32º F	2005	468.2
Expected Utiliztion Rate	100%		Temperature	330	Deg F	2011	588.9
Expected Annual Hours of Operation	7,652.6	Hours	Moisture Content	13.3%		Inflation Factor	1.26
Annual Interest Rate	5.5%		Actual Flow Rate	2,234,300	acfm		
Expected Equipment Life	20	yrs	Standardized Flow Rate	1,391,000	scfm @ 330º F		
Baseline NOx	0.200	lb/MMBtu	Dry Std Flow Rate	1,205,997	dscfm @ 330º F		

CONTROL EQUIPMENT COSTS

Capital Costs								
Direct Capital Costs								
Purchased Equipment (A)								1,257,796
Purchased Equipment Total (B)								**1,958,057**
Installation - Standard Costs								1,958,057
Installation - Site Specific Costs								NA
Installation Total								3,729,632
Total Direct Capital Cost, DC								5,687,689
Total Indirect Capital Costs, IC								391,611
Total Capital Investment (TCI) = DC + IC								**6,079,300**
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.						7,079
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost						756,131
Total Annual Cost (Annualized Capital Cost + Operating Cost)								**763,210**

Emission Control Cost Calculation

Pollutant	**Max Emis Lb/Hr**	**Pre-control Annual T/Yr**	**Cont Eff %**	**Exit Conc**	**Conc Units**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
Nitrogen Oxides (NOx)	1,205.2	4,611.4	24%			3510.5	1,100.9	693

Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 2 (Used PM Scrubber which has lowest installed cost multiplier)

Notes & Assumptions

1 Sept 2005 Cost Estimate from Foster Wheeler, Option 2, inflated to 2011 dollars. Ratio based on actual cost for Unit 2 instalaltion.

2 Total capital investment reflects actual installed costs for Unit 2 installation, infllated to 2011 dollars.

3 Assumed 0.1 hr/shift operatior and maintenance labor for LNB

4 Process, emissions and cost data listed above is for one unit.

5 For units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal

Great River Energy Coal Creek Station
BART Supplement - NOx Emission Control Cost Analysis
Table A-4: Unit 1 NOx Control - Foster Wheeler LNC3+

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) (1)			**1,257,796**
Instrumentation			
Sales Taxes			
Freight			
Purchased Equipment Total (B)			**1,958,057**
Installation			
Foundations & supports			
Handling & erection			
Electrical			
Piping			
Insulation			
Painting			
Installation Subtotal Standard Expenses (1)			**1,958,057**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Site Specific - Other		Site Specific	NA
Total Site Specific Costs			NA
Installation Total			**3,729,632**
Total Direct Capital Cost, DC			**5,687,689**
Indirect Capital Costs			
Engineering, supervision	5%	of purchased equip cost (B)	97,903
Construction & field expenses	10%	of purchased equip cost (B)	195,806
Contractor fees	0%	of purchased equip cost (B)	0
Start-up	1%	of purchased equip cost (B)	19,581
Performance test	1%	of purchased equip cost (B)	19,581
Model Studies	NA	of purchased equip cost (B)	NA
Contingencies	3%	of purchased equip cost (B)	58,742
Total Indirect Capital Costs, IC	20%	of purchased equip cost (B)	**391,611**
Ozone Generator, Installed Cost			**0**
Total Capital Investment (TCI) = DC + IC (2)			**6,079,300**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**6,079,300**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	NA		-
Supervisor	NA		-
Maintenance			
Maintenance Labor	37.00	$/Hr, 0.1 hr/8 hr shift, 7652.6 hr/yr	3,539
Maintenance Materials	100%	of maintenance labor costs	3,539
Utilities, Supplies, Replacements & Waste Management			
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
Total Annual Direct Operating Costs			**7,079**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	4,247
Administration (2% total capital costs)	2%	of total capital costs (TCI)	121,586
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	60,793
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	60,793
Capital Recovery	0.0837	for a 20- year equipment life and a 5.5% interest rate	508,712
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**756,131**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**763,210**

Great River Energy Coal Creek Station
BART Supplement - NOx Emission Control Cost Analysis
Table A-4: Unit 1 NOx Control - Foster Wheeler LNC3+

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Parts & Equipment:		
Equipment Life	5	years
CRF	0.0000	
Rep part cost per unit	0	$/ft^3
Amount Required	0	ft^3
Packing Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:			
Equipment Life	3		
CRF	0.3707		
Rep part cost per unit	0	$ each	
Amount Required	0	Number	
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax	
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr	OAQPS list replacement times from 5 - 20 min per bag.
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	
Annualized Cost	**0**		

Electrical Use							
	Flow acfm		**Δ P ft H2O**	**Efficiency**	**Hp**	**kW**	
Blower, Scrubber	2,234,300		0	0.7	-	0.0	EPA Cost Cont Manual 6th ed Section 5.2 Chapter 1 Eq 1.48
	Flow	**Liquid SPGR**	**Δ P ft H2O**	**Efficiency**	**Hp**	**kW**	
Circ Pump	000 gpm	1	0	0.7	-	0.0	EPA Cost Cont Manual 6th ed Section 5.2 Chapter 1 Eq 1.49
H2O WW Disch	0 gpm	1	0	0.7	-	0.0	EPA Cost Cont Manual 6th ed Section 5.2 Chapter 1 Eq 1.49
			lb/hr O_3				
LTO Electric Use	4.5 kW/lb O_3					0	
Other							
Total						0.0	

Reagent Use & Other Operating Costs						
Ozone Needed	1.8	lb O3/lb NOx	-	lb/hr O3		
Oxygen Needed	10%	wt O2 to O3 conversion		0 lb/hr O2	0 scfh O2	
LTO Cooling Water	150	gal/lb O3	0 gpm			
Liquid/Gas ratio	0.0	* L/G = Gal/1,000 acf				
Circulating Water Rate	0	gpm				
Water Makeup Rate/WW Disch =	20%	of circulating water rate =	0 gpm			
Scrubber Cost	10	$/scfm Gas	$0		Incremental cost per BOC. Need to increase vessel size over standard absorber.	
Ozone Generator	$350	lb O3/day	$0	Installed	Installed cost factor per BOC.	

Direct Operating Cost Calculations — **Annual hours of operation:** **7,652.6**; **Utilization Rate:** **100%**

Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
Operating Labor							
Op Labor	0	$/Hr	0.1	hr/8 hr shift	96	0	$/Hr, 0.1 hr/8 hr shift, 7652.6 hr/yr
Supervisor	15%	of Op.			NA	-	15% of Operator Costs
Maintenance							
Maint Labor	37.00	$/Hr	0.1	hr/8 hr shift	96	3,539	$/Hr, 0.1 hr/8 hr shift, 7652.6 hr/yr
Maint Mtls	100	% of Maintenance Labor			NA	3,539	100% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.0604	$/kwh	0.0	kW-hr	0	0	$/kwh, 0 kW-hr, 7652.6 hr/yr, 100% utilization
Water	0.3100	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 7652.6 hr/yr, 100% utilization
Cooling Water	0.3208	$kgal	0.0	gpm	0	0	$kgal, 0 gpm, 7652.6 hr/yr, 100% utilization
Comp Air	0.3671	$/kscf	0	kscfm	0	0	$/kscf, 0 kscfm, 7652.6 hr/yr, 100% utilization
WW Treat Neutralization	1.9572	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 7652.6 hr/yr, 100% utilization
WW Treat Biotreatement	4.9581	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 7652.6 hr/yr, 100% utilization
SW Disposal	0.0000	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 7652.6 hr/yr, 100% utilization
Haz W Disp	326.1933	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 7652.6 hr/yr, 100% utilization
Ammonia Mitigation	5.6100	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 7652.6 hr/yr, 100% utilization
Lost Ash Sales	12.3000	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 7652.6 hr/yr, 100% utilization
Lime	90.0000	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 7652.6 hr/yr, 100% utilization
Caustic	364.4367	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 7652.6 hr/yr, 100% utilization
Oxygen	17.9108	kscf	0.0	kscf/hr	0	0	kscf, 0 kscf/hr, 7652.6 hr/yr, 100% utilization

*annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

Great River Energy Coal Creek Station

BART Supplement - NOx Emission Control Cost Analysis

Table A-5: Unit 1 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (Maintain Ash Sales)

Operating Unit: **Unit 1**

Emission Unit Number	EU-1		Stack/Vent Number	SV-1	
Desgin Capacity	6,015	MMBtu/hr	Standardized Flow Rate	866,294	scfm @ 32º F
Expected Utiliztion Rate	100%		Temperature	330	Deg F
Expected Annual Hours of Operation	7,652.6	Hours	Moisture Content	13.3%	
Annual Interest Rate	5.5%		Actual Flow Rate	2,234,300	acfm
Expected Equipment Life	20	yrs	Standardized Flow Rate	1,391,000	scfm @ 330º F
Baseline NOx	0.200	lb/MMBtu	Dry Std Flow Rate	1,205,997	dscfm @ 330º F

CONTROL EQUIPMENT COSTS

Capital Costs								
Direct Capital Costs								
Purchased Equipment (A)								3,700,000
Purchased Equipment Total (B)								**8,465,600**
Installation - Standard Costs								1,270,000
Installation - Site Specific Costs								1,036,000
Installation Total								1,758,000
Total Capital Investment (TCI) = DC + IC								**12,176,084**
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.						3,282,068
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost						1,018,887
Total Annual Cost (Annualized Capital Cost + Operating Cost)								**4,300,954**

Emission Control Cost Calculation

Pollutant	**Max Emis Lb/Hr**	**Pre-control Annual T/Yr**	**Cont Eff %**	**Exit Conc**	**Conc Units**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
Nitrogen Oxides (NOx)	1,205.2	4,611.4	25.0%			3458.5	1,152.8	3,731

Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1

Notes & Assumptions

1. November 2011 SNCR Evaluation from URS
2. SNCR Maintenance Costs EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.21
3. Process, emissions and cost data listed above is for one unit.
4. For units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal
5. Retrofit factor of 60% used by URS based on site visit to Coal Creek Station.
6. SW disposal and fly ash sales data from Nov. 2011 Golder Fly Ash Evaluation, Appendix B2
7. One-time cost for Technology Licensing Fee for the SNCR process is ~0.5% of the Process Capital.

Great River Energy Coal Creek Station

BART Supplement - NOx Emission Control Cost Analysis

Table A-5: Unit 1 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (Maintain Ash Sales)

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment			**3,700,000**
Purchased Equipment Costs			
Instrumentation	10%	of purchased equipment cost	370,000
Site Specific and Prime Contractor Markup	28%	of purchased equipment cost	1,036,000
Freight	5%	of purchased equipment cost	185,000
Purchased Equipment Total	43%		5,291,000
Purchased Equipment Total+ Retrofit Factor (A)			**8,465,600**
Indirect Installation			
General Facilities		See Notes & Assumptions 1 on pg. 1 of Table	420,000
Engineering & Home Office		See Notes & Assumptions 1 on pg. 1 of Table	850,000
Process Contingency		See Notes & Assumptions 1 on pg. 1 of Table	488,000
Total Indirect Installation Costs (B)		See Notes & Assumptions 1 on pg. 1 of Table	**1,758,000**
Project Contingeny (C)		See Notes & Assumptions 1 on pg. 1 of Table	**1,540,000**
Total Plant Cost (D)		A + B + C	**11,763,600**
Allowance for Funds During Construction (E)		0 for SNCR	**0**
Prepaid Royalties (F)		See Notes & Assumptionss 1 and 7 on pg. 1 of Table	**42,000**
Pre Production Costs (G)		See Notes & Assumptions 1 on pg. 1 of Table	**236,000**
Inventory Capital (H)		Reagent Vol * $/gal	**134,484**
Intial Catalyst and Chemicals (I)		0 for SNCR	**0**
Total Capital Investment (TCI) = DC + IC		D + E + F + G +H + I	**12,176,084**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**12,176,084**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	NA		-
Supervisor	NA		-
Maintenance			
Maintenance Total	1.50	% of Total Capital Investment	182,641
Maintenance Materials	NA	% of Maintenance Labor	-
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.060	See Direct Operating Cost Calculations on last pg.	28,218
Water	0.310	See Direct Operating Cost Calculations on last pg.	8,256
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
Urea	500.00	See Direct Operating Cost Calculations on last pg.	3,062,953
NA	NA		-
Total Annual Direct Operating Costs			**3,282,068**
Indirect Operating Costs			
Overhead	NA	of total labor and material costs	NA
Administration (2% total capital costs)	NA	of total capital costs (TCI)	NA
Property tax (1% total capital costs)	NA	of total capital costs (TCI)	NA
Insurance (1% total capital costs)	NA	of total capital costs (TCI)	NA
Capital Recovery	0.08368	for a 20- year equipment life and a 5.5% interest rate	1,018,887
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**1,018,887**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**4,300,954**

See Summary page for notes and assumptions

Great River Energy Coal Creek Station

BART Supplement - NOx Emission Control Cost Analysis

Table A-5: Unit 1 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (Maintain Ash Sales)

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.08368	

Replacement Catayst		<- Enter Equipment Name to Get Cost
Equipment Life	5	years
CRF	0.2342	
Rep part cost per unit	0	$/ft^3
Amount Required	12	ft^3
Packing Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:		<- Enter Equipment Name to Get Cost	
Equipment Life	2	years	
CRF	0.0000		
Rep part cost per unit	0	$/ft^3	
Amount Required	0 Cages		
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax	See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs
Installation Labor	0	10 min per bag, Labor + Overhead (68% = $29.65/hr)	
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	EPA CCM list replacement times from 5 - 20 min per bag.
Annualized Cost	**0**		

Electrical Use			
NOx in	0.20	lb/MMBtu	kW
NSR	0.60		
Power			61.0
Total			61.0

Reagent Use & Other Operating Costs					
NOx in	0.20	lb/MMBtu	Urea Use	1601	lb/hr
Efficiency	25%		Volume 14 day inventory	269	ton
Duty	6,015	MMBtu/hr	Inventory Cost	$134,484	
Water Use	3480	gal/hr			

Direct Operating Cost Calculations — **Annual hours of operation:** **7,652.6**; **Utilization Rate:** **100%**

Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
Operating Labor							
Op Labor	37	$/Hr	0.0	hr/8 hr shift	0	0	$/Hr, 0.0 hr/8 hr shift, 7652.6 hr/yr
Supervisor	15%	of Op.			NA	-	15% of Operator Costs
Maintenance							
Maintenance Total	1.5	% of Total Capital Investment				182,641.26	% of Total Capital Investment
Maint Mtls	0	% of Maintenance Labor			NA	0	0% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.06045	$/kwh	61.00000	kW-hr	466,808.60	28,217.79	$/kwh, 61.0 kW-hr, 7652.6 hr/yr, 100% utilization
Water	0.31000	$/kgal	3480.00000	gph	26,631.05	8,255.62	0.31 $/kgal X 3,480.0 gph/1000 X 7652.6 hr/yr X 100% utilization
Cooling Water	0.32080	$kgal	0.00000	gpm	0	0	$kgal, 0 gpm, 7652.6 hr/yr, 100% utilization
Comp Air	0.36713	$/kscf	0.00000	scfm/kacfm**	0	0	$/kscf, 0.0 scfm/kacfm**, 7652.6 hr/yr, 100% utilization
WW Treat Neutralization	1.95716	$/kgal	0.00000	gpm	0	0	$/kgal, 0.0 gpm, 7652.6 hr/yr, 100% utilization
WW Treat Biotreatement	4.95814	$/kgal	0.00000	gpm	0	0	$/kgal, 0.0 gpm, 7652.6 hr/yr, 100% utilization
SW Disposal	0.00000	$/ton	7.18710	ton/hr	55,000	0	$/ton, 7.2 ton/hr, 7652.6 hr/yr, 100% utilization
Haz W Disp	326.19330	$/ton	0.00000	ton/hr	0	0	$/ton, 0.0 ton/hr, 7652.6 hr/yr, 100% utilization
Ammonia Mitigation	5.61	$/ton	0.00000	ton/hr	0	0	$/ton, 0.0 ton/hr, 7652.6 hr/yr, 100% utilization
Lost Ash Sales	12.3	$/ton	0.00000	ton/hr	0	0	$/ton, 0.0 ton/hr, 7652.6 hr/yr, 100% utilization
Lime	90.0	$/ton	0.00000	lb/hr	0	0	$/ton, 0.0 lb/hr, 7652.6 hr/yr, 100% utilization
Urea	500.0	$/ton	0.80050	ton/hr	6,125.91	3,062,953.15	500 $/ton X 0.8005 ton/hr X 7652.6 hr/yr X 100% utilization
Oxygen	17.91078	kscf	0.00000	kscf/hr	0	0	kscf, 0.0 kscf/hr, 7652.6 hr/yr, 100% utilization

** Std Air use is 2 scfm/kacfm

*annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

Great River Energy Coal Creek Station

BART Supplement - NOx Emission Control Cost Analysis

Table A-6: Unit 1 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (30% Lost Ash Sales)

Operating Unit: **Unit 1**

Emission Unit Number	EU-1		Stack/Vent Number	SV-1	
Desgin Capacity	6,015	MMBtu/hr	Standardized Flow Rate	866,294	scfm @ 32º F
Expected Utiliztion Rate	100%		Temperature	330	Deg F
Expected Annual Hours of Operation	7,652.6	Hours	Moisture Content	13.3%	
Annual Interest Rate	5.5%		Actual Flow Rate	2,234,300	acfm
Expected Equipment Life	20	yrs	Standardized Flow Rate	1,391,000	scfm @ 330º F
Baseline NOx	0.200	lb/MMBtu	Dry Std Flow Rate	1,205,997	dscfm @ 330º F

CONTROL EQUIPMENT COSTS

Capital Costs		
Direct Capital Costs		
Purchased Equipment (A)		3,700,000
Purchased Equipment Total (B)		**8,465,600**
Installation - Standard Costs		1,270,000
Installation - Site Specific Costs		1,036,000
Installation Total		1,758,000
Total Capital Investment (TCI) = DC + IC		**12,176,084**
Operating Costs		
Total Annual Direct Operating Costs	Labor, supervision, materials, replacement parts, utilities, etc.	5,500,243
Total Annual Indirect Operating Costs	Sum indirect oper costs + capital recovery cost	1,018,887
Total Annual Cost (Annualized Capital Cost + Operating Cost)		**6,519,129**

Emission Control Cost Calculation

Pollutant	**Max Emis Lb/Hr**	**Pre-control Annual T/Yr**	**Cont Eff %**	**Exit Conc**	**Conc Units**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
Nitrogen Oxides (NOx)	1,205.2	4,611.4	25.0%			3458.5	1,152.8	5,655

Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1

Notes & Assumptions

1. November 2011 SNCR Evaluation from URS
2. SNCR Maintenance Costs EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.21
3. Process, emissions and cost data listed above is for one unit.
4. For units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal
5. Retrofit factor of 60% used by URS based on site visit to Coal Creek Station.
6. SW disposal and fly ash sales data from Nov. 2011 Golder Fly Ash Evaluation, Appendix B2
7. One-time cost for Technology Licensing Fee for the SNCR process is ~0.5% of the Process Capital.

Great River Energy Coal Creek Station
BART Supplement - NOx Emission Control Cost Analysis
Table A-6: Unit 1 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (30% Lost Ash Sales)

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment			**3,700,000**
Purchased Equipment Costs			
Instrumentation	10.00%	of purchased equipment cost	370,000
Site Specific and Prime Contractor Markup	28.00%	of purchased equipment cost	1,036,000
Freight	5.00%	of purchased equipment cost	185,000
Purchased Equipment Total	43.00%		5,291,000
Purchased Equipment Total+ Retrofit Factor (A)			**8,465,600**
Indirect Installation			
General Facilities		See Notes & Assumptions 1 on pg. 1 of Table	420,000
Engineering & Home Office		See Notes & Assumptions 1 on pg. 1 of Table	850,000
Process Contingency		See Notes & Assumptions 1 on pg. 1 of Table	488,000
Total Indirect Installation Costs (B)		See Notes & Assumptions 1 on pg. 1 of Table	**1,758,000**
Project Contingeny (C)		See Notes & Assumptions 1 on pg. 1 of Table	**1,540,000**
Total Plant Cost (D)		A + B + C	**11,763,600**
Allowance for Funds During Construction (E)		0 for SNCR	**0**
Prepaid Royalties (F)		See Notes & Assumptionss 1 and 7 on pg. 1 of Table	**42,000**
Pre Production Costs (G)		See Notes & Assumptions 1 on pg. 1 of Table	**236,000**
Inventory Capital (H)		Reagent Vol * $/gal	**134,484**
Intial Catalyst and Chemicals (I)		0 for SNCR	**0**
Total Capital Investment (TCI) = DC + IC		D + E + F + G +H + I	**12,176,084**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**12,176,084**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	NA		-
Supervisor	NA		-
Maintenance			
Maintenance Total	1.50	% of Total Capital Investment	182,641
Maintenance Materials	NA	% of Maintenance Labor	-
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.060	See Direct Operating Cost Calculations on last pg.	28,218
Water	0.310	See Direct Operating Cost Calculations on last pg.	8,256
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
SW Disposal	5.44	See Direct Operating Cost Calculations on last pg.	637,648
NA	NA		-
Ammonia Mitigation	5.61	See Direct Operating Cost Calculations on last pg.	814,853
Lost Ash Sales	12.30	See Direct Operating Cost Calculations on last pg.	765,675
NA	NA		-
Urea	500.00	See Direct Operating Cost Calculations on last pg.	3,062,953
NA	NA		-
Total Annual Direct Operating Costs			**5,500,243**
Indirect Operating Costs			
Overhead	NA	of total labor and material costs	NA
Administration (2% total capital costs)	NA	of total capital costs (TCI)	NA
Property tax (1% total capital costs)	NA	of total capital costs (TCI)	NA
Insurance (1% total capital costs)	NA	of total capital costs (TCI)	NA
Capital Recovery	0.08368	for a 20- year equipment life and a 5.5% interest rate	1,018,887
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**1,018,887**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**6,519,129**

See Summary page for notes and assumptions

Great River Energy Coal Creek Station

BART Supplement - NOx Emission Control Cost Analysis

Table A-6: Unit 1 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (30% Lost Ash Sales)

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.08368	

Replacement Catayst		<- Enter Equipment Name to Get Cost
Equipment Life	5	years
CRF	0.2342	
Rep part cost per unit	0	$/ft^3
Amount Required	12	ft^3
Packing Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:		<- Enter Equipment Name to Get Cost	
Equipment Life	2	years	
CRF	0.0000		
Rep part cost per unit	0	$/ft^3	
Amount Required	0	Cages	
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax	See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs
Installation Labor	0	10 min per bag, Labor + Overhead (68% = $29.65/hr)	
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	EPA CCM list replacement times from 5 - 20 min per bag.
Annualized Cost	**0**		

Electrical Use			
NOx in	0.20	lb/MMBtu	kW
NSR	0.60		
Power			61.0
Total			61.0

Reagent Use & Other Operating Costs					
NOx in	0.20	lb/MMBtu	Urea Use	1601	lb/hr
Efficiency	25%		Volume 14 day inventory	269	ton
Duty	6,015	MMBtu/hr	Inventory Cost	$134,484	
Water Use	3480	gal/hr			

Direct Operating Cost Calculations — **Annual hours of operation:** **7,652.6**; **Utilization Rate:** **100%**

Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
Operating Labor							
Op Labor	37	$/Hr	0.0	hr/8 hr shift	0	0	$/Hr, 0.0 hr/8 hr shift, 7652.6 hr/yr
Supervisor	15%	of Op.			NA	-	15% of Operator Costs
Maintenance							
Maintenance Total	1.5	% of Total Capital Investment				182,641.26	% of Total Capital Investment
Maint Mtls	0	% of Maintenance Labor			NA	0	0% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.06045	$/kwh	61.00000	kW-hr	466,808.60	28,217.79	0.0604 $/kwh X 61.0 kW-hr X 7652.6 hr/yr X 100% utilization
Water	0.31000	$/kgal	3480.00000	gph	26,631.05	8,255.62	0.3100 $/kgal X 3,480.0 gph/1000 X 7652.6 hr/yr X 100% utilization
Cooling Water	0.32080	$kgal	0.00000	gpm	0	0	$kgal, 0 gpm, 7652.6 hr/yr, 100% utilization
Comp Air	0.36713	$/kscf	0.00000	scfm/kacfm**	0	0	$/kscf, 0.0 scfm/kacfm**, 7652.6 hr/yr, 100% utilization
WW Treat Neutralization	1.95716	$/kgal	0.00000	gpm	0	0	$/kgal, 0.0 gpm, 7652.6 hr/yr, 100% utilization
WW Treat Biotreatement	4.95814	$/kgal	0.00000	gpm	0	0	$/kgal, 0.0 gpm, 7652.6 hr/yr, 100% utilization
SW Disposal	5.43836	$/ton	15.32159	ton/hr	117,250	637,648	5.4384 $/ton X 15.3216 ton/hr X 7652.6 hr/yr X 100% utilization
Haz W Disp	326.19330	$/ton	0.00000	ton/hr	0	0	$/ton, 0.0 ton/hr, 7652.6 hr/yr, 100% utilization
Ammonia Mitigation	5.61	$/ton	18.98048	ton/hr	145,250	814,853	5.61 $/ton X 18.9805 ton/hr X 7652.6 hr/yr X 100% utilization
Lost Ash Sales	12.3	$/ton	8.13449	ton/hr	62,250.0	765,675	12.3 $/ton X 8.1345 ton/hr X 7652.6 hr/yr X 100% utilization
Lime	90.0	$/ton	0.00000	lb/hr	0	0	$/ton, 0.0 lb/hr, 7652.6 hr/yr, 100% utilization
Urea	500.0	$/ton	0.80050	ton/hr	6,125.91	3,062,953.15	500 $/ton X 0.8005 ton/hr X 7652.6 hr/yr X 100% utilization
Oxygen	17.91078	kscf	0.00000	kscf/hr	0	0	kscf, 0.0 kscf/hr, 7652.6 hr/yr, 100% utilization

** Std Air use is 2 scfm/kacfm *annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

Great River Energy Coal Creek Station

BART Supplement - NOx Emission Control Cost Analysis

Table A-7: Unit 1 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (100% Lost Ash Sales)

Operating Unit: **Unit 1**

Emission Unit Number	EU-1		Stack/Vent Number	SV-1	
Desgin Capacity	6,015	MMBtu/hr	Standardized Flow Rate	866,294	scfm @ 32º F
Expected Utiliztion Rate	100%		Temperature	330	Deg F
Expected Annual Hours of Operation	7,652.6	Hours	Moisture Content	13.3%	
Annual Interest Rate	5.5%		Actual Flow Rate	2,234,300	acfm
Expected Equipment Life	20	yrs	Standardized Flow Rate	1,391,000	scfm @ 330º F
Baseline NOx	0.200	lb/MMBtu	Dry Std Flow Rate	1,205,997	dscfm @ 330º F

CONTROL EQUIPMENT COSTS

Capital Costs								
Direct Capital Costs								
Purchased Equipment (A)								3,700,000
Purchased Equipment Total (B)								**8,465,600**
Installation - Standard Costs								1,270,000
Installation - Site Specific Costs								1,036,000
Installation Total								1,758,000
Total Capital Investment (TCI) = DC + IC								**12,176,084**
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.						7,775,768
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost						1,018,887
Total Annual Cost (Annualized Capital Cost + Operating Cost)								**8,794,654**

Emission Control Cost Calculation

Pollutant	**Max Emis Lb/Hr**	**Pre-control Annual T/Yr**	**Cont Eff %**	**Exit Conc**	**Conc Units**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
Nitrogen Oxides (NOx)	1,205.2	4,611.4	25.0%			3458.5	1,152.8	7,629

Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1

Notes & Assumptions

1. November 2011 SNCR Evaluation from URS
2. SNCR Maintenance Costs EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.21
3. Process, emissions and cost data listed above is for one unit.
4. For units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal
5. Retrofit factor of 60% used by URS based on site visit to Coal Creek Station.
6. SW disposal and fly ash sales data from Nov. 2011 Golder Fly Ash Evaluation, Appendix B2
7. One-time cost for Technology Licensing Fee for the SNCR process is ~0.5% of the Process Capital.

Great River Energy Coal Creek Station
BART Supplement - NOx Emission Control Cost Analysis
Table A-7: Unit 1 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (100% Lost Ash Sales)

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment			**3,700,000**
Purchased Equipment Costs			
Instrumentation	10.00%	of purchased equipment cost	370,000
Site Specific and Prime Contractor Markup	28.00%	of purchased equipment cost	1,036,000
Freight	5.00%	of purchased equipment cost	185,000
Purchased Equipment Total	43.00%		5,291,000
Purchased Equipment Total+ Retrofit Factor (A)			**8,465,600**
Indirect Installation			
General Facilities		See Notes & Assumptions 1 on pg. 1 of Table	420,000
Engineering & Home Office		See Notes & Assumptions 1 on pg. 1 of Table	850,000
Process Contingency		See Notes & Assumptions 1 on pg. 1 of Table	488,000
Total Indirect Installation Costs (B)		See Notes & Assumptions 1 on pg. 1 of Table	**1,758,000**
Project Contingeny (C)		See Notes & Assumptions 1 on pg. 1 of Table	**1,540,000**
Total Plant Cost (D)		A + B + C	**11,763,600**
Allowance for Funds During Construction (E)		0 for SNCR	**0**
Prepaid Royalties (F)		See Notes & Assumptionss 1 and 7 on pg. 1 of Table	**42,000**
Pre Production Costs (G)		See Notes & Assumptions 1 on pg. 1 of Table	**236,000**
Inventory Capital (H)		Reagent Vol * $/gal	**134,484**
Intial Catalyst and Chemicals (I)		0 for SNCR	**0**
Total Capital Investment (TCI) = DC + IC		D + E + F + G +H + I	**12,176,084**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**12,176,084**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	NA		-
Supervisor	NA		-
Maintenance			
Maintenance Total	1.50	% of Total Capital Investment	182,641
Maintenance Materials	NA	% of Maintenance Labor	-
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.060	See Direct Operating Cost Calculations on last pg.	28,218
Water	0.310	See Direct Operating Cost Calculations on last pg.	8,256
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
SW Disposal	7.40	See Direct Operating Cost Calculations on last pg.	1,941,450
NA	NA		-
NA	NA		-
Lost Ash Sales	12.30	See Direct Operating Cost Calculations on last pg.	2,552,250
NA	NA		-
Urea	500.00	See Direct Operating Cost Calculations on last pg.	3,062,953
NA	NA		-
Total Annual Direct Operating Costs			**7,775,768**
Indirect Operating Costs			
Overhead	NA	of total labor and material costs	NA
Administration (2% total capital costs)	NA	of total capital costs (TCI)	NA
Property tax (1% total capital costs)	NA	of total capital costs (TCI)	NA
Insurance (1% total capital costs)	NA	of total capital costs (TCI)	NA
Capital Recovery	0.08368	for a 20- year equipment life and a 5.5% interest rate	1,018,887
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**1,018,887**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**8,794,654**

See Summary page for notes and assumptions

Great River Energy Coal Creek Station

BART Supplement - NOx Emission Control Cost Analysis

Table A-7: Unit 1 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (100% Lost Ash Sales)

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.08368	

Replacement Catayst			<- Enter Equipment Name to Get Cost
Equipment Life	5	years	
CRF	0.2342		
Rep part cost per unit	0	$/ft^3	
Amount Required	12	ft^3	
Packing Cost	0	Cost adjusted for freight & sales tax	
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)	
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	
Annualized Cost	**0**		

Replacement Parts & Equipment:			<- Enter Equipment Name to Get Cost
Equipment Life	2	years	
CRF	0.0000		
Rep part cost per unit	0	$/ft^3	
Amount Required	0	Cages	
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax	See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs
Installation Labor	0	10 min per bag, Labor + Overhead (68% = $29.65/hr)	
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	EPA CCM list replacement times from 5 - 20 min per bag.
Annualized Cost	**0**		

Electrical Use			
NOx in	0.20	lb/MMBtu	kW
NSR	0.60		
Power			61.0
Total			61.0

Reagent Use & Other Operating Costs					
NOx in	0.20	lb/MMBtu	Urea Use	1601	lb/hr
Efficiency	25%		Volume 14 day inventory	269	ton
Duty	6,015	MMBtu/hr	Inventory Cost	$134,484	
Water Use	3480	gal/hr			

Direct Operating Cost Calculations — **Annual hours of operation:** **7,652.6** — **Utilization Rate:** **100%**

Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
Operating Labor							
Op Labor	37	$/Hr	0.0	hr/8 hr shift	0	0	$/Hr, 0.0 hr/8 hr shift, 7652.6 hr/yr
Supervisor	15%	of Op.			NA	-	15% of Operator Costs
Maintenance							
Maintenance Total	1.5	% of Total Capital Investment				182,641.26	% of Total Capital Investment
Maint Mtls	0	% of Maintenance Labor			NA	0	0% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.06045	$/kwh	61.00000	kW-hr	466,808.60	28,217.79	0.0604 $/kwh X 61.0 kW-hr X 7652.6 hr/yr X 100% utilization
Water	0.31000	$/kgal	3480.00000	gph	26,631.05	8,255.62	0.3100 $/kgal X 3,480.0 gph/1000 X 7652.6 hr/yr X 100% utilization
Cooling Water	0.32080	$kgal	0.00000	gpm	0	0	$kgal, 0 gpm, 7652.6 hr/yr, 100% utilization
Comp Air	0.36713	$/kscf	0.00000	scfm/kacfm**	0	0	$/kscf, 0.0 scfm/kacfm**, 7652.6 hr/yr, 100% utilization
WW Treat Neutralization	1.95716	$/kgal	0.00000	gpm	0	0	$/kgal, 0.0 gpm, 7652.6 hr/yr, 100% utilization
WW Treat Biotreatement	4.95814	$/kgal	0.00000	gpm	0	0	$/kgal, 0.0 gpm, 7652.6 hr/yr, 100% utilization
SW Disposal	7.39600	$/ton	34.30207	ton/hr	262,500	1,941,450	7.3960 $/ton X 34.3021 ton/hr X 7652.6 hr/yr X 100% utilization
Haz W Disp	326.19330	$/ton	0.00000	ton/hr	0	0	$/ton, 0.0 ton/hr, 7652.6 hr/yr, 100% utilization
Ammonia Mitigation	5.61	$/ton	0.00000	ton/hr	0	0	$/ton, 0.0 ton/hr, 7652.6 hr/yr, 100% utilization
Lost Ash Sales	12.3	$/ton	27.11497	ton/hr	207,500	2,552,250	12.3 $/ton X 27.1150 ton/hr X 7652.6 hr/yr X 100% utilization
Lime	90.0	$/ton	0.00000	lb/hr	0	0	$/ton, 0.0 lb/hr, 7652.6 hr/yr, 100% utilization
Urea	500.0	$/ton	0.80050	ton/hr	6,125.91	3,062,953.15	500.0 $/ton X 0.8005 ton/hr X 7652.6 hr/yr X 100% utilization
Oxygen	17.91078	kscf	0.00000	kscf/hr	0	0	kscf, 0.0 kscf/hr, 7652.6 hr/yr, 100% utilization

** Std Air use is 2 scfm/kacfm — *annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

Great River Energy Coal Creek Station

BART Supplement - NOx Emission Control Cost Analysis

Table A-8: Unit 2 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (Maintain Ash Sales)

Operating Unit: **Unit 2**

Emission Unit Number	EU-2		Stack/Vent Number	SV-2	
Desgin Capacity	6,022	MMBtu/hr	Standardized Flow Rate	866,294	scfm @ 32º F
Expected Utiliztion Rate	100%		Temperature	330	Deg F
Expected Annual Hours of Operation	8,409.6	Hours	Moisture Content	13.3%	
Annual Interest Rate	5.5%		Actual Flow Rate	2,234,300	acfm
Expected Equipment Life	20	yrs	Standardized Flow Rate	1,391,000	scfm @ 330º F
Baseline NOx	0.153	lb/MMBtu	Dry Std Flow Rate	1,205,997	dscfm @ 330º F

CONTROL EQUIPMENT COSTS

Capital Costs								
Direct Capital Costs								
Purchased Equipment (A)								3,600,000
Purchased Equipment Total (B)								**8,236,800**
Installation - Standard Costs								1,230,000
Installation - Site Specific Costs								1,008,000
Installation Total								1,702,000
Total Capital Investment (TCI) = DC + IC								**11,793,820**
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.						2,634,116
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost						986,899
Total Annual Cost (Annualized Capital Cost + Operating Cost)								**3,621,015**

Emission Control Cost Calculation

Pollutant	**Max Emis Lb/Hr**	**Pre-control Annual T/Yr**	**Cont Eff %**	**Exit Conc**	**Conc Units**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
Nitrogen Oxides (NOx)	918.5	3,862.3	20.0%			3089.8	772.5	4,688

Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1

Notes & Assumptions

1. November 2011 SNCR Evaluation from URS
2. SNCR Maintenance Costs EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.21
3. Process, emissions and cost data listed above is for one unit.
4. For units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal
5. Retrofit factor of 60% used by URS based on site visit to Coal Creek Station.
6. SW disposal and fly ash sales data from Nov. 2011 Golder Fly Ash Evaluation, Appendix B2
7. One-time cost for Technology Licensing Fee for the SNCR process is ~0.5% of the Process Capital.

Great River Energy Coal Creek Station

BART Supplement - NOx Emission Control Cost Analysis

Table A-8: Unit 2 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (Maintain Ash Sales)

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment			**3,600,000**
Purchased Equipment Costs			
Instrumentation	10.00%	of purchased equipment cost	360,000
Site Specific and Prime Contractor Markup	28.00%	of purchased equipment cost	1,008,000
Freight	5.00%	of purchased equipment cost	180,000
Purchased Equipment Total	43.00%		5,148,000
Purchased Equipment Total+ Retrofit Factor (A)			**8,236,800**
Indirect Installation			
General Facilities		See Notes & Assumptions 1 on pg. 1 of Table	410,000
Engineering & Home Office		See Notes & Assumptions 1 on pg. 1 of Table	820,000
Process Contingency		See Notes & Assumptions 1 on pg. 1 of Table	472,000
Total Indirect Installation Costs (B)		See Notes & Assumptions 1 on pg. 1 of Table	**1,702,000**
Project Contingeny (C)		See Notes & Assumptions 1 on pg. 1 of Table	**1,490,000**
Total Plant Cost (D)		A + B + C	**11,428,800**
Allowance for Funds During Construction (E)		0 for SNCR	**0**
Prepaid Royalties (F)		See Notes & Assumptionss 1 and 7 on pg. 1 of Table	**41,000**
Pre Production Costs (G)		See Notes & Assumptions 1 on pg. 1 of Table	**227,000**
Inventory Capital (H)		Reagent Vol * $/gal	**97,020**
Intial Catalyst and Chemicals (I)		0 for SNCR	**0**
Total Capital Investment (TCI) = DC + IC		D + E + F + G +H + I	**11,793,820**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**11,793,820**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	NA		-
Supervisor	NA		-
Maintenance			
Maintenance Total	1.50	% of Total Capital Investment	176,907
Maintenance Materials	NA	% of Maintenance Labor	-
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.060	See Direct Operating Cost Calculations on last pg.	22,367
Water	0.310	See Direct Operating Cost Calculations on last pg.	6,570
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
Urea	500.00	See Direct Operating Cost Calculations on last pg.	2,428,272
NA	NA		-
Total Annual Direct Operating Costs			**2,634,116**
Indirect Operating Costs			
Overhead	NA	of total labor and material costs	NA
Administration (2% total capital costs)	NA	of total capital costs (TCI)	NA
Property tax (1% total capital costs)	NA	of total capital costs (TCI)	NA
Insurance (1% total capital costs)	NA	of total capital costs (TCI)	NA
Capital Recovery	0.08368	for a 20- year equipment life and a 5.5% interest rate	986,899
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**986,899**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**3,621,015**

See Summary page for notes and assumptions

Great River Energy Coal Creek Station

BART Supplement - NOx Emission Control Cost Analysis

Table A-8: Unit 2 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (Maintain Ash Sales)

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.08368	

Replacement Catayst			<- Enter Equipment Name to Get Cost
Equipment Life	5	years	
CRF	0.2342		
Rep part cost per unit	0	$/ft^3	
Amount Required	12	ft^3	
Packing Cost	0	Cost adjusted for freight & sales tax	
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)	
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	
Annualized Cost	**0**		

Replacement Parts & Equipment:			
		<- Enter Equipment Name to Get Cost	
Equipment Life	2	years	
CRF	0.0000		
Rep part cost per unit	0	$/ft^3	
Amount Required	0	Cages	
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax	See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs
Installation Labor	0	10 min per bag, Labor + Overhead (68% = $29.65/hr)	
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	EPA CCM list replacement times from 5 - 20 min per bag.
Annualized Cost	**0**		

Electrical Use			
NOx in	0.15	lb/MMBtu	kW
NSR	0.44		
Power			44.0
Total			44.0

Reagent Use & Other Operating Costs					
NOx in	0.15	lb/MMBtu	Urea Use	1155	lb/hr
Efficiency	20%		Volume 14 day inventory	194	ton
Duty	6,022	MMBtu/hr	Inventory Cost	$97,020	
Water Use	2520	gal/hr			

Direct Operating Cost Calculations — **Annual hours of operation:** **8,409.6**; **Utilization Rate:** **100%**

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Operating Labor							
Op Labor	37	$/Hr	0.0	hr/8 hr shift	0	0	$/Hr, 0.0 hr/8 hr shift, 8409.6 hr/yr
Supervisor	15%	of Op.			NA	-	15% of Operator Costs
Maintenance							
Maintenance Total	1.5	% of Total Capital Investment				176,907.30	% of Total Capital Investment
Maint Mtls	0	% of Maintenance Labor			NA	0	0% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.06045	$/kwh	44.00000	kW-hr	370,022.40	22,367.23	0.0604 $/kwh X 44.0 kW-hr X 8409.6 hr/yr X 100% utilization
Water	0.31000	$/kgal	2520.00000	gph	21,192.19	6,569.58	0.3100 $/kgal X 2,520.0 gph/1000 X 8409.6 hr/yr X 100% utilization
Cooling Water	0.32080	$kgal	0.00000	gpm	0	0	$kgal, 0 gpm, 8409.6 hr/yr, 100% utilization
Comp Air	0.36713	$/kscf	0.00000	scfm/kacfm**	0	0	$/kscf, 0.0 scfm/kacfm**, 8409.6 hr/yr, 100% utilization
WW Treat Neutralization	1.95716	$/kgal	0.00000	gpm	0	0	$/kgal, 0.0 gpm, 8409.6 hr/yr, 100% utilization
WW Treat Biotreatement	4.95814	$/kgal	0.00000	gpm	0	0	$/kgal, 0.0 gpm, 8409.6 hr/yr, 100% utilization
SW Disposal	0.00000	$/ton	6.54014	ton/hr	55,000	0	$/ton, 6.5 ton/hr, 8409.6 hr/yr, 100% utilization
Haz W Disp	326.19330	$/ton	0.00000	ton/hr	0	0	$/ton, 0.0 ton/hr, 8409.6 hr/yr, 100% utilization
Ammonia Mitigation	5.61	$/ton	0.00000	ton/hr	0	0	$/ton, 0.0 ton/hr, 8409.6 hr/yr, 100% utilization
Lost Ash Sales	12.3	$/ton	0.00000	ton/hr	0	0	$/ton, 0.0 ton/hr, 8409.6 hr/yr, 100% utilization
Lime	90.0	$/ton	0.00000	lb/hr	0	0	$/ton, 0.0 lb/hr, 8409.6 hr/yr, 100% utilization
Urea	500.0	$/ton	0.57750	ton/hr	4,856.54	2,428,272.00	500.0 $/ton X 0.5775 ton/hr X 8409.6 hr/yr X 100% utilization
Oxygen	17.91078	kscf	0.00000	kscf/hr	0	0	kscf, 0.0 kscf/hr, 8409.6 hr/yr, 100% utilization

** Std Air use is 2 scfm/kacfm

*annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

Great River Energy Coal Creek Station

BART Supplement - NOx Emission Control Cost Analysis

Table A-9: Unit 2 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (30% Lost Ash Sales)

Operating Unit: **Unit 2**

Emission Unit Number	EU-2		Stack/Vent Number	SV-2	
Desgin Capacity	6,022	MMBtu/hr	Standardized Flow Rate	866,294	scfm @ 32º F
Expected Utiliztion Rate	100%		Temperature	330	Deg F
Expected Annual Hours of Operation	8,409.6	Hours	Moisture Content	13.3%	
Annual Interest Rate	5.5%		Actual Flow Rate	2,234,300	acfm
Expected Equipment Life	20	yrs	Standardized Flow Rate	1,391,000	scfm @ 330º F
Baseline NOx	0.153	lb/MMBtu	Dry Std Flow Rate	1,205,997	dscfm @ 330º F

CONTROL EQUIPMENT COSTS

Capital Costs								
Direct Capital Costs								
Purchased Equipment (A)								3,600,000
Purchased Equipment Total (B)								**8,236,800**
Installation - Standard Costs								1,230,000
Installation - Site Specific Costs								1,008,000
Installation Total								1,702,000
Total Capital Investment (TCI) = DC + IC								**11,793,820**
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.						4,852,291
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost						986,899
Total Annual Cost (Annualized Capital Cost + Operating Cost)								**5,839,190**

Emission Control Cost Calculation

Pollutant	**Max Emis Lb/Hr**	**Pre-control Annual T/Yr**	**Cont Eff %**	**Exit Conc**	**Conc Units**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
Nitrogen Oxides (NOx)	918.5	3,862.3	20.0%			3089.8	772.5	7,559

Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1

Notes & Assumptions

1. November 2011 SNCR Evaluation from URS
2. SNCR Maintenance Costs EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.21
3. Process, emissions and cost data listed above is for one unit.
4. For units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal
5. Retrofit factor of 60% used by URS based on site visit to Coal Creek Station.
6. SW disposal and fly ash sales data from Nov. 2011 Golder Fly Ash Evaluation, Appendix B2
7. One-time cost for Technology Licensing Fee for the SNCR process is ~0.5% of the Process Capital.

Great River Energy Coal Creek Station
BART Supplement - NOx Emission Control Cost Analysis
Table A-9: Unit 2 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (30% Lost Ash Sales)

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment			**3,600,000**
Purchased Equipment Costs			
Instrumentation	10.00%	of purchased equipment cost	360,000
Site Specific and Prime Contractor Markup	28.00%	of purchased equipment cost	1,008,000
Freight	5.00%	of purchased equipment cost	180,000
Purchased Equipment Total	43.00%		5,148,000
Purchased Equipment Total+ Retrofit Factor (A)			**8,236,800**
Indirect Installation			
General Facilities		See Notes & Assumptions 1 on pg. 1 of Table	410,000
Engineering & Home Office		See Notes & Assumptions 1 on pg. 1 of Table	820,000
Process Contingency		See Notes & Assumptions 1 on pg. 1 of Table	472,000
Total Indirect Installation Costs (B)		See Notes & Assumptions 1 on pg. 1 of Table	**1,702,000**
Project Contingeny (C)		See Notes & Assumptions 1 on pg. 1 of Table	**1,490,000**
Total Plant Cost (D)		A + B + C	**11,428,800**
Allowance for Funds During Construction (E)		0 for SNCR	**0**
Prepaid Royalties (F)		See Notes & Assumptionss 1 and 7 on pg. 1 of Table	**41,000**
Pre Production Costs (G)		See Notes & Assumptions 1 on pg. 1 of Table	**227,000**
Inventory Capital (H)		Reagent Vol * $/gal	**97,020**
Intial Catalyst and Chemicals (I)		0 for SNCR	**0**
Total Capital Investment (TCI) = DC + IC		D + E + F + G +H + I	**11,793,820**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**11,793,820**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	NA		-
Supervisor	NA		-
Maintenance			
Maintenance Total	1.50	% of Total Capital Investment	176,907
Maintenance Materials	NA	% of Maintenance Labor	-
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.060	See Direct Operating Cost Calculations on last pg.	22,367
Water	0.310	See Direct Operating Cost Calculations on last pg.	6,570
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
SW Disposal	5.44	See Direct Operating Cost Calculations on last pg.	637,648
NA	NA		-
Ammonia Mitigation	5.61	See Direct Operating Cost Calculations on last pg.	814,853
Lost Ash Sales	12.30	See Direct Operating Cost Calculations on last pg.	765,675
NA	NA		-
Urea	500.00	See Direct Operating Cost Calculations on last pg.	2,428,272
NA	NA		-
Total Annual Direct Operating Costs			**4,852,291**
Indirect Operating Costs			
Overhead	NA	of total labor and material costs	NA
Administration (2% total capital costs)	NA	of total capital costs (TCI)	NA
Property tax (1% total capital costs)	NA	of total capital costs (TCI)	NA
Insurance (1% total capital costs)	NA	of total capital costs (TCI)	NA
Capital Recovery	0.08368	for a 20- year equipment life and a 5.5% interest rate	986,899
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**986,899**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**5,839,190**

See Summary page for notes and assumptions

Great River Energy Coal Creek Station

BART Supplement - NOx Emission Control Cost Analysis

Table A-9: Unit 2 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (30% Lost Ash Sales)

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.08368	

Replacement Catayst		<- Enter Equipment Name to Get Cost
Equipment Life	5	years
CRF	0.2342	
Rep part cost per unit	0	\$/ft^3
Amount Required	12	ft^3
Packing Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:		<- Enter Equipment Name to Get Cost	
Equipment Life	2	years	
CRF	0.0000		
Rep part cost per unit	0	\$/ft^3	
Amount Required	0	Cages	
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax	See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs
Installation Labor	0	10 min per bag, Labor + Overhead (68% = \$29.65/hr)	
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	EPA CCM list replacement times from 5 - 20 min per bag.
Annualized Cost	**0**		

Electrical Use			
NOx in	0.15	lb/MMBtu	kW
NSR	0.44		
Power			44.0
Total			44.0

Reagent Use & Other Operating Costs					
NOx in	0.15	lb/MMBtu	Urea Use	1155	lb/hr
Efficiency	20%		Volume 14 day inventory	194	ton
Duty	6,022	MMBtu/hr	Inventory Cost	\$97,020	
Water Use	2520	gal/hr			

Direct Operating Cost Calculations — **Annual hours of operation:** **8,409.6**; **Utilization Rate:** **100%**

Item	Unit Cost \$	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
Operating Labor							
Op Labor	37	\$/Hr	0.0	hr/8 hr shift	0	0	\$/Hr, 0.0 hr/8 hr shift, 8409.6 hr/yr
Supervisor	15%	of Op.			NA	-	15% of Operator Costs
Maintenance							
Maintenance Total	1.5	% of Total Capital Investment				176,907.30	% of Total Capital Investment
Maint Mtls	0	% of Maintenance Labor			NA	0	0% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.06045	\$/kwh	44.00000	kW-hr	370,022.40	22,367.23	0.0604 \$/kwh X 44.0 kW-hr X 8409.6 hr/yr X 100% utilization
Water	0.31000	\$/kgal	2520.00000	gph	21,192.19	6,569.58	0.3100 \$/kgal X 2,520.0 gph/1000 X 8409.6 hr/yr X 100% utilization
Cooling Water	0.32080	\$kgal	0.00000	gpm	0	0	\$kgal, 0 gpm, 8409.6 hr/yr, 100% utilization
Comp Air	0.36713	\$/kscf	0.00000	scfm/kacfm**	0	0	\$/kscf, 0.0 scfm/kacfm**, 8409.6 hr/yr, 100% utilization
WW Treat Neutralization	1.95716	\$/kgal	0.00000	gpm	0	0	\$/kgal, 0.0 gpm, 8409.6 hr/yr, 100% utilization
WW Treat Biotreatement	4.95814	\$/kgal	0.00000	gpm	0	0	\$/kgal, 0.0 gpm, 8409.6 hr/yr, 100% utilization
SW Disposal	5.43836	\$/ton	13.94240	ton/hr	117,250	637,648	5.4384 \$/ton X 13.9 ton/hr X 8409.6 hr/yr X 100% utilization
Haz W Disp	326.19330	\$/ton	0.00000	ton/hr	0	0	\$/ton, 0.0 ton/hr, 8409.6 hr/yr, 100% utilization
Ammonia Mitigation	5.61	\$/ton	17.27193	ton/hr	145,250	814,853	5.6 \$/ton X 17.2719 ton/hr X 8409.6 hr/yr X 100% utilization
Lost Ash Sales	12.3	\$/ton	7.40225	ton/hr	62,250	765,675	12.3 \$/ton X 7.4023 ton/hr X 8409.6 hr/yr X 100% utilization
Lime	90.0	\$/ton	0.00000	lb/hr	0	0	\$/ton, 0.0 lb/hr, 8409.6 hr/yr, 100% utilization
Urea	500.0	\$/ton	0.57750	ton/hr	4,856.54	2,428,272.00	500.0 \$/ton X 0.5775 ton/hr X 8409.6 hr/yr X 100% utilization
Oxygen	17.91078	kscf	0.00000	kscf/hr	0	0	kscf, 0.0 kscf/hr, 8409.6 hr/yr, 100% utilization

** Std Air use is 2 scfm/kacfm

*annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

Great River Energy Coal Creek Station

BART Supplement - NOx Emission Control Cost Analysis

Table A-10: Unit 2 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (100% Lost Ash Sales)

Operating Unit: **Unit 2**

Emission Unit Number	EU-2		Stack/Vent Number	SV-2	
Desgin Capacity	6,022	MMBtu/hr	Standardized Flow Rate	866,294	scfm @ 32º F
Expected Utiliztion Rate	100%		Temperature	330	Deg F
Expected Annual Hours of Operation	8,409.6	Hours	Moisture Content	13.3%	
Annual Interest Rate	5.5%		Actual Flow Rate	2,234,300	acfm
Expected Equipment Life	20	yrs	Standardized Flow Rate	1,391,000	scfm @ 330º F
Baseline NOx	0.153	lb/MMBtu	Dry Std Flow Rate	1,205,997	dscfm @ 330º F

CONTROL EQUIPMENT COSTS

Capital Costs		
Direct Capital Costs		
Purchased Equipment (A)		3,600,000
Purchased Equipment Total (B)		**8,236,800**
Installation - Standard Costs		1,230,000
Installation - Site Specific Costs		1,008,000
Installation Total		1,702,000
Total Capital Investment (TCI) = DC + IC		**11,793,820**
Operating Costs		
Total Annual Direct Operating Costs	Labor, supervision, materials, replacement parts, utilities, etc.	7,127,816
Total Annual Indirect Operating Costs	Sum indirect oper costs + capital recovery cost	986,899
Total Annual Cost (Annualized Capital Cost + Operating Cost)		**8,114,715**

Emission Control Cost Calculation

Pollutant	**Max Emis Lb/Hr**	**Pre-control Annual T/Yr**	**Cont Eff %**	**Exit Conc**	**Conc Units**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
Nitrogen Oxides (NOx)	918.5	3,862.3	20.0%			3089.8	772.5	10,505

Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1

Notes & Assumptions

1 November 2011 SNCR Evaluation from URS
2 SNCR Maintenance Costs EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.21
3 Process, emissions and cost data listed above is for one unit.
4 For units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal
5 Retrofit factor of 60% used by URS based on site visit to Coal Creek Station.
6 SW disposal and fly ash sales data from Nov. 2011 Golder Fly Ash Evaluation, Appendix B2
7 One-time cost for Technology Licensing Fee for the SNCR process is ~0.5% of the Process Capital.

Great River Energy Coal Creek Station

BART Supplement - NOx Emission Control Cost Analysis

Table A-10: Unit 2 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (100% Lost Ash Sales)

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment			**3,600,000**
Purchased Equipment Costs			
Instrumentation	10.00%	of purchased equipment cost	360,000
Site Specific and Prime Contractor Markup	28.00%	of purchased equipment cost	1,008,000
Freight	5.00%	of purchased equipment cost	180,000
Purchased Equipment Total	43.00%		5,148,000
Purchased Equipment Total+ Retrofit Factor (A)			**8,236,800**
Indirect Installation			
General Facilities		See footnote 1 on pg. 1 of Table	410,000
Engineering & Home Office		See footnote 1 on pg. 1 of Table	820,000
Process Contingency		See footnote 1 on pg. 1 of Table	472,000
Total Indirect Installation Costs (B)		See footnote 1 on pg. 1 of Table	**1,702,000**
Project Contingeny (C)		See footnote 1 on pg. 1 of Table	**1,490,000**
Total Plant Cost (D)		A + B + C	**11,428,800**
Allowance for Funds During Construction (E)		0 for SNCR	**0**
Prepaid Royalties (F)		See footnotes 1 and 7 on pg. 1 of Table	**41,000**
Pre Production Costs (G)		See footnote 1 on pg. 1 of Table	**227,000**
Inventory Capital (H)		Reagent Vol * $/gal	**97,020**
Intial Catalyst and Chemicals (I)		0 for SNCR	**0**
Total Capital Investment (TCI) = DC + IC		D + E + F + G +H + I	**11,793,820**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**11,793,820**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	NA		-
Supervisor	NA		-
Maintenance			
Maintenance Total	1.50	% of Total Capital Investment	176,907
Maintenance Materials	NA	% of Maintenance Labor	-
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.060	See Direct Operating Cost Calculations on last pg.	22,367
Water	0.310	See Direct Operating Cost Calculations on last pg.	6,570
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
SW Disposal	7.40	See Direct Operating Cost Calculations on last pg.	1,941,450
NA	NA		-
NA	NA		-
Lost Ash Sales	12.30	See Direct Operating Cost Calculations on last pg.	2,552,250
NA	NA		-
Urea	500.00	See Direct Operating Cost Calculations on last pg.	2,428,272
NA	NA		-
Total Annual Direct Operating Costs			**7,127,816**
Indirect Operating Costs			
Overhead	NA	of total labor and material costs	NA
Administration (2% total capital costs)	NA	of total capital costs (TCI)	NA
Property tax (1% total capital costs)	NA	of total capital costs (TCI)	NA
Insurance (1% total capital costs)	NA	of total capital costs (TCI)	NA
Capital Recovery	0.08368	for a 20- year equipment life and a 5.5% interest rate	986,899
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**986,899**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**8,114,715**

See Summary page for notes and assumptions

Great River Energy Coal Creek Station

BART Supplement - NOx Emission Control Cost Analysis

Table A-10: Unit 2 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (100% Lost Ash Sales)

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.08368	

Replacement Catayst		<- Enter Equipment Name to Get Cost
Equipment Life	5	years
CRF	0.2342	
Rep part cost per unit	0	$/ft^3
Amount Required	12	ft^3
Packing Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:		<- Enter Equipment Name to Get Cost	
Equipment Life	2	years	
CRF	0.0000		
Rep part cost per unit	0	$/ft^3	
Amount Required	0	Cages	
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax	See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs
Installation Labor	0	10 min per bag, Labor + Overhead (68% = $29.65/hr)	
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	EPA CCM list replacement times from 5 - 20 min per bag.
Annualized Cost	**0**		

Electrical Use			
NOx in	0.15	lb/MMBtu	kW
NSR	0.44		
Power			44.0
Total			44.0

Reagent Use & Other Operating Costs					
NOx in	0.15	lb/MMBtu	Urea Use	1155	lb/hr
Efficiency	20%		Volume 14 day inventory	194	ton
Duty	6,022	MMBtu/hr	Inventory Cost	$97,020	
Water Use	2520	gal/hr			

Direct Operating Cost Calculations — **Annual hours of operation: 8,409.6** — **Utilization Rate: 100%**

Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
Operating Labor							
Op Labor	37	$/Hr	0.0	hr/8 hr shift	0	0	$/Hr, 0.0 hr/8 hr shift, 8409.6 hr/yr
Supervisor	15%	of Op.			NA	-	15% of Operator Costs
Maintenance							
Maintenance Total	1.5	% of Total Capital Investment				176,907.30	% of Total Capital Investment
Maint Mtls	0	% of Maintenance Labor			NA	0	0% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.06045	$/kwh	44.00000	kW-hr	370,022.40	22,367.23	0.0604 $/kwh X 44.0 kW-hr X 8409.6 hr/yr X 100% utilization
Water	0.31000	$/kgal	2520.00000	gph	21,192.19	6,569.58	0.31 $/kgal X 2,520.0 gph/1000 X 8409.6 hr/yr X 100% utilization
Cooling Water	0.32080	$kgal	0.00000	gpm	0	0	$kgal, 0 gpm, 8409.6 hr/yr, 100% utilization
Comp Air	0.36713	$/kscf	0.00000	scfm/kacfm**	0	0	$/kscf, 0.0 scfm/kacfm**, 8409.6 hr/yr, 100% utilization
WW Treat Neutralization	1.95716	$/kgal	0.00000	gpm	0	0	$/kgal, 0.0 gpm, 8409.6 hr/yr, 100% utilization
WW Treat Biotreatement	4.95814	$/kgal	0.00000	gpm	0	0	$/kgal, 0.0 gpm, 8409.6 hr/yr, 100% utilization
SW Disposal	7.39600	$/ton	31.21433	ton/hr	262,500	1,941,450	7.3960 $/ton X 31.2 ton/hr X 8409.6 hr/yr X 100% utilization
Haz W Disp	326.19330	$/ton	0.00000	ton/hr	0	0	$/ton, 0.0 ton/hr, 8409.6 hr/yr, 100% utilization
Ammonia Mitigation	5.61	$/ton	0.00000	ton/hr	0	0	$/ton, 0.0 ton/hr, 8409.6 hr/yr, 100% utilization
Lost Ash Sales	12.3	$/ton	24.67418	ton/hr	207,500	2,552,250	12.3 $/ton X 24.6742 ton/hr X 8409.6 hr/yr X 100% utilization
Lime	90.0	$/ton	0.00000	lb/hr	0	0	$/ton, 0.0 lb/hr, 8409.6 hr/yr, 100% utilization
Urea	500.0	$/ton	0.57750	ton/hr	4,856.54	2,428,272.00	500.0 $/ton X 0.5775 ton/hr X 8409.6 hr/yr X 100% utilization
Oxygen	17.91078	kscf	0.00000	kscf/hr	0	0	kscf, 0.0 kscf/hr, 8409.6 hr/yr, 100% utilization

** Std Air use is 2 scfm/kacfm

*annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

Appendix B

SNCR Evaluation for Coal Creek Station

COAL CREEK STATION
SELECTIVE NON-CATALYTIC REDUCTION (SNCR)
COST AND PERFORMANCE REVIEW

UNDERWOOD, MCLEAN COUNTY, NORTH DAKOTA

PROJECT NUMBER 28966-007

GREAT RIVER ENERGY
A Touchstone Energy Cooperative

URS ENERGY & CONSTRUCTION
7800 E. UNION AVE., SUITE 100
DENVER, CO 80237

Revision: 0 Status: Final

Introduction

Great River Energy (GRE) contracted URS Energy & Construction (URS) to conduct a review of the costs and performance capability of Selective Non-Catalytic Reduction (SNCR) at their Coal Creek Station (CCS) Units 1 & 2. This review was requested to provide; an estimate of the current capital cost for the installation of SNCR, operating and maintenance costs for SNCR, and the level of NOx reductions that can be achieved by SNCR.

The CCS units are identical 605 MW (gross - nominal) CE tangentially-fired furnaces burning North Dakota lignite. Each unit is equipped with Low NOx Burners (LNB) and Over-Fire Air (OFA). Unit 2's LNBs are 2nd generation technology while Unit 1's are the 1st generation installation. Unit 1 currently has a NOx emission rate of 0.20 lbs/MMBtu while Unit 2's NOx emission rate is 0.16 lbs/MMBtu.

The Final Best Achievable Retrofit Technology (BART) analysis submitted in 2007 was based on an inlet NOx concentration of 0.22 lbs/MMBtu and an SNCR removal efficiency of 50%. The current review uses the existing CCS NOx values presented in the previous paragraph and updated removal efficiencies. The following sections present data on SNCR capabilities and cost.

SNCR Capabilities

SNCR was originally developed in Japan in the 1970s for use on oil- and gas-fired units. Coal plant applications began in the late 1980s in Western Europe. Commercial U.S. installations on coal-fired utility boilers started in the early 1990s. More than 2 GW of capacity have been installed on coal-fired plants worldwide. SNCR requires injection of ammonia or urea into the proper temperature window within the back-pass of the furnace. The ammonia or urea reacts with NOx species to form nitrogen and water. Emission reduction capabilities range from 25% at 5-ppm ammonia slip to 30% at 10-ppm ammonia slip in most commercial installations.

An SNCR system will require the installation of reagent storage and transfer equipment, a multilevel injection grid and the necessary control instrumentation. Due to the elimination of the catalyst used in the SCR process, the SNCR consumption rates for ammonia or urea are typically 3-4 times the rates required for an SCR system on a per mole of NOx basis.

SNCR performance is dependent upon factors that are specific to each source. These factors are; flue gas temperature, flue gas residence time at temperatures within the reaction temperature range, reagent distribution, uncontrolled NOx levels, mixing between the injected reagent and the flue gas, and the CO and O2 concentrations in the flue gas stream. NOx reductions ranging from 25-75% have been reported with SNCR but the higher levels of reduction are only possible with high inlet NOx levels and

optimum temperatures and residence time. Typical SNCR performance for utility boilers is in the range of 20-35% NOx reductions.

The gas temperature at the point of injection is critical to the NOx reduction performance of an SNCR system. This window falls in a range of 1600-2000°F with an optimum temperature of approximately 1800°F. Above this temperature, ammonia begins to thermally decompose and below this temperature, the reaction rate for NOx reduction decreases, resulting in increased ammonia slip. The temperature profile in any given boiler changes with fluctuations in boiler load. Therefore, the optimum injection point will move during cycling operation and multiple injection points will be required. It should also be noted that the longer the ammonia or urea stays within the optimum temperature window, the higher the NOx reduction that is achieved. Residence times in excess of one second are desirable to achieve the maximum reduction efficiency. The minimum residence time is approximately 0.3 seconds for moderate performance. However, most large utility boilers have heat transfer surfaces (pendants and platens) positioned in this flue gas temperature zone. This reduces the effective use of the SNCR system, even when multiple injection levels are installed. In some cases, these internal obstructions will make the application of SNCR impractical.

Figure 1 shows SNCR NOx removal efficiency as a function of Inlet NOx concentration for 55 existing SNCR installations. The data shows the majority of the installations achieving 20-35% reductions in NOx and only a few installations achieving 50% or greater reductions. There is only one installation achieving 50% reduction at an inlet NOx concentration less than 0.4 lb/MMBtu. This single installation is a cyclone boiler burning a PRB/Illinois coal blend and is the only unit in the data set showing greater than 35% reduction for inlet NOx concentrations less than 0.4 lb/MMBtu.

This figure shows that there are no installations operating with Coal Creek's NOx levels that are achieving greater than 20-25% NOx reductions. The figure also shows that the majority of installations are achieving NOx reductions in the range of 20-30%. Based on the available data, from existing installations operating at the CCS inlet NOx levels used in the BART, the highest level of NOx reduction that could be expected is 30%. At the present CCS NOx levels, it is expected that the highest level of NOx reduction that could be expected is 20%.

Another factor to be considered in the application of SNCR is its effect upon fly ash sales. An ammonia slip of only 5 ppm, which is generally accepted as the minimum that can be achieved in an SNCR application, can render the fly ash produced by the unit unmarketable. CCS currently sells 400,000 tons/yr of fly ash. With SNCR, this fly ash will have to be disposed of in a landfill.

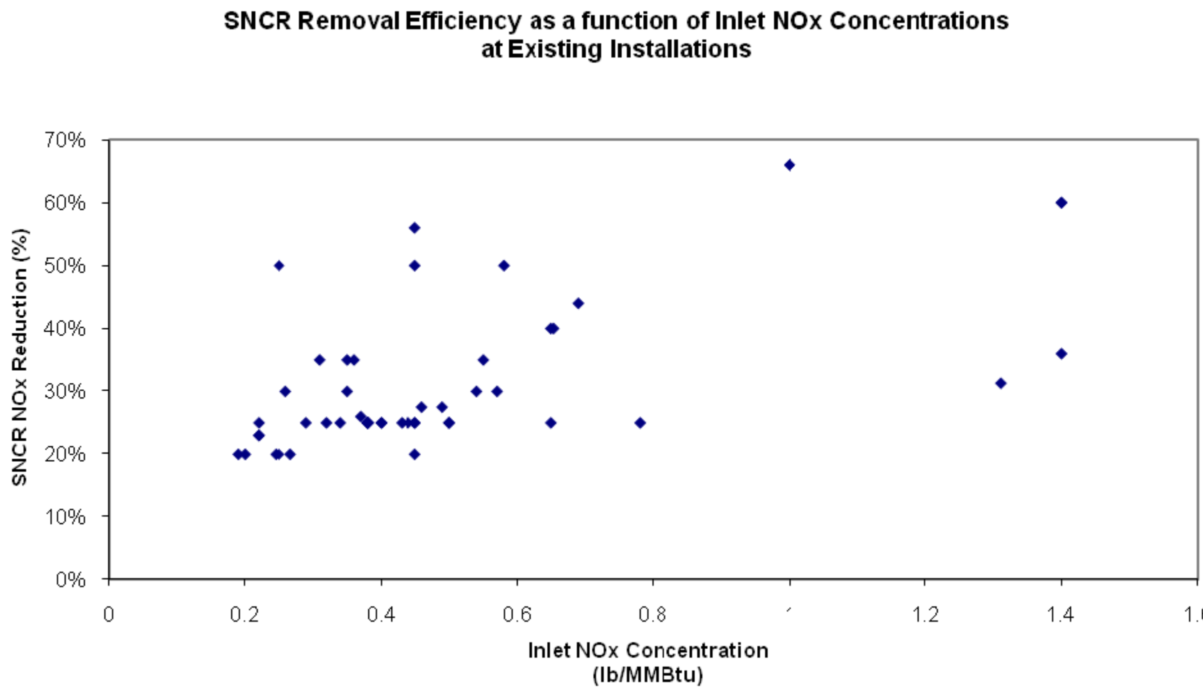

Figure 1 – SNCR Removal Efficiency

SNCR Costs

SNCR capital and operating costs were developed for five (5) different cases utilizing the Electric Power Research Institute's (EPRI) IECCOST model (Rev 3, Nov. 2010) with CCS site specific factors and cost components. The Integrated Emissions Control Cost Model (IECCOST) economic analysis workbook was first published by the Electric Power Research Institute in December 2004. IECCOST produces rough-order-of-magnitude (ROM) cost estimates (stated accuracy of ± 30%) of the installed capital and levelized annual operating costs for Integrated Emission Control (IEC) systems installed on coal-fired power plants. The IECCOST model allows comparison of cost information for conventional and developing SO_2, NOx, particulate, mercury, and integrated emissions control technologies. Costs for utility emission control systems are site-specific, and vary with technology, labor rates, construction conditions and material costs. The site-specific characteristics, operating conditions, process performance requirements and economic criteria serve as input to IECCOST.

IECCOST is able to calculate both new and retrofit plant costs. IECCOST calculates a retrofit factor for each cost area based on site congestion, existence of underground obstructions, soil conditions, seismic zone and state productivity. A series of combustion calculations are carried out based on the ultimate coal analysis provided by the utility and

the operating conditions specified for the boiler(s). The resulting flue gas composition serves as the basis for the calculation of a material balance for the control equipment. The material balance provides data for equipment sizing and calculation of the variable operating costs. The process-specific design criteria, including flue gas flow rate, pollutant removal rate, chemical consumption rate and waste production rate all are incorporated into the production of each process- and site-specific material balance.

The five (5) cases estimated for CCS are:

1. 0.22 lb/MMBtu inlet NOx with 30% reduction
2. 0.20 lb/MMBtu inlet NOx with 25% reduction
3. 0.16 lb/MMBtu inlet NOx with 20% reduction
4. 0.15 lb/MMBtu inlet NOx with 20% reduction
5. 0.22 lb/MMBtu inlet NOx with 50% reduction

These represent the initial BART assessment NOx rate of 0.22 lb/MMBtu with a commercially achievable reduction of 30% for case 1. Cases 2-4 are representative of CCS's existing NOx emission rates and commercially achievable reductions. The final case is the BART assessment case using 2011 dollars. The costs are for a urea-based SNCR system with 14 days of reagent storage. Urea pricing from a source local to CCS was obtained and the current cost of urea is $500/ton delivered to the site. The general plant input data and IECCOST outputs for SNCR capital and operation and maintenance costs are presented in the following section.

IECCOST DATA

Table 1 – Coal Creek Station Data

General Plant Technical Inputs

Total Gross Rating	MW	605
Gross Plant Heat Rate (GPHR)	Btu/KWhr	9,760
Total Net Rating (Less Auxiliary Power)	MW	572.0
Net Plant Heat Rate (NPHR, Without FGD)	Btu/KWhr	10,500
Plant Capacity Factor	%	90%
TECHNICAL INPUTS FOR BOILER:		
Boiler Heat Input	MMBtu/Hr	5,900
Boiler Heat Output	MMBtu/Hr	4,780
Total Air Downstream of Economizer	%	117.0%
Air Heater Leakage (% of econ. flue gas)	%	7.0%
Air Heater Outlet Gas Temp.	°F	300
Inlet Air Temp.	°F	80
Ambient Absolute Pressure	in. Hg	27.9
Pressure After Air Heater	in. H2O	-11
Moisture in Air	lb/lb dry air	0.013
Carbon Loss	%	0.5%
ASH SPLIT		
Fly Ash or Ash Overhead	%	76%
Bottom Ash	%	24%

Table 2 – SNCR Equipment Sizing

SNCR Equipment Sizing and Capacity Calcs			0.22 Inlet & 30% Reduction	0.20 Inlet & 25% Reduction	0.16 Inlet & 20% Reduction	0.15 Inlet & 20% Reduction	0.22 & 50% Reduction
Chosen Reagent			Urea	Urea	Urea	Urea	Urea
Required Reagent Injection	lb/hr		1991	1601	1188	1155	3318
Total Reagent Injection Flowrate	lb/hr		3982	3202	2375	2310	6636
NOx Removed	lb/hr		384	291	186	170	640
NOx Removed	tons/yr		1513	1147	734	670	2522
NOx Emissions	lb/hr		896	873	745	679	640
NOx Emissions	tons/yr		3531	3440	2935	2678	2522
Power Consumption	kW		75	61	45	44	126

Table 3 – Material Costs

SNCR Material Costs			0.22 Inlet & 30% Reduction	0.20 Inlet & 25% Reduction	0.16 Inlet & 20% Reduction	0.15 Inlet & 20% Reduction	0.22 & 50% Reduction
Cost Basis Year			2011	2011	2011	2011	2011
SNCR Equipment Cost	$		$3,800,000	$3,700,000	$3,600,000	$3,600,000	$4,200,000
Installation Factor			1.30	1.30	1.30	1.30	1.30
Installed Equipment Cost	$		$4,970,000	$4,800,000	$4,700,000	$4,700,000	$5,500,000
Prime Contractor's Markup	$		$497,000	$480,000	$470,000	$470,000	$550,000
Total Installed Cost	$		$5,500,000	$5,300,000	$5,100,000	$5,100,000	$6,000,000
Retrofit Factor			1.6	1.6	1.6	1.6	1.6
Total Equipment Cost	$		$8,750,000	$8,500,000	$8,200,000	$8,200,000	$9,600,000
General Facilities	$		$440,000	$420,000	$410,000	$410,000	$480,000
Engineering Fees	$		$875,000	$850,000	$820,000	$820,000	$960,000
Process Contingencies	$		$503,000	$488,000	$472,000	$472,000	$553,000
Project Contingencies	$		$1,580,000	$1,540,000	$1,490,000	$1,490,000	$1,740,000
Total Plant Cost (TPC)	$		$12,145,000	$11,790,000	$11,420,000	$11,400,000	$13,350,000
Total Cash Expended (TCE)	$		$12,145,000	$11,790,000	$11,420,000	$11,400,000	$13,350,000
Allowance for Funds During Constru	$		0	0	0	0	0
Total Plant Investment (TPI)	$		$12,145,000	$11,790,000	$11,420,000	$11,400,000	$13,350,000
Preproduction Costs	$		$243,000	$236,000	$228,000	$227,000	$267,000
Inventory Capital	$		$167,000	$134,000	$100,000	$98,000	$280,000
Initial Catalyst and Chemicals	$		$0	$0	$0	$0	$0
Prepaid Royalties	$		$44,000	$42,000	$41,000	$41,000	$48,000
Total Capital Requirement (TCR)	$		$12,600,000	$12,200,000	$11,800,000	$11,800,000	$13,900,000
Market Demand Escalation	$		$0	$0	$0	$0	$0
Power Outage Penalty	$		$0	$0	$0	$0	$0
Land Cost	$		$0	$0	$0	$0	$0
TCR w/ Market Dem., Power Outag	$		$12,600,000	$12,200,000	$11,800,000	$11,800,000	$13,900,000
	$/kW		21.80	21.10	20.40	20.40	24.00
	Mills/KWh		0.40	0.38	0.37	0.37	0.44

Table 4 – Operation & Maintenance Costs

SNCR O&M Costs			0.22 Inlet & 30% Reduction	0.20 Inlet & 25% Reduction	0.16 Inlet & 20% Reduction	0.15 Inlet & 20% Reduction	0.22 & 50% Reduction
Cost Basis Year			2011	2011	2011	2011	2011
Reagent Type			Urea	Urea	Urea	Urea	Urea
Reagent Consumption	lb/hr		1991	1601	1188	1155	3318
	tons/yr		7848	6310	4681	4553	13080
Water	gpm		72	58	43	42	119
Electricity	kW		75	61	45	44	126
NOx allowances generated	tons/yr		n/a	n/a	n/a	n/a	n/a
Reagent Cost	$/yr		$3,924,000	$3,155,000	$2,340,000	$2,280,000	$6,540,000
Water Cost	$/yr		$410,000	$330,000	$250,000	$240,000	$688,000
Additional Power Costs	$/yr		$24,000	$19,000	$142,000	$13,800	$40,000
NOx Credit	$/yr		$0	$0	$0	$0	$0
Total First Year Variable O&M Cost	$/yr		$4,360,000	$3,500,000	$2,600,000	$2,530,000	$7,270,000
Maintenance	$/yr		$189,000	$183,000	$177,000	$176,000	$210,000
Total First Year Fixed O&M Costs	$/yr		$189,000	$183,000	$177,000	$176,000	$210,000

Attachments

URS SNCR Experience
ICAC White Paper – SNCR for Controlling NOx Emissions – 2000
ICAC White Paper – SNCR for Controlling NOx Emissions – 2008 Update

ATTACHMENTS

The following table presents a listing a URS's SNCR experience. Additionally, a partial listing of the Integrated Emission Control (IEC) Technologies that URS has evaluated for the Electric Power Research Institute (EPRI) follows the SNCR experience list.

NO_X CONTROL EXPERIENCE – SNCR

Client	Project	Unit #	Location	Size (MW)	Fuel	PRB	Equipment Supplier	New (N) vs. Retrofit I	Completion Date	Scope
NRG Energy	5 Stations	14 Units	Various	2350	Coal		NA	R	Dec 02	FS, CE
Dayton Power & Light	Total System (6 plants)	15	Various	60-800	Coal		NA	R	1998	FS
Niagara Mohawk	Four Stations	1, 2, 3, 4	NY		Oil, Gas, Coal		NA	R	Dec 94	FS, CE
New York State Electric and Gas	System-wide	10 units	NY	Various	Coal			R	Dec 94	FS, CE
Duquesne Light and Power	System-wide		PA	Various	Coal		NA	R	Dec 93	FS, CE
Atlantic Electric	B. L. England Station			290	Coal		NA	R	Dec 93	FS, CE
Pennsylvania Power & Light	Brunner Island Station	3	PA	790	Coal		NA	R	Dec 93	FS, CE
PEPCO	Various	1, 2, 3, 4, 5, 6	Various	N/A	Coal, Oil, Gas		NA	R	Dec 93	FS, CE
Niagara Mohawk	Huntley Station	6, 7	Syracuse, NY	2 x 420	Coal		NA	R	Apr 93	FS, CE

NO_X CONTROL EXPERIENCE – SNCR

Client	Project	Unit #	Location	Size (MW)	Fuel	PRB	Equipment Supplier	New (N) vs. Retrofit I	Completion Date	Scope
Inland Steel and Nippon Steel (I/N Tek)	Furnaces and Aux. Boiler Continuous Galvanizing Line (9,000,000 tons/yr capacity)	N/A	IN	N/A	Gas		NA	N	Dec 92	FS, CE
Centerior Energy				72 thru 680	Coal			R	1992	FS, CE
Allegheny Energy Supply	Harrison Station	1, 2, 3	Shinnston, WV	3 x 685	Coal		NA	R	1992	E
San Diego Gas & Electric	System-Wide NO_X Compliance	13 Units	CA	Various	Various		NA	R	1991	PE
Entergy Services, Inc.	System-Wide NO_X Reduction Assessment	54 Units	Various	Various	Various		NA	R		FS
Chevron	El Segundo Refinery		CA		Refinery off-gas		NA	R		FS, CE
AES	Warrior Run	1	Cumberland, MD	180	Coal		NA	N	1998	E, P, C
PEPCO	Various	1, 2, 3, 4, 5, 6	Various	N/A	T-fired oil and coal Wall-fired oil and gas		NA	R	Dec 93	E
Tennessee Valley Authority	Johnsonville	6 units	Johnsonville, TN	6 x 100	Coal		NA	R	Dec 92	E
Los Angeles Dept. of Water & Power	Haynes	1, 2	Long Beach, CA	2 x 230	Gas/Oil		Ammonia injection	R	1992	E, C

NO_X CONTROL EXPERIENCE – SNCR

Client	Project	Unit #	Location	Size (MW)	Fuel	PRB	Equipment Supplier	New (N) vs. Retrofit I	Completion Date	Scope
Air Products	Stockton Cogeneration	1	Stockton, CA	50	Coal		NA	N	1988	D, E, CS
Chevron	El Segundo Refinery				Refinery off-gas		NA	R		FS
Texaco	Los Angeles Refinery		Los Angeles, CA	22	Refinery off-gas		NA	R		FS
Air Products	Cambria County	1	Pennsylvania		Waste Coal		NA	N		E, P

Legend:

BE	Bid Evaluation	D	Design	S	Startup
C	Construction	E	Engineering	STG	Steam Turbine Generator
CA	Construction Advisory	FS	Feasibility Study	T	Testing
CE	Cost Estimate	OE	Owner's Engineer	PRB	Powder River Basin Coal
CM	Construction Management	P	Procurement		

Integrated Emission Control Technologies evaluated for EPRI.

Gas Phase Oxidation Systems

Chem-Mod
ECO™
ECO2™
ISCA

Lextran SO2/NOx/Hg
LoTOx

Low-Temperature Multi-Pollutant Control System (MPCS)
THERMALONOx
Plasma/Electron Beam Systems
EBFGT
e-SCRUB™
Pioneer Industrial Technologies (PIT)
Pulsatech
WOWClean

Combustion Modification/Fuel Processing
Ashworth Combustor
Clean Combustion System (CCS)
Coal Tech
Emulsified Fuel Technology
Green Coal
High-Sodium Lignite-Derived Chars
K-Fuel
K-Lean
Lignite Cleaning System
The Mobotec System
N-Viro Fuel
Oxycombustion
Soot Free Catalyst
WRI Coal Processing

Wet Scrubbing Systems
Airborne

Aqueous Foam Air (AFA) Filter
CEFCO
Dry-Wet Hybrid Electrostatic Precipitator (ESP)
DynaWave
Eco Technologies
Envirolution/PureStream Gas-Liquid Contactor
FLU-ACE
Integrated Flue Gas Treatment
Integrated Advanced Tower
Ispra by SRT Group
LABSORB
Membrane Wet ESP
MercOx
PEA
Rapid Absorption Process (RAP)/Dry Absorption Process (DAP)
SkyMine

Dry Technologies
Argonne Spray Dryer
NOxOUT CASCADE / Turbosorp Technology (formerly CDS/SCR)
ClearGas Dry Scrubber
Copper Oxide
EMx (previously SCONOx/SCOSOx)
Indigo MAPS
Kuttner Luehr Filter Technology
Low Temperature Mercury Control (LTMC)
Novacon
PahlmanTM Process
ReACT Technology
SNOX

SOx-NOx-Rox Box (SNRB)
Trona Injection

Other Technologies
Argonne Hg/NOx Process
CANSOLV SO2/CO2 Process
GreenFuel
Integrated Pollutant Removal (IPR)
Low Temperature Sulfur Trioxide Removal System (LT-STRS) / Mitsubishi Mercury Treatment System (Mi-MeTS) (Previously MHI High Efficiency System / HCl Injection)
TIPS
Combined Plasma Scrubbing Technology (CPS)
Consummator
ECOBIK
Aqua Ammonia Process
BioDeNOx
Fungal Bioreactor
Plasma Enhanced ESP
ElectroCore

Appendix C

Fly Ash Storage and ASM Technology Evaluation

REPORT

FLY ASH STORAGE AND AMMONIA SLIP MITIGATION TECHNOLOGY EVALUATION

Great River Energy

Coal Creek Station

Submitted To: Great River Energy
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2875 Third Street SW
Underwood, North Dakota 58576

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Distribution: 4 Copies – Great River Energy
1 Copy – Golder Associates

November 15, 2011 **113-82161**

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Golder Associates

EXECUTIVE SUMMARY

Great River Energy (GRE) has requested that Golder Associates Inc. prepare a third-party review of potential ammonia slip mitigation (ASM) technology and cost comparisons for associated RCRA Subtitle D ash storage facility design for their Coal Creek Station (CCS) located in Underwood, North Dakota.

These evaluations are prepared in response to the United States Environmental Protection Agency's (EPA's) proposed Federal Implementation Plan (FIP) for the state of North Dakota. As part of the FIP process, the North Dakota Department of Health (NDDH) has requested that GRE prepare a Best Available Retrofit Technology (BART) analysis for nitrogen oxides (NOx) emissions, specifically evaluating the application of selective non-catalytic reduction (SNCR) emission control technology. Due to the potential for unreacted ammonia in the flue gas downstream of the SNCR (ammonia slip) reacting with sulfur compounds to form ammonia sulfates that deposit in the fly ash, there is concern over the significant impact on current fly ash sales. Therefore, GRE is evaluating an ASM technology at CCS as an option for treating ammonia slip impacted fly ash to allow continued beneficial use and sale of fly ash. This ASM technology is not proven for lignite derived fly ash and is presented as a potential option to reduce the impact of an SNCR on fly ash management. This evaluation includes an ASM technology cost estimation, fly ash disposal cost comparisons, and evaluation of the total cost impact of an SNCR on fly ash management at CCS.

Golder recently visited the Eastlake Station where Headwaters Energy Services' patented ASM technology is currently applied to manage ammonia levels in the fly ash. Based on this operation and Golder's knowledge of CCS and lignite coal-fired power plants, a cost estimate to apply ASM at CCS was prepared. The cost estimate includes costs for the ASM infrastructure including engineering and design, construction, and operations and maintenance. Costs are based on 2011 dollars and capital costs are annualized for a 20-year life and 5.5% interest rate. Existing fly ash sales infrastructure and operations and maintenance are not included in the cost estimate. ASM post-processing costs are estimated to be $5.61 per ton of fly ash treated.

Fly ash that cannot be marketed for beneficial use is disposed of in engineered and permitted facilities at CCS. Golder prepared a cost estimate for three potential operating scenarios: Scenario A – fly ash sales equal to the average sales over the past few years, Scenario B – ammonia slip impact of an SNCR makes fly ash at CCS unsalable, and Scenario C – ASM technology will be viable for ammonia impacted fly ash at CCS allowing a reduced amount of fly ash sales. A summary of the total estimated fly ash disposal costs is shown in the following table.

	Scenario A (Current Sales)	Scenario B (No Sales)	Scenario C (Reduced Sales, ASM)
Fly Ash Disposed (ton/yr)	110,000	525,000	234,500
Disposal Cost ($/ton)	$18.06	$11.18	$13.91
Annual Disposal Cost ($/yr)	$1,987,000	$5,870,000	$3,262,000
Annual Increase in Disposal Cost Compared to Scenario A ($/yr)	-	$3,883,000	$1,275,000

The landfill design included the specific size, location, infrastructure, liner, and cover relevant to each scenario. Costs for each scenario included the specific landfill design, engineering, and permitting costs, land acquisition, infrastructure development, liner construction, post-closure care, construction management and construction quality assurance (CQA), GRE internal costs, project contingencies, and operational costs. Based on the annual disposal cost estimate shown in the table above, the potential impact of an SNCR on the fly ash disposal costs at CCS may be an additional $3.9 million per year if fly ash is no longer marketable or an additional $1.3 million per year if the ASM technology proves successful.

The total cost impact of an SNCR on fly ash management at CCS includes ASM post-processing costs, fly ash disposal costs, and the loss in revenue generated from the sale of fly ash. Golder evaluated this total cost impact for each scenario, and is summarized in the table that follows. Based on this evaluation, the total additional cost impact to fly ash management as a result of an SNCR is between $4.4 and $9.0 million per year.

	Scenario A (Current Sales)	Scenario B (No Sales)	Scenario C (Reduced Sales, ASM)
Total (Disposal + Post Processing + Lost Sales)			
Annual Cost ($/yr)	$1,987,000	$10,975,000	$6,422,000
Unit Cost ($/ton produced)	$3.79	$20.91	$12.23
Additional Cost (Scenario B/C - Scenario A)			
Fly Ash Management Cost ($/yr)	-	$8,988,000	$4,435,000
Fly Ash Management Cost ($/ton produced)	-	$17.12	$8.45

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1.0 INTRODUCTION

Great River Energy (GRE) has requested that Golder prepare a third party review of ammonia slip mitigation technology, and cost comparisons for associated RCRA Subtitle D ash storage facility design for Coal Creek Station (CCS) located in Underwood, North Dakota. These evaluations are prepared in response to the United States Environmental Protection Agency's (EPA's) proposed Federal Implementation Plan (FIP) for the state of North Dakota. Based on the proposed FIP, GRE is evaluating selective non-catalytic reduction (SNCR) control technology to reduce nitrogen oxide (NO_x) emissions from CCS. If SNCR is installed at CCS, there is potential for unreacted ammonia in the flue gas downstream of the SNCR, called ammonia slip, and higher ammonia in fly ash. Due to the significant impact on current ash sales, GRE is evaluating a potential ammonia slip mitigation (ASM) technology patented by Headwaters Energy Services. In addition, GRE is evaluating three potential management scenarios for fly ash based on the potential impact of ammonia concentrations to the sale of fly ash.

Golder performed a third party review and estimated costs associated with implementation of Headwaters' ASM technology as applied to CCS. The review includes an estimate of the capital and operating and maintenance (O&M) costs for implementation of the ASM technology at CCS, with a focus on potential impacts to ash marketing and future sales to assist GRE in determining the feasibility of the ASM technology for operations at CCS. This evaluation is limited in scope given that "Headwaters has not conducted any field scale assessment on application of this technology to lignite derived fly ash. The limited current experience in commercial application and lack of field trials is not adequate for Headwaters to be able to provide any guarantee that the process can be successfully applied to treat lignite ash at the Coal Creek Station," per an email from Rafic Minkara (Headwaters) to John Weeda (GRE) on July 15, 2011.

Golder also prepared a cost comparison for three fly ash storage facility scenarios:

- Scenario 1: CCS's current fly ash sales rate (most fly ash sold);
- Scenario 2: No fly ash sales;
- Scenario 3: Application of ASM technology (allowing for some fly ash sales).

The cost evaluation includes a comparison of capital and O&M costs for each scenario assuming a new facility that meets EPA RCRA Subtitle D type regulations.

1.1 Qualifications

Golder Associates Corporation is an international employee-owned consulting engineering company specializing in the application of earth sciences and engineering to environmental, natural resources, and civil engineering projects. Operating since 1960, our company maintains a network of approximately

160 offices. Current worldwide employment exceeds 7,000 people. The United States operating company, Golder Associates Inc., employs approximately 1,200 people in 51 offices.

This project was conducted by a team based in our Denver, Colorado and Fort Collins, Colorado, offices. The project team was well-suited to perform the proposed services at CCS because of the experience of our technical staff on comparable projects, and our familiarity with the geotechnical and engineering properties of Subtitle D landfill designs. In addition, our team has a firm understanding of the engineering practice and regulatory environment surrounding coal-fired power plants, both in North Dakota and nationally, including ongoing rulemaking efforts by the EPA.

2.0 BACKGROUND

2.1 Regulatory Basis

In order to attain and maintain the National Ambient Air Quality Standards (NAAQS) within a state, state air quality agencies prepare State Implementation Plans (SIP) for EPA approval. If EPA disapproves of the SIP, either partially or fully, EPA will develop a Federal Implementation Plan (FIP) to address the deficiencies in the SIP.

On September 21, 2011, EPA proposed to partially disapprove the North Dakota SIP, specifically addressing regional haze and proposed a FIP to address the deficiency "concerning non-interference with programs to protect visibility in other states"[1]. As part of this process North Dakota Department of Health (NDDH) has requested a Best Available Retrofit Technology (BART) analysis for nitrogen oxides (NOx) emissions. This analysis was submitted by GRE in 2007 and additional evaluations and response to questions were submitted in 2010 and on July 15, 2011 to NDDH. NDDH is requesting additional analyses of selective non-catalytic reduction technology. This report does not include an SNCR evaluation, but provides a cost evaluation to address the potential impact the installation of SNCR would have on the existing GRE fly ash storage and sales.

2.2 SNCR and Ammonia Slip

Selective non-catalytic reduction (SNCR) technology is a post-combustion technology based on the chemical reduction of NOx into molecular nitrogen (N_2) and water vapor (H_2O). A nitrogen based reagent, such as urea, is injected into the post-combustion flue gas. The injection causes mixing of the reagent and flue gas while the heat in the flue gas provides energy for the reaction. The primary byproduct of the reaction is nitrous oxide (N_2O), which is a potent greenhouse gas (GHG).

Unreacted reagent in the flue gas downstream of the SNCR is called slip. This unreacted reagent will appear as ammonia, and reacts with sulfur compounds (from sulfur containing fuels) to form ammonia sulfates which deposit on the fly ash that is collected by the particulate emissions control equipment. The ammonia sulfates are stable in a dry state, but ammonia gas can release if the fly ash becomes wet. Ammonia content in the fly ash greater than 5 parts per million (ppm) (based on Headwaters' experience this level is 35 ppm) can result in release of ammonia gases which impact either the sale or storage and disposal of fly ash.

[1] Federal Register, EPA, 9/21/2011, www.federalregister.gov/articles/2011/9/21/2011-23372

3.0 AMMONIA SLIP MITIGATION

3.1 Background

Headwaters has developed an ammonia slip mitigation (ASM) technology to manage ammonia levels in the fly ash, so that a portion of the fly ash produced can be sold as a concrete additive. The Headwaters' ASM technology was initially developed in 2001 with the first US patent issued in 2004. The first commercial installation of ASM technology was installed at RG&E Russell Station in Rochester, New York in 2004. Russell Station used an SNCR and burned eastern bituminous coal.

The second commercial installation was installed at Eastlake Station in Ohio. Eastlake Station has a 600 megawatt (MW) unit that is fired with a 50/50 blend of Power River Basin (PRB) and eastern bituminous coal while generating approximately 100,000 TPY of fly ash. Headwaters is able to blend, treat, and market approximately 85% of the fly ash produced at Eastlake station. Fly ash is not treated during periods of highly variable ammonia concentrations, typically occurring during SNCR upset or plant load swings.

Currently, there are no commercial applications of ASM technology at a lignite-fired power plant, and Headwaters has not conducted any research on the application of the technology to lignite derived fly ash. Due to the lack of commercial experience with lignite derived fly ash, Headwaters will not provide a guarantee that the ASM technology can be successfully applied to lignite derived fly ash.

3.2 Process Description

The ASM technology mixes approximately 0.5-pound (lb) calcium hypochlorite (Cal-Hypo) with approximately 3,000-lb of fly ash in a hopper. The dose of cal-hypo, which is fed into the hopper using a rotary screw, is based on the ammonia concentration in the fly ash. Typical ammonia range for treatment is 50 to 150 ppm with a dosage of 0.2 to 1.3 lb of Cal-Hypo, resulting in ammonia concentrations after treatment of about 35 to 80 ppm.

Golder visited a current commercial application of ASM technology at the Eastlake Station (Figure 1). Fly ash from the electrostatic precipitator (ESP) is sent to one of two fly ash silos where the fly ash is tested daily to determine ammonia concentrations (Figure 2). If the ammonia concentrations are above 150 ppm, the fly ash is diverted for disposal. Fly ash with ammonia concentrations less than 150 ppm are sent to the third silo, after which it is "dosed" with Cal-Hypo and sent to the fourth silo (Figure 3 through Figure 5). The SNCR at Eastlake cannot keep the ammonia slip consistent, and often over-treats a portion of the fly ash stream. To increase the amount of treatable and marketable fly ash, fly ash with no ammonia from other sources is regularly blended into the Eastlake fly ash to keep the initial ammonia content below 150 ppm. Through the operation of the SNCR and by blending non-ammonia impacted fly ash with Eastlake's ammonia impacted fly ash, Eastlake is able to market approximately 85% of what

they produce because this fly ash is considered "treatable" (i.e., ammonia concentration levels are < 150 ppm). Diagrams of the East Lake Station system provided by Headwaters are shown in Appendix A. Subsequent to these diagrams, Headwaters has added a weigh hopper under the silo as shown in Figure 5.

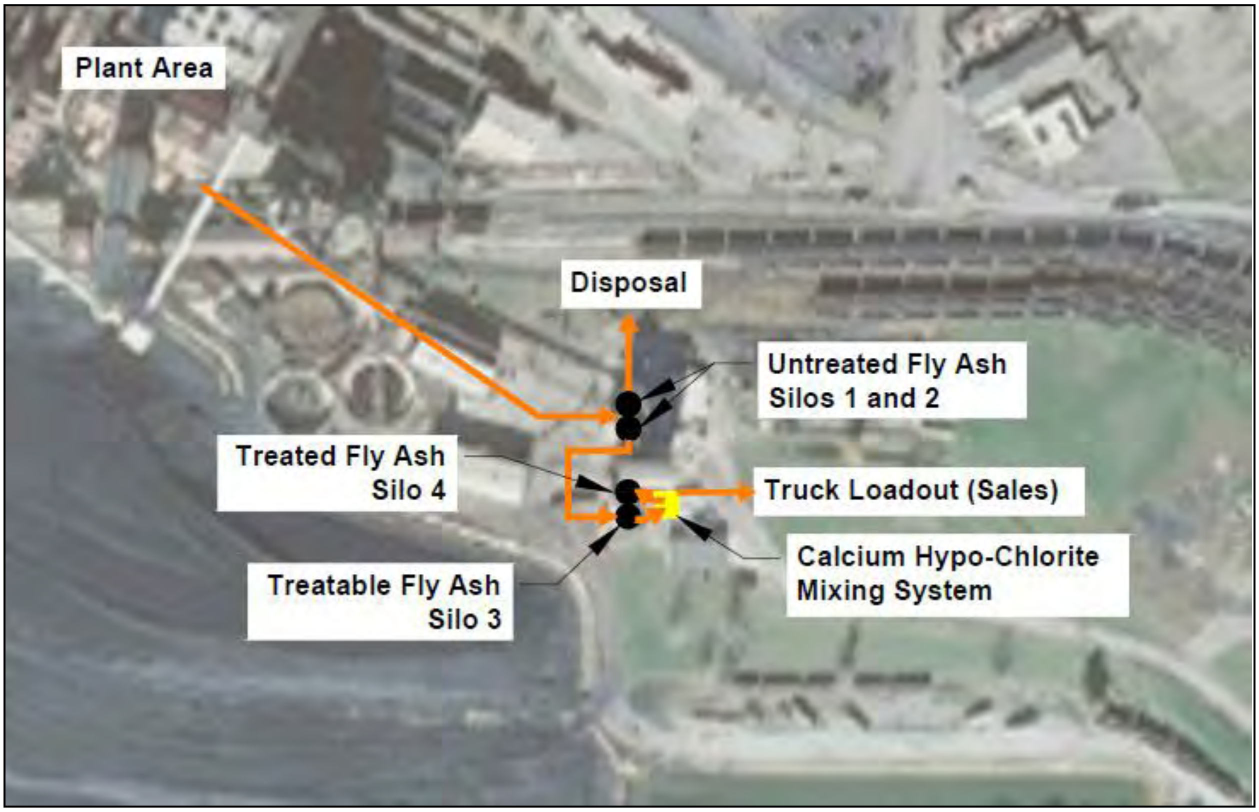


Figure 1: Eastlake Station ASM Schematic

Figure 2: Eastlake Station ASM Lab

Figure 3: Eastlake Station Silo 3, Silo 4, and ASM Setup

Figure 4: Eastlake Station ASM Control Panel

Figure 5: Eastlake Station ASM Mixing Hopper

3.3 Design and Limitations

Based on the Eastlake Station application, ASM is applied to fly ash with ammonia concentration levels less than 150 ppm. Ammonia levels can fluctuate based on plant load variations and SNCR operation. Ammonia concentrations are more consistent at base load conditions and dosing levels are typically based on this condition. Therefore, during load “swings,” it can be difficult to properly adjust the amount of ammonia injected into the flue gas resulting in varying concentrations of ammonia in the fly ash. If there is a plant upset condition, it may be several days until the ammonia concentrations in the fly ash being produced are at “treatable” levels again. The concern is two-fold. If the fly ash is not treated with enough Cal-Hypo, objectionable levels of ammonia will be released when the fly ash is mixed with water. Ammonia gas at low levels is an irritant but can be dangerous to life and health at high concentrations. If too much Cal-Hypo is added, chlorine gas will be released when the fly ash is mixed with water. Chlorine gas even at low concentrations is dangerous to life and health.

3.4 ASM Application at CCS

The application of ASM technology at CCS is being evaluated as an option for treating ammonia slip impacted fly ash to allow continued beneficial use and sale of fly ash.

3.4.1 Potential Design at CCS

For cost estimating, a potential layout for the application of ASM at CCS is shown in Figure 6. This potential layout utilizes the existing fly ash infrastructure including the truck load-out silos (91 and 92), the rail load-out silo (93), and the fly ash storage dome (94). To utilize ASM, the layout adds a new truck load-out silo south of Silos 91 and 92, and adds ASM Cal-Hypo feed systems at both the new truck load-out silo and the existing rail load-out silo (93). The general flow of material is treatable fly ash being routed to either the new truck load-out silo, the fly ash dome (94) or the rail load-out silo. From these silos, the fly ash is tested, and then mixed with Cal-Hypo as it is loaded into the trucks or rail cars. Additional testing of the resultant product would also be performed. Fly ash that is expected not to be treatable or saleable is routed to the exiting truck load-out silos (91 and 92) where it will be loaded into haul trucks and disposed at on-site disposal facilities.

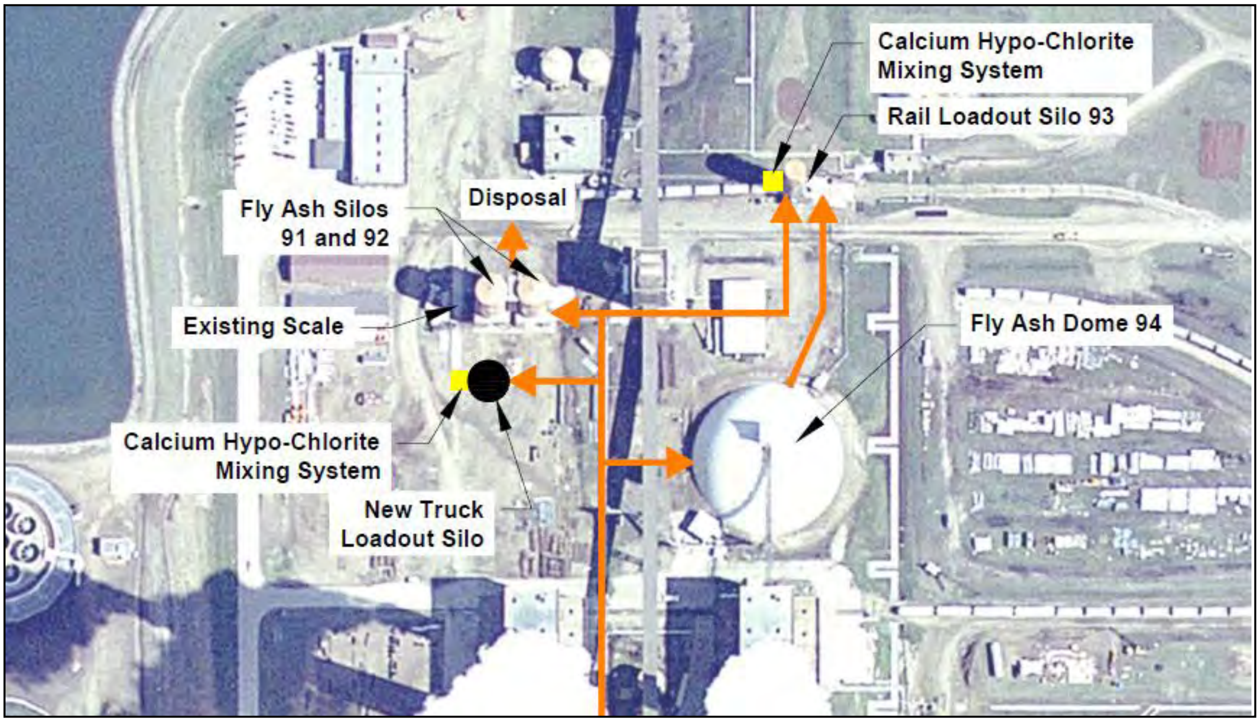


Figure 6: Coal Creek Station ASM Schematic

As discussed earlier, not all of the fly ash coming from the precipitators is expected to be within treatable levels of ammonia. In general, when the power generation units are operating at steady load and the SNCR ammonia injection system is operating properly, the fly ash produced should be treatable using the ASM system and will be collected in the rail load silo (93), the fly ash dome (94), or the new truck loadout silo (95). Conditions under which the ammonia content of the produced fly ash will be questionable include:

- Unit load swings causing variations in ash ammonia concentration (load swings may be due to regional wind penetration or variable load consistent with MISO);
- SNCR ammonia injection feed system problems; and
- Unit startup and shutdown which results in oily ash.

Golder expects that when any of these conditions occur, the fly ash produced will automatically be directed to the disposal silos (91 & 92). Fly ash will not be redirected to the sales silos (93, 94 or 95) until the upset is over and the fly ash collected in the first two rows of the electrostatic precipitator (ESP) has been tested and proven to have less than 150 ppm of ammonia in it.

Based on a review of the recent load profile at CCS, historic information on marketable fly ash at CCS, and an estimate of the reliability of the SNCR and ASM systems, approximately 30% of the fly ash now sent to the sales silos is assumed to have ammonia concentrations which will make it untreatable if an SNCR system is installed.

3.5 Cost Estimate

The cost estimate includes costs for the ASM infrastructure including engineering and design; construction; and operations and maintenance. Golder used actual costs from similar projects, and professional judgment to develop this cost estimate. Sources and assumptions are documented where appropriate. Some general assumptions for the cost estimate include:

- All costs are estimated in 2011 dollars.
- Capital costs are annualized based on a 20-year life and 5.5% interest rate.
- Existing fly ash sales infrastructure (silos, scales, rail facilities) and operations and maintenance are not included.

3.5.1 System Engineering and Design

This item is estimated as 10% of the total construction costs to develop the new facilities. Ten percent is based on Golder's professional judgment.

3.5.2 New Truck Load-Out Silo

The costs for the new truck load-out silo include site preparation, permit application, the silo and handling equipment, dust collection equipment, and feed piping. The costs for this construction are based on the construction of a similar fly ash sales terminal constructed for GRE in 2003. This silo had a 5,000-ton capacity and was used to transfer fly ash from rail cars to trucks (Figure 7). The total estimated cost for this item is $1.6 million and includes the following:

- Silo and truck scale similar to the Irondale, CO unit:
  - Silo slab on grade;
  - Starvrac reclaimer;
  - Truck scale beside the silo on grade;
  - Screw conveyor from discharge of the Starvrac reclaimer;
  - Bucket elevator to overhead;
  - Air slide ;
  - Building with the scale and ASM controls
- Additional items needed at CCS:
  - Feed piping and valves from each of the four fly ash conveying lines;
  - Higher capacity dust collectors to handle the high air flow from ESP.

Details for this cost estimate are included in Appendix B.

Figure 7: Typical Silo used in Cost Estimate

3.5.3 Cal-Hypo Feed System

The costs for the Cal-Hypo feed systems are estimated at $574,500 and include:

- Rail loadout silo (93):
  - Cal-Hypo storage and conveying building;
  - Day storage hopper for Cal-Hypo on the silo weigh bin floor;
  - Conveying system from the storage building to the day storage hopper;
  - Variable speed screw conveyor to feed Cal-Hypo into existing weigh hopper;
  - ASM system controls
- New truck loadout silo (95):
  - Weigh hopper above truck loadout spout;
  - Cal-Hypo storage and conveying building;
  - Day storage hopper for Cal-Hypo on the silo weigh bin floor;
  - Conveying system from the storage building to the day storage hopper;
  - Variable speed screw conveyor to feed Cal-Hypo into existing weigh hopper;
  - ASM system controls.

3.5.4 GRE Internal Costs

Internal costs for GRE to manage consultants, contractors, and in-house staff is estimated as 10% of the total costs (construction, engineering, permitting, CQA). Ten percent is based on GRE's experience with projects at CCS.

3.5.5 Project Contingency

Due to the order-of-magnitude scope of this cost estimate a contingency of 15% on the construction costs was added.

3.5.6 Operational and Maintenance Costs

ASM post-processing operations and maintenance costs are estimated as an annual cost. Operations costs include the cost of Cal-Hypo, fly ash sampling and testing costs, and labor to operate the system. Maintenance costs include labor and materials to maintain and repair the added equipment at the rail load-out silo (93) and the new truck load-out silo (95).

The estimated cost for this item, based on annual sale/processing of 290,500 tons, is approximately $1.4 million per year. Details for this cost estimate are included in Appendix B.

3.6 ASM Post-Processing Cost Summary

Using the quantities and the unit pricing described above, ASM post-processing costs are estimated as $5.61 per ton of fly ash treated.

4.0 FLY ASH DISPOSAL

Fly ash that cannot be marketed for beneficial use is disposed of in engineered and permitted facilities at CCS. Golder has prepared this order-of-magnitude cost estimate to compare costs between three scenarios defined to assess the potential impact of an SNCR on fly ash sales and disposal at CCS. Summary costs and key inputs are included in Table 1 through Table 3, and Figure 8 through Figure 10, with cost estimate details provided in Appendix B.

4.1 Fly Ash Disposal Scenarios

Three scenarios were evaluated to estimate the annual cost and the cost per ton to dispose of fly ash at CCS. These scenarios include:

- ***Scenario A*** – This scenario is the base case with fly ash sales equal to the average sales over the past few years. The scenario assumes that fly ash will be disposed of in a new landfill with a design based on RCRA Subtitle D practices, and has a 20-year disposal capacity. No post processing of the fly ash is required to make it marketable.
- ***Scenario B*** – This scenario assumes that the ammonia slip impact of an SNCR makes fly ash at CCS unsalable. The scenario also assumes that fly ash will be disposed of in a new landfill with a design based on RCRA Subtitle D practices, and has a 20-year disposal capacity.
- ***Scenario C*** – This scenario assumes that Headwater's ASM technology will be viable for ammonia impacted fly ash at CCS. However, sales will be reduced from current sales due to load swing impacts on ammonia slip, market conditions, and other factors previously identified. The scenario also assumes that fly ash will be disposed of in a new landfill with a design based on RCRA Subtitle D practices, and has a 20-year disposal capacity.

A summary of the fly ash production, sales, and disposal annual tonnages for these scenarios is provided in Table 1.

Table 1: Fly Ash Sales and Disposal Tons

	Scenario A (Current Sales)	Scenario B (No Sales)	Scenario C (Reduced Sales, ASM)
Fly Ash Produced (ton/yr)	525,000	525,000	525,000
Fly Ash Sold (ton/yr)	415,000	0	290,500
Fly Ash Disposed (ton/yr)	110,000	525,000	234,500

The total tonnage of fly ash produced is variable based on items such as plant load, plant efficiency, coal quality, and coal processing. Tonnage used in this analysis is meant to represent a typical or average amount of fly ash produced, sold, and disposed at CCS.

4.2 Landfill Design

For all three scenarios a 20-year disposal capacity and a RCRA Subtitle D design is assumed. It is also assumed that the landfill will be built on property not currently owned by GRE. For this cost estimate, it is assumed that property just west of the plant property would be purchased for the new facility. Figure 8 shows a potential location for these new facilities just west of the plant property and represents the approximate footprint required for Scenario A.

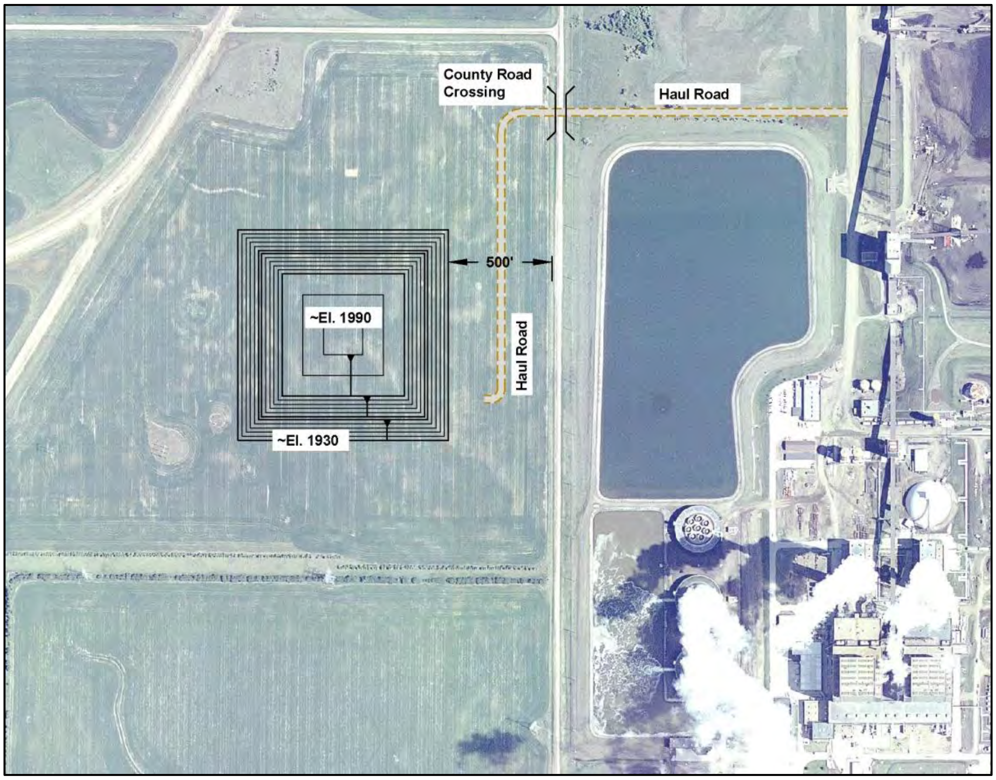


Figure 8: Potential Landfill Location (Scenario A)

4.2.1 Landfill Size

Landfill size is based on a 20-year fly ash disposal capacity. For the three scenarios this varies between 2.2 million and 10.5 million tons of capacity. For each Scenario, Golder developed a simplified landfill footprint that would provide the 20-year fly ash disposal capacity. The simplified landfill design assumes 10 feet of cut, 12-foot high soil berm, 3H:1V soil berm slopes, and 4H:1V fly ash slopes with a 5% crown. Based on preliminary engineering, the landfill capacity ranges between 75,000 and 118,000 cubic yards (cy) per lined acre due to the increased height capacity of a larger footprint facility. Figures showing the size of each Scenario are included in Appendix B.

The amount of cover area in relationship to the liner area has also been estimated based on preliminary engineering as 1.1 acres of cover for every 1 acre of liner.

The amount of land required is assumed to encompass at least a 500-foot buffer beyond this lined footprint to allow for access roads, fencing, support structures, and groundwater monitoring. For the land acquisition purchase estimate, the nearest whole or partial section of land to the required footprint was assumed.

Table 2 provides a summary of the estimated facility liner area, cover area, and site area for the three scenarios.

Table 2: Scenario Landfill Size

	Scenario A (Current Sales)	Scenario B (No Sales)	Scenario C (Reduced Sales, ASM)
Liner Acres (acres)	24.0	73.5	41.0
Cover Area (acres)	26.5	81.0	45.0
Site Area (acres)	160.0	240.0	160.0

4.2.2 Infrastructure Development

With the landfill constructed on a new property, considerable site development is required, which may include a haul truck access road, fencing and gates around the property, power to the new site, monitoring wells up- and down-gradient of the new facility, and a water return pipeline to allow the pumping of excess contact water from the site to the ash water tanks within the plant.

In addition, haul trucks will be required to cross a county road to deliver fly ash from the plant to the new facility. For safety and operational flexibility, a new country road bridge should be constructed to allow haul truck traffic under the county road. This bridge would include the bridge structure as well as the grading and embankment costs associated with the approach on the county road.

4.2.3 Liner

A liner design based on RCRA Subtitle D standards and historic practice at CCS was utilized. The assumed liner system is shown in Figure 9 and consists of (from bottom to top) a compacted clay layer ($1x10^{-7}$ cm/sec maximum permeability), a geomembrane liner, a leachate collection layer consisting of drainage material, piping and sumps, and a protective cover layer.

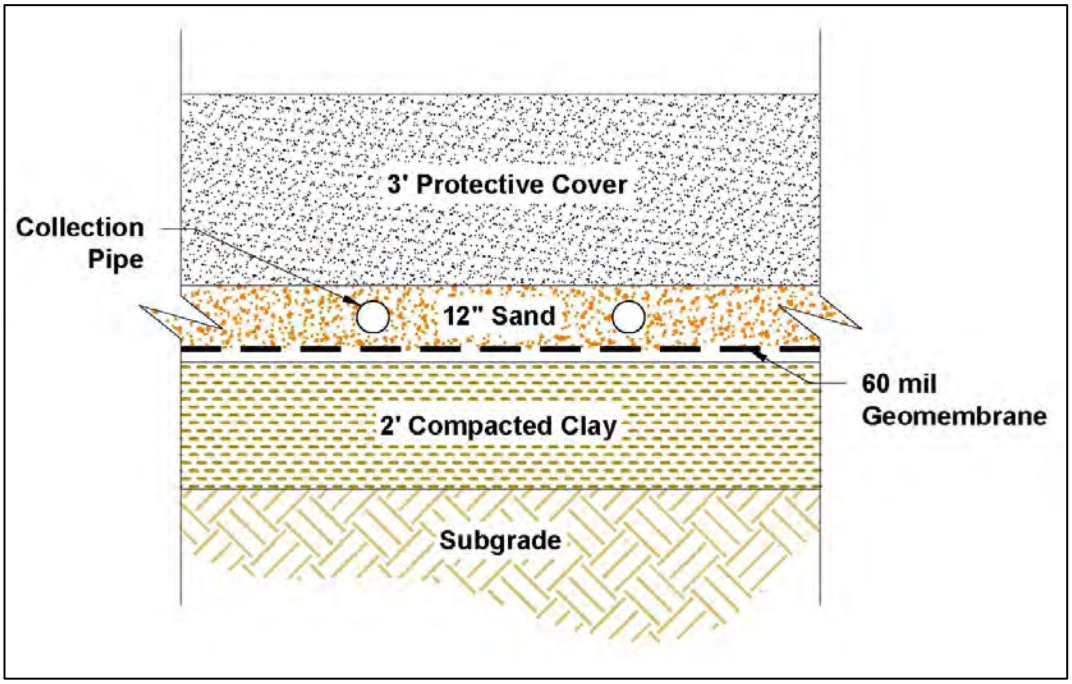


Figure 9: Composite Liner Detail

4.2.4 Cover

The final cover is also design based on RCRA Subtitle D standards and historic practice at CCS. The assumed cover system is shown in Figure 10 and consists of (from bottom to top) a compacted soil layer ($1x10^{-5}$ cm/sec maximum permeability), a textured geomembrane, a drainage layer consisting of drainage material and piping, and a vegetation layer. The drainage layer over the geomembrane is required to control the head on the liner and the resulting stability of growth medium. In addition, the cover will utilize terrace channels and armored down-chute channels to manage surface water runoff and reduce erosion.

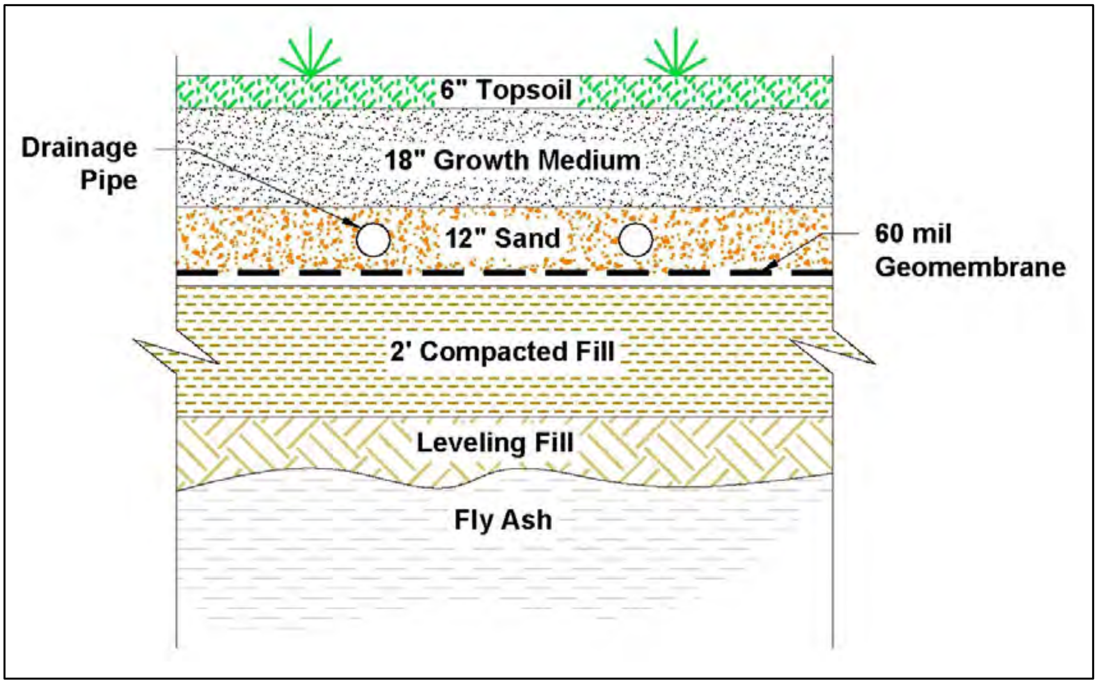


Figure 10: Composite Cover Detail

4.3 Cost Estimate

The cost estimate includes costs for the life of the disposal facility including engineering, design, and permitting; construction; and operations and maintenance, including closure and post-closure care. Golder used actual costs from similar projects at CCS, local contractor rates, RS Means manuals (RS Means 2010), and professional judgment to develop this cost estimate. Sources and assumptions are documented. Some general assumptions for the cost estimate include:

- All costs are estimated in 2011 dollars.
- Capital costs are annualized based on a 20-year life and 5.5% interest rate.
- Existing fly ash processing equipment (silos, unloaders, etc.) is not included. Disposal costs begin once the haul trucks are loaded with fly ash.
- Existing fly ash sales infrastructure (silos, scales, rail facilities) and operations and maintenance are not included.
- Disposal costs only include fly ash disposal and not facility airspace or operations and maintenance for other coal combustion products produced at CCS.

4.3.1 Engineering, Design, and Permitting

This item is estimated as 10% of the total construction costs to develop the facility. Ten percent is based on Golder's experience with coal combustion product facilities within the Midwest. The components included in this cost may include a facility siting evaluation, design of the facility, submittal of a solid waste landfill permit as well as permit renewals, submittal of air permits and NDPES permits, and creation of construction and bid packages for the facility.

The siting evaluation may include a hydrogeological characterization of the site, which includes drilling, soil testing, establishing groundwater baseline data, and preparing a hydrogeologic characterization report. Additional siting efforts may include a wetlands delineation, a site topographic survey, as well as other required evaluations.

Facility design includes both landfill design and infrastructure design. This includes grading plans, deposition plans, contact and surface water management plans, design of haul roads, and the design of the country bridge crossing.

Permitting may include the solid waste landfill permit, air permits, and an NPDES permit. This includes the development of operations plans for the facility, closure plans, post-closure care plans, groundwater sampling and analysis plans, a Stormwater Pollution Prevention (SWPP) plan, and other required submittals associated with the construction and operation of a new fly ash disposal facility.

4.3.2 Land Acquisition

Land acquisition of the property for the new facility includes site due diligence, and property purchase. Site due diligence may include survey, geotechnical characterization, environmental audit, and a landfill siting suitability evaluation. The property purchase may include legal fees as well as the purchase price. At this time, good crop land in the vicinity of CCS is selling for as much as $1,500 per acre. A unit cost of $2,000 per acre is used in the analysis to account for both the cost of the land and the site due diligence.

4.3.3 Infrastructure Development

The costs for the infrastructure development include fencing, monitoring well installation, power from the plant to landfill, facility access haul road, a return water pipeline, and a county road bridge crossing. The costs for this construction are estimated to be between $649,500 and $924,000 for the different scenarios. Details for the quantities and unit rates applied to this work are included in Appendix B.

4.3.4 Liner Construction

Liner construction includes several elements as described above including a compacted clay layer, a geomembrane liner, a leachate collection system, and protective cover. In addition, this construction effort will include clearing and grubbing, topsoil stripping and stockpiling, construction of temporary roads, soil excavation and stockpiling to be used for perimeter berms, compacted liner, and cover, and application of site controls such as erosion controls. The costs for this construction are estimated to be between $174,500 and $178,300 per acre for the different scenarios. Details for the quantities and unit rates applied to this work are included in Appendix B.

4.3.5 Final Cover Construction

Final cover construction includes leveling fill, compacted soil layer, a geomembrane liner, a drainage collection system, growth medium, topsoil, armored down-chute channels, and vegetation of the site. The costs for this construction are estimated to be between $132,400 and $143,000 per acre for the different scenarios. Details for the quantities and unit rates applied to this work are included in Appendix B.

4.3.6 Post-Closure Care

Post-closure care includes groundwater monitoring and reporting, annual site inspections, repair and maintenance of the final cover (soil, seeding, mowing, surface water structures), maintenance of the facility access roads and fencing, as well as permit required record keeping. Post closure care will occur for 30 years following the closure of the facility and is included in the capital/direct costs for this cost analysis. The costs for post closure care are estimated to be between $50,000 and $108,500 per year for the different scenarios. Details for the quantities and unit rates applied to this work are included in Appendix B.

4.3.7 Construction Management and Construction Quality Assurance

Throughout the construction effort, a construction manager will be on-site to communicate between the contractors and the design engineer. In addition to the construction manager, one or several construction quality assurance (CQA) monitors will be on-site during the construction. This item is estimated as 10% of the total construction costs to develop the facility. Ten percent is based on Golder's experience with coal combustion product facilities within the Midwest.

4.3.8 GRE Internal Costs

Internal costs for GRE to manage consultants, contractors, and in-house staff is estimated as 10% of the total costs (construction, engineering, permitting, CQA). Ten percent is based on GRE's experience with projects at CCS.

4.3.9 Project Contingency

Due to the order-of-magnitude scope of this cost estimate and the associated engineering and unit rate development, a contingency of 15% on the construction and land acquisition costs was added.

4.3.10 Operational Costs

Landfill operations and maintenance costs are estimated as an annual cost and include both engineering support and site operations. Engineering support includes design support; permit support, an annual inspection, groundwater monitoring, and an annual survey. Site operations include the ownership and operation of site haul and placement equipment, full-time site staff, and material expenses.

Estimated costs for this work are broken into haul costs, placement costs, and site management and maintenance costs.

Haul costs were estimated at $2.14 per ton based on haul distance, equipment capacity, operator costs, and equipment costs. Placement costs were estimated at $1.71 per ton based on dozer spreading with minimal compaction. Details on the haul and placement costs are included in Appendix B.

Site management and maintenance costs were estimated between $154,500 and $396,000 per year for the different scenarios. Details on the annual site management and maintenance costs are included in Appendix B.

4.4 Disposal Cost Summary

Using the quantities and the unit pricing described above, disposal costs were estimated for the three scenarios and are summarized in Table 3.

Table 3: Disposal Cost Summary

	Scenario A (Current Sales)	**Scenario B (No Sales)**	**Scenario C (Reduced Sales, ASM)**
Fly Ash Disposed (ton/yr)	110,000	525,000	234,500
Disposal Cost ($/ton)	$18.06	$11.18	$13.91
Annual Disposal Cost ($/yr)	$1,987,000	$5,870,000	$3,262,000
Annual Increase in Disposal Cost Compared to Scenario A ($/yr)	-	$3,883,000	$1,275,000

The disposal cost per ton is reduced with increased disposal quantity due to the efficiency of the landfill footprint (larger landfill can be built higher and has larger capacity), and the distribution of fixed costs (roads, bridge, fence) across a larger amount of disposed fly ash.

Based on the annual disposal cost estimate, the potential impact of an SNCR to the fly ash disposal costs at CCS may be an additional $3.9 million per year if fly ash is no longer marketable or an additional $1.3 million per year if the ASM technology proves successful.

5.0 COST IMPACT

The total cost impact of an SNCR on fly ash management at CCS requires the aggregation of the post-processing costs (ASM), the disposal costs, and the loss in revenue generated from the sale of fly ash. This total cost impact was evaluated for the three Scenarios discussed previously. As a basis for the cost comparison, Table 4 provides a summary of the annual tons of fly ash produced, sold, disposed, and the loss in fly ash sales in comparison to Scenario A (current sales).

Table 4: Fly Ash Sales and Disposal Tons

	Scenario A (Current Sales)	Scenario B (No Sales)	Scenario C (Reduced Sales, ASM)
Fly Ash Produced (ton/yr)	525,000	525,000	525,000
Fly Ash Sold (ton/yr)	415,000	0	290,500
Fly Ash Disposed (ton/yr)	110,000	525,000	234,500
Lost Fly Ash Sales (ton/yr)	0	415,000	124,500

5.1 Ammonia Slip Mitigation

Post-processing of ammonia slip impacted fly ash by Headwater's ASM technology is proposed as an option to maintain fly ash sales. This post-processing is only being applied to the sold fly ash tonnage in Scenario C. Depending upon the plant power profile and how the fly ash distribution system is setup, it is likely that additional tons of fly ash will be treated and disposed, but these potential costs impacts are not included. The cost impact for ASM post-processing is shown in Table 5.

Table 5: ASM Post-Processing Costs

	Scenario A (Current Sales)	Scenario B (No Sales)	Scenario C (Reduced Sales, ASM)
ASM Unit Rate Capital and O&M ($/ton sold)	$0.00	$0.00	$5.61
ASM Annual Capital and O&M ($/yr)	$0	$0	$1,629,000

5.2 Fly Ash Disposal

Disposal costs vary between the Scenarios with the per ton cost being reduced by disposal volume. The cost impact for fly ash disposal is shown in Table 6.

Table 6: Disposal Costs

	Scenario A (Current Sales)	Scenario B (No Sales)	Scenario C (Reduced Sales, ASM)
Unit Rate Capital and O&M ($/ton disposed)	$18.06	$11.18	$13.91
Annual Capital and O&M ($/yr)	$1,987,000	$5,870,000	$3,262,000

5.3 Lost Sales

The current fly ash sales are supported by a large investment in capital infrastructure as well as a large operations and maintenance contingency. Changes to the quantity of fly ash marketed and sold will have a direct impact on fly ash management costs, as the revenue currently used to offset fly ash management will be lost. The lost fly ash sales revenue is based on the 2010 average price per ton FOB of $41.00; with 30% of the sale price going to GRE as revenue. The cost impact of the potential loss in fly ash sales in shown in Table 7.

Table 7: Lost Fly Ash Sales

	Scenario A (Current Sales)	Scenario B (No Sales)	Scenario C (Reduced Sales, ASM)
Lost Fly Ash Sales Revenue ($/ton lost sales)	$12.30	$12.30	$12.30
Annual Lost Fly Ash Sales Revenue ($/yr)	$0	$5,105,000	$1,531,000

5.4 Combined Impact to Fly Ash Management

The combination of the ASM post-processing, fly ash disposal, and lost fly ash sales revenue is shown in Table 8. This table also shows the additional cost impact of Scenario B and Scenario C in comparison with the current sales (Scenario A).

Table 8: Total Fly Ash Management Costs

	Scenario A (Current Sales)	Scenario B (No Sales)	Scenario C (Reduced Sales, ASM)
Total (Disposal + Post Processing + Lost Sales)			
Annual Cost ($/yr)	$1,987,000	$10,975,000	$6,422,000
Unit Cost ($/ton produced)	$3.79	$20.91	$12.23
Additional Cost (Scenario B/C - Scenario A)			
Fly Ash Management Cost ($/yr)	-	$8,988,000	$4,435,000
Fly Ash Management Cost ($/ton produced)	-	$17.12	$8.45

The total additional cost impact to fly ash management as a result of an SNCR is between $4.4 and $9.0 million per year.

We appreciate the opportunity to provide this third-party review of Headwater's ASM technology, and an estimate of the potential impact of SNCR on fly ash management costs including disposal and sales. Please contact us if you have any questions about the information provided.

GOLDER ASSOCIATES INC.

Fawn W. Bergen, PE
Senior Project Engineer

Ron Jorgenson
Principal

FWB/TS/dls

6.0 REFERENCES

1. *EPA Air Pollution Control Cost Manual*, Sixth Edition, EPA/452/B-02-001, January 2002.

2. Email from Rafic Minkara, PhD, PE, Vice President – Technology, Headwaters Energy Services, July 15, 2011.

3. RSMeans, 2010. *Heavy Construction Cost Data, 24th Annual Edition*. Construction Publishers & Consultants; Kingston, MA.

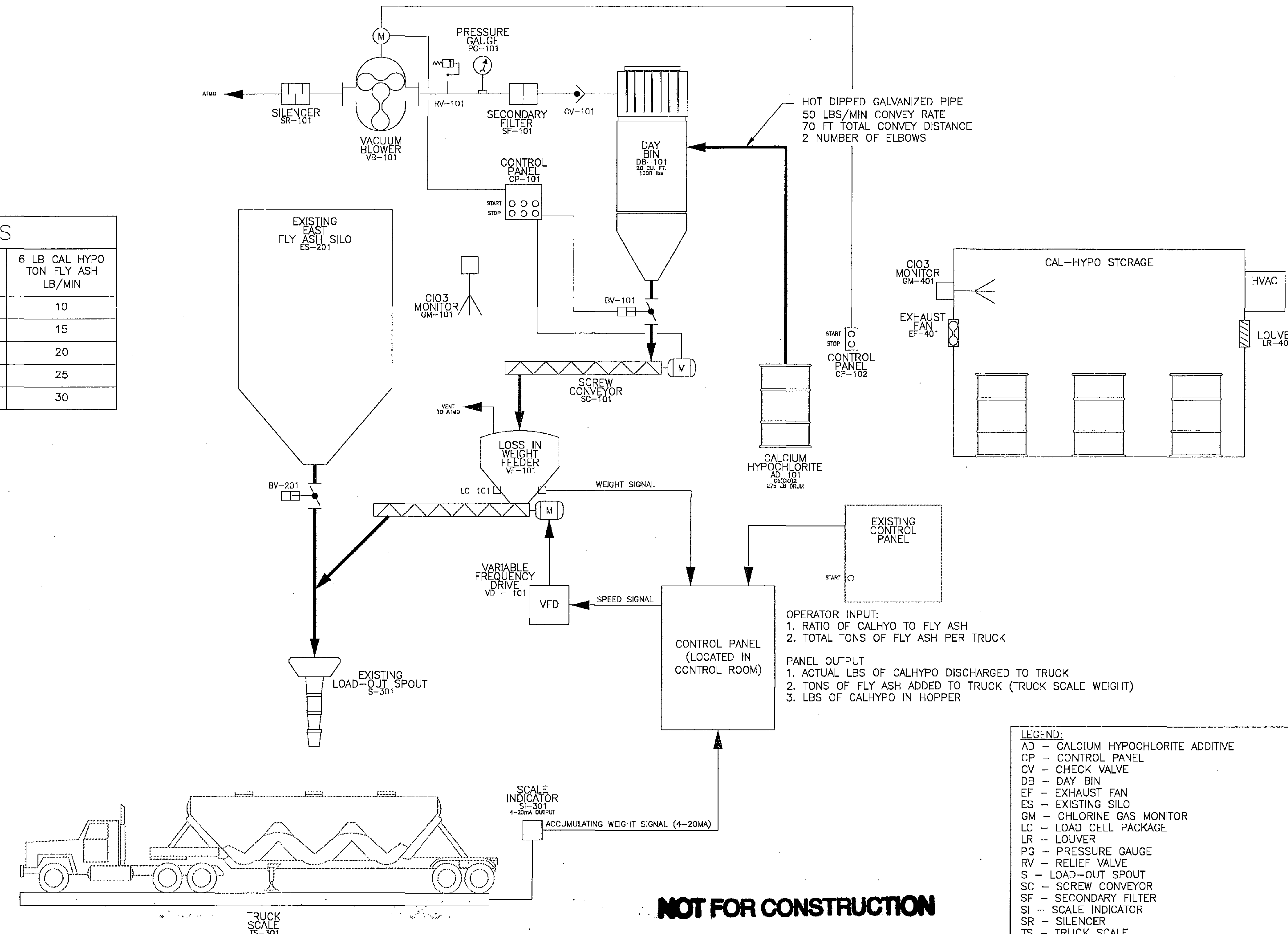
APPENDIX A

EASTLAKE ASM DESIGN DRAWINGS (HEADWATERS RESOURCES)

NOTES:
1. APPROXIMATELY 1½ TO 6 LBS CALCIUM HYPOCHLORITE/TON FLY ASH OR 38 LBS (1½*25) TO 150 LBS (6*25)/TRUCK
2. 30 TRUCKS MAX PER DAY. 1140 LBS (38*30) TO 4500 LBS (150*30) PER DAY
3. FLY ASH FEED RATE 300 TONS/HR TO 150 TONS/HR
4. CALCIUM HYPOCHLORITE FEED RATE 2.5 LBS/MIN TO 30 LBS/MIN
5. TRUCK LOAD TIME BETWEEN 5 AND 10 MINUTES
6. FLY ASH PH BETWEEN 11.5 TO 12
7. FLY ASH DENSITY 70 LBS LOOSE 100 LBS VIBRATED
8. CALHYPO APPROX. 50 LBS/FT³
9. CALHYPO DRUM 275 LBS

LOSS IN WEIGHT FEEDER RATES

FLY ASH LOAD–OUT TON/HR	1.5 LB CAL HYPO TON FLY ASH LB/MIN	2 LB CAL HYPO TON FLY ASH LB/MIN	4 LB CAL HYPO TON FLY ASH LB/MIN	6 LB CAL HYPO TON FLY ASH LB/MIN
100	2.5	3.3	6.7	10
150	3.75	5.0	10.0	15
200	5	6.7	13.3	20
250	6.25	8.3	16.7	25
300	7.5	10.0	20.0	30



OPERATOR INPUT:
1. RATIO OF CALHYO TO FLY ASH
2. TOTAL TONS OF FLY ASH PER TRUCK

PANEL OUTPUT
1. ACTUAL LBS OF CALHYPO DISCHARGED TO TRUCK
2. TONS OF FLY ASH ADDED TO TRUCK (TRUCK SCALE WEIGHT)
3. LBS OF CALHYPO IN HOPPER

NOT FOR CONSTRUCTION

LEGEND:
AD – CALCIUM HYPOCHLORITE ADDITIVE
CP – CONTROL PANEL
CV – CHECK VALVE
DB – DAY BIN
EF – EXHAUST FAN
ES – EXISTING SILO
GM – CHLORINE GAS MONITOR
LC – LOAD CELL PACKAGE
LR – LOUVER
PG – PRESSURE GAUGE
RV – RELIEF VALVE
S – LOAD–OUT SPOUT
SC – SCREW CONVEYOR
SF – SECONDARY FILTER
SI – SCALE INDICATOR
SR – SILENCER
TS – TRUCK SCALE
VB – VACUUM BLOWER
VD – VARIABLE SPEED DRIVE
VF – VIBRATORY FEEDER

HEADWATERS RESOURCES

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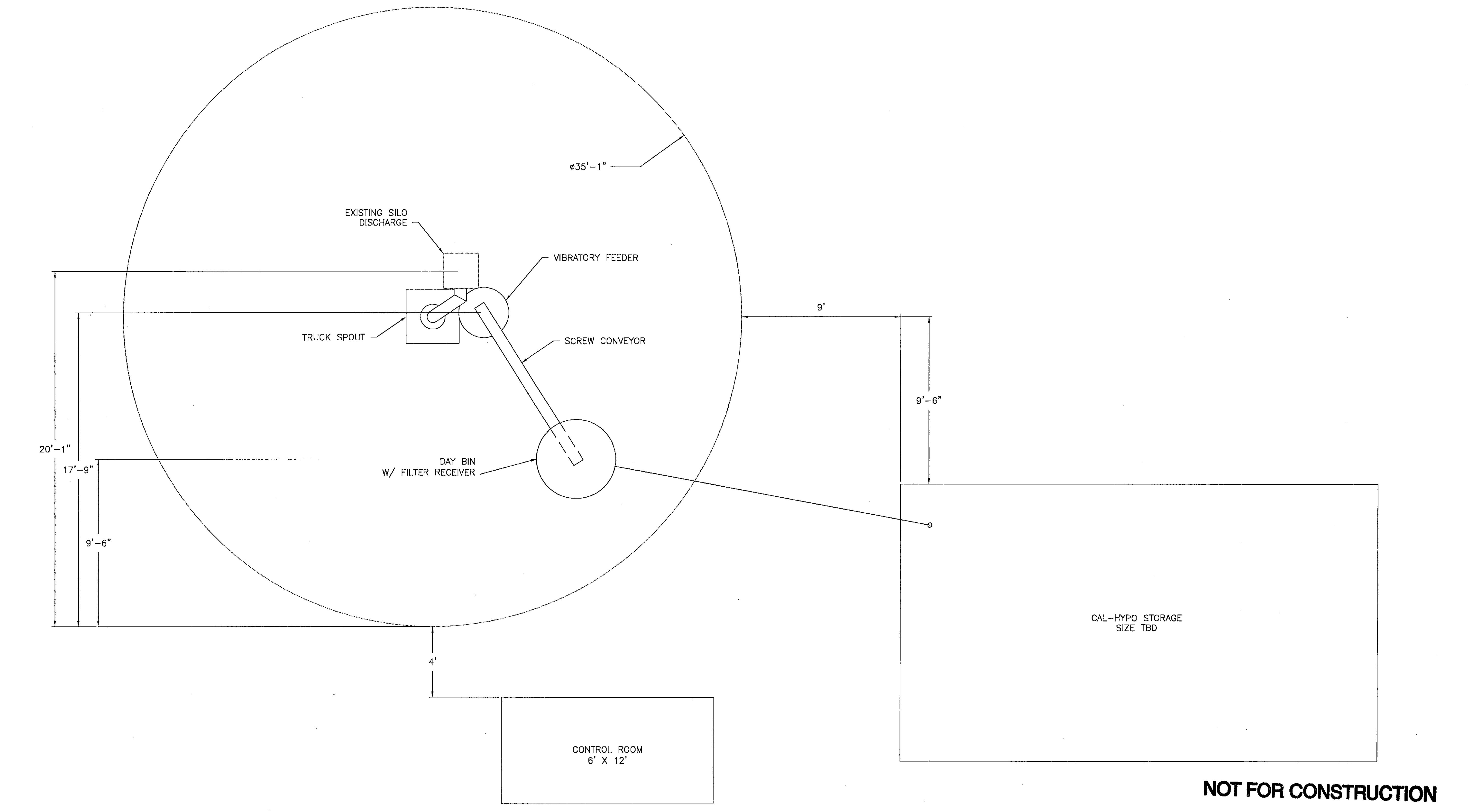
(801) 984-9400
FAX (801) 984-9419
www.headwaters.com

DATE	NO.	REVISION DESCRIPTION	BY
8/13/07	G	ADDED EXHAUST FAN & LOUVER	DCB
8/2/07	F	ADDED CONTROL PANELS	DCB
7/16/07	E	ADDED GAS MONITORS AND STORAGE BUILDING	DCB
5/21/07	B	GENERAL REV.	DCB

EAST LAKE AMMONIA SLIP MITIGATION PROCESS FLOW DIAGRAM
EAST LAKE, OH

SCALE: NO SCALE
DATE: 05-18-07
DESIGN BY: LS
DRAWN BY: DCB
CHECKED BY:
APPROVED BY:
SHEET NO. PF100
REVISION NO. G
PROJECT NO. R070H0



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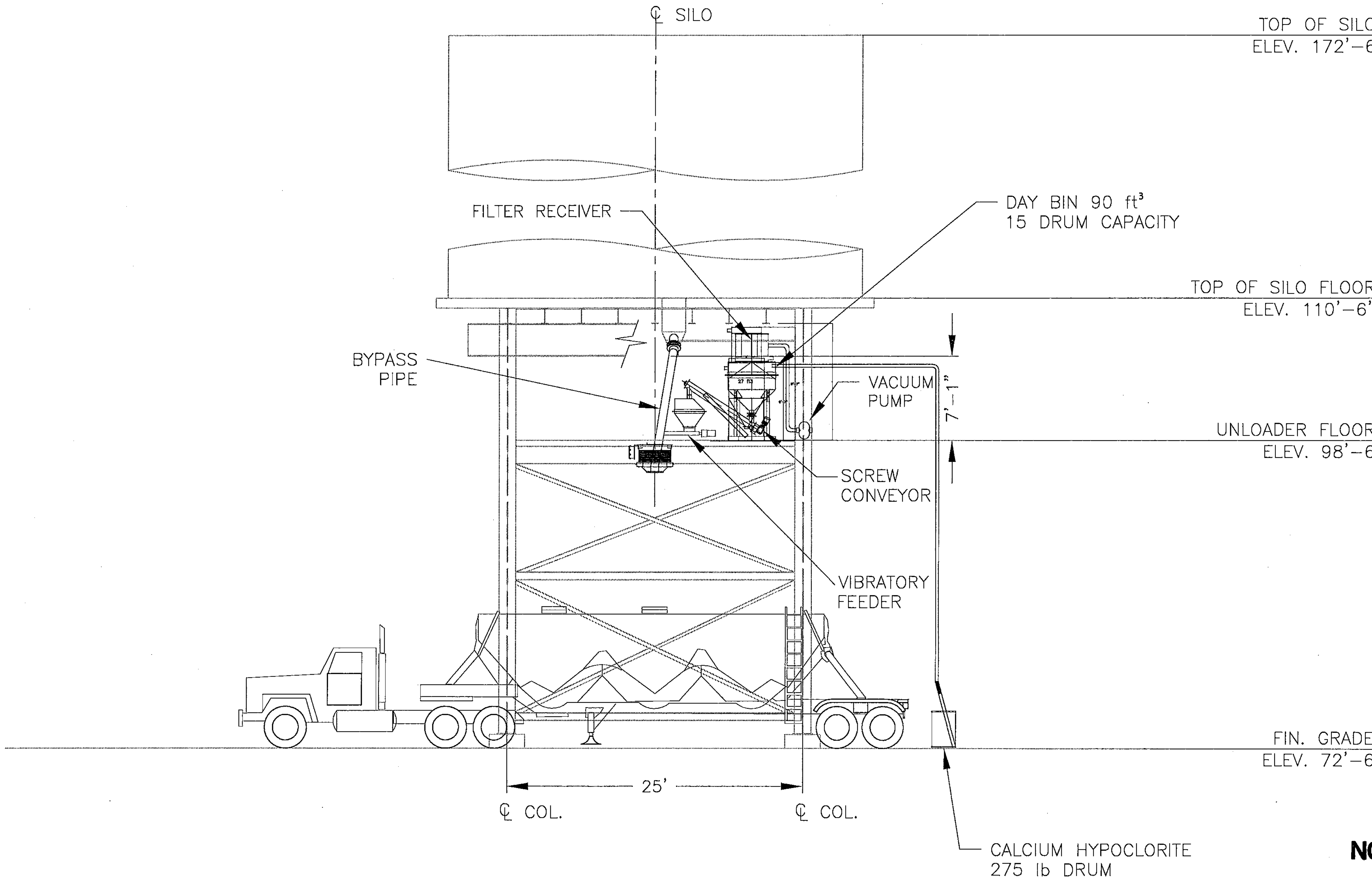
DATE	NO.	REVISION DESCRIPTION	BY
7/18/07	A	DRAWING CREATED	DCB

EAST LAKE
AMMONIA SLIP MITIGATION
PLAN VIEW
EAST LAKE, OH

SCALE: 3/16" = 1'	
DATE: 07-18-07	
DESIGN BY:	LAS
DRAWN BY:	DCB
CHECKED BY:	
APPROVED BY:	

SHEET NO. M100
REVISION NO. A
PROJECT NO. R07OH0



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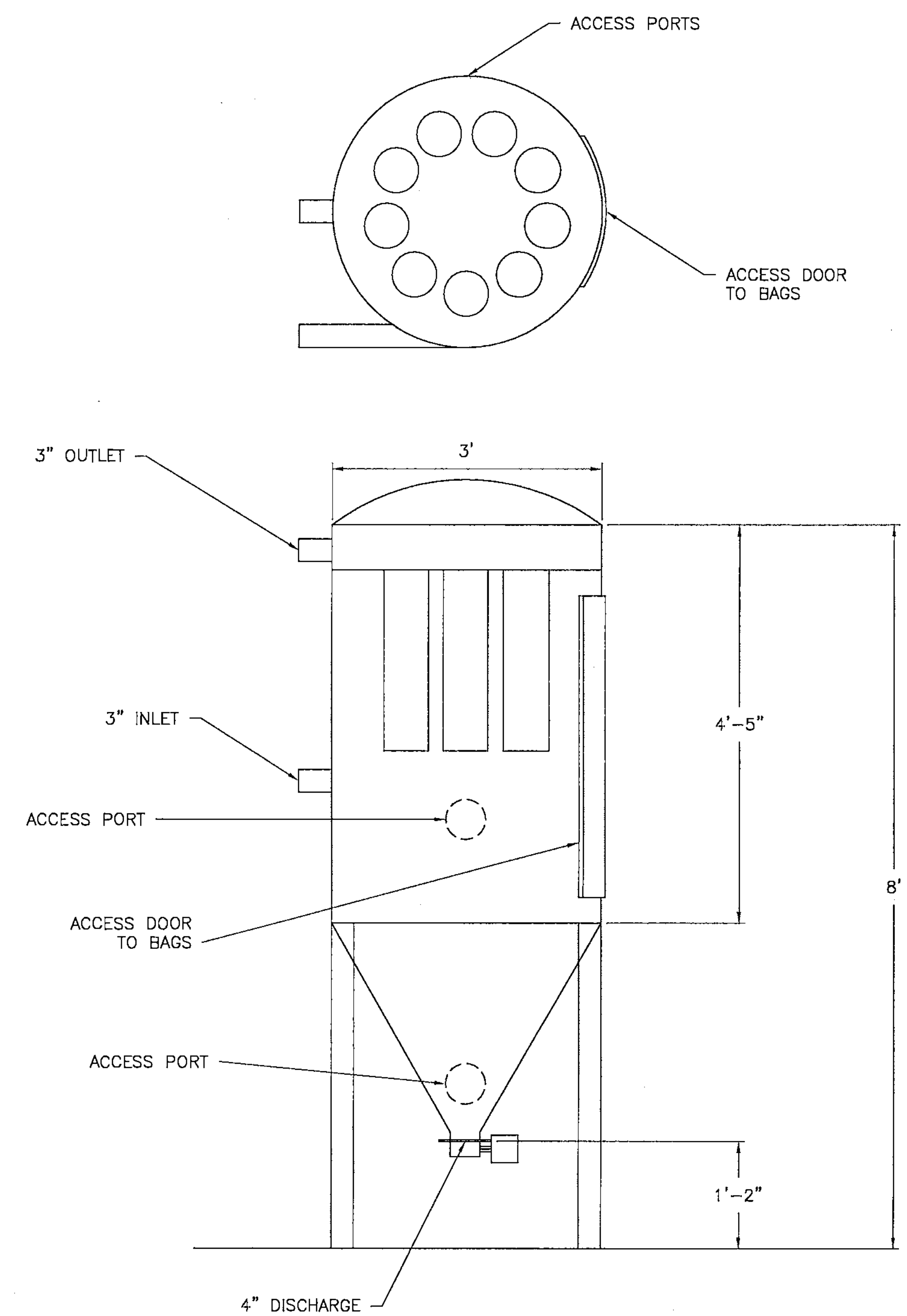
DATE	NO.	REVISION DESCRIPTION	BY
7/18/07	A	DRAWING CREATED	DCB

EAST LAKE
AMMONIA SLIP MITIGATION
ELEVATION
EAST LAKE, OH

SCALE: 1"=10'	
DATE: 07-18-07	
DESIGN BY:	LAS
DRAWN BY:	DCB
CHECKED BY:	
APPROVED BY:	
SHEET NO.	M101
REVISION NO.	A
PROJECT NO.	R070H0

NOTE:
1. EPOXY PAINT INSIDE AND OUT
2. TOTAL CAPACITY – 17 FT^3
3. USE 2' TEFLON–COATED BAGS



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DATE	NO.	REVISION DESCRIPTION	BY
8/6/07	B	RELOCATED ACCESS PORTS	DCB
8/3/07	A	DRAWING CREATED	DCB

EAST LAKE
AMMONIA SLIP MITIGATION
FILTER RECEIVER
EAST LAKE, OH

SCALE: 1/2" = 1'	
DATE: 08-03-07	
DESIGN BY:	LAS
DRAWN BY:	DCB
CHECKED BY:	
APPROVED BY:	

SHEET NO. M200

REVISION NO. B

PROJECT NO. R07OH0

APPENDIX B
COST ESTIMATE DETAILS

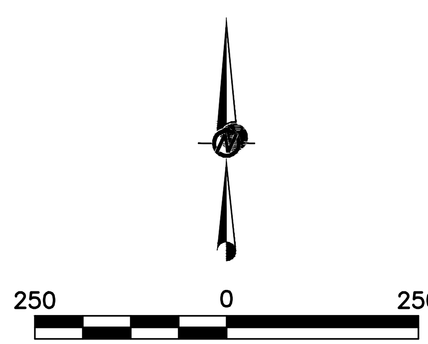
Legend

Fly Ash Stream

Calcium Hypo–Chlorite Mixing System

Notes

1. Eastlake Generating Plant has a truck loadout for both untreatable fly ash destined for disposal (silos 1 and 2) and treated fly ash (silo 4).



FOR DISCUSSION PURPOSES ONLY

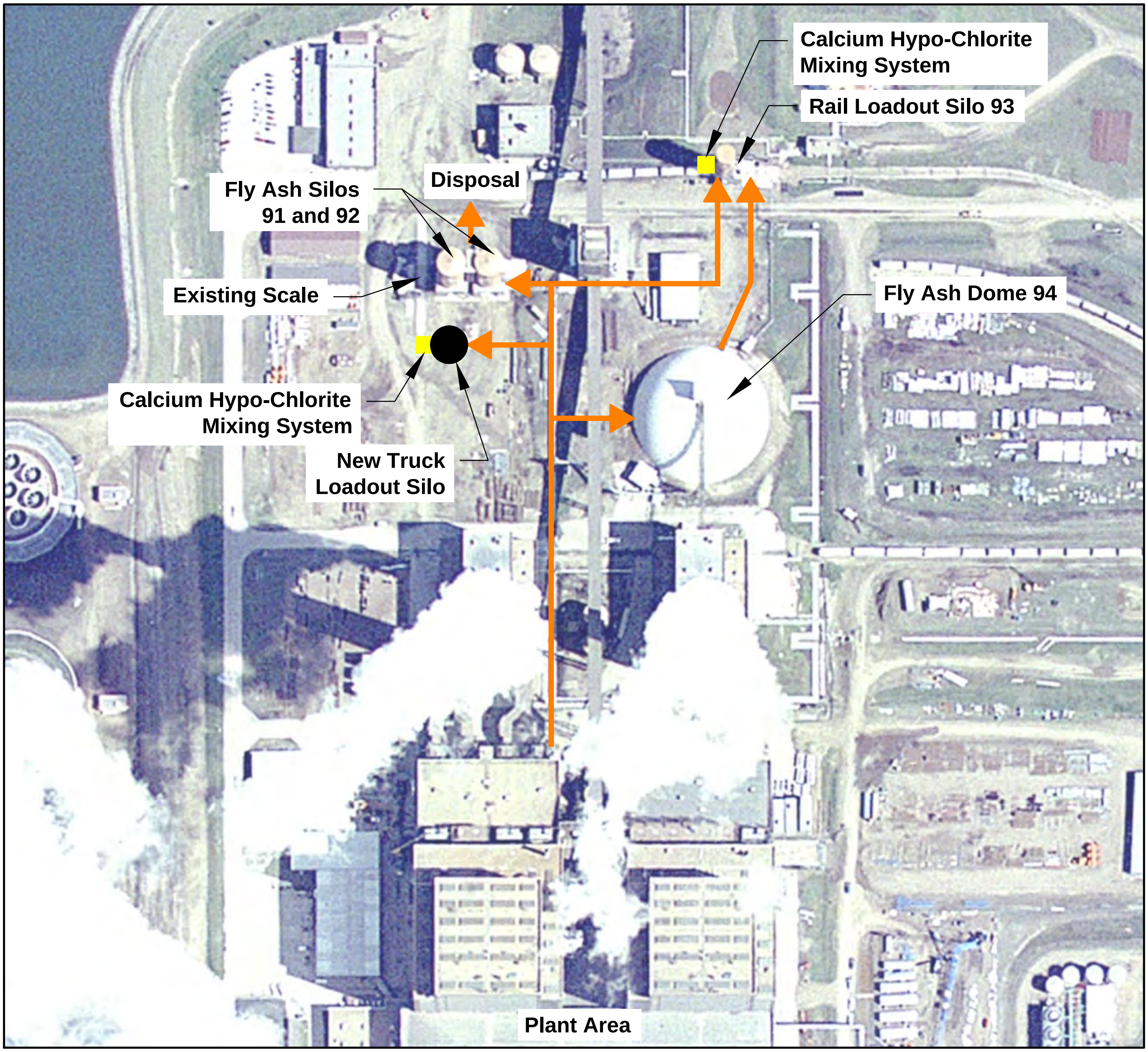
Golder Associates

Fly Ash Loadout Schematic
Eastlake Generating Plant

FIGURE 1

PROJECT No. 113–82161 CADD CCS DATE 11/1/11 FILE No. 11382161_Figures.dwg

Drawing File: J:\11JOBS\113-82161 GRE SNCR\Figures\ 11382161_Figures.dwg | Layout: Fly Ash Loadout-Eastlake | Modified: Nov 02, 2011 16:04 CSchuettpelz | Plotted: 11/02/11 4:05pm CSchuettpelz



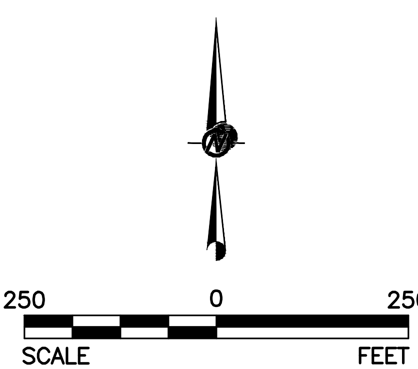
Legend

Fly Ash Stream

Calcium Hypo–Chlorite Mixing System

Notes

1. New truck loadout silo and scale are required to store treatable fly ash for sale.
2. Two Calcium Hypo–Chlorite Mixing Systems would be required near the new truck loadout silo and the rail loadout silo (93) for treating fly ash available for sale.
3. The existing fly ash silos (91 and 92) are available to store untreatable fly ash for disposal.
4. The existing Fly Ash Dome (94) is available to store treatable fly ash for rail sale.



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Fly Ash Loadout Schematic Coal Creek Station

FIGURE 2

PROJECT No. 113–82161 CADD CCS DATE 11/1/11 FILE No. 11382161_Figures.dwg

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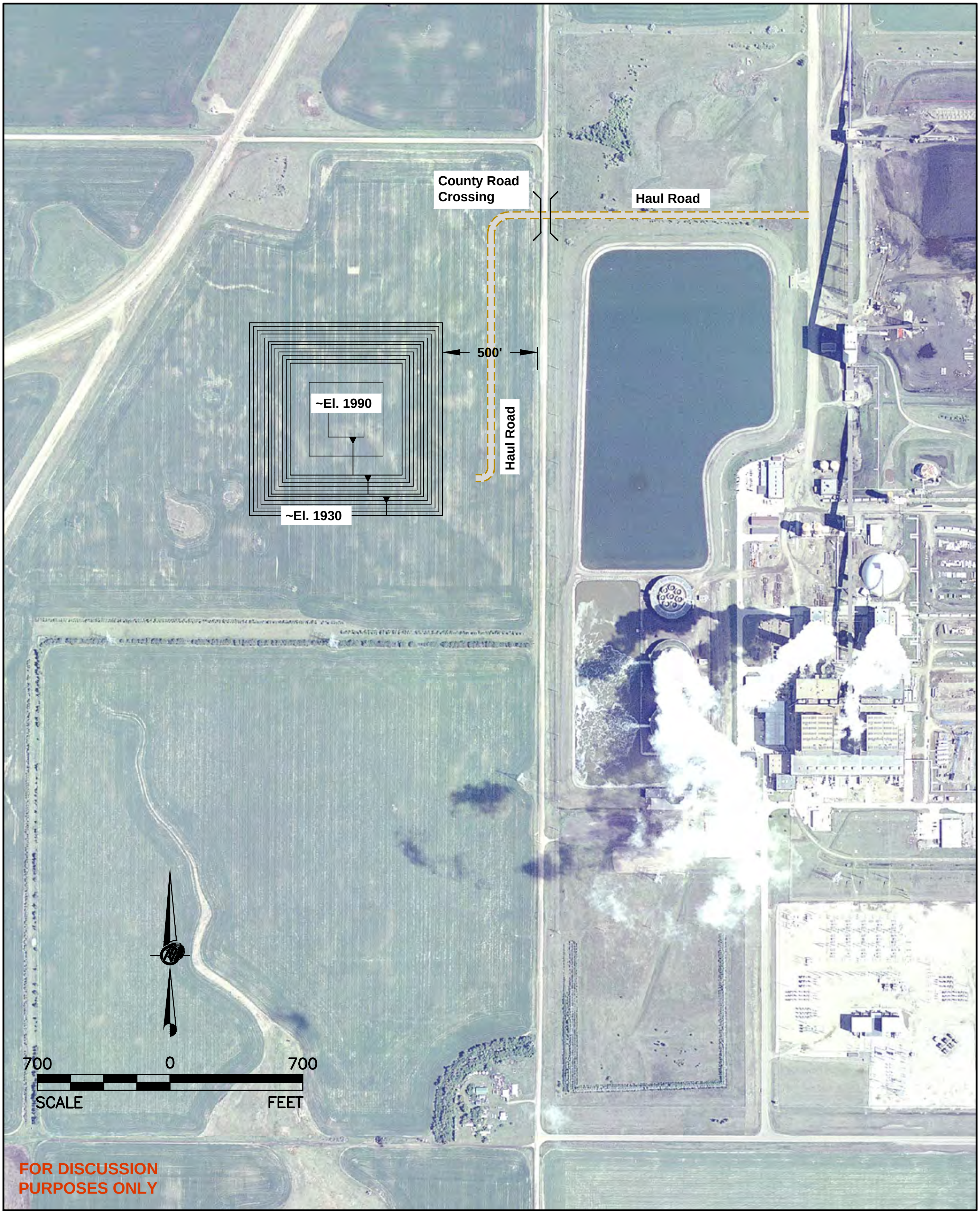


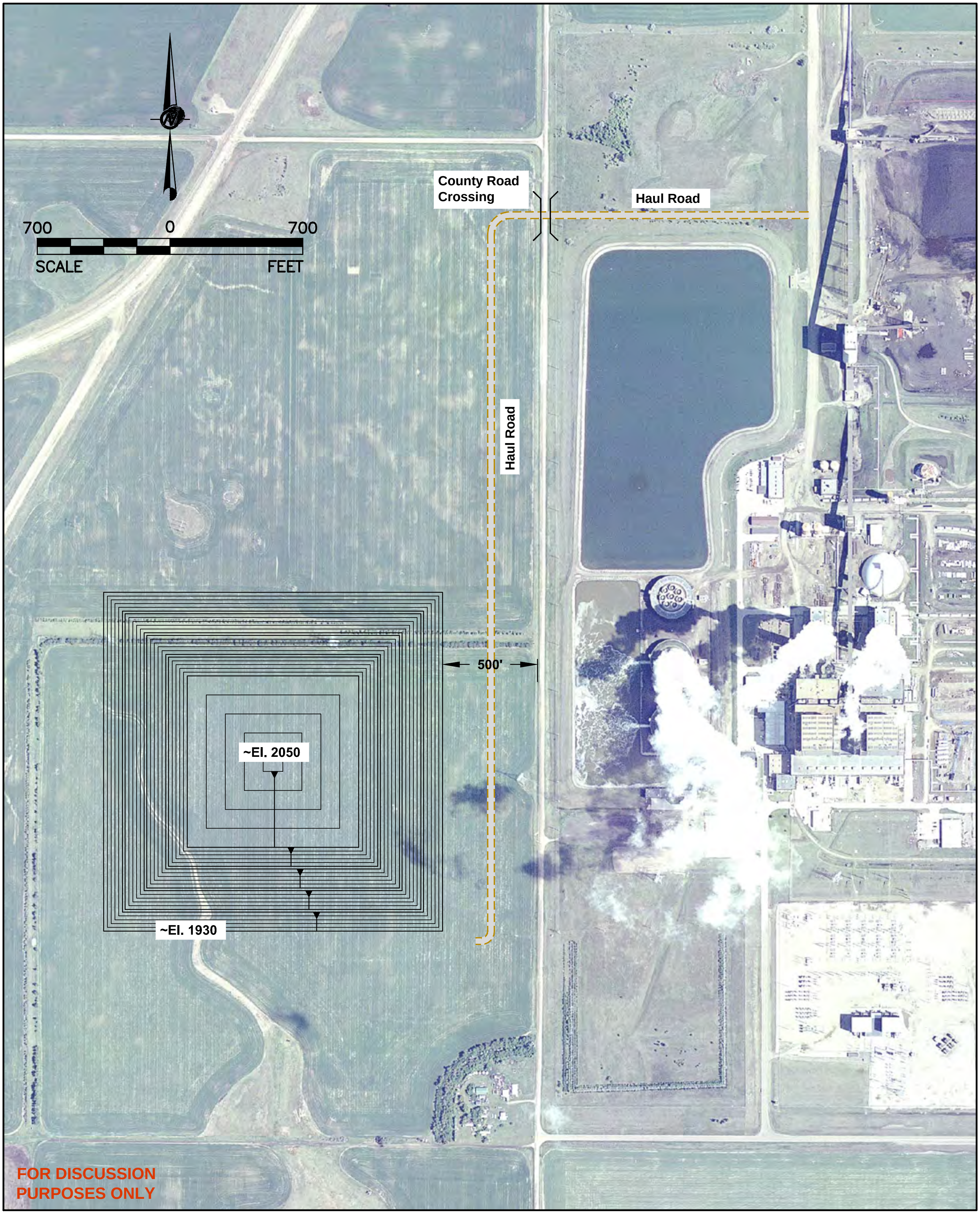
Scenario A
Fly Ash Containment Facility

Golder Associates

FIGURE 3

PROJECT No. 113-82161 CADD CCS DATE 11/1/11 FILE No. 11382161_Figures.dwg

Drawing File: J:\11JOBS\113-82161 GRE SNCR\Figures\ 11382161_Figures.dwg | Layout: Small Facility | Modified: Nov 02, 2011 16:04 CSchuettpelz | Plotted: 11/02/11 4:05pm CSchuettpelz



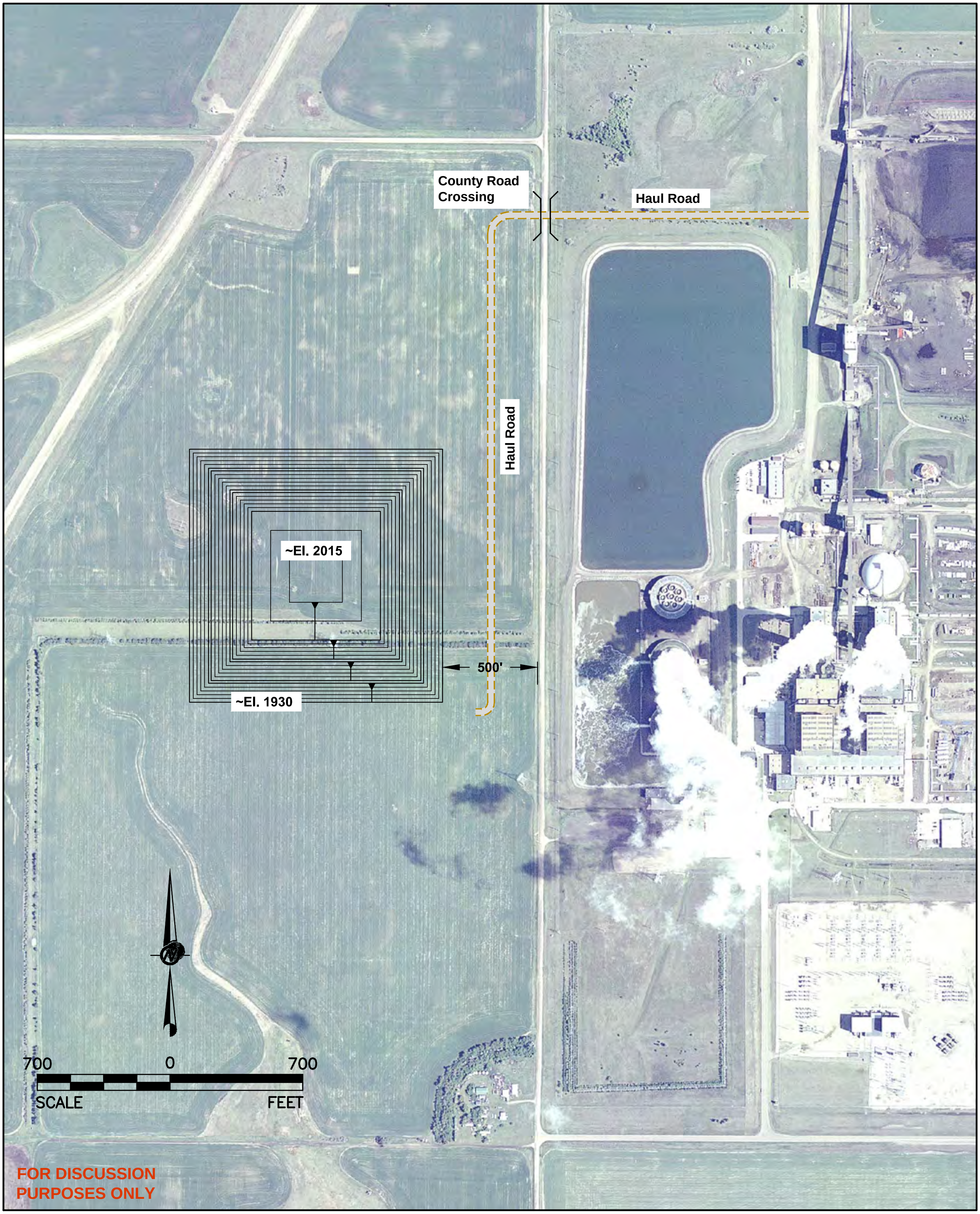
Scenario B
Fly Ash Containment Facility

Golder Associates

FIGURE 4

PROJECT No. 113–82161 CADD CCS DATE 11/1/11 FILE No. 11382161_Figures.dwg

Drawing File: J:\1JOBS\113-82161 GRE SNCR\Figures\ 11382161_Figures.dwg | Layout: Large Facility | Modified: Nov 02, 2011 16:04 CSchuettpelz | Plotted: 11/02/11 4:05pm CSchuettpelz



Scenario C
Fly Ash Containment Facility

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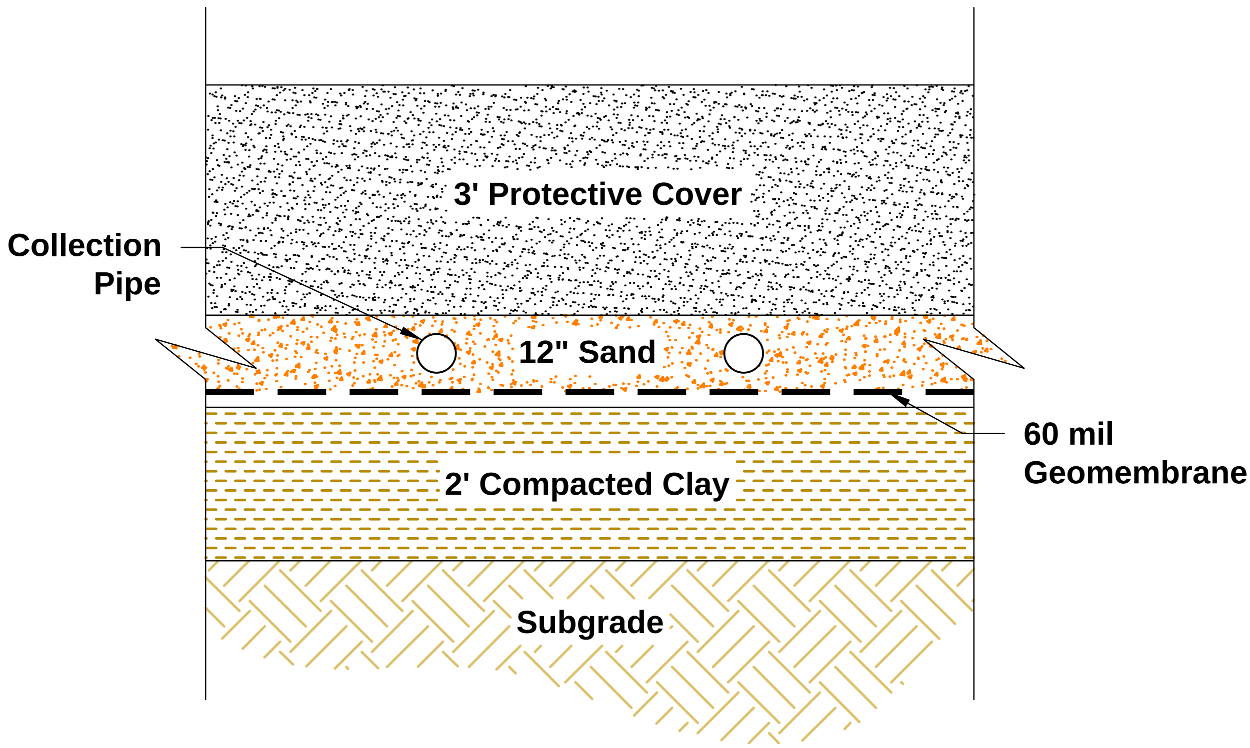
FIGURE 5

PROJECT No. 113-82161 CADD CCS DATE 11/1/11 FILE No. 11382161_Figures.dwg

Drawing File: J:\11JOBS\113-82161 GRE SNCR\Figures\ 11382161_Figures.dwg | Layout: Medium Facility | Modified: Nov 02, 2011 16:04 CSchuettpelz | Plotted: 11/02/11 4:05pm CSchuettpelz



FOR DISCUSSION
PURPOSES ONLY

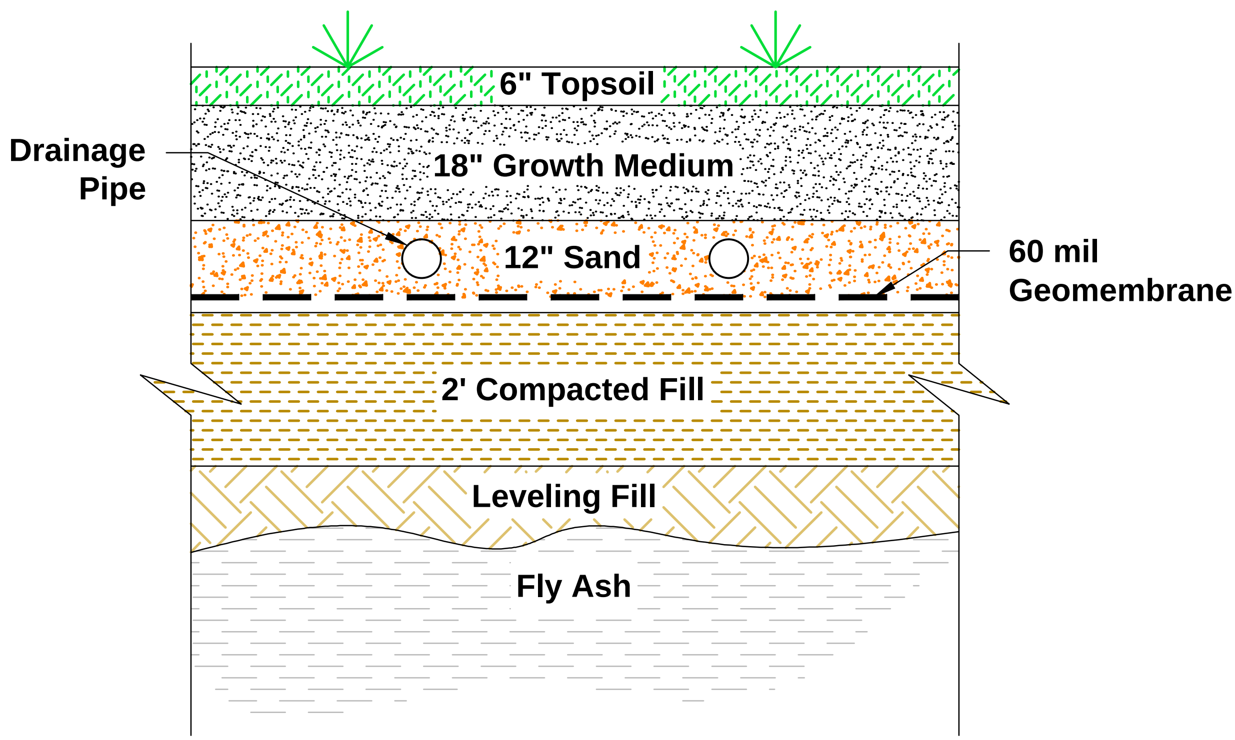
Golder Associates

Composite Liner

FIGURE 6

PROJECT No. 113–82161 CADD CCS DATE 11/1/11 FILE No. 11382161_Figures.dwg

Drawing File: J:\11JOBS\113-82161 GRE SNCR\Figures\ 11382161_Figures.dwg | Layout: Liner | Modified: Nov 02, 2011 16:04 CSchuettpelz | Plotted: 11/02/11 4:05pm CSchuettpelz



FOR DISCUSSION PURPOSES ONLY

Golder Associates

Cover

FIGURE 7

PROJECT No. 113-82161 CADD CCS DATE 11/1/11 FILE No. 11382161_Figures.dwg

Drawing File: J:\11JOBS\113-82161 GRE SNCR\Figures\ 11382161_Figures.dwg | Layout: Cover | Modified: Nov 02, 2011 16:04 CSchuettpelz | Plotted: 11/02/11 4:06pm CSchuettpelz

Fly Ash Management Impact Evaluation Summary (November 15, 2011)

	Option A	Option B	Option C
	Current fly ash sales with new RCRA Subtitle D landfill	No fly ash sales with new RCRA Subtitle D landfill	ASM technology to allow reduced fly ash sales with new RCRA Subtitle D landfill
Fly Ash Quantities			
Fly Ash production (ton/yr)	525,000	525,000	525,000
Fly Ash Sales (ton/yr)	415,000	0	290,500
Fly Ash Disposal (ton/yr)	110,000	525,000	234,500
Lost Fly Ash Sales (ton/yr)	0	415,000	124,500
ASM Fly Ash Post Processing			
ASM Unit Rate Capital and O&M ($/ton sold)	$ -	$ -	$ 5.61
ASM Annual Capital and O&M ($/yr)	$ -	$ -	$ 1,629,000
Fly Ash Disposal			
Lined Footprint (acres)	24.0	73.5	41.0
Unit Rate Capital and O&M ($/ton disposed)	$ 18.06	$ 11.18	$ 13.91
Annual Capital and O&M ($/yr)	$ 1,987,000	$ 5,870,000	$ 3,262,000
Lost Fly Ash Sales			
Lost Fly Ash Sales Revenue ($/ton lost sales)	$ 12.30	$ 12.30	$ 12.30
Annual Lost Fly Ash Sales Revenue ($/yr)	$ -	$ 5,105,000	$ 1,531,000
Total (Disposal + Post Processing + Lost Sales)			
Annual Cost ($/yr)	$ 1,987,000	$ 10,975,000	$ 6,422,000
Unit Cost ($/ton produced)	$ 3.79	$ 20.91	$ 12.23
Additional Cost (Scenario B/C - Scenario A)			
Fly Ash Management Cost ($/yr)	-	$ 8,988,000	$ 4,435,000
Fly Ash Management Cost ($/ton produced)	-	$ 17.12	$ 8.45

Notes:

Capital costs annualized based on 20-year life and 5.5% interest rate.

Disposal costs based on new facility built across county road from Coal Creek Station with 20-year life.

RCRA Subtitle D type facility (composite liner, leachate collection system, and composite cover).

Disposal costs only include fly ash disposal and not facility airspace or O&M for other CCPs.

Ammonia slip mitigation costs based on existing facility site visit and historic costs for fly ash infrastructure.

All costs are in 2011 dollars.

Lost fly ash sales revenue based on expected 2011 average price per ton FOB of $43 and 30% of sale price to GRE.

Existing fly ash sales infrastructure and O&M costs are not included.

Scenario A - Current Sales

Project	113-82161
Date	11/15/2011
By	TJS
Checked	JJS

Sizing Information

Annual Fly Ash Disposal	110,000	tn	
20yr Fly Ash Disposal	2,200,000	tn	
Fly Ash Dry Density (in-situ)	90	pcf	
20yr Fly Ash Quantity	1,811,000	cy	
Lined Footprint	24.0	ac	75,000 cy/ac
Disturbance Footprint	34.5	ac	100' offset on liner footprint
Berm Length	4,240	ft	20' offset on liner footprint
Total Footprint	160		500' offset on liner footprint, nearest 1/8 section
Total Cover Area	26.5	ac	1.1 ration of cover area to liner area

Direct/Capital Costs

Item	**Rate**		**#**		**Total Cost**	
Land Acquisition	$ 2,000	/ac	160.0	ac	$ 320,000	
Infrastructure Development	$ 649,500	ea	1.0	LS	$ 649,500	
County Road Crossing	$ 1,730,500	ea	1.0	LS	$ 1,730,500	
Liner Construction	$ 178,300	/ac	24.0	ac	$ 4,279,200	
Final Cover Construction	$ 143,000	/ac	26.5	ac	$ 3,789,500	
Post-Closure Care	$ 50,000	/yr	30.0	yr	$ 1,500,000	
Facility Design & Permitting (on construction)	10.0%	-	$ 10,448,700	LS	$ 1,044,870	
Construction Quality Assurance (on construction)	5.0%	-	$ 10,448,700	LS	$ 522,435	
GRE Internal Costs (on construction, design, CQA, & land purchase)	10.0%	-	$ 13,836,005	-	$ 1,384,000	
Project Contingency (on construction & land)	15.0%	-	$ 10,768,700	-	$ 1,615,000	
			Total Direct/Capital Costs		$ 16,835,005	
			Annualized Capital Cost*		$ 1,409,000	/yr
			Capital Costs		$ 12.81	/tn

Operational Costs

Hauling Costs	$ 2.14	/tn	110,000	tn/yr	$ 235,469	/yr
Placement Costs	$ 1.71	/tn	110,000	tn/yr	$ 188,000	/yr
Maintenance Costs	$ 154,500	/yr	1	yr	$ 154,500	/yr
			Annual Operational Costs		$ 578,000	/yr
			Operational Costs		$ 5.26	/tn

TOTAL DISPOSAL COSTS

Annual Costs	$ 1,987,000	/yr
20-Year Total Costs	$ 39,740,000	
Per Ton Cost	$ 18.06	/tn

Notes:

*Annualized capital cost based on 20-year life and 5.5% interest rate.

All costs are in 2011 dollars.

Scenario B - No Fly Ash Sales

Project	113-82161
Date	11/15/2011
By	TJS
Checked	JJS

Sizing Information

Annual Fly Ash Disposal	525,000	tn	
20yr Fly Ash Disposal	10,500,000	tn	
Fly Ash Dry Density (in-situ)	90	pcf	
20yr Fly Ash Quantity	8,642,000	cy	
Lined Footprint	73.5	ac	118,000 cy/ac
Disturbance Footprint	91.0	ac	100' offset on liner footprint
Berm Length	7,320	ft	20' offset on liner footprint
Total Footprint	240		500' offset on liner footprint, nearest 1/8 section
Total Cover Area	81.0	ac	1.1 ration of cover area to liner area

Direct/Capital Costs

Item	**Rate**		**#**		**Total Cost**	
Land Acquisition	$ 2,000	/ac	240.0	ac	$ 480,000	
Infrastructure Development	$ 924,000	ea	1.0	LS	$ 924,000	
County Road Crossing	$ 1,730,500	ea	1.0	LS	$ 1,730,500	
Liner Construction	$ 174,500	/ac	73.5	ac	$ 12,825,750	
Final Cover Construction	$ 132,400	/ac	81.0	ac	$ 10,724,400	
Post-Closure Care	$ 108,500	/yr	30.0	yr	$ 3,255,000	
Facility Design & Permitting (on construction)	10.0%	-	$ 26,204,650	LS	$ 2,620,465	
Construction Quality Assurance (on construction)	5.0%	-	$ 26,204,650	LS	$ 1,310,233	
GRE Internal Costs (on construction, design, CQA, & land purchase)	10.0%	-	$ 33,870,348	-	$ 3,387,000	
Project Contingency (on construction & land)	15.0%	-	$ 26,684,650	-	$ 4,003,000	
			Total Direct/Capital Costs		$ 41,260,348	
			Annualized Capital Cost*		$ 3,453,000	/yr
			Capital Costs		$ 6.58	/tn

Operational Costs

Hauling Costs	$ 2.14	/tn	525,000	tn/yr	$ 1,123,830	/yr
Placement Costs	$ 1.71	/tn	525,000	tn/yr	$ 897,273	/yr
Maintenance Costs	$ 396,000	/yr	1	yr	$ 396,000	/yr
			An. Operational Costs		$ 2,417,000	/yr
			Operational Costs		$ 4.60	/tn

TOTAL DISPOSAL COSTS

Annual Costs	$ 5,870,000	/yr
20-Year Total Costs	$ 117,400,000	
Per Ton Cost	$ 11.18	/tn

Notes:
*Annualized capital cost based on 20-year life and 5.5% interest rate.
All costs are in 2011 dollars.

Scenario C - Partial Fly Ash Sales with ASM

Project	113-82161
Date	11/15/2011
By	TJS
Checked	JJS

Sizing Information

Annual Fly Ash Disposal	234,500	tn	
20yr Fly Ash Disposal	4,690,000	tn	
Fly Ash Dry Density (in-situ)	90	pcf	
20yr Fly Ash Quantity	3,860,000	cy	
Lined Footprint	41.0	ac	94,000 cy/ac
Disturbance Footprint	54.0	ac	100' offset on liner footprint
Berm Length	5,500	ft	20' offset on liner footprint
Total Footprint	160		500' offset on liner footprint, nearest 1/8 section
Total Cover Area	45.0	ac	1.1 ration of cover area to liner area

Direct/Capital Costs

Item	**Rate**		**#**		**Total Cost**	
Land Acquisition	$ 2,000	/ac	160.0	ac	$ 320,000	
Infrastructure Development	$ 779,500	ea	1.0	LS	$ 779,500	
County Road Crossing	$ 1,730,500	ea	1.0	LS	$ 1,730,500	
Liner Construction	$ 175,600	/ac	41.0	ac	$ 7,199,600	
Final Cover Construction	$ 138,500	/ac	45.0	ac	$ 6,232,500	
Post-Closure Care	$ 72,500	/yr	30.0	yr	$ 2,175,000	
Facility Design & Permitting (on construction)	10.0%	-	$ 15,942,100	LS	$ 1,594,210	
Construction Quality Assurance (on construction)	5.0%	-	$ 15,942,100	LS	$ 797,105	
GRE Internal Costs (on construction, design, CQA, & land purchase)	10.0%	-	$ 20,828,415	-	$ 2,083,000	
Project Contingency (on construction & land)	15.0%	-	$ 16,262,100	-	$ 2,439,000	
			Total Direct/Capital Costs		$ 25,350,415	
			Annualized Capital Cost*		$ 2,121,000	/yr
			Capital Costs		$ 9.05	/tn

Operational Costs

Hauling Costs	$ 2.14	/tn	234,500	tn/yr	$ 501,977	/yr
Placement Costs	$ 1.71	/tn	234,500	tn/yr	$ 400,782	/yr
Maintenance Costs	$ 238,500	/yr	1	yr	$ 238,500	/yr
			An. Operational Costs		$ 1,141,000	/yr
			Operational Costs		$ 4.87	/tn

TOTAL DISPOSAL COSTS		
Annual Costs	$ 3,262,000	/yr
20-Year Total Costs	$ 65,240,000	
Per Ton Cost	$ 13.91	/tn

Notes:
*Annualized capital cost based on 20-year life and 5.5% interest rate.
All costs are in 2011 dollars.

ASM Post-Processing

Project	113-82161
Date	11/15/2011
By	REN
Checked	TJS

Sizing Information

Annual Fly Ash Sales 290,500 tn

Direct/Capital Costs

Item	**Rate**		**#**		**Total Cost**	
New Truck Load-out Silo	$ 1,568,500	ea	1.0	LS	$ 1,568,500	
Cal-Hypo Feed Systems (Rail silo)	$ 246,000	ea	1.0	LS	$ 246,000	
Cal-Hypo Feed Systems (New silo)	$ 328,500	ea	1.0	LS	$ 328,500	
System Design & Engineering (on construction)	10.0%	-	$ 2,143,000	-	$ 214,000	
GRE Internal Costs (on all)	10.0%	-	$ 2,357,000	-	$ 236,000	
Project Contingency (on construction)	15.0%	-	$ 2,143,000	-	$ 321,000	
			Total Direct/Capital Costs		$ 2,914,000	
			Annualized Capital Cost*		$ 244,000	/yr
			Capital Costs		$ 0.84	/tn

Operational Costs

Maintenance	$ 75.00	$/hr	4,600	hr	$ 345,000	/yr
Maintenance Materials	50%	-	$ 345,000	-	$ 172,500	/yr
Operations Materials	$ 75.00	$/hr	5,750	hr	$ 431,250	/yr
Operations Materials (Cal-Hypo)	$ 0.50	/tn	290,500	tn/yr	$ 145,250	/yr
Technology Royalty	$ 1.00	/tn	290,500	tn/yr	$ 290,500	/yr
			An. Operational Costs		$ 1,385,000	/yr
			Operational Costs		$ 4.77	/tn

TOTAL ASM COSTS

Annual Costs	$ 1,629,000	/yr
20-Year Total Costs	$ 32,580,000	
Per Ton Cost	$ 5.61	/tn

Notes:

*Annualized capital cost based on 20-year life and 5.5% interest rate.

Capital costs based on previous silo construction and discussions with Headwaters.

Assumed calcium hypo-chlorite cost of $1.00/lb.

Calcium hypo-chlorite mix rate is estimated between 0.3 and 1.3 lbs per 3,000 lbs of fly ash.

Scenario A (Current Sales) Unit Rate Details

PROJECT COMPONENT		QTY	UNIT	UNIT PRICE	TOTAL	Source	NOTES
Infrastructure Development				Total	$ 649,325	$ 649,500	
General							
	Mobilize/Demobilize	5%	%	$ -	$ 29,515		
	Miscellaneous Site Work & Materials	5%	%	$ -	$ 29,515		Erosion controls, offices, toilets, temporary roads, survey control, etc.
Civil							
	Road Topsoil Stripping and Stockpiling	7,778	CY	$ 2.21	$ 17,181	Ames 2005 construction bid	18" topsoil
	Access Road Construction	140,000	SF	$ 1.55	$ 217,101	RSMeans 2010 (01 55 23.50-0100)	8" Gravel temporary road ($13.55/SY = $1.51/sf), 4,000' x 35'
	Return Water Pipeline	2,640	LF	$ 41.52	$ 109,622	RSMeans 2008 (33 11 13.25-4160)	6" PVC, 3' deep
	Fence	8,090	LF	$ 23.66	$ 191,391	GRE Estimate	7' Chain link fence, GRE paid $22.30/ft in 2009
	Overhead Power (Plant to Landfill)	1	EA	$ 25,000	$ 25,000	Golder Estimate	$25,000 for 1/2 mile distribution w/ transformer
	Monitoring Well Installation	5	EA	$ 6,000	$ 30,000	Golder Estimate	
County Road Crossing				Total	$ 1,730,693	$ 1,730,500	
General							
	Mobilize/Demobilize	5%	%	$ -	$ 78,668		
	Misc. (erosion controls, toilets, etc)	5%	%	$ -	$ 78,668		Erosion controls, offices, toilets, temporary roads, survey control, etc.
Civil							
	Topsoil Stripping and Stockpiling	4,577	CY	$ 2.21	$ 10,111	Ames 2005 construction bid	18" topsoil
	Embankment Fill	35,591	CY	$ 3.59	$ 127,906	Northern 2006 construction bid	
	County Road Sub-Base Course	2,385	CY	$ 3.59	$ 8,572	Northern 2006 construction bid	2' Sub-base preparation
	County Road Base Course	32,200	SF	$ 1.55	$ 49,933	RSMeans 2010 (01 55 23.50-0100)	8" Gravel temporary road ($13.55/SY = $1.51/sf) 920' x35'
	Bridge Deck Construction	5,250	SF	$ 262	$ 1,376,836	2008 California DOT Average	150 ft bridge deck, 35 ft wide
Liner Construction				Total	$ 4,278,853	Cost Per Acre of Liner	$ 178,300
General							
	Mobilize/Demobilize	5%	%	$ -	$ 194,493		
	Miscellaneous Site Work & Materials	5%	%	$ -	$ 194,493		Erosion controls, offices, toilets, temporary roads, survey control, etc.
Civil							
	Clearing and Grubbing	35	AC	$ 6,077.00	$ 209,657	RSMeans 2010 (31 11 10.10-0200)	Clear & grub brush including stumps
	Topsoil Stripping & Stockpiling (18")	-	CY	$ 2.21		Ames 2005 construction bid	
		35	AC	$ 5,346	$ 184,429		
	Subgrade Cut to Stockpile	291,093	CY	$ 3.00	$ 873,280	Golder Estimate	10' across liner area: for liner, berms and cover
	Subgrade Cut/Embankment Fill	96,107	CY	$ 3.59	$ 345,383	Northern 2006 construction bid	612 ft2 cross section area
	Low Permeability Soil Liner (24")	-	CY	$ 4.32		Northern 2008 construction bid	
		24	AC	$ 13,927	$ 334,252		
	60-mil HDPE Liner	-	SF	$ 0.76		Northern 2008 construction bid	materials, waste, conformance testing, installation
		24	AC	$ 33,319	$ 799,666		
	Leachate Collection Layer, Sand (12")		CY	$ 25.00		Golder Estimate	
		24	AC	$ 40,333	$ 968,000		
	Protective Cover (3')	-	CY	$ 4.04		Northern 2008 construction bid	fly ash as protective cover
		6	AC	$ 19,569	$ 117,411		contractor place 25% (side slopes, haul routes)
Piping							
	LCS 4" Piping	4,475	LF	$ 5.25	$ 23,472	Northern 2008 construction bid	4" ADS N-12
	LCS 8" Piping	900	LF	$ 12.02	$ 10,818	Northern 2008 construction bid	8" ADS N-12
	LCS Sump/Riser	1	EA	$ 17,314	$ 17,314	Northern 2005 construction bid	
Equipment and Electrical							
	Power Posts at Pumps/Sumps	1	EA	$ 1,185	$ 1,185	RSMeans 2010 (26 24 16.30-0150)	Panelboard/utility box with outlets
	Collection pump	1	EA	$ 5,000	$ 5,000	Golder Estimate	

Scenario A (Current Sales) Unit Rate Details

PROJECT COMPONENT		QTY	UNIT	UNIT PRICE	TOTAL	Source	NOTES
Final Cover				Total	$ 3,790,408	Cost Per Acre of Cover	$ 143,000
General							
	Mobilize/Demobilize	5%	%	$ -	$ 172,291		
	Miscellaneous Site Work & Materials	5%	%	$ -	$ 172,291		Erosion controls, offices, toilets, temporary roads, survey control, etc.
Civil							
	Leveling Fill (6") & Compacted Fill (24")	-	CY	$ 3.59		Northern 2006 construction bid	
		27	AC	$ 14,495	$ 384,112		
	60-mil HDPE Liner	-	SF	$ 0.76		Northern 2008 construction bid	materials, waste, conformance testing, installation
		27	AC	$ 33,319	$ 882,965		
	Leachate Collection Layer, Sand (12")		CY	$ 25.00		Golder Estimate	
		27	AC	$ 40,333	$ 1,068,833		
	Growth Medium (18")		CY	$ 4.92		Northern 2010 construction bid	
		27	AC	$ 11,915	$ 315,738		
	Topsoil (6")		CY	$ 4.92		Same as Growth Medium	
		27	AC	$ 3,972	$ 105,246		
	Downchute Channels	57,600	SF	$ 10.82	$ 622,944	Northern 2010 construction bid	36' wide, 4 downchutes
	Seed and Mulch	27	AC	$ 2,490.11	$ 65,988	RSMeans 2010 (32 92 19.14-4600)	Slope mix, with mulch & fertilizer
Post Closure Care				Total	$ 50,020	$ 50,000	
	Groundwater Monitoring & Reporting	1	EA	$ 15,000	$ 15,000	Golder Estimate	$1,000 per well + $10,000 for the report
	Annual Site Inspection	1	EA	$ 1,060	$ 1,060	Golder Estimate	$1,000 per 25 acres
	Final Cover Repair	1	EA	$ 4,210	$ 4,210	Golder Estimate	2% of cover area, 12" growth medium/topsoil fill
	Seeding Repair	1	EA	$ 6,600	$ 6,600	Golder Estimate	10% of cover area
	Mowing and/or rodent, weed, & tree control	1	EA	$ 2,120	$ 2,120	Golder Estimate	$2,000 per 25 acres
	Surface Water Controls Maintenance	1	EA	$ 12,230	$ 12,230	Golder Estimate	1% of armored channel replaced + other repairs
	Gate and/or fence Maintenance	1	EA	$ 1,910	$ 1,910	Golder Estimate	1% of fence
	Recordkeeping	1	EA	$ 1,590	$ 1,590	Golder Estimate	$1,500 per 25 acres
	Direct Expenses	1	EA	$ 5,300	$ 5,300	Golder Estimate	$5,000 per 25 acres
Annual Operations & Maintenance Costs (not haul and place)				Total	$ 154,710	$ 154,500	
	Groundwater Monitoring & Reporting	1	EA	$ 15,000	$ 15,000	Golder Estimate	$1,000 per well + $10,000 for the report
	Annual Site Inspection	1	EA	$ 12,000	$ 12,000	Golder Estimate	$1,000 per 25 acres of liner per month
	Engineering Support	1	EA	$ 48,000	$ 48,000	Golder Estimate	$50,000 per 25 acres of liner
	Survey Control	1	EA	$ 25,000	$ 25,000	Golder Estimate	GPS unit(s), $25,000 per year
	Gate and/or fence Maintenance	1	EA	$ 1,910	$ 1,910	Golder Estimate	1% of fence
	Recordkeeping	1	EA	$ 4,800	$ 4,800	Golder Estimate	$5,000 per 25 acres
	Misc Work (contact water, dust, erosion, grading, etc)	1	EA	$ 48,000	$ 48,000	Golder Estimate	$50,000 per 25 acres
Haul & Place Costs							
	Haul Cost	1	CY	$ 2.14	$ 2.14	RSMeans 2010 (32 23 23.20-8180)	60cy Off-road, 20 min wait, 15 mph, 2 mile cycle
	Haul Cost	1	TON	$ 2.14	$ 2.14	Golder Estimate	75pcf haul density (1 ton/cy)
	Place Cost	1	CY	$ 1.42	$ 1.42	RSMeans 2010 (31 23 23.17-0020)	Dozer, no compaction
	Place Cost	1	TON	$ 1.71	$ 1.71	Golder Estimate	90pcf placed density (1.2 ton/cy)

Scenario B (No Sales) Unit Rate Details

PROJECT COMPONENT	QTY	UNIT	UNIT PRICE	TOTAL	Source	NOTES
Infrastructure Development			Total	$ 924,006	$ 924,000	
General						
Mobilize/Demobilize	5%	%	$ -	$ 42,000		
Miscellaneous Site Work & Materials	5%	%	$ -	$ 42,000		Erosion controls, offices, toilets, temporary roads, survey control, etc.
Civil						
Road Topsoil Stripping and Stockpiling	11,667	CY	$ 2.21	$ 25,772	Ames 2005 construction bid	18" topsoil
Access Road Construction	210,000	SF	$ 1.55	$ 325,652	RSMeans 2010 (01 55 23.50-0100)	8" Gravel temporary road ($13.55/SY = $1.51/sf), 6,000' x 35'
Return Water Pipeline	2,640	LF	$ 41.52	$ 109,622	RSMeans 2008 (33 11 13.25-4160)	6" PVC, 3' deep
Fence	11,157	LF	$ 23.66	$ 263,960	GRE Estimate	7' Chain link fence, GRE paid $22.30/ft in 2009
Overhead Power (Plant to Landfill)	1	EA	$ 25,000	$ 25,000	Golder Estimate	$25,000 for 1/2 mile distribution w/ transformer
Monitoring Well Installation	15	EA	$ 6,000	$ 90,000	Golder Estimate	
County Road Crossing			Total	$ 1,730,693	$ 1,730,500	
General						
Mobilize/Demobilize	5%	%	$ -	$ 78,668		
Misc. (erosion controls, toilets, etc)	5%	%	$ -	$ 78,668		Erosion controls, offices, toilets, temporary roads, survey control, etc.
Civil						
Topsoil Stripping and Stockpiling	4,577	CY	$ 2.21	$ 10,111	Ames 2005 construction bid	18" topsoil
Embankment Fill	35,591	CY	$ 3.59	$ 127,906	Northern 2006 construction bid	
County Road Sub-Base Course	2,385	CY	$ 3.59	$ 8,572	Northern 2006 construction bid	2' Sub-base preparation
County Road Base Course	32,200	SF	$ 1.55	$ 49,933	RSMeans 2010 (01 55 23.50-0100)	8" Gravel temporary road ($13.55/SY = $1.51/sf) 920' x35'
Bridge Deck Construction	5,250	SF	$ 262	$ 1,376,836	2008 California DOT Average	150 ft bridge deck, 35 ft wide
Liner Construction			Total	$ 12,827,387	Cost Per Acre of Liner	$ 174,500
General						
Mobilize/Demobilize	5%	%	$ -	$ 583,063		
Miscellaneous Site Work & Materials	5%	%	$ -	$ 583,063		Erosion controls, offices, toilets, temporary roads, survey control, etc.
Civil						
Clearing and Grubbing	91	AC	$ 6,077.00	$ 553,007	RSMeans 2010 (31 11 10.10-0200)	Clear & grub brush including stumps
Topsoil Stripping & Stockpiling (18")	-	CY	$ 2.21		Ames 2005 construction bid	
	91	AC	$ 5,346	$ 486,465		
Subgrade Cut to Stockpile	1,019,880	CY	$ 3.00	$ 3,059,640	Golder Estimate	10' across liner area: for liner, berms and cover
Subgrade Cut/Embankment Fill	165,920	CY	$ 3.59	$ 596,275	Northern 2006 construction bid	612 ft2 cross section area
Low Permeability Soil Liner (24")	-	CY	$ 4.32		Northern 2008 construction bid	
	74	AC	$ 13,927	$ 1,023,647		
60-mil HDPE Liner	-	SF	$ 0.76		Northern 2008 construction bid	materials, waste, conformance testing, installation
	74	AC	$ 33,319	$ 2,448,978		
Leachate Collection Layer, Sand (12")		CY	$ 25.00		Golder Estimate	
	74	AC	$ 40,333	$ 2,964,500		
Protective Cover (3')	-	CY	$ 4.04		Northern 2008 construction bid	fly ash as protective cover
	18	AC	$ 19,569	$ 359,572		contractor place 25% (side slopes, haul routes)
Piping						
LCS 4" Piping	15,640	LF	$ 5.25	$ 82,033	Northern 2008 construction bid	4" ADS N-12
LCS 8" Piping	3,340	LF	$ 12.02	$ 40,147	Northern 2008 construction bid	8" ADS N-12
LCS Sump/Riser	2	EA	$ 17,314	$ 34,628	Northern 2005 construction bid	
Equipment and Electrical						
Power Posts at Pumps/Sumps	2	EA	$ 1,185	$ 2,369	RSMeans 2010 (26 24 16.30-0150)	Panelboard/utility box with outlets
Collection pump	2	EA	$ 5,000	$ 10,000	Golder Estimate	

Scenario B (No Sales) Unit Rate Details

PROJECT COMPONENT		QTY	UNIT	UNIT PRICE	TOTAL	Source	NOTES
Final Cover				Total	$ 10,724,703	Cost Per Acre of Cover	$ 132,400
General							
	Mobilize/Demobilize	5%	%	$ -	$ 487,486		
	Miscellaneous Site Work & Materials	5%	%	$ -	$ 487,486		Erosion controls, offices, toilets, temporary roads, survey control, etc.
Civil							
	Leveling Fill (6") & Compacted Fill (24")	-	CY	$ 3.59		Northern 2006 construction bid	
		81	AC	$ 14,495	$ 1,174,078		
	60-mil HDPE Liner	-	SF	$ 0.76		Northern 2008 construction bid	materials, waste, conformance testing, installation
		81	AC	$ 33,319	$ 2,698,874		
	Leachate Collection Layer, Sand (12")		CY	$ 25.00		Golder Estimate	
		81	AC	$ 40,333	$ 3,267,000		
	Growth Medium (18")		CY	$ 4.92		Northern 2010 construction bid	
		81	AC	$ 11,915	$ 965,085		
	Topsoil (6")		CY	$ 4.92		Same as Growth Medium	
		81	AC	$ 3,972	$ 321,695		
	Downchute Channels	103,680	SF	$ 10.82	$ 1,121,299	Northern 2010 construction bid	36' wide, 4 downchutes
	Seed and Mulch	81	AC	$ 2,490.11	$ 201,699	RSMeans 2010 (32 92 19.14-4600)	Slope mix, with mulch & fertilizer
Post Closure Care				Total	$ 108,670	$ 108,500	
	Groundwater Monitoring & Reporting	1	EA	$ 25,000	$ 25,000	Golder Estimate	$1,000 per well + $10,000 for the report
	Annual Site Inspection	1	EA	$ 3,240	$ 3,240	Golder Estimate	$1,000 per 25 acres
	Final Cover Repair	1	EA	$ 12,870	$ 12,870	Golder Estimate	2% of cover area, 12" growth medium/topsoil fill
	Seeding Repair	1	EA	$ 20,170	$ 20,170	Golder Estimate	10% of cover area
	Mowing and/or rodent, weed, & tree control	1	EA	$ 6,480	$ 6,480	Golder Estimate	$2,000 per 25 acres
	Surface Water Controls Maintenance	1	EA	$ 17,210	$ 17,210	Golder Estimate	1% of armored channel replaced + other repairs
	Gate and/or fence Maintenance	1	EA	$ 2,640	$ 2,640	Golder Estimate	1% of fence
	Recordkeeping	1	EA	$ 4,860	$ 4,860	Golder Estimate	$1,500 per 25 acres
	Direct Expenses	1	EA	$ 16,200	$ 16,200	Golder Estimate	$5,000 per 25 acres
Annual Operations & Maintenance Costs (not haul and place)				Total	$ 396,140	$ 396,000	
	Groundwater Monitoring & Reporting	1	EA	$ 25,000	$ 25,000	Golder Estimate	$1,000 per well + $10,000 for the report
	Annual Site Inspection	1	EA	$ 34,800	$ 34,800	Golder Estimate	$1,000 per 25 acres of liner per month
	Engineering Support	1	EA	$ 147,000	$ 147,000	Golder Estimate	$50,000 per 25 acres of liner
	Survey Control	1	EA	$ 25,000	$ 25,000	Golder Estimate	GPS unit(s), $25,000 per year
	Gate and/or fence Maintenance	1	EA	$ 2,640	$ 2,640	Golder Estimate	1% of fence
	Recordkeeping	1	EA	$ 14,700	$ 14,700	Golder Estimate	$5,000 per 25 acres
	Misc Work (contact water, dust, erosion, grading, etc)	1	EA	$ 147,000	$ 147,000	Golder Estimate	$50,000 per 25 acres
Haul & Place Costs							
	Haul Cost	1	CY	$ 2.14	$ 2.14	RSMeans 2010 (32 23 23.20-8180)	60cy Off-road, 20 min wait, 15 mph, 2 mile cycle
	Haul Cost	1	TON	$ 2.14	$ 2.14	Golder Estimate	75pcf haul density (1 ton/cy)
	Place Cost	1	CY	$ 1.42	$ 1.42	RSMeans 2010 (31 23 23.17-0020)	Dozer, no compaction
	Place Cost	1	TON	$ 1.71	$ 1.71	Golder Estimate	90pcf placed density (1.2 ton/cy)

Scenario C (Reduced Sales with ASM) Unit Rate Details

PROJECT COMPONENT	QTY	UNIT	UNIT PRICE	TOTAL	Source	NOTES
Infrastructure Development			Total	$ 779,431	$ 779,500	
General						
Mobilize/Demobilize	5%	%	$ -	$ 35,429		
Miscellaneous Site Work & Materials	5%	%	$ -	$ 35,429		Erosion controls, offices, toilets, temporary roads, survey control, etc.
Civil						
Road Topsoil Stripping and Stockpiling	9,722	CY	$ 2.21	$ 21,476	Ames 2005 construction bid	18" topsoil
Access Road Construction	175,000	SF	$ 1.55	$ 271,376	RSMeans 2010 (01 55 23.50-0100)	8" Gravel temporary road ($13.55/SY = $1.51/sf), 5,000' x 35'
Return Water Pipeline	2,640	LF	$ 41.52	$ 109,622	RSMeans 2008 (33 11 13.25-4160)	6" PVC, 3' deep
Fence	9,346	LF	$ 23.66	$ 221,099	GRE Estimate	7' Chain link fence, GRE paid $22.30/ft in 2009
Overhead Power (Plant to Landfill)	1	EA	$ 25,000	$ 25,000	Golder Estimate	$25,000 for 1/2 mile distribution w/ transformer
Monitoring Well Installation	10	EA	$ 6,000	$ 60,000	Golder Estimate	
County Road Crossing			Total	$ 1,730,693	$ 1,730,500	
General						
Mobilize/Demobilize	5%	%	$ -	$ 78,668		
Misc. (erosion controls, toilets, etc)	5%	%	$ -	$ 78,668		Erosion controls, offices, toilets, temporary roads, survey control, etc.
Civil						
Topsoil Stripping and Stockpiling	4,577	CY	$ 2.21	$ 10,111	Ames 2005 construction bid	18" topsoil
Embankment Fill	35,591	CY	$ 3.59	$ 127,906	Northern 2006 construction bid	
County Road Sub-Base Course	2,385	CY	$ 3.59	$ 8,572	Northern 2006 construction bid	2' Sub-base preparation
County Road Base Course	32,200	SF	$ 1.55	$ 49,933	RSMeans 2010 (01 55 23.50-0100)	8" Gravel temporary road ($13.55/SY = $1.51/sf) 920' x35'
Bridge Deck Construction	5,250	SF	$ 262	$ 1,376,836	2008 California DOT Average	150 ft bridge deck, 35 ft wide
Liner Construction			Total	$ 7,200,075	Cost Per Acre of Liner	$ 175,600
General						
Mobilize/Demobilize	5%	%	$ -	$ 327,276		
Miscellaneous Site Work & Materials	5%	%	$ -	$ 327,276		Erosion controls, offices, toilets, temporary roads, survey control, etc.
Civil						
Clearing and Grubbing	54	AC	$ 6,077.00	$ 328,158	RSMeans 2010 (31 11 10.10-0200)	Clear & grub brush including stumps
Topsoil Stripping & Stockpiling (18")	-	CY	$ 2.21		Ames 2005 construction bid	
	54	AC	$ 5,346	$ 288,672		
Subgrade Cut to Stockpile	536,800	CY	$ 3.00	$ 1,610,400	Golder Estimate	10' across liner area: for liner, berms and cover
Subgrade Cut/Embankment Fill	124,667	CY	$ 3.59	$ 448,021	Northern 2006 construction bid	612 ft2 cross section area
Low Permeability Soil Liner (24")	-	CY	$ 4.32		Northern 2008 construction bid	
	41	AC	$ 13,927	$ 571,014		
60-mil HDPE Liner	-	SF	$ 0.76		Northern 2008 construction bid	materials, waste, conformance testing, installation
	41	AC	$ 33,319	$ 1,366,097		
Leachate Collection Layer, Sand (12")		CY	$ 25.00		Golder Estimate	
	41	AC	$ 40,333	$ 1,653,667		
Protective Cover (3')	-	CY	$ 4.04		Northern 2008 construction bid	fly ash as protective cover
	10	AC	$ 19,569	$ 200,578		contractor place 25% (side slopes, haul routes)
Piping						
LCS 4" Piping	7,770	LF	$ 5.25	$ 40,754	Northern 2008 construction bid	4" ADS N-12
LCS 8" Piping	1,220	LF	$ 12.02	$ 14,664	Northern 2008 construction bid	8" ADS N-12
LCS Sump/Riser	1	EA	$ 17,314	$ 17,314	Northern 2005 construction bid	
Equipment and Electrical						
Power Posts at Pumps/Sumps	1	EA	$ 1,185	$ 1,185	RSMeans 2010 (26 24 16.30-0150)	Panelboard/utility box with outlets
Collection pump	1	EA	$ 5,000	$ 5,000	Golder Estimate	

Scenario C (Reduced Sales with ASM) Unit Rate Details

PROJECT COMPONENT	QTY	UNIT	UNIT PRICE	TOTAL	Source	NOTES
Final Cover			Total	$ 6,232,264	Cost Per Acre of Cover	$ 138,500
General						
Mobilize/Demobilize	5%	%	$ -	$ 283,285		
Miscellaneous Site Work & Materials	5%	%	$ -	$ 283,285		Erosion controls, offices, toilets, temporary roads, survey control, etc.
Civil						
Leveling Fill (6") & Compacted Fill (24")	-	CY	$ 3.59		Northern 2006 construction bid	
	45	AC	$ 14,495	$ 652,266		
60-mil HDPE Liner	-	SF	$ 0.76		Northern 2008 construction bid	materials, waste, conformance testing, installation
	45	AC	$ 33,319	$ 1,499,374		
Leachate Collection Layer, Sand (12")		CY	$ 25.00		Golder Estimate	
	45	AC	$ 40,333	$ 1,815,000		
Growth Medium (18")		CY	$ 4.92		Northern 2010 construction bid	
	45	AC	$ 11,915	$ 536,158		
Topsoil (6")		CY	$ 4.92		Same as Growth Medium	
	45	AC	$ 3,972	$ 178,719		
Downchute Channels	80,640	SF	$ 10.82	$ 872,122	Northern 2010 construction bid	36' wide, 4 downchutes
Seed and Mulch	45	AC	$ 2,490.11	$ 112,055	RSMeans 2010 (32 92 19.14-4600)	Slope mix, with mulch & fertilizer
Post Closure Care			Total	$ 72,390	$ 72,500	
Groundwater Monitoring & Reporting	1	EA	$ 20,000	$ 20,000	Golder Estimate	$1,000 per well + $10,000 for the report
Annual Site Inspection	1	EA	$ 1,800	$ 1,800	Golder Estimate	$1,000 per 25 acres
Final Cover Repair	1	EA	$ 7,150	$ 7,150	Golder Estimate	2% of cover area, 12" growth medium/topsoil fill
Seeding Repair	1	EA	$ 11,210	$ 11,210	Golder Estimate	10% of cover area
Mowing and/or rodent, weed, & tree control	1	EA	$ 3,600	$ 3,600	Golder Estimate	$2,000 per 25 acres
Surface Water Controls Maintenance	1	EA	$ 14,720	$ 14,720	Golder Estimate	1% of armored channel replaced + other repairs
Gate and/or fence Maintenance	1	EA	$ 2,210	$ 2,210	Golder Estimate	1% of fence
Recordkeeping	1	EA	$ 2,700	$ 2,700	Golder Estimate	$1,500 per 25 acres
Direct Expenses	1	EA	$ 9,000	$ 9,000	Golder Estimate	$5,000 per 25 acres
Annual Operations & Maintenance Costs (not haul and place)			Total	$ 238,610	$ 238,500	
Groundwater Monitoring & Reporting	1	EA	$ 20,000	$ 20,000	Golder Estimate	$1,000 per well + $10,000 for the report
Annual Site Inspection	1	EA	$ 19,200	$ 19,200	Golder Estimate	$1,000 per 25 acres of liner per month
Engineering Support	1	EA	$ 82,000	$ 82,000	Golder Estimate	$50,000 per 25 acres of liner
Survey Control	1	EA	$ 25,000	$ 25,000	Golder Estimate	GPS unit(s), $25,000 per year
Gate and/or fence Maintenance	1	EA	$ 2,210	$ 2,210	Golder Estimate	1% of fence
Recordkeeping	1	EA	$ 8,200	$ 8,200	Golder Estimate	$5,000 per 25 acres
Misc Work (contact water, dust, erosion, grading, etc)	1	EA	$ 82,000	$ 82,000	Golder Estimate	$50,000 per 25 acres
Haul & Place Costs						
Haul Cost	1	CY	$ 2.14	$ 2.14	RSMeans 2010 (32 23 23.20-8180)	60cy Off-road, 20 min wait, 15 mph, 2 mile cycle
Haul Cost	1	TON	$ 2.14	$ 2.14	Golder Estimate	75pcf haul density (1 ton/cy)
Place Cost	1	CY	$ 1.42	$ 1.42	RSMeans 2010 (31 23 23.17-0020)	Dozer, no compaction
Place Cost	1	TON	$ 1.71	$ 1.71	Golder Estimate	90pcf placed density (1.2 ton/cy)

ASM Unit Rate Details

PROJECT COMPONENT	QTY	UNIT OF MEASURE	UNIT PRICE	TOTAL	Source	NOTES
New Silo			Total	$ 1,568,494	**$ 1,568,500**	
Miscellaneous Site Work & Materials	10%	%	$ -	$ 142,590		Erosion controls, offices, toilets, temporary roads, survey control, etc.
Silo slab on grade	1	EA	$ 536,796	$ 536,796	2003 Irondale CO Unit less RR & land	Site prep, silo & handling equipment, permit
Starvac reclaimer	1	EA	$ 83,455	$ 83,455		
Truck scale	1	EA	$ 81,474	$ 81,474		Beside the silo on grade
Screw conveyor	1	EA	$ 24,626	$ 24,626		From Starvac reclaimer to bucket elevator
Bucket Elevator	1	EA	$ 88,927	$ 88,927		From screw conveyor to overhead airslide
Air Slide	1	EA	$ 26,906	$ 26,906		From bucket elevator to new weigh hopper
Truck load-out spout	1	EA	$ 45,604	$ 45,604		From new weigh hopper to truck
Building	1	EA	$ 11,401	$ 11,401		With scales and ASM controls
Feed piping & valves	1	EA	$ 329,202	$ 329,202	Golder Estimate	From each of the four fly ash conveying lines
Dust collectors	1	EA	$ 197,512	$ 197,512	Golder Estimate	Higher capacity to handle high air flow from ESP
Cal-Hypo Feed System (Rail Load-out Silo)			Total	$ 245,960	**$ 246,000**	
Miscellaneous Site Work & Materials	10%	%	$ -	$ 22,360		
Storage & Conveying Building	1,000	SF	$ 50.00	$ 50,000	GRE 2009 Construction Project	$35/sf for large insulated bldg, use $50/sf
Building Foundation	62	CY	$ 300.00	$ 18,600	Worley Parsons Jul09	12' x 40' x 1' thick plus 1' x 5' perimeter
Day Storage Hopper	1	EA	$ 15,000	$ 15,000	Golder Estimate	On the silo weigh bin floor
Conveying System	1	EA	$ 20,000	$ 20,000	Golder Estimate	From stroage building to the day storage hopper
Variable speed conveyor	1	EA	$ 20,000	$ 20,000	Golder Estimate	To feed cal-hypo into the existing weigh hopper
ASM System Controls	1	EA	$ 100,000	$ 100,000	Golder Estimate	
Cal-Hypo Feed System (New Truck Load-out Silo)			Total	$ 328,460	**$ 328,500**	
Miscellaneous Site Work & Materials	10%	%	$ -	$ 29,860		
Weigh Hopper	1	EA	$ 75,000	$ 75,000	Golder Estimate	Above truck load-out spout
Storage & Conveying Building	1,000	SF	$ 50.00	$ 50,000	GRE 2009 Construction Project	$35/sf for large insulated bldg, use $50/sf for 25'x40
Building Foundation	62	CY	$ 300.00	$ 18,600	Worley Parsons Jul09	25' x 40' x 1' thick plus 1' x 5' perimeter
Day Storage Hopper	1	EA	$ 15,000	$ 15,000	Golder Estimate	On the silo weigh bin floor
Conveying System	1	EA	$ 20,000	$ 20,000	Golder Estimate	From stroage building to the day storage hopper
Variable speed conveyor	1	EA	$ 20,000	$ 20,000	Golder Estimate	To feed cal-hypo into the existing weigh hopper
ASM System Controls	1	EA	$ 100,000	$ 100,000	Golder Estimate	

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Appendix D

Visibility Impact Tables

Summary of Modeling Inputs

Description		Emission Rate Input										
		Stack Velocity	Stack Height	PM10		PM2.5 (fine)	PM (coarse)	SO_2		NOx		
NOx Control	Units	m/s (ft/s)	m (ft)	% reduction	lb/hr	lb/hr	lb/hr	% reduction	lb/hr	% reduction	lb/hr	30-Day Rolling lb/MMBtu
Pre-BART Protocol	1	25.9 (85)	201.0 (659.4)	NA - base	249.2	101.9	147.3	NA - base	5733.5	NA - base	1772.3	NA - base
	1& 2	25.9 (85)	201.0 (659.4)	NA - base	465.3	190.3	275.0	NA - base	10702.8	NA - base	3594.7	NA - base
LNC3+	1	19.5 (64)	208.2 (682.7)	0%	249.2	101.9	147.3	69%	1756.4	31%	1227.6	0.187
	1& 2	19.5 (64)	208.2 (682.7)	0%	465.3	190.3	275.0	67%	3514.8	32%	2456.5	0.187
LNC3+ with Tuning	1	19.5 (64)	208.2 (682.7)	0%	249.2	101.9	147.3	69%	1756.4	38%	1104.4	0.168
	1& 2	19.5 (64)	208.2 (682.7)	0%	465.3	190.3	275.0	67%	3514.8	39%	2210.0	0.168
SNCR	1	19.5 (64)	208.2 (682.7)	0%	249.2	101.9	147.3	69%	1756.4	39%	1082.7	0.165
	1 & 2	19.5 (64)	208.2 (682.7)	0%	465.3	190.3	275.0	67%	3514.8	40%	2166.7	0.165
SNCR with LNC3+	1	19.5 (64)	208.2 (682.7)	0%	249.2	101.9	147.3	69%	1756.4	50%	880.6	0.134
	1& 2	19.5 (64)	208.2 (682.7)	0%	465.3	190.3	275.0	67%	3514.8	51%	1762.2	0.134

Year 2000 Modeling Results

Description		Average Improvement (98th%)	Visibility Impairment											
			TRNP South Unit			TRNP North Unit			TRNP Elkhorn Ranch			Lostwood WA		
NOx Control	Units		Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV	Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV	Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV	Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV
Pre-BART Protocol	1	--	24	0.299	1.229	21	0.318	0.941	18	0.212	0.777	37	0.503	1.183
	1& 2	--	41	0.553	2.176	41	0.586	1.836	35	0.401	1.391	58	0.945	2.157
LNC3+	1	60%	7	0.124	0.495	6	0.117	0.376	2	0.088	0.321	6	0.219	0.445
	1& 2	57%	17	0.243	0.965	17	0.232	0.778	10	0.175	0.632	28	0.427	0.884
LNC3+ with Tuning	1	62%	7	0.117	0.472	6	0.115	0.354	2	0.084	0.311	6	0.207	0.428
	1& 2	59%	17	0.231	0.922	17	0.228	0.743	10	0.167	0.608	26	0.407	0.844
SNCR	1	62%	7	0.116	0.468	6	0.114	0.351	2	0.084	0.308	6	0.204	0.427
	1 & 2	59%	16	0.229	0.914	17	0.227	0.736	10	0.167	0.602	26	0.404	0.837
SNCR with LNC3+	1	65%	7	0.110	0.431	6	0.111	0.315	2	0.076	0.280	4	0.187	0.415
	1& 2	62%	16	0.218	0.842	13	0.220	0.667	10	0.150	0.549	25	0.367	0.810

Year 2001 Modeling Results

Description		Average Improvement (98th%)	Visibility Impairment											
			TRNP South Unit			TRNP North Unit			TRNP Elkhorn Ranch			Lostwood WA		
NOx Control	Units		Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV	Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV	Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV	Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV
Pre-BART Protocol	1	--	21	0.251	1.209	27	0.372	1.154	16	0.192	1.056	40	0.522	2.362
	1& 2	--	34	0.466	2.181	46	0.694	2.094	27	0.365	1.949	56	0.984	4.038
LNC3+	1	58%	7	0.097	0.498	7	0.129	0.470	7	0.076	0.478	18	0.221	0.971
	1& 2	54%	19	0.193	0.974	22	0.255	0.918	15	0.152	0.937	31	0.437	1.855
LNC3+ with Tuning	1	60%	7	0.096	0.477	6	0.126	0.452	5	0.075	0.449	17	0.211	0.943
	1& 2	56%	19	0.191	0.933	21	0.251	0.883	13	0.149	0.880	30	0.418	1.803
SNCR	1	60%	7	0.097	0.473	6	0.126	0.449	5	0.075	0.444	17	0.209	0.938
	1 & 2	56%	19	0.191	0.926	21	0.250	0.877	13	0.149	0.870	30	0.414	1.794
SNCR with LNC3+	1	63%	5	0.090	0.438	6	0.125	0.419	4	0.071	0.395	15	0.193	0.892
	1& 2	59%	18	0.179	0.859	18	0.247	0.822	10	0.142	0.776	30	0.382	1.709

Year 2002 Modeling Results

Description		Average Improvement (98th%)	Visibility Impairment											
			TRNP South Unit			TRNP North Unit			TRNP Elkhorn Ranch			Lostwood WA		
NOx Control	Units		Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV	Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV	Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV	Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV
Pre-BART Protocol	1	--	38	0.540	2.559	30	0.385	2.113	23	0.310	1.703	32	0.385	1.814
	1& 2	--	50	0.971	4.475	45	0.706	3.557	42	0.581	3.039	45	0.707	3.190
LNC3+	1	55%	22	0.210	1.096	15	0.147	0.967	13	0.140	0.840	12	0.143	0.806
	1& 2	50%	33	0.422	2.109	24	0.291	1.850	19	0.277	1.609	24	0.284	1.547
LNC3+ with Tuning	1	57%	20	0.202	1.040	14	0.144	0.910	13	0.132	0.795	12	0.139	0.763
	1& 2	53%	32	0.407	2.006	23	0.283	1.745	19	0.261	1.524	24	0.275	1.466
SNCR	1	58%	20	0.201	1.030	14	0.143	0.899	13	0.131	0.787	12	0.138	0.755
	1 & 2	53%	32	0.405	1.987	23	0.283	1.726	19	0.258	1.510	24	0.275	1.452
SNCR with LNC3+	1	62%	20	0.189	0.936	14	0.138	0.804	12	0.117	0.711	12	0.134	0.683
	1& 2	58%	30	0.381	1.814	23	0.269	1.550	18	0.232	1.369	24	0.266	1.319

Average Incremental Control Comparison for 98th % Δ-dV

Description		Year 2000			Year 2001			Year 2002			Year 2000-2002 Average		
NOx Control	Units	Average Impairment	Improvement from Protocol	Incremental Improvement [1]	Average Impairment	Improvement from Protocol	Incremental Improvement [1]	Average Impairment	Improvement from Protocol	Incremental Improvement [1]	Average Impairment	Improvement from Protocol	Incremental Improvement [1]
Pre-BART Protocol	1	1.033	NA	NA	1.445	NA	NA	2.047	NA	NA	1.508	NA	NA
	1& 2	1.890	NA	NA	2.566	NA	NA	3.565	NA	NA	2.674	NA	NA
LNC3+	1	0.409	0.623	0.623	0.604	0.841	0.841	0.927	1.120	1.120	0.647	0.861	0.861
	1& 2	0.815	1.075	1.075	1.171	1.395	1.395	1.779	1.787	1.787	1.255	1.419	1.419
LNC3+ with Tuning	1	0.391	0.641	0.018	0.580	0.865	0.024	0.877	1.170	0.050	0.616	0.892	0.031
	1& 2	0.779	1.111	0.036	1.125	1.441	0.046	1.685	1.880	0.093	1.196	1.477	0.058
SNCR	1	0.389	0.644	0.003	0.576	0.869	0.004	0.868	1.180	0.009	0.611	0.898	0.005
	1 & 2	0.772	1.118	0.007	1.117	1.449	0.008	1.669	1.897	0.017	1.186	1.488	0.011
SNCR with LNC3+	1	0.360	0.672	0.028	0.536	0.909	0.040	0.784	1.264	0.084	0.560	0.948	0.051
	1& 2	0.717	1.173	0.055	1.042	1.524	0.075	1.513	2.052	0.156	1.091	1.583	0.095

[1] Average incremental improvement as compared to the next highest emission rate; not necessarily a reflection of physical control option (e.g. SNCR alone is not a feasible option for Unit 2 because LNC3+ has already been installed. This scenario would require removal of LNC3+ on Unit 2 to be achieved.)

Appendix E

Low-Baseline NOx SNCR Demonstration (EPRI Study)

This appendix contains confidential business information and is being submitted under separate seal.
Copyrighted material is not currently available for public release.

Appendix F

URS SNCR Evaluation Supplement

URS

March 30, 2012

Debra Nelson
Great River Energy
12300 Elm Creek Boulevard
Maple Grove, MN 55369

RE: URS Response to EPA FIP Exchange

Dear Debra:

Great River Energy (GRE) contracted URS Energy & Construction (URS) to conduct a review of the costs and performance capability of Selective Non-Catalytic Reduction (SNCR) at their Coal Creek Station (CCS) Units 1 & 2. This review was requested to provide:

- A site-specific rough order of magnitude estimate with a stated accuracy of ±30% for the 2011 capital cost required for installation of SNCR onto the Coal Creek units
- Site-specific operating and maintenance costs for SNCR operation at Coal Creek
- The level of NOx reduction expected when using SNCR on these units.

Cost Estimating Methodology - The basis for the cost estimates was stated to be the EPRI IECCOST model, which URS previously developed for the Electric Power Research Institute. This model provides site-specific cost estimates for all types of emissions control system installations, including individual systems that are designed to remove SO_2, NOx, Hg, and particulate matter. It also evaluates costs for multi-pollutant control systems, producing conceptual cost estimates that are site-specific based on the plant location, current operating characteristics, fuels burned, etc.

EPRI IECCOST Model development has continued for more than ten years; during that period URS has installed all of the commercial systems at utility installations, and become intimately familiar with all emissions control technologies. Consequently URS is very familiar with the relationship between the vendor island costs and the Total Capital Requirement for an emissions control retrofit. This extensive project experience also identified the performance capabilities and emission rate guarantees for the various technologies through review of bid documents and budgetary quote submittals under real world conditions.

The model is updated and escalated continuously as new projects are completed, calibrating the cost estimating results against actual project costs and performance. The economic model used for these calculations is IECCOST Version 3.1 that will be published by EPRI later in 2012.

URS Capabilities and Qualifications - URS is an engineering and construction company that has provided emissions control technology assessments, economic analyses, balance of plant designs, construction, construction management and startup assistance to utility and other industrial clients since the 1970's. During this period, URS participated in more than 30 SNCR projects at multiple sites using systems supplied by multiple vendors.

Total Capital Requirement Cost Estimates - URS is not a technology supplier. The supplier is typically responsible for installation of only their process island and system performance guarantees. The installation of the balance of plant (BOP) equipment, construction management, foundations, utility tie-ins (electrical, water, air, instrumentation and controls interface,

interconnecting piping, new flue gas emissions monitoring equipment, boiler and air heater modifications, retrofit difficulty due to existing plant access and congestion issues, et al) typically falls outside of the scope of supply for the SNCR vendor. Published cost estimates and vendor proposals in many cases do not consider these BOP cost impacts on the Total Capital Requirement for the installation of emissions control equipment. URS's project experience provides a basis for the assessment of these BOP costs that must be added to the vendor supplied equipment's installed costs to determine the true total capital cost of an installation.

<u>Retrofit Factor</u> - A site visit was made to the Coal Creek plant by one of the URS air quality control engineering staff. Based on his assessment of the site and the location for installation of the SNCR equipment, the retrofit difficulty for this plant was established to be moderately difficult due the constraints provided by existing equipment at the plant. Based on previous industry assessments of the cost impacts of retrofit difficulty, a retrofit factor of 1.6 was established for this moderately difficult SNCR installation. Previous industry surveys by Radian and Kellogg (EPA-450/3-74-015 – "Factors Affecting Ability to Retrofit FGD Systems" & EPA R2-72-100 – "Applicability of SO_2-Control Processes to Power Plants" and the EPA/600/S7-90/008 – "Verification of Simplified Procedure for Site-Specific SO_2 and NOx Control Cost Estimates") attempted to quantify the retrofit cost impacts compared to new equipment installations. These surveys established retrofit factors based on retrofit difficulty that are multiplied times the new plant installed cost estimates to determine the retrofit installed cost. The site assessment by the URS staff resulted in the moderately difficult retrofit assessment, which was translated in the capital cost estimate as a 60% adder to the new equipment installation cost to account for decreasing productivity due to movement of parts and materials around existing equipment and structures, limited access to construction sites due to overhead, underground and side obstructions by existing equipment, crane access, etc.

<u>SNCR Expected Performance</u> – SNCR system performance is directly impacted by the flue gas temperature at the point of urea/ammonia injection, and by the current concentration of NOx in the outlet flue gas. Injection outside the correct temperature window results in significant reductions in reduction efficiency. The lower the current NOx concentration in the outlet flue gas, the lower the reduction efficiency that can be achieved (reduced driving force for the NOx reduction reactions). The performance claims in published articles are typically short term, optimized test results, and are typically inflated compared to the performance guarantees that are actually offered for actual installations. Given the relatively low NOx concentrations in the Coal Creek flue gas, the reduction capabilities of SNCR were set at values in the 20-30% range based on data from other recent projects. The urea feed rate used in the calculation of operating costs

For comparison, recent FuelTech papers (one of the major SNCR vendors) stated that larger utility boilers (such as exist at Coal Creek at 605MW) have reported lower performance mainly due to the size of the units, inaccessible areas for injection, and load following control issues. NOx reductions in the range of 20 – 30% are common for units that start with NOx emission rates of 0.15-0.25 lbs NOx/MMBtu. Urea injection rates to obtain these reduction efficiencies varied from site to site, but fell in the range of 1.1-1.5 normalized stoichiometric ratio while maintaining acceptable ammonia slip rates. All-in costs for these systems were stated to be in the range of $10-20/kW. The injection rates assumed for this URS analysis of SNCR for Coal Creek used NSR injection rates that varied from 1.3-1.5 over the range of control evaluated of 20-30% NOx reduction. All of these performance values and estimated capital costs fall in the ranges stated in the supplier papers.

If you have any additional questions, please contact me.

Sincerely,

Robert J. Keeth
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URS Energy & Construction, Inc.
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303-843-379
robert.keeth@urs.com

Appendix G

Golder Fly Ash Evaluation Supplement

April 2, 2012 Project No. 113-82161

Diane Stockdill
Great River Energy
Coal Creek Station
2875 Third Street SW
Underwood, North Dakota 58576

RE: SNCR IMPACT TO FLY ASH MARKETABILITY AND MANAGEMENT COSTS

Dear Diane:

1.0 BACKGROUND

Golder Associates Inc. (Golder) submitted a report to Great River Energy (GRE) on November 15, 2011, providing a third party review of Headwater's ammonia slip mitigation (ASM) technology. Additionally, the review included a detailed engineering estimate of potential disposal costs associated with fly ash impacted by ammonia slip from selective non-catalytic reduction (SNCR) emission controls at GRE's Coal Creek Station (CCS).

This report was included as part of GRE's submittal of November 21, 2011 to the U.S. EPA Region 8 (EPA), with comments responding to the Proposed Rule for the Approval and Promulgation of Implementation Plans: North Dakota Regional Haze State Implementation Plan, Federal Implementation Plan for Interstate Transport of Pollution Affecting Visibility and Regional Haze (Docket ID No. EPA-R08-OAR-2010-0406).

The EPA provided a prepublication version of the "final rule" to GRE on March 2, 2012, which included EPA's response to various comments including those in GRE's November 21, 2011 submittal:

- Section V: Issues Raised by Commenters and EPA's Responses;
- Part E: Comments on BART Determination;
- Subpart 2: CCS Units 1 and 2;
- Item d: CCS Coal Ash had several comments; and
- EPA responses addressing the potential for SNCR to impact fly ash sales and the cost of this impact.

Below are Golder's responses to the EPA's comments on our November 15, 2011 report concerning the potential impact of SNCR controls to fly ash marketability at CCS and the potential cost impact if fly ash requires ASM technology and is less marketable and therefore, placed in greater quantities into disposal facilities.

2.0 SNCR IMPACT TO FLY ASH MARKETABILITY

The potential impact to fly ash marketability is a function of the SNCR ammonia slip adsorption onto the fly ash particles, and the acceptable (allowable) ammonia levels in fly ash by the fly ash end users.

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2.1 Ammonia Adsorption onto Fly Ash

Based on available literature, the adsorption of ammonia onto fly ash from SNCR emission controls is highly variable and dependent upon factors such as SNCR operation, fuel type/fuel mix, boiler configuration, ash content, ash mineralogy, ash alkalinity, ash sulfur content, and temperature. Limited published data are available for ammonia levels in fly ash for coal-fired power plants utilizing SNCR emissions controls, with no published information being found for energy generation facilities burning lignite coal.

In a 2007 EPRI study on the handling, disposal, and sale of ammoniated fly ash (EPRI 2007), responses from eight units utilizing SNCRs were discussed. All the units fired a PRB/eastern bituminous coal blend, were predominantly smaller units, were predominantly wall-fired, and had actual ammonia slip up to 5 parts per million (ppm). Only four units had tested levels of ammonia in the fly ash, with the measured levels ranging from less than 100 ppm to over 200 ppm. Several references attempt to relate the amount of ammonia slip to the ammonia levels in fly ash and suggest that a 2 ppm ammonia slip may result in fly ash ammonia levels from less than 50 ppm to several hundred ppm (Murarka 2003, Bittner 2001, Hinton 2012, Larrimore 2002). In addition, when explaining ash sales impacts at CCS, Sahu (2011) references a figure created by Larrimore (2002) that indicates ammonia slip levels above 2 ppm can lead to "restricted use" of fly ash and ammonia slip levels above 4 ppm may lead to "unmarketable" fly ash for use in ready mix.

2.2 Allowable Ammonia Present In Fly Ash

The amount of "allowable" ammonia present in fly ash destined for beneficial use varies depending on ash marketer preferences and the ultimate end use. Higher concentrations of ammonia present in fly ash are a result of ammonia slip in SCR or SNCR systems (EPRI 2007). Fly ash impacted with elevated levels of ammonia results in ammonia being released into the air when water is added. At low levels, ammonia is a nuisance; however, at higher exposure levels, ammonia can cause irritation of the eyes, throat, and nose as well as difficulty breathing (NIOSH 2011). Strength characteristics do not appear to be affected by the presence of ammonia in fly ash (Rathbone and Robl 2001).

Elevated concentrations of ammonia in fly ash contribute to releases into the environment during placement (with the presence of water), and a reluctance of fly ash marketers and users (i.e. Headwaters Resources, Lafarge, etc.) to buy fly ash for sales to the construction industry. EPRI (2007) explains that the "…industry rule-of-thumb indicates that ammonia contamination on fly ash that is destined for concrete/cement utilization must have less than 100 ppm ammonia to be useable." Headwaters indicated (January 11, 2010) that they "…quit shipping anything over 100 ppm…" in reference to the Eastlake facility, which has had an SNCR system since 2007. Eastlake has attempted to decrease ammonia content in the fly ash to less than 50 ppm using ASM to improve fly ash marketability. Lafarge (January 26, 2010) has found "…when the ammonia levels exceed 40 part per million in the fly ash that the consumer notices the ammonia and finds it to be objectionable." Additional references have generally found that approximately 100 ppm is the maximum "acceptable" ammonia level in fly ash (Bittner et al. 2001, Giampi 2000, Bittner and Gasiorowski 2005). Other sources cite 100 ppm as an acceptable allowable ammonia level in fly ash for enclosed spaces, but allow a higher limit of 200 ppm in well ventilated areas (Brendel et al. 2000, Larrimore 2002).

The amount of ammonia in fly ash can be related to the ammonia off-gassed during placement. Both NIOSH and OSHA have health-based exposure limits for ammonia in the air. NIOSH has a recommended exposure limit (REL) of 25 ppm and OSHA's permissible exposure limit (PEL) is 50 ppm. A "comfortable" threshold of 10 ppm ammonia is referenced by Rathbone and Robl (2001). Rathbone and Robl (2001) evaluated the relationship between ammonia in fly ash and the corresponding amount in air using laboratory and field-scale test methods:

$$NH_{3\,ash} = \frac{(NH_{3\,water})(Water - to - Cement\ ratio)}{(Fly\ Ash\ Content)}$$

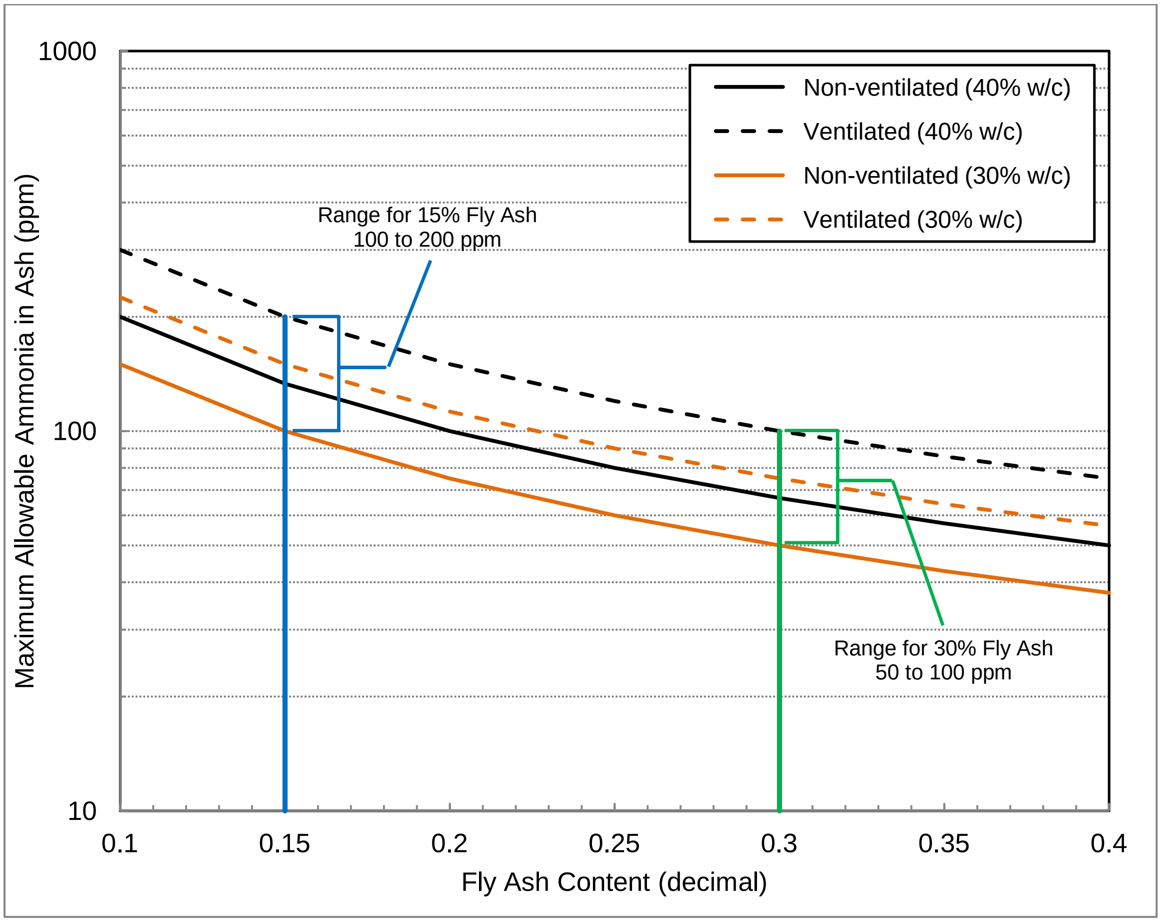
The lab and field scale testing found allowable ammonia levels in the concrete water prior to setting (for 10 ppm in the air), to be approximately 50 mg/l for non-ventilated spaces and 75 mg/l for well ventilated spaces.

Fly ash from CCS is a desirable high quality material and has been used extensively in North Dakota, Minnesota, Colorado, and as far as California. In a review of fly ash uses in North Dakota, the Energy & Environmental Research Center (EERC) stated:

> "NDDOT uses fly ash in almost all concrete projects at a replacement rate of 30%. A replacement rate between 15% and 30% is specified by most state DOTs (if they specify fly ash use at all), making NDDOT's specification on the higher end compared to other states. For mass pours, a replacement rate of 40% is allowed and is more typical." (EERC 2011)

Based on these uses of CCS fly ash, the above relationship was used to evaluate the maximum allowable ammonia content in fly ash for 15% and 30% fly ash mixtures, for water cement ratios between 30% and 40%, and for well-ventilated and non-ventilated areas. Results of the calculations are shown in the following table and the figure below.

Condition	**Ammonia in Air***	**Water/Cement Ratio**	**Allowable Ammonia Content in Fly Ash (15% fly ash mixture)**	**Allowable Ammonia Content in Fly Ash (30% fly ash mixture)**
	ppm	**-**	**ppm**	**ppm**
Ventilated	10	0.4	200	100
Non-Ventilated	10	0.4	133	67
Ventilated	10	0.3	150	75
Non-Ventilated	10	0.3	100	50
*Practical limit based on experience (Rathbone and Robl 2001)				



2.3 Marketability Conclusions

When ammoniated fly ash is used in concrete, the ammonia can be released into the air during placement and may cause irritation to individuals placing the concrete. The amount of ammonia released into the air is a function of fly ash content, the water/cement ratio of the concrete batch, and the ammonia concentration in the ash. Generally, industry experience indicates that fly ash used for concrete should have less than 100 ppm ammonia to prevent handling issues from limiting the marketability of the ash. Based on the use of CCS fly ash as a high percentage cement replacement (30%), a calculated allowable ammonia level in the fly ash may range between 50 ppm and 100 ppm. When discussing ash sales impacts at CCS, Sahu (2011) cites Larrimore (2002) in concluding that 2 ppm ammonia slip can result in 100 ppm ammonia in ash. According to Larrimore (2002), 4 ppm ammonia slip can result in 200 ppm ammonia in ash, a potentially unmarketable level of ammonia for use in ready mix. Because the ash marketer and ready mix user may not know the exact use of fly ash when it is purchased and placed in a silo, the practical limit for CCS fly ash is 50 ppm or less to allow its use in a wide variety of applications. This limit is also supported by the anecdotal comments from both Headwaters and Lafarge.

Definitive information is not available for the levels of ammonia that could be present in the fly ash at CCS due to SNCR ammonia slip. However, review of available literature indicates a reasonably high probability that ammonia concentrations would be in the range that is problematic for marketers and end users of CCS fly ash. Therefore, it is prudent for engineering costs evaluations to assume ammonia levels in CCS fly ash will be higher than the acceptable ammonia levels for CCS fly ash destined for beneficial use, and therefore to assume that CCS fly ash will be disposed or will require treatment with ASM technology to be sold for beneficial use.

3.0 SNCR COST IMPACT TO FLY ASH MANAGEMENT

Golder previously provided a detailed engineering cost estimate for the potential impact to fly ash management as a result of SNCR emissions controls at CCS. Based on the EPA responses, supporting information and clarifications are provided below.

3.1 Fly Ash Disposal Facility Design Basis

The previous evaluation indicated that each cost estimate was prepared assuming that fly ash will be disposed of in a new landfill with a design based on RCRA Subtitle D practices. This may have been taken as a speculative/highly conservative estimate based on impending coal combustion residue (CCR) regulations being developed by the EPA (see EPA response to comment on page 111 of rule prepublication).

In actuality, the assumed design is based on current North Dakota Department of Health (NDDH) regulations (NDDH, http://www.legis.nd.gov/information/acdata/html/33-20.html), which are in-line with RCRA Subtitle D practices. In the early 1990s the NDDH revised its Solid Waste Management and Land Protection rules adopting environmentally sound controls such as composite liners, leachate collection systems, surface water controls, and ground water monitoring.

3.2 Fly Ash Disposal Unit Cost Estimate

Disposal costs of $11 to $18 per ton were estimated based on site-specific designs for the disposal of fly ash at CCS. These disposal costs were based on a detailed engineering cost estimate for CCS including costs from landfill development to post-closure care. In the EPA's responses (page 110), they indicated "we find a disposal cost of $5/ton is reasonable in the improbable event that some ash would need to be disposed."

The cost estimate of $5/ton deemed reasonable by the EPA is not supported by an engineering cost estimate, is not supported by industry information, and is not supported by recent work published by the EPA.

In 2010, the EPA estimated baseline (i.e. current) CCP disposal costs in their Regulatory Impact Analysis for EPA's Proposed RCRA Regulation of Coal Combustion Residues (CCR) Generated by the Electric Utility Industry (EPA 2010). In Chapter 3 of that report, the EPA provided a cost estimate for the management of CCRs and estimated a range of $2/ton to $80/ton with an average of $59/ton. In discussion of these results, the report indicates that $2/ton is reflective of unlined, near-plant impoundments in states with low regulatory requirements, and the high end of $80/ton is reflective of off-site commercial disposal in landfills. Fly ash disposal facilities at CCS are clay- or composite-lined, engineered impoundments and landfills located at varying distances from the plant. North Dakota has comprehensive regulatory requirements in place for ash disposal facilities.

The EPA report further references information from the American Coal Ash Association (ACAA) to validate its cost estimate. The ACAA routinely collects ash disposal and beneficial use information from its members and has developed estimates for the disposal of CCPs. From the ACAA website and referenced in the EPA report:

> "As one can see, a variety of factors enter into determining disposal costs. The lowest cost occurs when a disposal site is located near the power plant and the material being disposed can be easily handled. If the material can be piped, rather than trucked, costs are usually lower. In these types of situations, cost may be as low as $3.00 to $5.00 per ton. In other areas, when distance is far away and the material must be handled several times due to its moisture content or volume, costs could range from $20.00 to $40.00 a ton. In some areas, the costs are even higher. If new sites are required and extensive permitting processes take place, the total cost of the facility may be increased, resulting in higher disposal costs over time." (ACAA, http://acaa.affiniscape.com/displaycommon.cfm?an=1&subarticlenbr=5#Q13)

The disposal of fly ash at CCS does not fall at either cost extreme (unlined impoundment or off-site commercial disposal), and the engineering estimate of $11 to $18 per ton appears well within the EPA's cost estimate and industry practice.

3.3 Lost Fly Ash Sales Revenue

Part of the cost impact to fly ash management is the loss of fly ash sales revenue currently being generated. Based on information from GRE, the 2010 average fly ash sales price per ton was $41.00 with 30% of the sales price going to GRE ($12.30/ton) as revenue and 70% of the sales price going to the fly ash marketer Headwaters ($28.70/ton).

EPA commented that GRE should use $5/ton rather than the updated value of $12.30/ton, and suggested that the lost revenue price included lost revenue to other parties. Based on follow-up discussions with GRE, it was confirmed that the $41/ton is the 2010 average FOB Coal Creek Station sales price and the $12.30/ton portion attributed to GRE does not include lost revenue to other parties. Based on this confirmation, the $12.30/ton rather than the $5/ton is more appropriate for the conditions at Coal Creek Station.

3.4 Cost Impact Conclusions

The fly ash disposal cost estimate is based on an engineering design reflective of the practice in North Dakota, and Golder's engineering estimate of $11 to $18 per ton for fly ash disposal appears to be well within the EPA's cost estimate and consistent with industry practice. Further, the lost fly ash sales revenue of $12.30/ton reported in the cost impact evaluation is reflective of current conditions at CCS.

The disposal and lost revenue cost estimates are valid, and based on the uncertainty with respect to ammonia levels in fly ash, the previous evaluation with respect to fly ash management cost is reasonable.

GOLDER ASSOCIATES INC.

Ron R. Jorgenson
Principal

Todd Stong, P.E.
Senior Engineer

TJS/RRJ/kcs

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Great River Energy's
Legal and Technical Review Of
U.S. EPA's BART Determination for Coal Creek Station

I. INTRODUCTION

On March 2, 2012, EPA issued its *Approval and Promulgation of Implementation Plans; North Dakota; Regional Haze State Implementation Plan; Federal Implementation Plan for Interstate Transport of Pollution Affecting Visibility and Regional Haze*, 76 Fed. Reg. ____(April __, 2012) ("FIP"). EPA largely upheld the North Dakota Department of Health's ("NDDH's") SIP with two exceptions: the NOx Best Available Retrofit Technology ("BART") requirement for Great River Energy's Coal Creek Station ("CCS"), and Reasonable Progress requirements for Basin Electric's Antelope Valley Station. Below, GRE addresses EPA's FIP and its rationale for requiring selective non-catalytic reduction ("SNCR") at CCS. In particular, GRE explains that EPA failed to rationally apply the Clean Air Act's ("CAA's") five-factor BART analysis and GRE responds to key EPA arguments for rejecting NDDH's BART determination.

In rejecting NDDH's BART determination for CCS, EPA made numerous errors, including the following:

- Conducted an improper cost analysis by ignoring the existing controls in use at CCS, including LNC3+ and DryFining^{TM};
- Failed to analyze, or ignored, the incremental cost of SNCR compared to existing and planned controls at CCS, including LNC3+ and DryFining;
- Ignored the demonstrated lack of visibility benefits resulting from its requirement to install SNCR at CCS; and
- Rejected, without validated support, the likelihood of ammonia slip and fly ash contamination.

Beyond these errors, EPA purported to reject NDDH's BART determination for CCS because NDDH relied on cost analyses that contained an error in one component of the costs – the cost of ash contamination and disposal. While objecting to this one component, EPA rejected NDDH's entire BART analysis and NDDH's valuation of the other four, equally important, factors in the BART determination.

The foregoing errors, as well as EPA's failure to give any credence to the values that NDDH's placed on the other BART factors, demonstrate that EPA did not conduct a valid BART analysis for CCS. EPA failed to comply with the CAA requirements and the Agency's own guidelines.

II. EPA's "COST OF CONTROLS" ANALYSIS IS INCONSISTENT WITH THE STATUTE AND EPA'S OWN GUIDANCE

EPA's principal basis for rejecting NDDH's BART determination was NDDH's reliance on purportedly incorrect information regarding the cost associated with ammonia contamination of merchantable fly ash resulting from using SNCR. GRE has addressed the cost issue that EPA raised and has reflected those changes in GRE's Supplemental Best Available Retrofit Technology Refined Analysis for NOx Emissions, April 5, 2012 ("BART Supplement"). EPA asserts, incorrectly, that there should be no ammonia slip or fly ash contamination from using SNCR.[1] However, EPA's own cost analysis is seriously flawed and inconsistent with both the CAA and its own Guidance. EPA made two significant errors in conducting its cost analysis of SNCR. First, it ignored the emission controls already installed and in use that have significantly reduced NOx emissions at CCS. Second, EPA failed to examine the incremental, or marginal, costs of SNCR beyond the existing and planned controls at CCS.

A. <u>EPA Failed to Consider Existing Pollution Controls in Use at CCS and Current Emissions in Performing Its Cost Analysis</u>

Under CAA §169A, the State (or EPA Administrator) must take into consideration five factors in determining BART. One of the five factors is "any existing pollution control technology in use at the source." 42 U.S.C. § 7491(g)(2). EPA completely disregarded this obligation and, instead, relied on 9-year-old emissions data in its cost analysis. The effect of using the inaccurate, inflated emissions data is to distort EPA's cost numbers and make SNCR seem more cost-effective than it is.

EPA relied on emissions data from 2003 and 2004 in its cost analysis. EPA did this notwithstanding its acknowledgement that current emissions are significantly lower. *See* FIP at 20. Since 2004, GRE has made multiple improvements in the combustion and emissions at CCS, including: (1) installing new, adjustable SOFA nozzles in Unit 1 in 2005; (2) installing expanded over-fire air registers in Unit 2 in 2007; (3) installing close coupled over-fire air (CCOFA) on Unit 2 in 2010; and (4) installing DryFining at both units in 2010. All of these measures had beneficial impacts on NOx formation and emissions, reducing emission rates at Unit 2 from 0.22 lbs/mmBtu in 2004 to 0.153 currently. For Unit 1, emissions were reduced from 0.22 in 2004 to 0.20 lbs/mmBtu in 2010.

EPA's failure to acknowledge these installed controls is inconsistent with the plain language of the statute and EPA's own BART guidance. "[B]aseline emissions rate should represent a realistic depiction of anticipated annual emissions for the source." *See* 69 Fed. Reg. 25224. EPA's reliance on 2003 - 2004 emissions from CCS is not a "realistic depiction" of CCS's current or anticipated emissions. By using incorrect emissions data, EPA created and relied on admittedly inaccurate cost effectiveness numbers, the very grounds on which it rejected NDDH's BART determination.

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[1] EPA's assertion is addressed below in Section IV, and by Golder Associates in Exhibit G to the BART Supplement.

EPA's explanation for using inaccurate emission data is both irrational and inapposite to CCS. EPA argues that using emissions resulting from existing emission controls (as required by the statute) would "reward sources that install lesser controls in advance of a BART determination in an effort to avoid more stringent controls." FIP at 95. Whatever EPA's policy considerations, GRE did not install such controls to "game" the BART process. The DryFining technology involved a multi-year, $270 million investment in partnership with the Department of Energy to improve the emissions resulting from coal combustion. The installation of new SOFA nozzles and LNC3+ was done as part of DryFining and in cooperation with the NDDH to achieve better combustion and lower NOx emissions. There is nothing in the record to suggest any of this was done to avoid more stringent BART. It was not.

EPA's statement that these controls were "voluntary" and, thus, EPA need not consider them in evaluating BART is nonsensical. There is nothing in the statute that says voluntarily installed emission controls can or should be ignored. The statute says that EPA must take into consideration "*existing pollution control technology in use at the source*." EPA cannot simply assume emissions that do not exist to bolster its goal of making SNCR appear more cost effective than it is. Further, this is a policy decision beyond EPA's authority. Congress expressly requires EPA to consider existing controls when determining BART. *See* 42 U.S.C. § 7491(g)(2); *St. Mary's Hosp. of Rochester, Minnesota v. Leavitt*, 535 F.3d 802, 806 (8th Cir. 2008) ("The plain meaning of a statute controls, if there is one, regardless of an agency's interpretation."). Although that may result in companies having to do less under BART, that may be precisely what Congress intended. Encouraging sources to install controls voluntarily – as CCS did – results in achieving emission reductions and visibility improvements earlier than might otherwise be required. EPA's policy would discourage companies from ever voluntarily reducing emissions; in other words, EPA is pursuing the "no good deed goes unpunished" theme of regulation.[2]

Finally, EPA acknowledges that it refused to use accurate, current emission rates from CCS because using the lower emission levels would "skew the 5-factor BART analysis by reducing the emissions reductions from combinations of control options and increasing the cost effectiveness values." FIP at 98. This admission lays bare the inaccuracy of the Agency's cost effectiveness assertions and the inappropriateness of EPA's BART determination for CCS.

B. EPA Failed to Properly Calculate and Consider the Incremental Cost of SNCR in Making Its BART Determination

EPA also failed to consider the incremental cost of SNCR in contravention of its own regulations and guidance. EPA guidelines direct the states as follows. "In addition to the average cost effectiveness of a control option, you *should* also calculate incremental cost effectiveness. You *should* consider the incremental cost effectiveness in combination with the total cost effectiveness in order to justify elimination of a control option. *See* 69 Fed. Reg. 25224 (emphases added); 70 Fed. Reg. 39127 ("We *continue* to believe that *both* average and

[2] By EPA's logic, GRE should have done nothing over the past nine years while waiting for a BART determination. This would have postponed any NOx reductions from approximately 2005 until 2018 (five years after BART is determined).

incremental costs provide information useful for making control determinations.") (emphases added).

To justify SNCR, EPA inexplicably ignored half of its own "cost of controls" analysis. Instead, EPA looked only at the total cost of installing both LNC3+ *and* SNCR (as opposed to SNCR alone) and compared that total cost to the emission reductions achieved using both technologies. As discussed above, the emission reductions from LNC3+ (in addition to the DryFining) already have been achieved at Unit 2 and the LNC3+ is planned for Unit 1. The cost of LNC3+ is a small fraction of the costs of SNCR, yet it generates most of the NOx emission reductions. By combining the two costs into one control option, EPA further distorts the cost-effectiveness of SNCR. If EPA had looked at the cost-effectiveness of SNCR alone (i.e., incremental cost), it would have to admit that the emission rate would decline by only 0.023 lbs/mmBtu: from 0.153 lbs/mmBtu to EPA's proposed rate of 0.13 lbs/mmBtu.

The impact of EPA's error is dramatic. Even if we accepted EPA's unfounded assumption that there would be no fly ash contamination resulting from SNCR, the incremental cost of using SNCR would be $8,534 per ton for Unit 1 and $4,688 per ton for Unit 2. EPA's estimate that the cost effectiveness is under $2,500 per ton is misleading because the cost-efficient reductions come from the use of LNC3+, a technology already installed at Unit 2 and planned for Unit 1.[3] *See* BART Supplement, Table 3.1. SNCR cannot be justified on the basis of achieving such a small incremental reduction in NOx emissions at such high costs, particularly in light of the other factors that weigh against SNCR.

III. EPA Failed to Properly Consider the Lack of Visibility Benefits Resulting From the Installation of SNCR

The flaws in EPA's BART analysis were not limited to only cost-related considerations. EPA also failed to give serious consideration to other statutory factors that Congress required to be part of any BART analysis, especially the lack of any demonstrable visibility benefit resulting from SNCR. The modeling on which both NDDH and EPA relied demonstrates that there would be no discernable visibility improvement resulting from installation of SNCR. *See* 76 Fed. Reg. 58,622. The degree of predicted visibility improvement, approximately 0.105 deciviews, is only one tenth of the level that EPA asserts is perceivable by the human eye. Given the many sources of variability of inputs to CALPUFF's visibility analysis versus actual impacts, a difference of 0.1 deciviews between options may reflect no real difference at all. *See* attached Memorandum from Andrew Skoglund, Barr Engineering, to William Bumpers (April 4, 2012).

EPA made no effort in its final rule to dispute that there will be no real improvement in visibility resulting from SNCR. Instead, EPA surprisingly states that "perceptibility of visibility improvement is not a test for the suitability of BART controls." FIP at 112. While EPA later acknowledges that deciview improvements is one of the five factors, it then says that the "Guidelines provide flexibility in determining the weight and significance to be assigned to each factor" and that achieving a perceptible benefit of 0.5 deciview is not a prerequisite for selecting

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[3] The significantly higher incremental costs associated with Unit 1 are due to lower utilization and associated emissions at Unit 1 compared to Unit 2.

BART. FIP at 112. While Congress made clear that the state has great discretion in deciding the weight to accord each factor, EPA has effectively eliminated any import associated with the one factor (visibility) that is the central focus of the regional haze rule. EPA is simply imposing controls and costs on CCS notwithstanding that EPA cannot predict with any confidence that there will be any visibility improvement. This is contrary to the entire objective of the statute.

EPA's only attempt to justify ignoring the lack of visibility benefits resulting from its proposed BART was to note that NDDH was satisfied with a similarly small improvement at another source. *See* 76 Fed. Reg. 58,623. But this explanation completely ignores NDDH's source-specific determination for CCS that an estimated 0.1 deciview improvement did not justify the large costs of SNCR. *See* 76 Fed. Reg. 58,624. EPA's attempt to cherry pick the visibility level from a separate BART analysis ignores NDDH's valuation of all of the other four factors, including a much lower cost, that affected the determination.

Even the theoretical improvement of 0.105 deciviews is likely exaggerated. EPA criticizes the modeling that GRE provided because the various control scenarios were modeled together; that is, the NOx control options were modeled along with the SO_2 reductions. But EPA has repeatedly recognized that its modeling requirements overstate real-world visibility improvements by five to seven times. *See, e.g.,* EPA North Dakota Proposed FIP, Technical Support Document, B-41; FIP at 55. EPA's justification is that modeling based on "current degraded visibility conditions would result in a smaller relative benefit than would a comparison relative to natural background visibility." FIP at 55.[4] Importantly, EPA admits that it undertook no independent modeling of the prescribed emission reductions, so EPA cannot state that SNCR will result in *any* visibility improvement, FIP at 99.

IV. EPA's Conclusion that SNCR Will Result In No Fly Ash Contamination Is Unrealistic

The principal basis EPA cites for rejecting NDDH's BART determination is that NDDH had relied on costs provided by GRE for installation of SNCR that included one incorrect value – the cost of disposing of contaminated fly ash.[5] *See* 76 Fed. Reg. 58,603-04. GRE has corrected that value.[6] As discussed above, even if we assumed that there would be zero contamination of the fly ash, the marginal cost of SNCR ($4,688 per ton for Unit 2 and $8,534 per ton for Unit 1) coupled with the lack of any visibility benefit cannot justify SNCR. But EPA's assertion in the FIP that there will be no wastage of fly ash is not supportable. Exhibit G to the BART Supplement is a report from Golder Associates, addressing EPA's assertion that SNCR would not result in any fly ash contamination and reaffirming the expected costs of fly ash disposal. As demonstrated by Golder Associates and below (1) EPA's assertion that CCS could maintain ammonia slip to below 2 ppm is unsupported and almost certainly wrong; and (2) even at 2 ppm

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[4] Put differently, EPA does not allow modeling of what is expected to actually happen because that would confirm EPA's approach results in little or no real-world visibility improvements.

[5] GRE had initially included FOB price of ash. The value was not in error, but GRE agreed that the FOB price was not the correct value for the BART cost analysis.

[6] Golder Associates concludes that a cost of $12.30 per ton is the expected cost of lost fly ash sales resulting from ammonia contamination. BART Supplement, Exhibit G at 6.

ammonia slip, a significant amount of CCS's fly ash would become unmerchantable and require disposal.

In EPA's proposed BART determination, EPA recognized that using SNCR could, and likely would, result in some contamination of GRE's merchantable fly ash at CCS. *See* 76 Fed. Reg. 58,620-21. Consequently, EPA assigned costs to SNCR associated with the lost sales and increased disposal costs associated with the contaminated fly ash. *Id*. In the final FIP, EPA asserts that SNCR at CCS would not contaminate <u>any</u> fly ash because "current technology has made it possible to control ammonia slip from SNCR to levels . . . in a range of 2 ppm or less." *See* FIP at 102. In making this remarkable assertion, EPA relies essentially on a single case study – the "Andover Report." *See* FIP at 102 n.32. The Andover Report provides virtually no support for EPA's claims.

The Andover Report's results cannot be relied on to make any operating assumptions about CCS. It states upfront that "[e]xperience with the TDLAS method on coal power plants has had mixed success – and unfortunately, *far more failures than successes*." Andover Report at page 5 (emphasis added). In the course of examining this technology further, the Andover Report analyzes the use of SNCR at the CP Crane station in Baltimore. The CP Crane station consists of two, 200MW cyclone boilers. It is subject to the Maryland Healthy Air Act, a law that imposes a company-wide, NOx tonnage limitation on power plant owners. CP Crane is one of multiple plants owned and operated by Constellation Energy in Maryland. Constellation installed NOx controls on all of its plants in Maryland, installing SCR on its larger, base load plants, and installing SNCR on CP Crane. GRE contacted Constellation about EPA's assertions. Constellation officials informed GRE that the plant conducted four, one-hour performance tests when commissioning the system,[7] on which the Andover Report is based. Since this commissioning test, Constellation has rarely run the SNCR at CP Crane. Constellation's plant is not subject to a short term NOx rate limit, is not subject to an ammonia slip limit and Constellation does not monitor the ammonia slip. The SNCR system has process monitors but they are not certified. The initial NOx rate at these cyclone burners is approximately 0.4 lbs/mmBtu. Because there is no enforceable NOx rate, the level of ammonia injection is completely discretionary. Constellation does not know what its actual ammonia slip rate is, or would be if the SNCR were actually being utilized. Thus, Mr. Staudt's paper, which is based on the initial, short-term, commissioning test, in no way represents a reasoned basis for EPA's assertions that ammonia slip can be held consistently below 2 ppm or that there will be no fly ash loss as a result of installing SNCR at CCS.[8]

In response to EPA's FIP, Golder Associates ("Golder") has re-examined the literature on the impact of ammonia on fly ash, including the studies referenced by Dr. Sahu in the FIP. *See* FIP at 102 n.35. Golder demonstrates that there is no literature that supports EPA's contention that no fly ash wastage is expected. To the contrary, even if ammonia slip could be limited to 2 ppm on a constant basis – something that has never been demonstrated – ammonia

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[7] This short-term commissioning test is hardly an indication of what can be achieved at a much larger facility over a longer term and a wider range of operating levels.

[8] EPA's reference to the Big Brown plant in Texas is similarly unpersuasive. According to EIA data and Luminant, Big Brown landfills approximately one third of its fly ash.

concentration in fly ash could be as high as 100 ppm, which Golder concludes would significantly limit the sale of CCS's fly ash. BART Supplement, Exhibit G at 3-4.

Golder also addresses EPA's criticism of the costs assigned for disposing of contaminated fly ash. BART Supplement, Exhibit G at 5-6. Golder points out that its costs are based on NDDH Solid Waste Management and Land Protection regulations (NDDH, http://www.legis.nd.gov/information/acdata/html/33-20.html). NDDH's rules require controls such as composite liners, leachate collection systems, surface water controls, and ground water monitoring. As a result, Golder estimates the cost of fly ash disposal to be between $11 and $18 per ton. Golder also demonstrates that EPA's estimate of $5 per ton is not supported by any analysis and is inconsistent with EPA's own regulatory impact analysis from 2010, which estimated a range of $2 to $80 per ton, with an average cost of $59 per ton. BART Supplement, Exhibit G at 5. Golder also confirms that the cost of lost fly ash sales for GRE is $12.30 per ton. BART Supplement, Exhibit G at 6.

Perhaps recognizing the fundamental weakness of its assertion, EPA noted that even if SNCR did cause some ammonia contamination, "three possible systems" could be used to cure the problem. *See* FIP at 102 n.35. EPA did not even bother to analyze whether any of these technologies might actually work at CCS. The manufacturer of one of those technologies stated that "[t]he limited current experience in commercial application and lack of research is not adequate for Headwaters to be able to provide any guarantee that the process can be successfully applied to treat lignite ash at the Coal Creek Station." *See* July 15, 2011 Email from Rafic Minkara, PhD., PE (Headwaters) to John Weeda (GRE), forwarded to Gail Fallon and Carl Daly (EPA) on July 15, 2011. Despite the manufacturer's lack of confidence as to whether its own technology would work, EPA asserted its "consultants are aware of no technical reason that ASM technology would not be effective to mitigate ammonia on fly ash from lignite." *See* FIP at 102 n.35. EPA cites nothing to justify its conclusion that the technology in question should work when the technology's own creator refused to support the conclusion. Making bald assertions that are unsupported at best, and flatly contradicted at worst, by evidence in the record is textbook arbitrary and capricious.

III. EPA'S CONSIDERATION OF THE OTHER FACTORS WAS IRRATIONAL

A. Other Cost Errors

1. EPA Arbitrarily Rejected URS's Cost Data

EPA's disregard of construction cost analysis of SNCR at CCS is unfounded. URS is a leading engineering and construction company that has participated in the construction and installation of SNCR projects at more than 30 coal-fired power plants. EPA's criticism that URS is not an SNCR vendor, and thus unable to opine on the costs of installing SNCR at CCS is arbitrary and capricious. *See* FIP at 121-124. As URS states:

> URS is not a technology supplier. The supplier is typically responsible for installation of only their process island and system performance guarantees. The installation of the balance of plant (BOP) equipment, construction management, foundations, utility tie-ins (electrical, water, air, instrumentation and controls

> interface, interconnecting piping, new flue gas emissions monitoring equipment, boiler and air heater modifications, retrofit difficulty due to existing plant access and congestion issues, et al) typically falls outside of the scope of supply for the SNCR vendor. Published cost estimates and vendor proposals in many cases do not consider these BOP cost impacts on the Total Capital Requirement for the installation of emissions control equipment. URS's project experience provides a basis for the assessment of these BOP costs that must be added to the vendor supplied equipment's installed costs to determine the true total capital cost of an installation.

See Letter from URS to Debra Nelson, March 30, 2012, BART Supplement, Exhibit F.

URS also has reconfirmed the basis for the retrofit factor of 1.6 based on the difficulty of installation at CCS. *See* BART Supplement, Exhibit F. URS also further explains the basis for its skepticism regarding SNCR's effectiveness when the initial NOx emission rates are in the lower range, similar to the NOx rate at CCS Unit 2. *See* BART Supplement, Exhibit F. EPA simply had no reasoned basis for disregarding URS's cost and performance analysis. EPA repeatedly refers to information from SNCR-designer Fuel Tech, but EPA's information appears to have been gleaned largely from a promotional website rather than site-specific analysis. *See* FIP at 20 n.2, 97 n.29. EPA's claim that its "consultant" received some sort of input from a SNCR vendor is so vague as to render it useless. *See* FIP at 102 n.34. The record does not show that EPA asked Fuel Tech to evaluate whether its technology would work at CCS. In any event, the follow up analysis provided by URS demonstrates that its cost analysis is well grounded.

2. EPA Provided No Rational Basis for Departing From its Guidelines' Presumptive Values

EPA's FIP ignored the Agency's own Guidelines, which require careful consideration of EPA's presumptive emissions limits. EPA's Guidelines explain that "we believe that States should carefully consider the specific NOx rate limits for different categories of coal-fired utility units, differentiated by boiler design and type of coal burned, set forth below as likely BART limits." *See* 70 Fed. Reg. 39134. EPA went on to note that "States have the ability to consider the specific characteristics of the source at issue and to find that the presumptive limits would not be appropriate for that source." However, EPA's BART analysis does not even acknowledge the existence of its own presumptive emissions limits much less reflect "careful" consideration of them. *See* 76 Fed. Reg. 58620-23. Furthermore, EPA offers no explanation why a departure from them is appropriate in this particular case, particularly where no visibility benefit would result from doing so. EPA cannot ignore its own Guidelines and nonetheless claim to have undertaken a legally-adequate BART analysis. EPA certainly would not allow a state to do so.

B. Energy and Non-Air Quality Environmental Impacts of Compliance

The CAA also requires consideration of the energy and non-air quality environmental impacts resulting from the use of relevant control technologies. This includes the energy requirements of the technology, the local availability of necessary fuels, and the generation of solid or hazardous wastes as a result of applying a control technology. *See* 70 Fed. Reg. 39,169. As already discussed above, EPA assumed contrary to all reasonable evidence that no fly ash

would be contaminated due to SNCR. EPA was therefore able to avoid considering the non-air environmental impacts arising from the creation of hundreds of thousands of tons of solid waste (and perhaps hazardous wastes depending on EPA's consideration of how to regulate fly ash). EPA's unsupported conclusion about fly ash therefore prevented EPA from properly considering two factors – the cost of controls and non-air environmental impacts.

IV. CONCLUSION

EPA rejected NDDH's entire BART analysis principally because of a purported error in a single cost component: the cost of contaminated fly ash. EPA then utilized flawed cost analysis and inaccurate emissions data to justify installation of SNCR. EPA effectively ignored all of the other BART factors, especially the lack of any measurable visibility improvement that might result from investing tens of millions of dollars to install and operate SNCR. GRE has provided NDDH with a revised BART analysis, including a refined cost analysis that examines the average and incremental cost, and cost-effectiveness of various levels of NOx emissions control. In light of the lack of any discernable visibility improvement at any Class I area, NDDH would be justified in supporting its initial BART determination at any cost level, including EPA's artificially low average cost per ton of $2500 per ton. The actual incremental cost of SNCR will be $4,688 per ton and, for Unit 1, will be $8,534 per ton, even if no costs are assigned to the loss of merchantable fly ash. The costs are significantly higher, and other environmental impacts worse, if fly ash contamination were to result from using SNCR. The documentation demonstrates this is very likely.

NDDH's initial BART determination was in compliance with the statutory obligations. With the refined BART analysis, and updated cost information, NDDH can make its own BART determination, assigning its own values to the five BART factors and should not accept EPA's usurpation of NDDH's authority.

GREAT RIVER ENERGY

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April 5, 2012

Mr. Terry O'Clair
Director, Division of Air Quality
North Dakota Department of Health
918 E. Divide Ave.
Bismarck, ND 58501-1947

RE: Coal Creek NOx BART Analysis

Dear Mr. O'Clair:

We are herewith responding to your letter of February 28, 2012, in which you requested that Great River Energy ("GRE") provide additional information to assist the North Dakota Department of Health ("NDDH") with its ongoing Best Available Retrofit Technology ("BART") determination for Coal Creek Station ("CCS"). You requested that GRE address some issues with its year 2000 visibility modeling, verify certain costs and data related to various pollution control options, and address some inconsistencies between GRE's cost analysis and the U.S. EPA's Control Cost Manual for certain cost components.

Enclosed is GRE's Supplemental Best Available Retrofit Technology Refined Analysis for NOx Emissions, April 5, 2012 ("BART Supplement"), which provides a supplemental BART analysis that addresses the issues raised in the February 28, 2012 letter (as well as issues raised in your January 19, 2012 letter). In particular, GRE asked Barr Engineering to rerun the visibility modeling analysis as requested by NDDH. The revised visibility modeling, reflected in both Table 3.2 and Appendix D of the BART Supplement, demonstrates that the incremental visibility improvement of adding SNCR to Units 1 and 2 is essentially non-existent at only 0.106 deciviews. The BART Supplement also includes additional cost information from URS addressing your questions about the EPA Control Cost Manual and URS's departures from assumptions that EPA makes about costs. Barr Engineering also has included the cost/economic analyses regarding the impact of ammonia contamination on fly ash marketability and disposal costs based upon information provided by Golder Associates. Those costs are reflected in Table 3.1 of the BART Supplement. The costs reflect the expected costs depending on whether 0%, 30% or 100% of the fly ash becomes unmarketable due to ammonia contamination. Barr Engineering concluded that, even if no costs are attributable to ammonia contamination, installing SNCR on to already existing or planned controls would reduce NOx emissions at Unit 2 at a rate of $4,688/ton and $8,534/ton at Unit 1. Thus, SNCR remains well outside the range of cost-effective control technologies.

GRE's revised BART analysis provided today includes a refined cost analysis that examines the average and incremental cost, and cost-effectiveness, of various levels of NOx emissions control as well as a revised visibility impact analysis of various levels of control. In light of the lack of any discernable visibility improvement at any Class I area, NDDH would be justified in supporting its initial BART determination at any cost level, including EPA's artificially low average cost of less than $2,500 per ton. The actual incremental cost of SNCR will be in excess of $4,500 per ton for Unit 2 and over $8,000 per ton for Unit 1, even if no costs are assigned to the loss of merchantable fly ash. The actual costs will be even higher.

GRE greatly appreciates NDDH's continued work on the CCS BART. Please do not hesitate to contact me or my staff if you would like to discuss any of these matters in greater detail.

Sincerely,

Mary Jo Roth

Mary Jo Roth
Manager, Environmental Services

Enclosures

c: William M. Bumpers, Esq.
Eric Olsen, GRE
Deb Nelson, GRE

Great River Energy Coal Creek Station
BART Supplement - NOx Emission Control Cost Analysis

Update Key

Change related to utilization (non-outage scale up)
Change related to update in baseline for Unit 2 (0.201 lb/MMBtu)

Technical Update 06/07/2012

Table A-1: Cost Summary

NO_x Control Cost Summary - Unit 1

Case	Control Technology [1]	Annual Designed Emissions lb/MMBtu	Control Eff % from Baseline [3]	Controlled Emissions T/yr	Emission Reduction T/yr	Installed Capital Cost MM$	Annualized Control Cost MM$/yr	Pollution Control Cost $/ton	Annual Incremental Cost $/ton [4]	See Table XX for additional information
3 [2]	SNCR + LNC3+ - 100% Lost Ash Sales	0.122	39%	3,085.6	1,994.3	$17.873	$8.879	$4,452	$10,457	A-4, A-10
	SNCR + LNC3+ - 30% Lost Ash Sales						$6.604	$3,311	$7,524	A-4, A-9
	SNCR + LNC3+ - No Ash Impacts						*$4.385*	*$2,199*	*$4,666*	*A-4, A-8*
2	SNCR - 100% Lost Ash Sales	0.151	25%	3,809.9	1,270.0	$12.176	$9.101	$7,167	NA - Inferior Control	A-7
	SNCR - 30% Lost Ash Sales						$6.826	$5,375	NA - Inferior Control	A-6
	SNCR - No Ash Impacts						*$4.608*	*$3,628*	*NA - Inferior Control*	*A-5*
1	LNC3+	0.153	24%	3,861.6	1,218.2	$6.079	$0.764	$627	$627	A-4
0	Baseline Control - Standard LNC3	0.201	NA-Base	5,079.9	NA-Base	NA-Base	NA-Base	NA-Base	NA-Base	A-3

NO_x Control Cost Summary - Unit 2

Case	Control Technology [1]	Annual Designed Emissions lb/MMBtu	Control Eff % from Baseline [3]	Controlled Emissions T/yr	Emission Reduction T/yr	Installed Capital Cost MM$	Annualized Control Cost MM$/yr	Pollution Control Cost $/ton	Annual Incremental Cost $/ton [4]	See Table XX for additional information
2 [5]	SNCR + LNC3+ - 100% Lost Ash Sales	0.122	39%	3,089.2	1996.6	$17.873	$8.879	$4,447	$10,444	A-4, A-10
	SNCR + LNC3+ - 30% Lost Ash Sales						$6.604	$3,307	$7,516	A-4, A-9
	SNCR + LNC3+ - No Ash Impacts						*$4.385*	*$2,196*	*$4,661*	*A-4, A-8*
1	LNC3+	0.153	24%	3,866.1	1,219.6	$6.079	$0.764	$627	$627	A-4
0	Baseline Control - LNC3	0.201	NA-Base	5,085.8	NA-Base	NA-Base	NA-Base	NA-Base	NA-Base	A-3

[1] Ash impact scenarios align with November 2011 Golder report.
No Ash Impacts - Golder Scenario A; *Scenario provided for reference only and does not represent a feasible outcome*
30% Lost Ash Sales - Golder Scenario C
100% Lost Ash Sales - Golder Scenario B

[2] Capital costs for combined control scenario on Unit 1 are calculated using LNC3+ costs for Unit 1 (scenario 1) and SNCR costs for Unit 2, as unit 2 presently has LNC3+ installed.

[3] Calculated on a mass basis.

[4] Incremental costs calculated as the difference in annualized operating cost divided by the difference in emission reduction for the next lowest level of dominant control.

[5] Scenario represents incremental imprevement from the LNC3+ controls already installed on Unit 1. Design emissions rely on inlet of 0.153 lb/MMBtu NOx.

Great River Energy Coal Creek Station **Technical Update 06/07/2012**

BART Supplement - NOx Emission Control Cost Analysis

Table A-2: Emission Inventory Data / Baseline Emission Rate for BART Control Cost Analysis

Scaled to Unit 2 operating hours to reflect non-outage year for Unit 1 | Scaled to Unit 1 to reflect higher baseline emissions for Unit 2

Equipment Information: GRE Coal Creek Unit I			6015	MMBtu/hr		**Baseline Emis**	
Year (12-Month Avg. Period)	Jul 2010 - Jun 2011	Aug 2010 - Jul 2011	Sep 2010 - Aug 2011	Oct 2010 - Sep 2011	Nov 2010 -Oct 2011	**Unit 1**	**Unit 2**
Hours of Operation	7,700	7,700	7,635	7,599	7,629	8,410	8,410
Fuels Used:							
Quanity of Lignite - Tons	3,356,248	3,352,605	3,296,938	3,268,966	3,282,270	3,638,972	3,688,805
Percent Sulfur in Coal (Average)	0.64%	0.65%	0.65%	0.66%	0.61%	0.64%	0.64%
BTU per Unit of Coal (Average)	6,415	6,448	6,482	6,517	6,003	6,373	6,373
Heat Input	4.410E+07	4.422E+07	4.356E+07	4.320E+07	4.346E+07	48,032,232	47,761,077
MMBtu/hr	5,727	5,743	5,705	5,685	5,697	5,712	5,679
% of Capacity	95.2%	95.5%	94.8%	94.5%	94.7%	95.0%	95.0%
NOx lb/MMBtu	0.200	0.200	0.199	0.200	0.203	0.200	0.201 [1]
Total Stack Emissions:							
NOx Emitted Tons Per Year:	4,416.3	4,412.0	4,333.1	4,330.2	4,402.3	4,811.9	4,791.6
NOx Emitted Lb Per Hour:	1,204.8	1,200.3	1,196.7	1,205.8	1,218.5	1204.6	1199.5
Stack Emissions --- Lignite:							
NOX CEM Annual Average lb/MMBtu	0.201	0.200	0.200	0.201	0.203	0.201	0.153 [1]

Equipment Information: GRE Coal Creek Unit II			6022	MMBtu/hr	
Year	Jul 2010 - Jun 2011	Aug 2010 - Jul 2011	Sep 2010 - Aug 2011	Oct 2010 - Sep 2011	Nov 2010 -Oct 2011
Hours of Operation	8,430	8,430	8,397	8,401	8,390
Fuels Used:					
Quanity of Lignite - Tons	3,730,674	3,718,253	3,676,481	3,672,436	3,646,178
Percent Sulfur in Coal (Average)	0.64%	0.65%	0.65%	0.66%	0.61%
BTU per Unit of Coal (Average)	6,415	6,448	6,482	6,517	6,003
Heat Input	4.810E+07	4.799E+07	4.757E+07	4.764E+07	4.751E+07
MMBtu/hr	5,706	5,692	5,665	5,671	5,662
% of Capacity	94.9%	94.6%	94.2%	94.3%	94.1%
NOx lb/MMBtu [1]	0.152	0.153	0.152	0.152	0.153
Total Stack Emissions:					
NOx Emitted Tons Per Year:	3,662.4	3,666.8	3,610.4	3,626.8	3,646.1
Stack Emissions --- Lignite:					
NOX CEM Annual Average lb/MMBtu [1]	0.152	0.153	0.152	0.153	0.154

[1] Although Unit 2's actual 2010-2011 NOx emissions were 0.152-0.153, the pre-LNC3+ emissions rate was the 0.201 which is used in this analysis.

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BART Supplement - NOx Emission Control Cost Analysis

Table A-3: Summary of Utility, Chemical and Supply Costs

Operating Unit: Unit 1 or 2 **Study Year** 2011

From Golder Report

Item	Unit Cost	Units	Reference Cost	Year	Data Source	Notes
Operating Labor	37.00	$/hr	25.86	2002	Stone & Webster 2002 Cost Estimate; confirmed by GRE	
Maintenance Labor	37.00	$/hr	26.25	2002	Stone & Webster 2002 Cost Estimate; confirmed by GRE	
Electricity	0.0604	$/kwh	0.049	2004	DOE Average Retail Price of Industrial Electricity, 2004	http://www.eia.doe.gov/emeu/aer/txt/ptb0810.html
Water	0.31	$/kgal	0.79	2002	Stone & Webster 2002 Cost Estimate; confirmed by GRE	
Cooling Water	0.32	$kgal	0.23	1999	EPA Air Pollution Control Cost Manual, 6th ed. Section 3.1 Ch 1	Ch 1 Carbon Adsorbers, 1999 $0.15 - $0.30 Avg of 22.5 and 7 yrs and 3% inflation
Compressed Air	0.37	$/kscf	0.25	1998	EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1	Example problem; Dried & Filtered, Ch 1.6 '98 cost adjusted for 3% inflation
Wastewater Disposal Neutralization	1.96	$/kgal	1.50	2002	EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 2 Chapter 2.5.5.5	Section 2 lists $1- $2/1000 gal. Cost adjusted for 3% inflation Sec 6 Ch 3 lists $1.30 - $2.15/1,000 gal
Wastewater Disposal Bio-Treat	4.96	$/kgal	3.80	2002	EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 5.2 Chapter 1	Ch 1 lists $1.00 - $6.00 for municipal treatment, $3.80 is average. Cost adjusted for 3% inflation
Solid Waste Disposal - No Impact	0.000	$/ton	0.00	2011	Assume no chang in GRE landfill cost for ash	Fly ash disposal of 0 net tons
Solid Waste Disposal - 30% Lost	5.438	$/ton	5.438	2011	Golder Fly Ash Management Evaluation - Nov. 2011	Cost per ton of $13.91/ ton for 234,500 tons less existing cost of $18.06/tons for 110,000 tons
Solid Waste Disposal - 100% Lost	7.396	$/ton	7.396	2011	Golder Fly Ash Management Evaluation - Nov. 2011	Cost per ton of $11.18/ ton for 525,000 tons less existing cost of $18.06/tons for 110,000 tons
Hazardous Waste Disposal	326.19	$/ton	250.00	2002	EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 2 Chapter 2.5.5.5	Section 2 lists $200 - $300/ton Used $250/ton. Cost adjusted for 3% inflation
Waste Transport	0.65	$/ton-mi	0.500	2002	EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 3	Example problem. Cost adjusted for 3% inflation
Ash Sales	12.300	$/ton	12.300	2011	Golder Fly Ash Management Evaluation - Nov. 2011	$/ton received for sale of ash; this amount is lost if ash cannot be sold
Ammonia Mitigation	5.610	$/ton	5.610	2011	Golder Fly Ash Management Evaluation - Nov. 2011	
Chemicals & Supplies						
Lime	90.00	$/ton	72.19	2005	GRE per Diane Stockdill 12/6/05 email	Cost adjusted for 3% inflation
Caustic	364	$/ton	305.21	2005	GRE per Diane Stockdill 12/6/05 email	Cost adjusted for 3% inflation
Urea	500	$/ton	500	2011	URS SNCR Report - November 2011	
Oxygen	17.91	kscf	15.00	2005	Get cost from Air Prod Website	Cost adjusted for 3% inflation
EPA Urea	179.1	$/ton				
Ammonia	1	$/lb	0.92	2005	GRE per Diane Stockdill	Cost adjusted for 3% inflation
Other						
Sales Tax	0	%			GRE per Diane Stockdill 12/6/05 email	
Interest Rate	5.50%	%			GRE per Diane Stockdill 12/6/05 email	Estimated prime rate plus 3%

Please note, for units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal

Future Operating Scenario for BART Cost Analysis

Operating Information	Unit 1	Unit 2			Data Source	Notes
Annual Op. Hrs	8,409.6	8,409.6	Hours		July 2010 to October 2011 Coal Creek Emission Data	
Utilization Rate	100.0%	100.0%			GRE per Diane Stockdill 12/6/05 email	
Equipment Life	20	20	yrs			Engineering Estimate
Coal Ash	11.70	11.70	wt % ash		2010 Coal Creek Emission Inventory	
Coal Sulfur	0.64	0.64	% Coal Sulfur Content		July 2010 to October 2011 Coal Creek Emission Data	
Coal Heating Value	6,373	6,373	Btu/lb of coal		July 2010 to October 2011 Coal Creek Emission Data	
Design Capacity	6,015	6,022	MMBtu/hr			
ID Fan Flow Rates	Assumes coal drying with DryFining™					
Standardized Flow Rate	866293.7	866293.7	scfm @ 32º F			
Temperature	330.0	330.0	Deg F		GRE per G. Riveland 4/5/06 email	
Moisture Content	13.3%	13.3%			GRE per G. Riveland 4/5/06 email	
Actual Flow Rate	2,234,300	2,234,300	acfm		GRE per G. Riveland 4/5/06 email	
Standardized Flow Rate	1,391,000	1,391,000	scfm @ 330º F		GRE per G. Riveland 4/5/06 email	
Dry Std Flow Rate	1,205,997	1,205,997	dscfm @ 330º F			
NOx Pollutant Data						
Max Emis (lb/hr)	1,208.1	1,209.5			Calculated using baseline emission rate and design capacities	
Max Emis (tpy)	5,079.9	5,085.8			Calculated	
Baseline Emiss (lb/MMBtu)	0.201	0.201			Unit 1 average prior to LNC3+ installation	

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BART Supplement - NOx Emission Control Cost Analysis
Table A-4: Unit 1 NOx Control - Foster Wheeler LNC3+

Operating Unit: **Unit 1**

Emission Unit Number	EU-1		Stack/Vent Number	SV-1		CEPCI	
Desgin Capacity	6,015	MMBtu/hr	Standardized Flow Rate	866,294	scfm @ 32º F	2005	468.2
Expected Utiliztion Rate	100%		Temperature	330	Deg F	2011	588.9
Expected Annual Hours of Operation	8,409.6	Hours	Moisture Content	13.3%		Inflation Factor	1.26
Annual Interest Rate	5.5%		Actual Flow Rate	2,234,300	acfm		
Expected Equipment Life	20	yrs	Standardized Flow Rate	1,391,000	scfm @ 330º F		
Baseline NOx	0.201	lb/MMBtu	Dry Std Flow Rate	1,205,997	dscfm @ 330º F		

CONTROL EQUIPMENT COSTS

Capital Costs			
Direct Capital Costs			
Purchased Equipment (A)			1,257,796
Purchased Equipment Total (B)			**1,958,057**
Installation - Standard Costs			1,958,057
Installation - Site Specific Costs			NA
Installation Total			3,729,632
Total Direct Capital Cost, DC			5,687,689
Total Indirect Capital Costs, IC			391,611
Total Capital Investment (TCI) = DC + IC			**6,079,300**
Operating Costs			
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.	7,779
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	756,551
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**764,330**

Emission Control Cost Calculation

Pollutant	Max Emis Lb/Hr	Pre-control Annual T/Yr	Cont Eff %	Exit Conc	Conc Units	Cont Emis T/yr	Reduction T/yr	Cont Cost $/Ton Rem
Nitrogen Oxides (NOx)	1,208.1	5,079.9	24%			3861.6	1,218.2	627

Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 2 (Used PM Scrubber which has lowest installed cost multiplier)

Notes & Assumptions

1. Sept 2005 Cost Estimate from Foster Wheeler, Option 2, inflated to 2011 dollars. Ratio based on actual cost for Unit 2 instalaltion.
2. Total capital investment reflects actual installed costs for Unit 2 installation, infllated to 2011 dollars.
3. Assumed 0.1 hr/shift operatior and maintenance labor for LNB
4. Process, emissions and cost data listed above is for one unit.
5. For units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal

Great River Energy Coal Creek Station
BART Supplement - NOx Emission Control Cost Analysis
Table A-4: Unit 1 NOx Control - Foster Wheeler LNC3+

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) (1)			**1,257,796**
Instrumentation			
Sales Taxes			
Freight			
Purchased Equipment Total (B)			**1,958,057**
Installation			
Foundations & supports			
Handling & erection			
Electrical			
Piping			
Insulation			
Painting			
Installation Subtotal Standard Expenses (1)			**1,958,057**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Site Specific - Other		Site Specific	NA
Total Site Specific Costs			NA
Installation Total			**3,729,632**
Total Direct Capital Cost, DC			**5,687,689**
Indirect Capital Costs			
Engineering, supervision	5%	of purchased equip cost (B)	97,903
Construction & field expenses	10%	of purchased equip cost (B)	195,806
Contractor fees	0%	of purchased equip cost (B)	0
Start-up	1%	of purchased equip cost (B)	19,581
Performance test	1%	of purchased equip cost (B)	19,581
Model Studies	NA	of purchased equip cost (B)	NA
Contingencies	3%	of purchased equip cost (B)	58,742
Total Indirect Capital Costs, IC	20%	of purchased equip cost (B)	**391,611**
Ozone Generator, Installed Cost			**0**
Total Capital Investment (TCI) = DC + IC (2)			**6,079,300**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**6,079,300**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	NA		-
Supervisor	NA		-
Maintenance			
Maintenance Labor	37.00	$/Hr, 0.1 hr/8 hr shift, 8409.6 hr/yr	3,889
Maintenance Materials	100%	of maintenance labor costs	3,889
Utilities, Supplies, Replacements & Waste Management			
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
Total Annual Direct Operating Costs			**7,779**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	4,667
Administration (2% total capital costs)	2%	of total capital costs (TCI)	121,586
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	60,793
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	60,793
Capital Recovery	0.0837	for a 20- year equipment life and a 5.5% interest rate	508,712
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**756,551**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**764,330**

Great River Energy Coal Creek Station
BART Supplement - NOx Emission Control Cost Analysis
Table A-4: Unit 1 NOx Control - Foster Wheeler LNC3+

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Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Parts & Equipment:		
Equipment Life	5	years
CRF	0.0000	
Rep part cost per unit	0	$/ft^3
Amount Required	0	ft^3
Packing Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:			
Equipment Life	3		
CRF	0.3707		
Rep part cost per unit	0	$ each	
Amount Required	0	Number	
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax	
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr	OAQPS list replacement times from 5 - 20 min per bag.
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	
Annualized Cost	**0**		

Electrical Use							
	Flow acfm		Δ P ft H2O	Efficiency	Hp	kW	
Blower, Scrubber	2,234,300		0	0.7	-	0.0	EPA Cost Cont Manual 6th ed Section 5.2 Chapter 1 Eq 1.48
	Flow	Liquid SPGR	Δ P ft H2O	Efficiency	Hp	kW	
Circ Pump	000 gpm	1	0	0.7	-	0.0	EPA Cost Cont Manual 6th ed Section 5.2 Chapter 1 Eq 1.49
H2O WW Disch	0 gpm	1	0	0.7	-	0.0	EPA Cost Cont Manual 6th ed Section 5.2 Chapter 1 Eq 1.49
			lb/hr O_3				
LTO Electric Use	4.5	kW/lb O_3				0	
Other							
Total						0.0	

Reagent Use & Other Operating Costs						
Ozone Needed	1.8	lb O3/lb NOx	-	lb/hr O3		
Oxygen Needed	10%	wt O2 to O3 conversion	0	lb/hr O2	0	scfh O2
LTO Cooling Water	150	gal/lb O3	0	gpm		
Liquid/Gas ratio	0.0	* L/G = Gal/1,000 acf				
Circulating Water Rate	0	gpm				
Water Makeup Rate/WW Disch =	20%	of circulating water rate =	0 gpm			
Scrubber Cost	10	$/scfm Gas	$0		Incremental cost per BOC. Need to increase vessel size over standard absorber.	
Ozone Generator	$350	lb O3/day	$0	Installed	Installed cost factor per BOC.	

Direct Operating Cost Calculations — **Annual hours of operation:** **8,409.6**; **Utilization Rate:** **100%**

Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
Operating Labor							
Op Labor	0	$/Hr	0.1	hr/8 hr shift	105	0	$/Hr, 0.1 hr/8 hr shift, 8409.6 hr/yr
Supervisor	15%	of Op.			NA	-	15% of Operator Costs
Maintenance							
Maint Labor	37.00	$/Hr	0.1	hr/8 hr shift	105	3,889	$/Hr, 0.1 hr/8 hr shift, 8409.6 hr/yr
Maint Mtls	100	% of Maintenance Labor			NA	3,889	100% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.0604	$/kwh	0.0	kW-hr	0	0	$/kwh, 0 kW-hr, 8409.6 hr/yr, 100% utilization
Water	0.3100	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 8409.6 hr/yr, 100% utilization
Cooling Water	0.3208	$kgal	0.0	gpm	0	0	$kgal, 0 gpm, 8409.6 hr/yr, 100% utilization
Comp Air	0.3671	$/kscf	0	kscfm	0	0	$/kscf, 0 kscfm, 8409.6 hr/yr, 100% utilization
WW Treat Neutralization	1.9572	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 8409.6 hr/yr, 100% utilization
WW Treat Biotreatement	4.9581	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 8409.6 hr/yr, 100% utilization
SW Disposal	0.0000	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8409.6 hr/yr, 100% utilization
Haz W Disp	326.1933	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8409.6 hr/yr, 100% utilization
Ammonia Mitigation	5.6100	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8409.6 hr/yr, 100% utilization
Lost Ash Sales	12.3000	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8409.6 hr/yr, 100% utilization
Lime	90.0000	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 8409.6 hr/yr, 100% utilization
Caustic	364.4367	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 8409.6 hr/yr, 100% utilization
Oxygen	17.9108	kscf	0.0	kscf/hr	0	0	kscf, 0 kscf/hr, 8409.6 hr/yr, 100% utilization

*annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

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BART Supplement - NOx Emission Control Cost Analysis

Table A-5: Unit 1 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (Maintain Ash Sales)

Operating Unit: **Unit 1**

Emission Unit Number	EU-1		Stack/Vent Number	SV-1	
Desgin Capacity	6,015	MMBtu/hr	Standardized Flow Rate	866,294	scfm @ 32º F
Expected Utiliztion Rate	100%		Temperature	330	Deg F
Expected Annual Hours of Operation	8,409.6	Hours	Moisture Content	13.3%	
Annual Interest Rate	5.5%		Actual Flow Rate	2,234,300	acfm
Expected Equipment Life	20	yrs	Standardized Flow Rate	1,391,000	scfm @ 330º F
Baseline NOx	0.201	lb/MMBtu	Dry Std Flow Rate	1,205,997	dscfm @ 330º F

CONTROL EQUIPMENT COSTS

Capital Costs								
Direct Capital Costs								
Purchased Equipment (A)								3,700,000
Purchased Equipment Total (B)								**8,465,600**
Installation - Standard Costs								1,270,000
Installation - Site Specific Costs								1,036,000
Installation Total								1,758,000
Total Capital Investment (TCI) = DC + IC								**12,176,084**
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.						3,588,665
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost						1,018,887
Total Annual Cost (Annualized Capital Cost + Operating Cost)								**4,607,552**

Emission Control Cost Calculation

Pollutant	**Max Emis Lb/Hr**	**Pre-control Annual T/Yr**	**Cont Eff %**	**Exit Conc**	**Conc Units**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
Nitrogen Oxides (NOx)	1,208.1	5,079.9	25.0%			3809.9	1,270.0	3,628

Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1

Notes & Assumptions

1. November 2011 SNCR Evaluation from URS
2. SNCR Maintenance Costs EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.21
3. Process, emissions and cost data listed above is for one unit.
4. For units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal
5. Retrofit factor of 60% used by URS based on site visit to Coal Creek Station.
6. SW disposal and fly ash sales data from Nov. 2011 Golder Fly Ash Evaluation, Appendix B2
7. One-time cost for Technology Licensing Fee for the SNCR process is ~0.5% of the Process Capital.

Great River Energy Coal Creek Station

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BART Supplement - NOx Emission Control Cost Analysis

Table A-5: Unit 1 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (Maintain Ash Sales)

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment			**3,700,000**
Purchased Equipment Costs			
Instrumentation	10%	of purchased equipment cost	370,000
Site Specific and Prime Contractor Markup	28%	of purchased equipment cost	1,036,000
Freight	5%	of purchased equipment cost	185,000
Purchased Equipment Total	43%		5,291,000
Purchased Equipment Total+ Retrofit Factor (A)			**8,465,600**
Indirect Installation			
General Facilities		See Notes & Assumptions 1 on pg. 1 of Table	420,000
Engineering & Home Office		See Notes & Assumptions 1 on pg. 1 of Table	850,000
Process Contingency		See Notes & Assumptions 1 on pg. 1 of Table	488,000
Total Indirect Installation Costs (B)		See Notes & Assumptions 1 on pg. 1 of Table	**1,758,000**
Project Contingeny (C)		See Notes & Assumptions 1 on pg. 1 of Table	**1,540,000**
Total Plant Cost (D)		A + B + C	**11,763,600**
Allowance for Funds During Construction (E)		0 for SNCR	**0**
Prepaid Royalties (F)		See Notes & Assumptionss 1 and 7 on pg. 1 of Table	**42,000**
Pre Production Costs (G)		See Notes & Assumptions 1 on pg. 1 of Table	**236,000**
Inventory Capital (H)		Reagent Vol * $/gal	**134,484**
Intial Catalyst and Chemicals (I)		0 for SNCR	**0**
Total Capital Investment (TCI) = DC + IC		D + E + F + G +H + I	**12,176,084**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**12,176,084**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	NA		-
Supervisor	NA		-
Maintenance			
Maintenance Total	1.50	% of Total Capital Investment	182,641
Maintenance Materials	NA	% of Maintenance Labor	-
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.060	See Direct Operating Cost Calculations on last pg.	31,009
Water	0.310	See Direct Operating Cost Calculations on last pg.	9,072
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
Urea	500.00	See Direct Operating Cost Calculations on last pg.	3,365,942
NA	NA		-
Total Annual Direct Operating Costs			**3,588,665**
Indirect Operating Costs			
Overhead	NA	of total labor and material costs	NA
Administration (2% total capital costs)	NA	of total capital costs (TCI)	NA
Property tax (1% total capital costs)	NA	of total capital costs (TCI)	NA
Insurance (1% total capital costs)	NA	of total capital costs (TCI)	NA
Capital Recovery	0.08368	for a 20- year equipment life and a 5.5% interest rate	1,018,887
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**1,018,887**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**4,607,552**

See Summary page for notes and assumptions

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BART Supplement - NOx Emission Control Cost Analysis

Table A-5: Unit 1 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (Maintain Ash Sales)

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.08368	

Replacement Catayst		<- Enter Equipment Name to Get Cost
Equipment Life	5	years
CRF	0.2342	
Rep part cost per unit	0	$\$/ft^3$
Amount Required	12	ft^3
Packing Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:		<- Enter Equipment Name to Get Cost	
Equipment Life	2	years	
CRF	0.0000		
Rep part cost per unit	0	$\$/ft^3$	
Amount Required	0	Cages	
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax	See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs
Installation Labor	0	10 min per bag, Labor + Overhead (68% = $29.65/hr)	
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	EPA CCM list replacement times from 5 - 20 min per bag.
Annualized Cost	**0**		

Electrical Use			
NOx in	0.20	lb/MMBtu	kW
NSR	0.60		
Power			61.0
Total			61.0

Reagent Use & Other Operating Costs					
NOx in	0.20	lb/MMBtu	Urea Use	1601	lb/hr
Efficiency	25%		Volume 14 day inventory	269	ton
Duty	6,015	MMBtu/hr	Inventory Cost	$134,484	
Water Use	3480	gal/hr			

Direct Operating Cost Calculations — **Annual hours of operation: 8,409.6** — **Utilization Rate: 100%**

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Operating Labor							
Op Labor	37	$/Hr	0.0	hr/8 hr shift	0	0	$/Hr, 0.0 hr/8 hr shift, 8409.6 hr/yr
Supervisor	15%	of Op.			NA	-	15% of Operator Costs
Maintenance							
Maintenance Total	1.5	% of Total Capital Investment				182,641.26	% of Total Capital Investment
Maint Mtls	0	% of Maintenance Labor			NA	0	0% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.06045	$/kwh	61.00000	kW-hr	512,985.60	31,009.11	$/kwh, 61.0 kW-hr, 8409.6 hr/yr, 100% utilization
Water	0.31000	$/kgal	3480.00000	gph	29,265.41	9,072.28	0.31 $/kgal X 3,480.0 gph/1000 X 8409.6 hr/yr X 100% utilization
Cooling Water	0.32080	$kgal	0.00000	gpm	0	0	$kgal, 0 gpm, 8409.6 hr/yr, 100% utilization
Comp Air	0.36713	$/kscf	0.00000	scfm/kacfm**	0	0	$/kscf, 0.0 scfm/kacfm**, 8409.6 hr/yr, 100% utilization
WW Treat Neutralization	1.95716	$/kgal	0.00000	gpm	0	0	$/kgal, 0.0 gpm, 8409.6 hr/yr, 100% utilization
WW Treat Biotreatement	4.95814	$/kgal	0.00000	gpm	0	0	$/kgal, 0.0 gpm, 8409.6 hr/yr, 100% utilization
SW Disposal	0.00000	$/ton	6.54014	ton/hr	55,000	0	$/ton, 6.5 ton/hr, 8409.6 hr/yr, 100% utilization
Haz W Disp	326.19330	$/ton	0.00000	ton/hr	0	0	$/ton, 0.0 ton/hr, 8409.6 hr/yr, 100% utilization
Ammonia Mitigation	5.61	$/ton	0.00000	ton/hr	0	0	$/ton, 0.0 ton/hr, 8409.6 hr/yr, 100% utilization
Lost Ash Sales	12.3	$/ton	0.00000	ton/hr	0	0	$/ton, 0.0 ton/hr, 8409.6 hr/yr, 100% utilization
Lime	90.0	$/ton	0.00000	lb/hr	0	0	$/ton, 0.0 lb/hr, 8409.6 hr/yr, 100% utilization
Urea	500.0	$/ton	0.80050	ton/hr	6,731.88	3,365,942.40	500 $/ton X 0.8005 ton/hr X 8409.6 hr/yr X 100% utilization
Oxygen	17.91078	kscf	0.00000	kscf/hr	0	0	kscf, 0.0 kscf/hr, 8409.6 hr/yr, 100% utilization

** Std Air use is 2 scfm/kacfm

*annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

Great River Energy Coal Creek Station **Technical Update 06/07/2012**

BART Supplement - NOx Emission Control Cost Analysis

Table A-6: Unit 1 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (30% Lost Ash Sales)

Operating Unit: **Unit 1**

Emission Unit Number	EU-1		Stack/Vent Number	SV-1	
Desgin Capacity	6,015	MMBtu/hr	Standardized Flow Rate	866,294	scfm @ 32º F
Expected Utiliztion Rate	100%		Temperature	330	Deg F
Expected Annual Hours of Operation	8,409.6	Hours	Moisture Content	13.3%	
Annual Interest Rate	5.5%		Actual Flow Rate	2,234,300	acfm
Expected Equipment Life	20	yrs	Standardized Flow Rate	1,391,000	scfm @ 330º F
Baseline NOx	0.201	lb/MMBtu	Dry Std Flow Rate	1,205,997	dscfm @ 330º F

CONTROL EQUIPMENT COSTS

Capital Costs		
Direct Capital Costs		
Purchased Equipment (A)		3,700,000
Purchased Equipment Total (B)		**8,465,600**
Installation - Standard Costs		1,270,000
Installation - Site Specific Costs		1,036,000
Installation Total		1,758,000
Total Capital Investment (TCI) = DC + IC		**12,176,084**
Operating Costs		
Total Annual Direct Operating Costs	Labor, supervision, materials, replacement parts, utilities, etc.	5,806,840
Total Annual Indirect Operating Costs	Sum indirect oper costs + capital recovery cost	1,018,887
Total Annual Cost (Annualized Capital Cost + Operating Cost)		**6,825,727**

Emission Control Cost Calculation

Pollutant	**Max Emis Lb/Hr**	**Pre-control Annual T/Yr**	**Cont Eff %**	**Exit Conc**	**Conc Units**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
Nitrogen Oxides (NOx)	1,208.1	5,079.9	25.0%			3809.9	1,270.0	5,375

Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1

Notes & Assumptions

1. November 2011 SNCR Evaluation from URS
2. SNCR Maintenance Costs EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.21
3. Process, emissions and cost data listed above is for one unit.
4. For units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal
5. Retrofit factor of 60% used by URS based on site visit to Coal Creek Station.
6. SW disposal and fly ash sales data from Nov. 2011 Golder Fly Ash Evaluation, Appendix B2
7. One-time cost for Technology Licensing Fee for the SNCR process is ~0.5% of the Process Capital.

Great River Energy Coal Creek Station

Technical Update 06/07/2012

BART Supplement - NOx Emission Control Cost Analysis

Table A-6: Unit 1 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (30% Lost Ash Sales)

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment			**3,700,000**
Purchased Equipment Costs			
Instrumentation	10.00%	of purchased equipment cost	370,000
Site Specific and Prime Contractor Markup	28.00%	of purchased equipment cost	1,036,000
Freight	5.00%	of purchased equipment cost	185,000
Purchased Equipment Total	43.00%		5,291,000
Purchased Equipment Total+ Retrofit Factor (A)			**8,465,600**
Indirect Installation			
General Facilities		See Notes & Assumptions 1 on pg. 1 of Table	420,000
Engineering & Home Office		See Notes & Assumptions 1 on pg. 1 of Table	850,000
Process Contingency		See Notes & Assumptions 1 on pg. 1 of Table	488,000
Total Indirect Installation Costs (B)		See Notes & Assumptions 1 on pg. 1 of Table	**1,758,000**
Project Contingeny (C)		See Notes & Assumptions 1 on pg. 1 of Table	**1,540,000**
Total Plant Cost (D)		A + B + C	**11,763,600**
Allowance for Funds During Construction (E)		0 for SNCR	**0**
Prepaid Royalties (F)		See Notes & Assumptionss 1 and 7 on pg. 1 of Table	**42,000**
Pre Production Costs (G)		See Notes & Assumptions 1 on pg. 1 of Table	**236,000**
Inventory Capital (H)		Reagent Vol * $/gal	**134,484**
Intial Catalyst and Chemicals (I)		0 for SNCR	**0**
Total Capital Investment (TCI) = DC + IC		D + E + F + G +H + I	**12,176,084**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**12,176,084**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	NA		-
Supervisor	NA		-
Maintenance			
Maintenance Total	1.50	% of Total Capital Investment	182,641
Maintenance Materials	NA	% of Maintenance Labor	-
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.060	See Direct Operating Cost Calculations on last pg.	31,009
Water	0.310	See Direct Operating Cost Calculations on last pg.	9,072
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
SW Disposal	5.44	See Direct Operating Cost Calculations on last pg.	637,648
NA	NA		-
Ammonia Mitigation	5.61	See Direct Operating Cost Calculations on last pg.	814,853
Lost Ash Sales	12.30	See Direct Operating Cost Calculations on last pg.	765,675
NA	NA		-
Urea	500.00	See Direct Operating Cost Calculations on last pg.	3,365,942
NA	NA		-
Total Annual Direct Operating Costs			**5,806,840**
Indirect Operating Costs			
Overhead	NA	of total labor and material costs	NA
Administration (2% total capital costs)	NA	of total capital costs (TCI)	NA
Property tax (1% total capital costs)	NA	of total capital costs (TCI)	NA
Insurance (1% total capital costs)	NA	of total capital costs (TCI)	NA
Capital Recovery	0.08368	for a 20- year equipment life and a 5.5% interest rate	1,018,887
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**1,018,887**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**6,825,727**

See Summary page for notes and assumptions

Great River Energy Coal Creek Station **Technical Update 06/07/2012**

BART Supplement - NOx Emission Control Cost Analysis

Table A-6: Unit 1 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (30% Lost Ash Sales)

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.08368	

Replacement Catayst		<- Enter Equipment Name to Get Cost
Equipment Life	5	years
CRF	0.2342	
Rep part cost per unit	0	$/ft^3
Amount Required	12	ft^3
Packing Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:		<- Enter Equipment Name to Get Cost	
Equipment Life	2	years	
CRF	0.0000		
Rep part cost per unit	0	$/ft^3	
Amount Required	0 Cages		
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax	See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs
Installation Labor	0	10 min per bag, Labor + Overhead (68% = $29.65/hr)	
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	EPA CCM list replacement times from 5 - 20 min per bag.
Annualized Cost	**0**		

Electrical Use			
NOx in	0.20	lb/MMBtu	kW
NSR	0.60		
Power			61.0
Total			61.0

Reagent Use & Other Operating Costs					
NOx in	0.20	lb/MMBtu	Urea Use	1601	lb/hr
Efficiency	25%		Volume 14 day inventory	269	ton
Duty	6,015	MMBtu/hr	Inventory Cost	$134,484	
Water Use	3480	gal/hr			

Direct Operating Cost Calculations **Annual hours of operation:** **8,409.6**
Utilization Rate: **100%**

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Operating Labor							
Op Labor	37	$/Hr	0.0	hr/8 hr shift	0	0	$/Hr, 0.0 hr/8 hr shift, 8409.6 hr/yr
Supervisor	15%	of Op.			NA	-	15% of Operator Costs
Maintenance							
Maintenance Total	1.5	% of Total Capital Investment				182,641.26	% of Total Capital Investment
Maint Mtls	0	% of Maintenance Labor			NA	0	0% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.06045	$/kwh	61.00000	kW-hr	512,985.60	31,009.11	0.0604 $/kwh X 61.0 kW-hr X 8409.6 hr/yr X 100% utilization
Water	0.31000	$/kgal	3480.00000	gph	29,265.41	9,072.28	0.3100 $/kgal X 3,480.0 gph/1000 X 8409.6 hr/yr X 100% utilization
Cooling Water	0.32080	$kgal	0.00000	gpm	0	0	$kgal, 0 gpm, 8409.6 hr/yr, 100% utilization
Comp Air	0.36713	$/kscf	0.00000	scfm/kacfm**	0	0	$/kscf, 0.0 scfm/kacfm**, 8409.6 hr/yr, 100% utilization
WW Treat Neutralization	1.95716	$/kgal	0.00000	gpm	0	0	$/kgal, 0.0 gpm, 8409.6 hr/yr, 100% utilization
WW Treat Biotreatement	4.95814	$/kgal	0.00000	gpm	0	0	$/kgal, 0.0 gpm, 8409.6 hr/yr, 100% utilization
SW Disposal	5.43836	$/ton	13.94240	ton/hr	117,250	637,648	5.4384 $/ton X 13.9424 ton/hr X 8409.6 hr/yr X 100% utilization
Haz W Disp	326.19330	$/ton	0.00000	ton/hr	0	0	$/ton, 0.0 ton/hr, 8409.6 hr/yr, 100% utilization
Ammonia Mitigation	5.61	$/ton	17.27193	ton/hr	145,250	814,853	5.61 $/ton X 17.2719 ton/hr X 8409.6 hr/yr X 100% utilization
Lost Ash Sales	12.3	$/ton	7.40225	ton/hr	62,250.0	765,675	12.3 $/ton X 7.4023 ton/hr X 8409.6 hr/yr X 100% utilization
Lime	90.0	$/ton	0.00000	lb/hr	0	0	$/ton, 0.0 lb/hr, 8409.6 hr/yr, 100% utilization
Urea	500.0	$/ton	0.80050	ton/hr	6,731.88	3,365,942.40	500 $/ton X 0.8005 ton/hr X 8409.6 hr/yr X 100% utilization
Oxygen	17.91078	kscf	0.00000	kscf/hr	0	0	kscf, 0.0 kscf/hr, 8409.6 hr/yr, 100% utilization

** Std Air use is 2 scfm/kacfm *annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

Great River Energy Coal Creek Station **Technical Update 06/07/2012**

BART Supplement - NOx Emission Control Cost Analysis

Table A-7: Unit 1 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (100% Lost Ash Sales)

Operating Unit: **Unit 1**

Emission Unit Number	EU-1		Stack/Vent Number	SV-1	
Desgin Capacity	6,015	MMBtu/hr	Standardized Flow Rate	866,294	scfm @ 32º F
Expected Utiliztion Rate	100%		Temperature	330	Deg F
Expected Annual Hours of Operation	8,409.6	Hours	Moisture Content	13.3%	
Annual Interest Rate	5.5%		Actual Flow Rate	2,234,300	acfm
Expected Equipment Life	20	yrs	Standardized Flow Rate	1,391,000	scfm @ 330º F
Baseline NOx	0.201	lb/MMBtu	Dry Std Flow Rate	1,205,997	dscfm @ 330º F

CONTROL EQUIPMENT COSTS

Capital Costs								
Direct Capital Costs								
Purchased Equipment (A)								3,700,000
Purchased Equipment Total (B)								**8,465,600**
Installation - Standard Costs								1,270,000
Installation - Site Specific Costs								1,036,000
Installation Total								1,758,000
Total Capital Investment (TCI) = DC + IC								**12,176,084**
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.						8,082,365
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost						1,018,887
Total Annual Cost (Annualized Capital Cost + Operating Cost)								**9,101,252**

Emission Control Cost Calculation

Pollutant	**Max Emis Lb/Hr**	**Pre-control Annual T/Yr**	**Cont Eff %**	**Exit Conc**	**Conc Units**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
Nitrogen Oxides (NOx)	1,208.1	5,079.9	25.0%			3809.9	1,270.0	7,167

Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1

Notes & Assumptions

1. November 2011 SNCR Evaluation from URS
2. SNCR Maintenance Costs EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.21
3. Process, emissions and cost data listed above is for one unit.
4. For units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal
5. Retrofit factor of 60% used by URS based on site visit to Coal Creek Station.
6. SW disposal and fly ash sales data from Nov. 2011 Golder Fly Ash Evaluation, Appendix B2
7. One-time cost for Technology Licensing Fee for the SNCR process is ~0.5% of the Process Capital.

Great River Energy Coal Creek Station **Technical Update 06/07/2012**

BART Supplement - NOx Emission Control Cost Analysis

Table A-7: Unit 1 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (100% Lost Ash Sales)

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment			**3,700,000**
Purchased Equipment Costs			
Instrumentation	10.00%	of purchased equipment cost	370,000
Site Specific and Prime Contractor Markup	28.00%	of purchased equipment cost	1,036,000
Freight	5.00%	of purchased equipment cost	185,000
Purchased Equipment Total	43.00%		5,291,000
Purchased Equipment Total+ Retrofit Factor (A)			**8,465,600**
Indirect Installation			
General Facilities		See Notes & Assumptions 1 on pg. 1 of Table	420,000
Engineering & Home Office		See Notes & Assumptions 1 on pg. 1 of Table	850,000
Process Contingency		See Notes & Assumptions 1 on pg. 1 of Table	488,000
Total Indirect Installation Costs (B)		See Notes & Assumptions 1 on pg. 1 of Table	**1,758,000**
Project Contingeny (C)		See Notes & Assumptions 1 on pg. 1 of Table	**1,540,000**
Total Plant Cost (D)		A + B + C	**11,763,600**
Allowance for Funds During Construction (E)		0 for SNCR	**0**
Prepaid Royalties (F)		See Notes & Assumptionss 1 and 7 on pg. 1 of Table	**42,000**
Pre Production Costs (G)		See Notes & Assumptions 1 on pg. 1 of Table	**236,000**
Inventory Capital (H)		Reagent Vol * $/gal	**134,484**
Intial Catalyst and Chemicals (I)		0 for SNCR	**0**
Total Capital Investment (TCI) = DC + IC		D + E + F + G +H + I	**12,176,084**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**12,176,084**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	NA		-
Supervisor	NA		-
Maintenance			
Maintenance Total	1.50	% of Total Capital Investment	182,641
Maintenance Materials	NA	% of Maintenance Labor	-
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.060	See Direct Operating Cost Calculations on last pg.	31,009
Water	0.310	See Direct Operating Cost Calculations on last pg.	9,072
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
SW Disposal	7.40	See Direct Operating Cost Calculations on last pg.	1,941,450
NA	NA		-
NA	NA		-
Lost Ash Sales	12.30	See Direct Operating Cost Calculations on last pg.	2,552,250
NA	NA		-
Urea	500.00	See Direct Operating Cost Calculations on last pg.	3,365,942
NA	NA		-
Total Annual Direct Operating Costs			**8,082,365**
Indirect Operating Costs			
Overhead	NA	of total labor and material costs	NA
Administration (2% total capital costs)	NA	of total capital costs (TCI)	NA
Property tax (1% total capital costs)	NA	of total capital costs (TCI)	NA
Insurance (1% total capital costs)	NA	of total capital costs (TCI)	NA
Capital Recovery	0.08368	for a 20- year equipment life and a 5.5% interest rate	1,018,887
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**1,018,887**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**9,101,252**

See Summary page for notes and assumptions

Great River Energy Coal Creek Station **Technical Update 06/07/2012**

BART Supplement - NOx Emission Control Cost Analysis

Table A-7: Unit 1 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (100% Lost Ash Sales)

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.08368	

Replacement Catayst		<- Enter Equipment Name to Get Cost
Equipment Life	5	years
CRF	0.2342	
Rep part cost per unit	0	$/ft^3
Amount Required	12	ft^3
Packing Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:		<- Enter Equipment Name to Get Cost	
Equipment Life	2	years	
CRF	0.0000		
Rep part cost per unit	0	$/ft^3	
Amount Required	0	Cages	
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax	See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs
Installation Labor	0	10 min per bag, Labor + Overhead (68% = $29.65/hr)	
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	EPA CCM list replacement times from 5 - 20 min per bag.
Annualized Cost	**0**		

Electrical Use			
NOx in	0.20	lb/MMBtu	kW
NSR	0.60		
Power			61.0
Total			61.0

Reagent Use & Other Operating Costs					
NOx in	0.20	lb/MMBtu	Urea Use	1601	lb/hr
Efficiency	25%		Volume 14 day inventory	269	ton
Duty	6,015	MMBtu/hr	Inventory Cost	$134,484	
Water Use	3480	gal/hr			

Direct Operating Cost Calculations — **Annual hours of operation:** **8,409.6**; **Utilization Rate:** **100%**

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Operating Labor							
Op Labor	37	$/Hr	0.0	hr/8 hr shift	0	0	$/Hr, 0.0 hr/8 hr shift, 8409.6 hr/yr
Supervisor	15%	of Op.			NA	-	15% of Operator Costs
Maintenance							
Maintenance Total	1.5	% of Total Capital Investment				182,641.26	% of Total Capital Investment
Maint Mtls	0	% of Maintenance Labor			NA	0	0% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.06045	$/kwh	61.00000	kW-hr	512,985.60	31,009.11	0.0604 $/kwh X 61.0 kW-hr X 8409.6 hr/yr X 100% utilization
Water	0.31000	$/kgal	3480.00000	gph	29,265.41	9,072.28	0.3100 $/kgal X 3,480.0 gph/1000 X 8409.6 hr/yr X 100% utilization
Cooling Water	0.32080	$kgal	0.00000	gpm	0	0	$kgal, 0 gpm, 8409.6 hr/yr, 100% utilization
Comp Air	0.36713	$/kscf	0.00000	scfm/kacfm**	0	0	$/kscf, 0.0 scfm/kacfm**, 8409.6 hr/yr, 100% utilization
WW Treat Neutralization	1.95716	$/kgal	0.00000	gpm	0	0	$/kgal, 0.0 gpm, 8409.6 hr/yr, 100% utilization
WW Treat Biotreatement	4.95814	$/kgal	0.00000	gpm	0	0	$/kgal, 0.0 gpm, 8409.6 hr/yr, 100% utilization
SW Disposal	7.39600	$/ton	31.21433	ton/hr	262,500	1,941,450	7.3960 $/ton X 31.2143 ton/hr X 8409.6 hr/yr X 100% utilization
Haz W Disp	326.19330	$/ton	0.00000	ton/hr	0	0	$/ton, 0.0 ton/hr, 8409.6 hr/yr, 100% utilization
Ammonia Mitigation	5.61	$/ton	0.00000	ton/hr	0	0	$/ton, 0.0 ton/hr, 8409.6 hr/yr, 100% utilization
Lost Ash Sales	12.3	$/ton	24.67418	ton/hr	207,500	2,552,250	12.3 $/ton X 24.6742 ton/hr X 8409.6 hr/yr X 100% utilization
Lime	90.0	$/ton	0.00000	lb/hr	0	0	$/ton, 0.0 lb/hr, 8409.6 hr/yr, 100% utilization
Urea	500.0	$/ton	0.80050	ton/hr	6,731.88	3,365,942.40	500.0 $/ton X 0.8005 ton/hr X 8409.6 hr/yr X 100% utilization
Oxygen	17.91078	kscf	0.00000	kscf/hr	0	0	kscf, 0.0 kscf/hr, 8409.6 hr/yr, 100% utilization

** Std Air use is 2 scfm/kacfm

*annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

Great River Energy Coal Creek Station **Technical Update 06/07/2012**

BART Supplement - NOx Emission Control Cost Analysis

Table A-8: Unit 2 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (Maintain Ash Sales)

Operating Unit: **Unit 2**

Emission Unit Number	EU-2		Stack/Vent Number	SV-2	
Desgin Capacity	6,022	MMBtu/hr	Standardized Flow Rate	866,294	scfm @ 32º F
Expected Utiliztion Rate	100%		Temperature	330	Deg F
Expected Annual Hours of Operation	8,409.6	Hours	Moisture Content	13.3%	
Annual Interest Rate	5.5%		Actual Flow Rate	2,234,300	acfm
Expected Equipment Life	20	yrs	Standardized Flow Rate	1,391,000	scfm @ 330º F
Inlet NOx	0.153	lb/MMBtu	Dry Std Flow Rate	1,205,997	dscfm @ 330º F

CONTROL EQUIPMENT COSTS

Capital Costs								
Direct Capital Costs								
Purchased Equipment (A)								3,600,000
Purchased Equipment Total (B)								**8,236,800**
Installation - Standard Costs								1,230,000
Installation - Site Specific Costs								1,008,000
Installation Total								1,702,000
Total Capital Investment (TCI) = DC + IC								**11,793,820**
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.						2,634,116
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost						986,899
Total Annual Cost (Annualized Capital Cost + Operating Cost)								**3,621,015**

Emission Control Cost Calculation

Pollutant	**Max Emis Lb/Hr**	**Pre-control Annual T/Yr**	**Cont Eff %**	**Exit Conc**	**Conc Units**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
Nitrogen Oxides (NOx)	1,209.5	5,085.8	20.0%			4068.6	1,017.2	3,560

Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1

Notes & Assumptions

1. November 2011 SNCR Evaluation from URS
2. SNCR Maintenance Costs EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.21
3. Process, emissions and cost data listed above is for one unit.
4. For units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal
5. Retrofit factor of 60% used by URS based on site visit to Coal Creek Station.
6. SW disposal and fly ash sales data from Nov. 2011 Golder Fly Ash Evaluation, Appendix B2
7. One-time cost for Technology Licensing Fee for the SNCR process is ~0.5% of the Process Capital.

Great River Energy Coal Creek Station **Technical Update 06/07/2012**

BART Supplement - NOx Emission Control Cost Analysis

Table A-8: Unit 2 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (Maintain Ash Sales)

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment			**3,600,000**
Purchased Equipment Costs			
Instrumentation	10.00%	of purchased equipment cost	360,000
Site Specific and Prime Contractor Markup	28.00%	of purchased equipment cost	1,008,000
Freight	5.00%	of purchased equipment cost	180,000
Purchased Equipment Total	43.00%		5,148,000
Purchased Equipment Total+ Retrofit Factor (A)			**8,236,800**
Indirect Installation			
General Facilities		See Notes & Assumptions 1 on pg. 1 of Table	410,000
Engineering & Home Office		See Notes & Assumptions 1 on pg. 1 of Table	820,000
Process Contingency		See Notes & Assumptions 1 on pg. 1 of Table	472,000
Total Indirect Installation Costs (B)		See Notes & Assumptions 1 on pg. 1 of Table	**1,702,000**
Project Contingeny (C)		See Notes & Assumptions 1 on pg. 1 of Table	**1,490,000**
Total Plant Cost (D)		A + B + C	**11,428,800**
Allowance for Funds During Construction (E)		0 for SNCR	**0**
Prepaid Royalties (F)		See Notes & Assumptionss 1 and 7 on pg. 1 of Table	**41,000**
Pre Production Costs (G)		See Notes & Assumptions 1 on pg. 1 of Table	**227,000**
Inventory Capital (H)		Reagent Vol * $/gal	**97,020**
Intial Catalyst and Chemicals (I)		0 for SNCR	**0**
Total Capital Investment (TCI) = DC + IC		D + E + F + G +H + I	**11,793,820**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**11,793,820**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	NA		-
Supervisor	NA		-
Maintenance			
Maintenance Total	1.50	% of Total Capital Investment	176,907
Maintenance Materials	NA	% of Maintenance Labor	-
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.060	See Direct Operating Cost Calculations on last pg.	22,367
Water	0.310	See Direct Operating Cost Calculations on last pg.	6,570
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
Urea	500.00	See Direct Operating Cost Calculations on last pg.	2,428,272
NA	NA		-
Total Annual Direct Operating Costs			**2,634,116**
Indirect Operating Costs			
Overhead	NA	of total labor and material costs	NA
Administration (2% total capital costs)	NA	of total capital costs (TCI)	NA
Property tax (1% total capital costs)	NA	of total capital costs (TCI)	NA
Insurance (1% total capital costs)	NA	of total capital costs (TCI)	NA
Capital Recovery	0.08368	for a 20- year equipment life and a 5.5% interest rate	986,899
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**986,899**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**3,621,015**

See Summary page for notes and assumptions

Great River Energy Coal Creek Station

BART Supplement - NOx Emission Control Cost Analysis
Table A-8: Unit 2 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (Maintain Ash Sales)

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.08368	

Replacement Catayst		<- Enter Equipment Name to Get Cost
Equipment Life	5	years
CRF	0.2342	
Rep part cost per unit	0	$/ft^3
Amount Required	12	ft^3
Packing Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:		<- Enter Equipment Name to Get Cost	
Equipment Life	2	years	
CRF	0.0000		
Rep part cost per unit	0	$/ft^3	
Amount Required	0	Cages	
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax	See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs
Installation Labor	0	10 min per bag, Labor + Overhead (68% = $29.65/hr)	
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	EPA CCM list replacement times from 5 - 20 min per bag.
Annualized Cost	**0**		

Electrical Use			
NOx in	0.15	lb/MMBtu	kW
NSR	0.44		
Power			44.0
Total			44.0

Reagent Use & Other Operating Costs					
NOx in	0.15	lb/MMBtu	Urea Use	1155	lb/hr
Efficiency	20%		Volume 14 day inventory	194	ton
Duty	6,022	MMBtu/hr	Inventory Cost	$97,020	
Water Use	2520	gal/hr			

Direct Operating Cost Calculations — **Annual hours of operation: 8,409.6**; **Utilization Rate: 100%**

Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
Operating Labor							
Op Labor	37	$/Hr	0.0	hr/8 hr shift	0	0	$/Hr, 0.0 hr/8 hr shift, 8409.6 hr/yr
Supervisor	15%	of Op.			NA	-	15% of Operator Costs
Maintenance							
Maintenance Total	1.5	% of Total Capital Investment				176,907.30	% of Total Capital Investment
Maint Mtls	0	% of Maintenance Labor			NA	0	0% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.06045	$/kwh	44.00000	kW-hr	370,022.40	22,367.23	0.0604 $/kwh X 44.0 kW-hr X 8409.6 hr/yr X 100% utilization
Water	0.31000	$/kgal	2520.00000	gph	21,192.19	6,569.58	0.3100 $/kgal X 2,520.0 gph/1000 X 8409.6 hr/yr X 100% utilization
Cooling Water	0.32080	$kgal	0.00000	gpm	0	0	$kgal, 0 gpm, 8409.6 hr/yr, 100% utilization
Comp Air	0.36713	$/kscf	0.00000	scfm/kacfm**	0	0	$/kscf, 0.0 scfm/kacfm**, 8409.6 hr/yr, 100% utilization
WW Treat Neutralization	1.95716	$/kgal	0.00000	gpm	0	0	$/kgal, 0.0 gpm, 8409.6 hr/yr, 100% utilization
WW Treat Biotreatement	4.95814	$/kgal	0.00000	gpm	0	0	$/kgal, 0.0 gpm, 8409.6 hr/yr, 100% utilization
SW Disposal	0.00000	$/ton	6.54014	ton/hr	55,000	0	$/ton, 6.5 ton/hr, 8409.6 hr/yr, 100% utilization
Haz W Disp	326.19330	$/ton	0.00000	ton/hr	0	0	$/ton, 0.0 ton/hr, 8409.6 hr/yr, 100% utilization
Ammonia Mitigation	5.61	$/ton	0.00000	ton/hr	0	0	$/ton, 0.0 ton/hr, 8409.6 hr/yr, 100% utilization
Lost Ash Sales	12.3	$/ton	0.00000	ton/hr	0	0	$/ton, 0.0 ton/hr, 8409.6 hr/yr, 100% utilization
Lime	90.0	$/ton	0.00000	lb/hr	0	0	$/ton, 0.0 lb/hr, 8409.6 hr/yr, 100% utilization
Urea	500.0	$/ton	0.57750	ton/hr	4,856.54	2,428,272.00	500.0 $/ton X 0.5775 ton/hr X 8409.6 hr/yr X 100% utilization
Oxygen	17.91078	kscf	0.00000	kscf/hr	0	0	kscf, 0.0 kscf/hr, 8409.6 hr/yr, 100% utilization

** Std Air use is 2 scfm/kacfm — *annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

Great River Energy Coal Creek Station **Technical Update 06/07/2012**

BART Supplement - NOx Emission Control Cost Analysis

Table A-9: Unit 2 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (30% Lost Ash Sales)

Operating Unit: **Unit 2**

Emission Unit Number	EU-2		Stack/Vent Number	SV-2	
Desgin Capacity	6,022	MMBtu/hr	Standardized Flow Rate	866,294	scfm @ 32º F
Expected Utiliztion Rate	100%		Temperature	330	Deg F
Expected Annual Hours of Operation	8,409.6	Hours	Moisture Content	13.3%	
Annual Interest Rate	5.5%		Actual Flow Rate	2,234,300	acfm
Expected Equipment Life	20	yrs	Standardized Flow Rate	1,391,000	scfm @ 330º F
Inlet NOx	0.153	lb/MMBtu	Dry Std Flow Rate	1,205,997	dscfm @ 330º F

CONTROL EQUIPMENT COSTS

Capital Costs								
Direct Capital Costs								
Purchased Equipment (A)								3,600,000
Purchased Equipment Total (B)								**8,236,800**
Installation - Standard Costs								1,230,000
Installation - Site Specific Costs								1,008,000
Installation Total								1,702,000
Total Capital Investment (TCI) = DC + IC								**11,793,820**
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.						4,852,291
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost						986,899
Total Annual Cost (Annualized Capital Cost + Operating Cost)								**5,839,190**

Emission Control Cost Calculation

Pollutant	**Max Emis Lb/Hr**	**Pre-control Annual T/Yr**	**Cont Eff %**	**Exit Conc**	**Conc Units**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
Nitrogen Oxides (NOx)	1,209.5	5,085.8	20.0%			4068.6	1,017.2	5,741

Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1

Notes & Assumptions

1. November 2011 SNCR Evaluation from URS
2. SNCR Maintenance Costs EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.21
3. Process, emissions and cost data listed above is for one unit.
4. For units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal
5. Retrofit factor of 60% used by URS based on site visit to Coal Creek Station.
6. SW disposal and fly ash sales data from Nov. 2011 Golder Fly Ash Evaluation, Appendix B2
7. One-time cost for Technology Licensing Fee for the SNCR process is ~0.5% of the Process Capital.

Great River Energy Coal Creek Station — **Technical Update 06/07/2012**

BART Supplement - NOx Emission Control Cost Analysis

Table A-9: Unit 2 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (30% Lost Ash Sales)

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment			**3,600,000**
Purchased Equipment Costs			
Instrumentation	10.00%	of purchased equipment cost	360,000
Site Specific and Prime Contractor Markup	28.00%	of purchased equipment cost	1,008,000
Freight	5.00%	of purchased equipment cost	180,000
Purchased Equipment Total	43.00%		5,148,000
Purchased Equipment Total+ Retrofit Factor (A)			**8,236,800**
Indirect Installation			
General Facilities		See Notes & Assumptions 1 on pg. 1 of Table	410,000
Engineering & Home Office		See Notes & Assumptions 1 on pg. 1 of Table	820,000
Process Contingency		See Notes & Assumptions 1 on pg. 1 of Table	472,000
Total Indirect Installation Costs (B)		See Notes & Assumptions 1 on pg. 1 of Table	**1,702,000**
Project Contingeny (C)		See Notes & Assumptions 1 on pg. 1 of Table	**1,490,000**
Total Plant Cost (D)		A + B + C	**11,428,800**
Allowance for Funds During Construction (E)		0 for SNCR	**0**
Prepaid Royalties (F)		See Notes & Assumptionss 1 and 7 on pg. 1 of Table	**41,000**
Pre Production Costs (G)		See Notes & Assumptions 1 on pg. 1 of Table	**227,000**
Inventory Capital (H)		Reagent Vol * $/gal	**97,020**
Intial Catalyst and Chemicals (I)		0 for SNCR	**0**
Total Capital Investment (TCI) = DC + IC		D + E + F + G +H + I	**11,793,820**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**11,793,820**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	NA		-
Supervisor	NA		-
Maintenance			
Maintenance Total	1.50	% of Total Capital Investment	176,907
Maintenance Materials	NA	% of Maintenance Labor	-
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.060	See Direct Operating Cost Calculations on last pg.	22,367
Water	0.310	See Direct Operating Cost Calculations on last pg.	6,570
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
SW Disposal	5.44	See Direct Operating Cost Calculations on last pg.	637,648
NA	NA		-
Ammonia Mitigation	5.61	See Direct Operating Cost Calculations on last pg.	814,853
Lost Ash Sales	12.30	See Direct Operating Cost Calculations on last pg.	765,675
NA	NA		-
Urea	500.00	See Direct Operating Cost Calculations on last pg.	2,428,272
NA	NA		-
Total Annual Direct Operating Costs			**4,852,291**
Indirect Operating Costs			
Overhead	NA	of total labor and material costs	NA
Administration (2% total capital costs)	NA	of total capital costs (TCI)	NA
Property tax (1% total capital costs)	NA	of total capital costs (TCI)	NA
Insurance (1% total capital costs)	NA	of total capital costs (TCI)	NA
Capital Recovery	0.08368	for a 20- year equipment life and a 5.5% interest rate	986,899
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**986,899**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**5,839,190**

See Summary page for notes and assumptions

Great River Energy Coal Creek Station

Technical Update 06/07/2012

BART Supplement - NOx Emission Control Cost Analysis

Table A-9: Unit 2 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (30% Lost Ash Sales)

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.08368	

Replacement Catayst		<- Enter Equipment Name to Get Cost
Equipment Life	5	years
CRF	0.2342	
Rep part cost per unit	0	$\$/ft^3$
Amount Required	12	ft^3
Packing Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:		<- Enter Equipment Name to Get Cost	
Equipment Life	2	years	
CRF	0.0000		
Rep part cost per unit	0	$\$/ft^3$	
Amount Required	0	Cages	
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax	See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs
Installation Labor	0	10 min per bag, Labor + Overhead (68% = $29.65/hr)	
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	EPA CCM list replacement times from 5 - 20 min per bag.
Annualized Cost	**0**		

Electrical Use			
NOx in	0.15	lb/MMBtu	kW
NSR	0.44		
Power			44.0
Total			44.0

Reagent Use & Other Operating Costs					
NOx in	0.15	lb/MMBtu	Urea Use	1155	lb/hr
Efficiency	20%		Volume 14 day inventory	194	ton
Duty	6,022	MMBtu/hr	Inventory Cost	$97,020	
Water Use	2520	gal/hr			

Direct Operating Cost Calculations — **Annual hours of operation:** **8,409.6**; **Utilization Rate:** **100%**

Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
Operating Labor							
Op Labor	37	$/Hr	0.0	hr/8 hr shift	0	0	$/Hr, 0.0 hr/8 hr shift, 8409.6 hr/yr
Supervisor	15%	of Op.			NA	-	15% of Operator Costs
Maintenance							
Maintenance Total	1.5	% of Total Capital Investment				176,907.30	% of Total Capital Investment
Maint Mtls	0	% of Maintenance Labor			NA	0	0% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.06045	$/kwh	44.00000	kW-hr	370,022.40	22,367.23	0.0604 $/kwh X 44.0 kW-hr X 8409.6 hr/yr X 100% utilization
Water	0.31000	$/kgal	2520.00000	gph	21,192.19	6,569.58	0.3100 $/kgal X 2,520.0 gph/1000 X 8409.6 hr/yr X 100% utilization
Cooling Water	0.32080	$kgal	0.00000	gpm	0	0	$kgal, 0 gpm, 8409.6 hr/yr, 100% utilization
Comp Air	0.36713	$/kscf	0.00000	scfm/kacfm**	0	0	$/kscf, 0.0 scfm/kacfm**, 8409.6 hr/yr, 100% utilization
WW Treat Neutralization	1.95716	$/kgal	0.00000	gpm	0	0	$/kgal, 0.0 gpm, 8409.6 hr/yr, 100% utilization
WW Treat Biotreatement	4.95814	$/kgal	0.00000	gpm	0	0	$/kgal, 0.0 gpm, 8409.6 hr/yr, 100% utilization
SW Disposal	5.43836	$/ton	13.94240	ton/hr	117,250	637,648	5.4384 $/ton X 13.9 ton/hr X 8409.6 hr/yr X 100% utilization
Haz W Disp	326.19330	$/ton	0.00000	ton/hr	0	0	$/ton, 0.0 ton/hr, 8409.6 hr/yr, 100% utilization
Ammonia Mitigation	5.61	$/ton	17.27193	ton/hr	145,250	814,853	5.6 $/ton X 17.2719 ton/hr X 8409.6 hr/yr X 100% utilization
Lost Ash Sales	12.3	$/ton	7.40225	ton/hr	62,250	765,675	12.3 $/ton X 7.4023 ton/hr X 8409.6 hr/yr X 100% utilization
Lime	90.0	$/ton	0.00000	lb/hr	0	0	$/ton, 0.0 lb/hr, 8409.6 hr/yr, 100% utilization
Urea	500.0	$/ton	0.57750	ton/hr	4,856.54	2,428,272.00	500.0 $/ton X 0.5775 ton/hr X 8409.6 hr/yr X 100% utilization
Oxygen	17.91078	kscf	0.00000	kscf/hr	0	0	kscf, 0.0 kscf/hr, 8409.6 hr/yr, 100% utilization

** Std Air use is 2 scfm/kacfm

*annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

Great River Energy Coal Creek Station

BART Supplement - NOx Emission Control Cost Analysis

Table A-10: Unit 2 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (100% Lost Ash Sales)

Operating Unit: **Unit 2**

Emission Unit Number	EU-2		Stack/Vent Number	SV-2	
Desgin Capacity	6,022	MMBtu/hr	Standardized Flow Rate	866,294	scfm @ 32º F
Expected Utiliztion Rate	100%		Temperature	330	Deg F
Expected Annual Hours of Operation	8,409.6	Hours	Moisture Content	13.3%	
Annual Interest Rate	5.5%		Actual Flow Rate	2,234,300	acfm
Expected Equipment Life	20	yrs	Standardized Flow Rate	1,391,000	scfm @ 330º F
Inlet NOx	0.153	lb/MMBtu	Dry Std Flow Rate	1,205,997	dscfm @ 330º F

CONTROL EQUIPMENT COSTS

Capital Costs								
Direct Capital Costs								
Purchased Equipment (A)								3,600,000
Purchased Equipment Total (B)								**8,236,800**
Installation - Standard Costs								1,230,000
Installation - Site Specific Costs								1,008,000
Installation Total								1,702,000
Total Capital Investment (TCI) = DC + IC								**11,793,820**
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.						7,127,816
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost						986,899
Total Annual Cost (Annualized Capital Cost + Operating Cost)								**8,114,715**

Emission Control Cost Calculation

Pollutant	Max Emis Lb/Hr	Pre-control Annual T/Yr	Cont Eff %	Exit Conc	Conc Units	Cont Emis T/yr	Reduction T/yr	Cont Cost $/Ton Rem
Nitrogen Oxides (NOx)	1,209.5	5,085.8	20.0%			4068.6	1,017.2	7,978

Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1

Notes & Assumptions

1. November 2011 SNCR Evaluation from URS
2. SNCR Maintenance Costs EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.21
3. Process, emissions and cost data listed above is for one unit.
4. For units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal
5. Retrofit factor of 60% used by URS based on site visit to Coal Creek Station.
6. SW disposal and fly ash sales data from Nov. 2011 Golder Fly Ash Evaluation, Appendix B2
7. One-time cost for Technology Licensing Fee for the SNCR process is ~0.5% of the Process Capital.

Great River Energy Coal Creek Station **Technical Update 06/07/2012**

BART Supplement - NOx Emission Control Cost Analysis

Table A-10: Unit 2 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (100% Lost Ash Sales)

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment			**3,600,000**
Purchased Equipment Costs			
Instrumentation	10.00%	of purchased equipment cost	360,000
Site Specific and Prime Contractor Markup	28.00%	of purchased equipment cost	1,008,000
Freight	5.00%	of purchased equipment cost	180,000
Purchased Equipment Total	43.00%		5,148,000
Purchased Equipment Total+ Retrofit Factor (A)			**8,236,800**
Indirect Installation			
General Facilities		See footnote 1 on pg. 1 of Table	410,000
Engineering & Home Office		See footnote 1 on pg. 1 of Table	820,000
Process Contingency		See footnote 1 on pg. 1 of Table	472,000
Total Indirect Installation Costs (B)		See footnote 1 on pg. 1 of Table	**1,702,000**
Project Contingeny (C)		See footnote 1 on pg. 1 of Table	**1,490,000**
Total Plant Cost (D)		A + B + C	**11,428,800**
Allowance for Funds During Construction (E)		0 for SNCR	**0**
Prepaid Royalties (F)		See footnotes 1 and 7 on pg. 1 of Table	**41,000**
Pre Production Costs (G)		See footnote 1 on pg. 1 of Table	**227,000**
Inventory Capital (H)		Reagent Vol * $/gal	**97,020**
Intial Catalyst and Chemicals (I)		0 for SNCR	**0**
Total Capital Investment (TCI) = DC + IC		D + E + F + G +H + I	**11,793,820**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**11,793,820**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	NA		-
Supervisor	NA		-
Maintenance			
Maintenance Total	1.50	% of Total Capital Investment	176,907
Maintenance Materials	NA	% of Maintenance Labor	-
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.060	See Direct Operating Cost Calculations on last pg.	22,367
Water	0.310	See Direct Operating Cost Calculations on last pg.	6,570
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
SW Disposal	7.40	See Direct Operating Cost Calculations on last pg.	1,941,450
NA	NA		-
NA	NA		-
Lost Ash Sales	12.30	See Direct Operating Cost Calculations on last pg.	2,552,250
NA	NA		-
Urea	500.00	See Direct Operating Cost Calculations on last pg.	2,428,272
NA	NA		-
Total Annual Direct Operating Costs			**7,127,816**
Indirect Operating Costs			
Overhead	NA	of total labor and material costs	NA
Administration (2% total capital costs)	NA	of total capital costs (TCI)	NA
Property tax (1% total capital costs)	NA	of total capital costs (TCI)	NA
Insurance (1% total capital costs)	NA	of total capital costs (TCI)	NA
Capital Recovery	0.08368	for a 20- year equipment life and a 5.5% interest rate	986,899
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**986,899**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**8,114,715**

See Summary page for notes and assumptions

Great River Energy Coal Creek Station **Technical Update 06/07/2012**

BART Supplement - NOx Emission Control Cost Analysis

Table A-10: Unit 2 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (100% Lost Ash Sales)

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.08368	

Replacement Catayst		<- Enter Equipment Name to Get Cost
Equipment Life	5	years
CRF	0.2342	
Rep part cost per unit	0	$/ft^3
Amount Required	12	ft^3
Packing Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:		<- Enter Equipment Name to Get Cost	
Equipment Life	2	years	
CRF	0.0000		
Rep part cost per unit	0	$/ft^3	
Amount Required	0	Cages	
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax	See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs
Installation Labor	0	10 min per bag, Labor + Overhead (68% = $29.65/hr)	
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	EPA CCM list replacement times from 5 - 20 min per bag.
Annualized Cost	**0**		

Electrical Use			
NOx in	0.15	lb/MMBtu	kW
NSR	0.44		
Power			44.0
Total			44.0

Reagent Use & Other Operating Costs					
NOx in	0.15	lb/MMBtu	Urea Use	1155	lb/hr
Efficiency	20%		Volume 14 day inventory	194	ton
Duty	6,022	MMBtu/hr	Inventory Cost	$97,020	
Water Use	2520	gal/hr			

Direct Operating Cost Calculations — **Annual hours of operation:** **8,409.6** — **Utilization Rate:** **100%**

Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
Operating Labor							
Op Labor	37	$/Hr	0.0	hr/8 hr shift	0	0	$/Hr, 0.0 hr/8 hr shift, 8409.6 hr/yr
Supervisor	15%	of Op.			NA	-	15% of Operator Costs
Maintenance							
Maintenance Total	1.5	% of Total Capital Investment				176,907.30	% of Total Capital Investment
Maint Mtls	0	% of Maintenance Labor			NA	0	0% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.06045	$/kwh	44.00000	kW-hr	370,022.40	22,367.23	0.0604 $/kwh X 44.0 kW-hr X 8409.6 hr/yr X 100% utilization
Water	0.31000	$/kgal	2520.00000	gph	21,192.19	6,569.58	0.31 $/kgal X 2,520.0 gph/1000 X 8409.6 hr/yr X 100% utilization
Cooling Water	0.32080	$kgal	0.00000	gpm	0	0	$kgal, 0 gpm, 8409.6 hr/yr, 100% utilization
Comp Air	0.36713	$/kscf	0.00000	scfm/kacfm**	0	0	$/kscf, 0.0 scfm/kacfm**, 8409.6 hr/yr, 100% utilization
WW Treat Neutralization	1.95716	$/kgal	0.00000	gpm	0	0	$/kgal, 0.0 gpm, 8409.6 hr/yr, 100% utilization
WW Treat Biotreatement	4.95814	$/kgal	0.00000	gpm	0	0	$/kgal, 0.0 gpm, 8409.6 hr/yr, 100% utilization
SW Disposal	7.39600	$/ton	31.21433	ton/hr	262,500	1,941,450	7.3960 $/ton X 31.2 ton/hr X 8409.6 hr/yr X 100% utilization
Haz W Disp	326.19330	$/ton	0.00000	ton/hr	0	0	$/ton, 0.0 ton/hr, 8409.6 hr/yr, 100% utilization
Ammonia Mitigation	5.61	$/ton	0.00000	ton/hr	0	0	$/ton, 0.0 ton/hr, 8409.6 hr/yr, 100% utilization
Lost Ash Sales	12.3	$/ton	24.67418	ton/hr	207,500	2,552,250	12.3 $/ton X 24.6742 ton/hr X 8409.6 hr/yr X 100% utilization
Lime	90.0	$/ton	0.00000	lb/hr	0	0	$/ton, 0.0 lb/hr, 8409.6 hr/yr, 100% utilization
Urea	500.0	$/ton	0.57750	ton/hr	4,856.54	2,428,272.00	500.0 $/ton X 0.5775 ton/hr X 8409.6 hr/yr X 100% utilization
Oxygen	17.91078	kscf	0.00000	kscf/hr	0	0	kscf, 0.0 kscf/hr, 8409.6 hr/yr, 100% utilization

** Std Air use is 2 scfm/kacfm *annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

GREAT RIVER ENERGY®
A Touchstone Energy® Cooperative

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June 7, 2012

VIA ELECTRONIC
AND U.S. MAIL

Mr. Terry O'Clair
Director, Division of Air Quality
North Dakota Department of Health
918 E. Divide Ave.
Bismarck, ND 58501-1947

RE: Coal Creek NOx BART Analysis: Technical Update

Dear Mr. O'Clair:

Please find enclosed a brief technical update to accompany Great River Energy's ("GRE's") April 5, 2012 Coal Creek Station Units 1 and 2 Supplemental Best Available Retrofit Technology Refined Analysis for NOx Emissions ("Supplemental BART Analysis"). GRE has updated the tables in its Supplemental BART Analysis to assist the North Dakota Department of Health ("NDDH") to evaluate the cost of several scenarios not expressly addressed in GRE's April 5, 2012 submission. GRE's update contains new control cost numbers based on the following assumptions:

- Coal Creek Station Unit 2's NOx emissions baseline has been adjusted to 0.201 lb/MMBtu instead of 0.153 lb/MMBtu;
- Baseline operating hours for Units 1 and 2 and the resulting emissions have been scaled up to reflect emissions in non-outage years; the result of this scale-up is a control efficiency of 39% (instead of 33%) for SNCR and LNC3+ together.

This update confirms GRE's long-standing position that LNC3+ is cost effective, but that SCNR and LNC3+ is not the Best Available Retrofit Technology ("BART") for Coal Creek Station Units 1 and 2 because the combined technologies are not cost effective on an actual or incremental basis. Even under a lowest-cost scenario that assumes no impact to ash sales, which we know is infeasible, the two controls remove NOx at a cost of roughly $2,200/ton, which is well above the presumptive standards set by EPA's BART guidelines. More importantly, the incremental cost of SNCR is roughly $4,700/ton, which demonstrates SNCR is not a cost-effective addition to the already-efficient LNC3+ controls. The cost of SNCR cannot be justified given that it results in no visibility improvements beyond that achieved with LNC3+ alone.

Please do not hesitate to call me if you have any questions about this update.

Sincerely,

Mary Jo Roth

Mary Jo Roth
Manager, Environmental Services

Enclosures

c: Tom Bachman, NDDH
William M. Bumpers (via e-mail)
Eric Olsen, GRE
Deb Nelson, GRE

GREAT RIVER ENERGY®

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Coal Creek Station Units 1 and 2
June 7, 2012 Technical Update

to

"Supplemental Best Available Retrofit Technology Refined Analysis for NOx Emissions," April 5, 2012

Coal Creek Station Technical Update to Supplemental BART Analysis for NOx Emissions

June 7, 2012

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1.0 Introduction

In December 2007, GRE submitted its final Best Available Retrofit Technology (BART) evaluation for Regional Haze controls to the North Dakota Department of Health (NDDH). The NDDH incorporated the proposed emission limits for Coal Creek Station (CCS) Units 1 and 2 into their proposed State Implementation Plan (SIP) and issued a draft Permit to Construct (PTC) for these BART emission limits. As part of their review of North Dakota's draft SIP, EPA requested supplemental data and documentation concerning Coal Creek's BART analysis. GRE provided the requested information.

On September 21, 2011, EPA proposed a Federal Implementation Plan (FIP), which would override certain NDDH determinations, particularly with respect to required NOx emission limits for certain coal-fired utility units. On November 3, 2011, NDDH requested that GRE provide a supplemental BART analysis that is focused on NOx control options at Coal Creek Station. In particular, GRE performed more refined analyses on selective non-catalytic reduction (SNCR) cost assumptions, achievable control levels and the overall impacts to beneficial use of ash for Coal Creek Station Units 1 and 2. An updated refined analysis was provided to address questions from NDDH on January 19, 2012. In response to questions from NDDH, a complete supplemental submittal was provided to NDDH on April 5, 2012.

Based on these refined analyses, Great River Energy still asserts that use of its state-of-the-art coal drying technology, DryFining™, in conjunction with second generation combustion control low-NOx burners with separated overfire air (LNC3+), meets EPA's presumptive BART NOx limit of 0.17 lb/MMBtu, and is consistent with cost effective thresholds. When all factors are adequately considered, including ammoniated ash impacts and incremental improvements in visibility, SNCR is not considered cost effective for Coal Creek Station given the lack of resulting incremental visibility improvements in the affected Class I areas.

This technical update is issued in response to additional inquiries from NDDH. This technical update, in conjunction with the April 5 supplemental submittal, provides the complete refined analysis of BART controls for Coal Creek Station.

Update to Section 2.2 Revision of Baseline NOx Emissions

Although GRE does not concede that NDDH's BART analysis may disregard any existing controls in use at a unit, GRE has nonetheless calculated a revised baseline for Unit 2 of 0.201 lb. NOx/MMBtu at NDDH's request. This value represents the baseline emissions for Unit 2 taking into consideration the installation of DryFining™ technology while not including the emission reductions gained through the installation of the LNC3+ tuning. The LNC3+ technology was installed in Unit 2 prior to the installation of the DryFining technology and is currently in use. Since Unit 2 has not operated with a DryFining-only configuration, we must utilize the information from Unit 1's emissions baseline as a surrogate for the projected baseline for the operation of LNC3+ as a stand-alone technology.

Update to Section 3.1 SNCR Control Cost Analysis

This technical update has modified the precision of some of the numbers in Table 3.1. The operating scenario utilized to calculate cost effectiveness was based on averaging data from outage and non-outage years, which GRE believes most accurately reflects real-world conditions. To portray the most-conservative, worst-case conditions the operating hours have been adjusted to portray a non-outage year. Due to the change in the baseline and operating hours, the control efficiency value has increased to 39 percent for the LNC3+ with SNCR technology combination in all lost ash sale scenarios. Although the recalculations have lowered the values for cost-effectiveness they remain above EPA's presumptive cost-effectiveness thresholds, and when all factors are considered GRE's conclusion that the installation of SNCR is not cost effective remains valid. Revised Table 3.1 is below.

Table 3.1 Control Cost Summary (2011$)

<table>
<tr><th>Unit ID</th><th>Control Description</th><th>NOx Emissions (lb/MMBtu)</th><th>Control Eff. From Baseline (%)</th><th>Emission Reduction from Baseline (T/yr)</th><th>Installed Capital Cost ($MM)</th><th>Annualized Operating Cost ($MM)</th><th>Pollution Control Cost ($/ton)</th><th>Incremental Cost $/ton</th></tr>
<tr><td rowspan="8">Unit 1</td><td>SNCR,LNC3+,100% Lost Ash Sales (Scenario B)</td><td rowspan="3">0.122</td><td rowspan="3">39%</td><td rowspan="3">1,994.3</td><td rowspan="3">$17.87</td><td>$8.879</td><td>$4,452</td><td>$10,457</td></tr>
<tr><td>SNCR,LNC3+,30% Lost Ash Sales (Scenario C)</td><td>$6.604</td><td>$3,311</td><td>$7,524</td></tr>
<tr><td>SNCR,LNC3+,No Ash Impacts (Scenario A)</td><td>$4.385</td><td>$2,199</td><td>$4,666</td></tr>
<tr><td>SNCR, 100% Lost Ash Sales (Scenario B)</td><td rowspan="3">0.151</td><td rowspan="3">25%</td><td rowspan="3">1,270.0</td><td rowspan="3">$12.18</td><td>$9.101</td><td>$7,167</td><td rowspan="3">NA – Inferior Control</td></tr>
<tr><td>SNCR, 30% Lost Ash Sales (Scenario C)</td><td>$6.826</td><td>$5,375</td></tr>
<tr><td>SNCR, No Ash Impacts (Scenario A)</td><td>$4.608</td><td>$3,628</td></tr>
<tr><td>LNC3+</td><td>0.153</td><td>24%</td><td>1,218.2</td><td>$6.08</td><td>$0.764</td><td>$627</td><td>$627</td></tr>
<tr><td>Baseline (LNC3)</td><td>0.201</td><td>NA-Base</td><td>NA-Base</td><td>NA-Base</td><td>NA-Base</td><td>NA-Base</td><td>NA-Base</td></tr>
<tr><td rowspan="4">Unit 2</td><td>SNCR,LNC3+,100% Lost Ash Sales (Scenario B)</td><td rowspan="3">0.122</td><td rowspan="3">39%</td><td rowspan="3">1,996.6</td><td rowspan="3">$17.87</td><td>$8.879</td><td>$4,447</td><td>$10,444</td></tr>
<tr><td>SNCR,LNC3+,30% Lost Ash Sales (Scenario C)</td><td>$6.604</td><td>$3,307</td><td>$7,516</td></tr>
<tr><td>SNCR,LNC3+,No Ash Impacts (Scenario A)</td><td>$4.385</td><td>$2,196</td><td>$4,661</td></tr>
<tr><td>LNC3+</td><td>0.153</td><td>24%</td><td>1,219.6</td><td>$6.08</td><td>$0.764</td><td>$627</td><td>$627</td></tr>
<tr><td></td><td>Baseline – LNC3</td><td>0.201</td><td>NA-Base</td><td>NA-Base</td><td>NA-Base</td><td>NA-Base</td><td>NA-Base</td><td>NA-Base</td></tr>
</table>

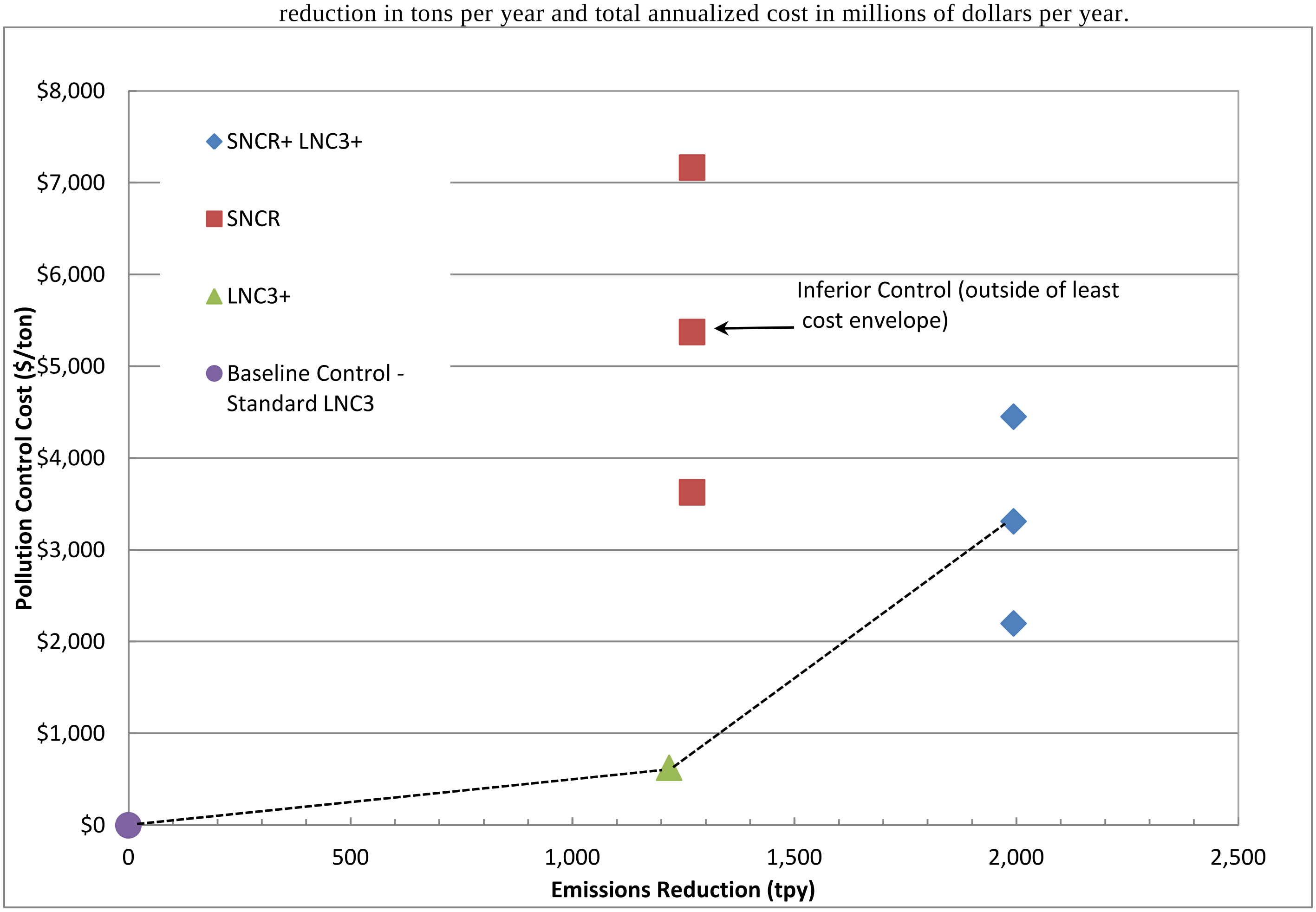
A "No Ash Impacts" scenario is provided for reference only as it does not represent a feasible control option.

GRE takes this opportunity to reiterate that the controlled NOx emission concentrations and mass rates have been evaluated on an annual average basis and are not representative of anticipated operation on a shorter scale averaging period (30-day rolling or 24-hour rolling), consistent with BART guidance that costs be normalized to the expected annual emissions reduction. The 30-day rolling limits are intended to be inclusive of unit startup and shutdown as well as variability in load. Consequently, associated BART limits must be higher than stated annual averages used for estimating cost effectiveness (e.g., LNC3+ is evaluated at 0.153 lb. NOx/MMBtu on an annual average basis with an anticipated 30-day rolling limit of 0.17 lb. NOx/MMBtu). Section 2.2.2 Load Variability in the April 5, 2012 submittal summarizes these effects.

The modified baseline has also shifted the values for the least cost envelope graph which we have supplied for the sake of completeness. The assumptions concerning this table remain the same. Following the graph for least cost LNC3+ would be installed prior to installing any additional technology. The installation of SNCR alone would be an inferior technology and is deemed not cost effective.

Figure 3.1 Incremental NOx Analysis

The remaining feasible technologies are illustrated on the basis of annualized emissions reduction in tons per year and total annualized cost in millions of dollars per year.



3.3 SNCR Visibility Impacts

Table 3.2 Difference in Impairment and Incremental Cost for LNC3+ with Tuning and SNCR with LNC3+

Unit ID	2000 (dV)	2001 (dV)	2002 (dV)	Average (dV)	Incremental Cost per dV (MM$/dV)[1]
Unit 1	0.031	0.044	0.093	0.056	$103.81
Unit 1 & 2	0.062	0.083	0.172	0.106	$110.26

[1] Incremental cost comparison (2011$) of LNC3+ with SNCR with LNC3+ at 30% lost ash sales

The visibility analysis demonstrates that SNCR will not result in actual improvement to visibility in North Dakota's affected Class I areas, and potential modeled improvements will come at a prohibitive incremental cost exceeding $100 million (2011$) per deciview. Utilities in North Dakota only contribute ~6 percent to total NOx emissions in the State. Consequently, any additional utility NOx reductions will not have an appreciable effect on visibility improvement. Additional details regarding modeling inputs and visibility impairment is presented in Appendix D to the April 5, 2012 submittal.

4.0 Conclusions of Technical Update

In evaluating the impacts of Unit 1's technologies it was concluded that installation of SNCR alone (without LNC3+) is an economically inferior technology and therefore is not further evaluated incrementally. When the SNCR and LNC3+ technologies were evaluated together for Unit 1 and Unit 2 they were deemed not cost effective on an incremental basis and therefore not an appropriate BART technology. GRE included the visibility tables for the associated LNC3+, and SNCR cases presented in Table 3.1. The final conclusion for the visibility impacts is that, based on our refined analysis, the state Class I areas would not see any economically justifiable improvements in visibility by requiring a level of NOx control above LNC3+ for Coal Creek Station, and additional reductions would be cost prohibitive on a dollar per deciview basis (Table 3.2).

The refined analysis and subsequent updates clearly demonstrate that the presumptive NOx limit of 0.17 lb/MMBtu is both cost effective and results in significant visibility improvements in North Dakota's Class I areas.

Appendix A

Updated Pollution Control Cost Evaluations

IPM Model – Revisions to Cost and Performance for APC Technologies

SNCR Cost Development Methodology

FINAL

August 2010

Project 12301-007

Perrin Quarles Associates, Inc.

Prepared by

Sargent & Lundy LLC

55 East Monroe Street • Chicago, IL 60603 USA • 312-269-2000

LEGAL NOTICE

This analysis ("Deliverable") was prepared by Sargent & Lundy, L.L.C. ("S&L"), expressly for the sole use of Perrin Quarles Associates, Inc. ("Client") in accordance with the agreement between S&L and Client. This Deliverable was prepared using the degree of skill and care ordinarily exercised by engineers practicing under similar circumstances. Client acknowledges: (1) S&L prepared this Deliverable subject to the particular scope limitations, budgetary and time constraints, and business objectives of the Client; (2) information and data provided by others may not have been independently verified by S&L; and (3) the information and data contained in this Deliverable are time sensitive and changes in the data, applicable codes, standards, and acceptable engineering practices may invalidate the findings of this Deliverable. Any use or reliance upon this Deliverable by third parties shall be at their sole risk.

This work was funded and reviewed by the U.S. Environmental Protection Agency under the supervision of William A. Stevens, Senior Advisor – Power Technologies. Additional input and review was provided by Dr. Jim Staudt, President of Andover Technology Partners.

SNCR Cost Development Methodology – Final

Establishment of Cost Basis

The formulation of the SNCR cost estimating model is based upon a proprietary Sargent & Lundy LLC (S&L) in-house data base of recent (2009) quotes for both lump sum contracts and EPC. The S&L data was analyzed in detail regarding project specifics such as coal type, boiler type, and NOx reduction efficiency. The S&L in-house data includes projects that involved cyclone boilers, T-fired and wall fired systems with multiple levels of injection. The cyclone boiler costs include rich reagent injection (RRI). The data was the basis for the cost estimate formulations developed.

The S&L data was fitted with a least squares curve to establish the trend in $/kW as a function of gross MW. The EPA/IPM SNCR cost model parameters were adjusted to account for market changes and escalation, and then the model output was compared to the S&L data. The EPA/IPM model output followed a $/kW correlation very similar to the S&L in-house data, once the adjustments were made to the model.

The rapid rise in project costs at the lower end of the MW range is due primarily to economies of scale. Additionally, older power plants in the 50 MW range tend to have plant sites that are more compact and therefore difficult to accommodate the reagent storage areas and piping, injection mixing/dilution equipment and construction activities. The smaller power plants also tend to have older control systems which may require upgrades to accommodate the new SNCR control system.

The S&L data includes SNCR projects with various types of boilers, coals, sulfur levels and retrofit complexities. The data represents an average of boiler effects, such as cyclone, wall fired or CFB. The least squares curve fits were based upon the following assumptions:

- Retrofit Factor =1
- Gross Heat Rate = 10,000
- SO_2 Rate = < 3 lb/MMBtu
- Type of Coal = PRB
- Project Execution = Multiple lump sum contracts

Methodology

Inputs

To predict future retrofit costs several input variables are required. The unit size in MW and NOx levels are the major variables for the capital cost estimation followed by the type of fuel (high sulfur Bituminous). The fuel type affects the air pre-heater costs if sulfuric acid or ammonium bisulfate deposition poses a problem. In general, if the level of SO_2 is above 3 lb/MMBtu, it is assumed that air heater modifications will be required. The unit heat rate factors into the amount of NOx generated and ultimately the size of the

SNCR Cost Development Methodology – Final

SNCR reagent preparation system. A retrofit factor that equates to difficulty in construction of the system must be defined. The NO_x rate and removal efficiency will impact the amount of urea required and size of the reagent handling equipment.

The inputs that impact the variable O&M costs are based primarily on the plant capacity factor and the removal efficiency. The NOx removal efficiency specifically affects the reagent and dilution water costs.

Outputs

Total Project Costs (TPC)

The base module costs are calculated for each required module (BM). The base module costs include:

- Equipment;
- Installation;
- Buildings;
- Foundations;
- Electrical; and
- Retrofit factor.

The base module costs do not include:

- Engineering and Construction Management
- Owner's cost; and
- AFUDC.

The base modules are:

BMS =	Base module SNCR cost.
BMA =	Base module air pre-heater cost.
BMB =	Base module balance of plant costs including: piping, electrical, site upgrades, etc…
BM =	BMS + BMA + BMB

The total base module cost (BM) is increased by:

- Engineering and construction management costs at 10% of the BM cost;
- Labor adjustment for 6 x 10 hour shift premium, per diem, etc., at 10% of the BM cost; and
- Contractor profit and fees at 10% of the BM cost.

SNCR Cost Development Methodology – Final

A capital, engineering, and construction cost subtotal (CECC) is established as the sum of the BM and the additional engineering and construction fees.

Additional expenditures for the project are computed based on the CECC. The additional project costs include:

- Owner's home office costs (owner's engineering, management, and procurement) at 5% of the CECC.

The total project cost is based on a multiple lump sum contract approach. Should a turnkey engineering procurement construction (EPC) contract be executed, the total project cost could be 10 to 15% higher than what is currently estimated.

Escalation is not included in the estimate. The total project cost (TPC) is the sum of the CECC and the Owner's home office costs. An example of the capital cost estimation is included in Table 1.

Fixed O&M (FOM)
The fixed operating and maintenance cost is a function of the additional operations staff (FOMO) and maintenance labor and materials (FOMM) associated with the SNCR installation. The FOM is the sum of the FOMO and the FOMM.

The following factors and assumptions underlie calculations of the FOM:

- In general, 1 additional operator is required for all installations. The FOMO is based on the number of additional operations staff required; and

- The fixed costs for maintenance materials and labor are a direct function of the base module cost (BM) at a retrofit factor of 1.0.

Variable O&M (VOM)
Variable O&M is a function of:

- Reagent consumption;
- Dilution water consumption.

All of the VOM costs must be adjusted for the plant capacity factor.

The reagent consumption rate is a function of unit size, NO_x feed rate and removal efficiency. A utilization factor of 15% is used for units with an inlet NOx of 0.3 lb/MMBtu or lower and 25% for units with an inlet NOx greater than 0.3 lb/MMBtu. For CFB boilers a utilization factor of 25% is used. A reagent cost of $620 per ton of 100%

urea is used in the model. The dilution water usage is based upon reagent consumption rate.

The auxiliary power required for the SNCR system is not included in the VOM. The major systems that impact the power requirements are compressed air or blower requirements for the urea injection system and the reagent supply system.

The variables that contribute to the overall VOM are:

VOMR = Variable O&M costs for urea reagent.

VOMM = Variable O&M costs for dilution water.

VOM = VOMR + VOMM.

SNCR Cost Development Methodology – Final

Table 1. Example of the Capital Cost Estimate Work Sheet (for T-fired boilers).

Variable	Designation	Units	Value	Calculation
Boiler Type			Tangential	<--- User Input
Unit Size	A	(MW)	300	<--- User Input
Retrofit Factor	B		1	<--- User Input (An "average" retrofit has a factor = 1.0)
Heat Rate	C	(Btu/kWh)	10000	<--- User Input
NOx Rate	D	(lb/MMBtu)	0.22	<--- User Input
SO2 Rate	E	(lb/MMBtu)	2	
Type of Coal	E		Bituminuous	<--- User Input
Coal Factor	F		1	Bit=1.0, PRB=1.05, Lig=1.07
Heat Rate Factor	G		1	C/10,000
Heat Input	H	(Btu/hr)	3.00E+09	A*C*1000
Capacity Factor	I	(%)	85	<--- User Input
Nox Removal Efficiency	J	%	25	
Nox Removed	K	lb/h	1.65E+02	D*H/10^6*J/100
Urea Rate (100%)	L	(lb/hr)	717	K/UF/46*30; IF Boiler Type = CFB OR D > 0.3 THEN UF = 0.25; ELSE UF = 0.15
Water Required	M	(lb/hr)	6457	L*9
Aux Power	N	(%)	0.05	Auxiliary Power is not used in the Variable O&M Costs
Dilution Water Rate	O	(1000 gph)	0.77	M*0.12/1000
Urea Cost 50% wt solution	P	($/ton)	310	
Aux Power Cost	Q	($/kWh)	0.06	
Dilution Water Cost	R	($/kgal)	1	
Operating Labor Rate	S	($/hr)	60	Labor cost including all benefits

Costs are all based on 2009 dollars

Capital Cost Calculation		Example		Comments
Includes - Equipment, installation, buildings, foundations, electrical, and retrofit difficulty				
BMS ($) =	B*F/1.05*200000*(A*G)^0.42	$	2,090,000	SNCR (Injectors, Blowers, DCS, Reagent System) Cost
BMA ($) =	IF E ≥ 3 THEN 65000*(B)*(A*G)^0.78; ELSE 0	$	-	Air Heater Modification / SO3 Control (Bituminous only & > 3lb/mmBtu)
BMB ($) =	270000*(A)^0.33*(K)^0.12	$	3,273,000	Balance of Plant Cost (Piping, Including Site Upgrades)
BM ($) =	BMS + BMA + BMB	$	5,363,000	Total bare module cost including retrofit factor
BM ($/KW) =			18	Base cost per kW
Total Project Cost				
A1 = 10% of BM		$	536,000	Engineering and Construction Management costs
A2 = 10% of BM		$	536,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc…
A3 = 10% of BM		$	536,000	Contractor profit and fees
CECC ($) = BM+A1+A2+A3		**$**	**6,971,000**	Capital, engineering and construciton cost subtotal
CECC ($/kW) =			**23**	Capital, engineering and construciton cost subtotal per kW
B1 = 5% of CECC		$	349,000	Owners costs including all "home office" costs (owners engineering, management, and procurement activities)
TPC ($) = CECC + B1		**$**	**7,320,000**	Total project cost
TPC ($/kW) =			**24**	Total project cost per kW

Table 2. Example of the Fixed and Variable O&M Cost Estimate Work Sheet (for T-fired boilers).

Variable	Designation	Units	Value	Calculation
Boiler Type			Tangential	<--- User Input
Unit Size	A	(MW)	300	<--- User Input
Retrofit Factor	B		1	<--- User Input (An "average" retrofit has a factor = 1.0)
Heat Rate	C	(Btu/kWh)	10000	<--- User Input
NOx Rate	D	(lb/MMBtu)	0.22	<--- User Input
SO2 Rate	E	(lb/MMBtu)	2	
Type of Coal	E		Bituminuous	<--- User Input
Coal Factor	F		1	Bit=1.0, PRB=1.05, Lig=1.07
Heat Rate Factor	G		1	C/10,000
Heat Input	H	(Btu/hr)	3.00E+09	A*C*1000
Capacity Factor	I	(%)	85	<--- User Input
Nox Removal Efficiency	J	%	25	
Nox Removed	K	lb/h	1.65E+02	D*H/10^6*J/100
Urea Rate (100%)	L	(lb/hr)	717	K/UF/46*30; IF Boiler Type = CFB OR D > 0.3 THEN UF = 0.25; ELSE UF = 0.15
Water Required	M	(lb/hr)	6457	L*9
Aux Power	N	(%)	0.05	Auxiliary Power is not used in the Variable O&M Costs
Dilution Water Rate	O	(1000 gph)	0.77	M*0.12/1000
Urea Cost 50% wt solution	P	($/ton)	310	
Aux Power Cost	Q	($/kWh)	0.06	
Dilution Water Cost	R	($/kgal)	1	
Operating Labor Rate	S	($/hr)	60	Labor cost including all benefits

Costs are all based on 2009 dollars

Fixed O&M Cost			
FOMO ($/kW yr) = (1/2 operator time assumed)*2080*S/(A*1000)	$	0.21	Fixed O&M additional operating labor costs
FOMM ($/kW yr) = 0.012*BM/A/1000	$	0.21	Fixed O&M additional maintenance material and labor costs
FOM ($/kW yr) = FOMO + FOMM	**$**	**0.42**	Total Fixed O&M costs
Variable O&M Cost			
VOMR ($/MWh) = L*P/A/1000	$	0.74	Variable O&M costs for Urea
VOMM ($/MWh) = O*R/A	$	0.00	Variable O&M costs for dilution water
VOM ($/MWh) = VOMR + VOMM	**$**	**0.74**	

Table 3. Example of the Capital Cost Estimate Work Sheet (for CFB boilers).

Variable	Designation	Units	Value	Calculation
Boiler Type			CFB	<--- User Input
Unit Size	A	(MW)	300	<--- User Input
Retrofit Factor	B		1	<--- User Input (An "average" retrofit has a factor = 1.0)
Heat Rate	C	(Btu/kWh)	10000	<--- User Input
NOx Rate	D	(lb/MMBtu)	0.15	<--- User Input
SO2 Rate	E	(lb/MMBtu)	0.2	
Type of Coal	E		Bituminuous	<--- User Input
Coal Factor	F		1	Bit=1.0, PRB=1.05, Lig=1.07
Heat Rate Factor	G		1	C/10,000
Heat Input	H	(Btu/hr)	3.00E+09	A*C*1000
Capacity Factor	I	(%)	85	<--- User Input
Nox Removal Efficiency	J	%	25	
Nox Removed	K	lb/h	1.13E+02	D*H/10^6*J/100
Urea Rate (100%)	L	(lb/hr)	293	K/UF/46*30; IF Boiler Type = CFB OR D > 0.3 THEN UF = 0.25; ELSE UF = 0.15
Water Required	M	(lb/hr)	2641	L*9
Aux Power	N	(%)	0.05	Auxiliary Power is not used in the Variable O&M Costs
Dilution Water Rate	O	(1000 gph)	0.32	M*0.12/1000
Urea Cost 50% wt solution	P	($/ton)	310	
Aux Power Cost	Q	($/kWh)	0.06	
Dilution Water Cost	R	($/kgal)	1	
Operating Labor Rate	S	($/hr)	60	Labor cost including all benefits

Costs are all based on 2009 dollars

Capital Cost Calculation		Example		Comments
Includes - Equipment, installation, buildings, foundations, electrical, and retrofit difficulty				
BMS ($) =	B*F/1.05*200000*(A*G)^0.42	$	1,568,000	SNCR (Injectors, Blowers, DCS, Reagent System) Cost
BMA ($) =	IF E ≥ 3 THEN 65000*(B)*(A*G)^0.78; ELSE 0	$	-	Air Heater Modification / SO3 Control (Bituminous only & > 3lb/mmBtu)
BMB ($) =	270000*(A)^0.33*(K)^0.12	$	2,344,000	Balance of Plant Cost (Piping, Including Site Upgrades)
BM ($) =	BMS + BMA + BMB	$	3,912,000	Total bare module cost including retrofit factor
BM ($/KW) =			13	Base cost per kW
Total Project Cost				
A1 = 10% of BM		$	391,000	Engineering and Construction Management costs
A2 = 10% of BM		$	391,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc…
A3 = 10% of BM		$	391,000	Contractor profit and fees
CECC ($) = BM+A1+A2+A3		**$**	**5,085,000**	Capital, engineering and construciton cost subtotal
CECC ($/kW) =			**17**	Capital, engineering and construciton cost subtotal per kW
B1 = 5% of CECC		$	254,000	Owners costs including all "home office" costs (owners engineering, management, and procurement activities)
TPC ($) = CECC + B1		**$**	**5,339,000**	Total project cost
TPC ($/kW) =			**18**	Total project cost per kW

Table 4. Example of the Fixed and Variable O&M Cost Estimate Work Sheet (for CFB boilers).

Variable	Designation	Units	Value	Calculation
Boiler Type			CFB	<--- User Input
Unit Size	A	(MW)	300	<--- User Input
Retrofit Factor	B		1	<--- User Input (An "average" retrofit has a factor = 1.0)
Heat Rate	C	(Btu/kWh)	10000	<--- User Input
NOx Rate	D	(lb/MMBtu)	0.15	<--- User Input
SO2 Rate	E	(lb/MMBtu)	0.2	
Type of Coal	E		Bituminous	<--- User Input
Coal Factor	F		1	Bit=1.0, PRB=1.05, Lig=1.07
Heat Rate Factor	G		1	C/10,000
Heat Input	H	(Btu/hr)	3.00E+09	A*C*1000
Capacity Factor	I	(%)	85	<--- User Input
Nox Removal Efficiency	J	%	25	
Nox Removed	K	lb/h	1.13E+02	D*H/10^6*J/100
Urea Rate (100%)	L	(lb/hr)	293	K/UF/46*30; IF Boiler Type = CFB OR D > 0.3 THEN UF = 0.25; ELSE UF = 0.15
Water Required	M	(lb/hr)	2641	L*9
Aux Power	N	(%)	0.05	Auxiliary Power is not used in the Variable O&M Costs
Dilution Water Rate	O	(1000 gph)	0.32	M*0.12/1000
Urea Cost 50% wt solution	P	($/ton)	310	
Aux Power Cost	Q	($/kWh)	0.06	
Dilution Water Cost	R	($/kgal)	1	
Operating Labor Rate	S	($/hr)	60	Labor cost including all benefits

Costs are all based on 2009 dollars			
Fixed O&M Cost			
FOMO ($/kW yr) = (1/2 operator time assumed)*2080*S/(A*1000)	$	0.21	Fixed O&M additional operating labor costs
FOMM ($/kW yr) = 0.012*BM/A/1000	$	0.16	Fixed O&M additional maintenance material and labor costs
FOM ($/kW yr) = FOMO + FOMM	**$**	**0.37**	Total Fixed O&M costs
Variable O&M Cost			
VOMR ($/MWh) = L*P/A/1000	$	0.30	Variable O&M costs for Urea
VOMM ($/MWh) = O*R/A	$	0.00	Variable O&M costs for dilution water
VOM ($/MWh) = VOMR + VOMM	**$**	**0.30**	

IPM SNCR COST
COAL CREEK STATION
RETROFIT FACTOR = 1.0

Variable	Designation	Units	Value	Calculation
Boiler Type			TANGENTIAL	User Input
Unit Size	A	MW	601.5	User Input
Retrofit Factor	B		1	User Input "Average" = 1.0
Heat Rate	C	Btu/kw-hr	10000	User Input
NOx Rate	D	lb/MMbtu	0.153	User Input
SO2 rate	E	lb/MMBtu	2	User Input
Type of Coal			lignite	User Input
Coal Factor	F		1.07	Bit. = 1.0; PRB = 1.06; Lignite = 1.07
Heat Rate Factor	G		1	C/10,000
Heat Input	H	Btu/hr	6.015E+09	A*C*1000
Capacity Factor	I		87	User Input
NOx Removal Eff.	J	%	20	User Input
NOx Removed	K	lb/hr	1.841E+02	$D*H/10^6*J/100$
Urea Rate (100%)	L	lb/hr	8.003E+02	K/UF/46*30 UF=0.25 FOR CFB OR D>0.3; OTHERWISE 0.15
Water Required	M	lb/hr	7202.308696	L*9
Aux. Power	N	%	0.05	
Dilution Water Rate	O	1000 gph	0.864277043	M*0.12/1000
Urea Cost 50% Soln.	P	$/ton	250	User Input
Aux. Power Cost	Q	$/kwh	0.06	User Input
Dilution Water Cost	R	$/kgal	3	User Input
Op. Labor Rate	S	$/hr	60	User Input
Capital Cost Calculation				
BMS	2,995,735			SNCR (Injectors, blowers, DCS, Reagent System) Cost
BMA	0			Air Heater Modifications
BMB	4,171,636			Balance of the Plant Cost (Piping, Including Site Upgrades)
BM	7,167,371			Total Bare Module Cost including retrofit factor
Total Project Cost				

IPM SNCR COST
COAL CREEK STATION
RETROFIT FACTOR = 1.0

A1	716,737			Engineering and Construction Management Costs (10% of BM)
A2	716,737			Labor Adjustment (10% of BM)
A3	716,737			Contractor Profit and Fees (10% of BM)
CECC	9,317,582			Capital, Engineering, and Construction Cost Subtotal (BM+A1+A2+A3)
B1	465,879			Owner's Cost (5% of CECC)
TPC	9,783,461			Total Project Cost (CECC + B1) (2009 dollars)

TPC (2011 dollars) = (9,783,461)(1.05) = $10,272,634

IPM SNCR COST
COAL CREEK STATION
RETROFIT FACTOR = 1.3

Variable	Designation	Units	Value	Calculation
Boiler Type			Tangential	User Input
Unit Size	A	MW	601.5	User Input
Retrofit Factor	B		1.3	User Input "Average" = 1.0
Heat Rate	C	Btu/kw-hr	10000	User Input
NOx Rate	D	lb/MMbtu	0.153	User Input
SO2 rate	E	lb/MMBtu	2	User Input
Type of Coal			lignite	User Input
Coal Factor	F		1.07	Bit. = 1.0; PRB = 1.06; Lignite = 1.07
Heat Rate Factor	G		1	C/10,000
Heat Input	H	Btu/hr	6.02E+09	A*C*1000
Capacity Factor	I		87	User Input
NOx Removal Eff.	J	%	20	User Input
NOx Removed	K	lb/hr	1.84E+02	$D*H/10^6*J/100$
Urea Rate (100%)	L	lb/hr	8.00E+02	K/UF/46*30 UF=0.25 FOR CFB OR D>0.3; OTHERWISE 0.15
Water Required	M	lb/hr	7202.308696	L*9
Aux. Power	N	%	0.05	
Dilution Water Rate	O	1000 gph	0.864277043	M*0.12/1000
Urea Cost 50% Soln.	P	$/ton	250	User Input
Aux. Power Cost	Q	$/kwh	0.06	User Input
Dilution Water Cost	R	$/kgal	3	User Input
Op. Labor Rate	S	$/hr	60	User Input
Capital Cost Calculation				
BMS	3,894,456			SNCR (Injectors, blowers, DCS, Reagent System) Cost
BMA	0			Air Heater Modifications
BMB	4,171,636			Balance of the Plant Cost (Piping, Including Site Upgrades)
BM	8,066,092			Total Bare Module Cost including retrofit factor
Total Project Cost				
A1	806,609			Engineering and Construction Management Costs (10% of BM)

IPM SNCR COST
COAL CREEK STATION
RETROFIT FACTOR = 1.3

A2	806,609			Labor Adjustment (10% of BM)
A3	806,609			Contractor Profit and Fees (10% of BM)
CECC	10,485,919			Capital, Engineering, and Construction Cost Subtotal (BM+A1+A2+A3)
B1	524,296			Owner's Cost (5% of CECC)
TPC	11,010,215			Total Project Cost (CECC + B1) (2009 dollars)

TPC (2011 dollars) = (11,010,215)(1.05) = 11,560,726

IPM SNCR COST
COAL CREEK STATION
RETROFIT FACTOR = 1.6

Variable	Designation	Units	Value	Calculation
Boiler Type			Tangential	User Input
Unit Size	A	MW	600	User Input
Retrofit Factor	B		1.6	User Input "Average" = 1.0
Heat Rate	C	Btu/kw-hr	10000	User Input
NOx Rate	D	lb/MMbtu	0.153	User Input
SO2 rate	E	lb/MMBtu	2	User Input
Type of Coal			lignite	User Input
Coal Factor	F		1.07	Bit. = 1.0; PRB = 1.06; Lignite = 1.07
Heat Rate Factor	G		1	C/10,000
Heat Input	H	Btu/hr	6.015E+09	A*C*1000
Capacity Factor	I		87	User Input
NOx Removal Eff.	J	%	20	User Input
NOx Removed	K	lb/hr	184.059	$D*H/10^6*J/100$
Urea Rate (100%)	L	lb/hr	800.2565217	K/UF/46*30 UF=0.25 FOR CFB OR D>0.3; OTHERWISE 0.15
Water Required	M	lb/hr	7202.308696	L*9
Aux. Power	N	%	0.05	
Dilution Water Rate	O	1000 gph	0.864277043	M*0.12/1000
Urea Cost 50% Soln.	P	$/ton	250	User Input
Aux. Power Cost	Q	$/kwh	0.06	User Input
Dilution Water Cost	R	$/kgal	3	User Input
Op. Labor Rate	S	$/hr	60	User Input
Capital Cost Calculation				
BMS	4,788,153			SNCR (Injectors, blowers, DCS, Reagent System) Cost
BMA	0			Air Heater Modifications
BMB	4,168,200			Balance of the Plant Cost (Piping, Including Site Upgrades)
BM	8,956,352			Total Bare Module Cost including retrofit factor
Total Project Cost				
A1	895,635			Engineering and Construction Management Costs (10% of BM)

IPM SNCR COST
COAL CREEK STATION
RETROFIT FACTOR = 1.6

A2	895,635			Labor Adjustment (10% of BM)
A3	895,635			Contractor Profit and Fees (10% of BM)
CECC	11,643,258			Capital, Engineering, and Construction Cost Subtotal (BM+A1+A2+A3)
B1	582,163			Owner's Cost (5% of CECC)
TPC	12,225,421			Total Project Cost (CECC + B1) 2009 dollars

TPC (2011) = (12,225,421)(1.05) = $12,836,692

MEMO TO : Regional Haze File

FROM : Tom Bachman, P.E. T.B.
Senior Environmental Engineer
Division of Air Quality

RE : Coal Creek BART for NO_x

DATE : April 18, 2012

In February 2012, the Department received a revised copy of Great River Energy's report entitled "Coal Creek Station Units 1 and 2; Best Available Retrofit Technology Refined Analysis for NO_x Emissions". The primary cost associated with SNCR (based on no lost ash sales) is the reagent that is used for SNCR. URS, a consultant for Great River Energy, estimated that 1,155 lb/hr of urea would be required in each boiler to lower NO_x emissions from 0.153 lb/10^6 Btu to 0.122 lb/10^6 Btu, a 20% reduction. Since urea is usually fed into the boiler using a 50% solution of urea, the actual feed rate would be 2,310 lb/hr of a 50% solution. To determine if URS's estimate was reasonable, the EPA Air Pollution Control Cost Manual (hereafter Control Cost Manual) was reviewed. The Control Cost Manual provides an equation (Equation 1.15) to estimate the amount of reagent consumption.

$$m_{reagent} = \frac{(NO_{x\ in})\ (Q_B)\ (\acute{\eta}_{NOx})\ (NSR)\ (M_{reagent})}{(M_{NOx})\qquad (SR_T)}$$

Where:

$NO_{x\ in}$	=	Uncontrolled NO_x emission rate (lb/10^6 Btu)
Q_B	=	Boiler heat input (10^6 Btu/hr)
$\acute{\eta}_{NOx}$	=	NO_x removal rate
NSR	=	Normalized Stoichiometric Ratio
$m_{reagent}$	=	Molecular Weight of Reagent (60.06 for urea)
M_{NOx}	=	Molecular Weight of NO_x (use 46.01)
SR_T	=	Ratio of equivalent moles of NH_2 per mole of reagent injected (2 for urea)

For Coal Creek Unit 2:

$NO_{x\ in}$	=	0.153 lb/10^6 Btu
Q_B	=	6,022 x 10^6 Btu/hr
$\acute{\eta}_{NOx}$	=	(0.153 – 0.122) / (0.153) = 0.203
NSR	=	$\frac{[(2)\ (NO_{x\ in}) + 0.7]\ (\acute{\eta}_{NOx})}{(NO_{x\ in})}$

$$NSR = \frac{[(2)(0.153) + 0.7](0.203)}{0.153}$$

$$NSR = 1.335$$

$$m_{reagent} = \frac{(0.153)(6022)(0.203)(1.335)(60.06)}{(46.01)(2)}$$

$m_{reagent}$ = 163 lb/hr of urea (100%)

$m_{reagent}$ = 326 lb/hr of 50% urea

Because of the large discrepancy between the Control Cost Manual and URS's predicted urea usage, I contacted Minnkota Power Cooperative to determine the amount of urea they were using in their Unit 2 SNCR system (see attached email). Minnkota indicated they are using between two and eight gallons per minute of 50% urea solution (1,737,997 gallons in 2011) with an ammonia slip around 1.5 ppm (5 ppm guaranteed by the supplier). Two to eight gallons per minute is 1,140 to 4,560 lb/hr of 50% urea solution (specific gravity = 1.14).

Rate = (2 gpm) (8.333 lb/gal) (1.14) (60 minutes/hr)
Rate = 1,140 lb/hr

Rate = (8 gpm) (8.333 lb/gal) (1.14) (60 minutes/hr)
Rate = 4,560 lb/hr

Minnkota is reducing NO_x emissions from 0.40 lb/10^6 Btu (2009 annual average – prior to SNCR installation) to 0.32 lb/10^6 Btu (2011 annual average – after SNCR installation). In 2011, Unit 2 at the M.R. Young Station had a heat input of 4.1664 x 10^{13} Btu and operated 8,385 hours (see attached data from Clean Air Markets Division). The average heat input was:

H.I. = (4.1664×10^{13} Btu) ÷ (8,385 hr)
H.I = $4{,}969 \times 10^6$ Btu/hr

Using Equation 1.15 from the Control Cost Manual, the expected urea usage rate can be calculated as follows:

$$\acute{\eta}_{NOx} = \frac{(0.40 - 0.32)}{(0.40)} = 0.20$$

$$NSR = \frac{[(2)(0.40) + 0.7](0.20)}{(0.40)}$$

$$NSR = 0.75$$

$$m_{reagent} = \frac{(0.40)(4{,}969)(0.20)(0.75)(60.06)}{(46.01)(2)}$$

$m_{reagent}$ = 195 lb/hr (100% urea)

$m_{reagent}$ = 390 lb/hr (50% urea)

As noted above, Minnkota is feeding between 1,140 and 4,560 lb/hr of 50% urea solution to achieve the 0.08 lb/10^6 Btu NO_x reduction. The ratio of the actual feed rate to the predicted feed rate (from Control Cost Manual) is:

Lower Feed Rate Ratio = (1,140) / (390) = 2.92

Upper Feed Rate Ratio = (4,560) / (390) = 11.69

If you apply these ratios to the urea feed rate predicted by the Control Cost Manual for Coal Creek Station Unit 2, the actual urea feed rate (50% solution) would be :

Lower Coal Creek Expected Feed Rate	=	(2.92) (326 lb/hr)
	=	952 lb/hr
Upper Coal Creek Expected Feed Rate	=	(11.69) (326 lb/hr)
	=	3,811 lb/hr

URS has estimated that 2,310 lb/hr of 50% urea solution will be necessary to achieve the required NO_x reduction (20.3%). URS's estimate of 2,310 lb/hr falls about in the middle of the range predicted (based on actual usage at M.R. Young Station Unit 2).

The large discrepancy between the amount of reagent usage predicted by the Control Cost Manual and the actual usage can be explained by closely examining the Control Cost Manual. Equation 1.15 predicts the amount of urea consumed by the NO_x it reacts with. However, it does not predict the loss of urea due to combustion or ammonia slip. Equation 1.13 provides an estimation of the "utilization" of the reagent. The Control Cost Manual states "Reagent utilization is the ratio of moles of reagent reacted to the moles injected."

(Eq. 1.13) $$\text{Utilization} = \frac{\acute{\eta}_{NOx}}{NSR}$$

In the case of M.R. Young Station Unit 2, the estimated utilization is:

$$\text{Utilization} = \frac{0.20}{0.75} = 26.7\%$$

This utilization rate is consistent with the latest revisions to the Integrated Planning Model (IPM) model which states "A utilization factor of 15% is used for units with an inlet NOx of 0.3 lb/MMBtu or lower and 25% for units with an inlet NOx greater than 0.3 lb/MMBtu." (*IPM Model – Revisions to Cost and Performance for APC Technologies; SNCR Cost Development Methodology; August 2010)*

Based on actual usage and the amount of reagent consumption from Equation 1.15, M.R. Young Station Unit 2 "utilization" is:

$$\text{Upper Utilization} = \frac{390\ \text{lb/hr}}{1{,}140\ \text{lb/hr}} = 0.342\ (34.2\%)$$

$$\text{Lower Utilization} = \frac{390\ \text{lb/hr}}{4{,}560\ \text{lb/hr}} = 0.085\ (8.5\%)$$

The utilization predicted by Equation 1.13 (26.7%) falls within this range. Even with the low utilization rate, Minnkota has measured ammonia slip at only 1.5 ppm, which is very low for an SNCR system.

For Coal Creek Station Unit 2, the predicted utilization is:

$$\text{Utilization} = \frac{0.203}{1.335} = 0.152\ (15.2\%)$$

Again, 15.2% is consistent with the latest IPM default utilization of 15%.

Based on 15.2% utilization, the expected feed rate of urea (50% solution) at Coal Creek 2 would be:

$$\text{Expected Feed Rate} = \frac{(326\ \text{lb/hr})}{(0.152)} = 2{,}116\ \text{lb/hr}$$

If you consider just the annual urea (50% solution) usage at M.R. Young Station Unit 2 in 2011, this equates to 1,968 lb/hr (annual average).

$$\text{Annual Average Feed Rate} = \frac{(1{,}737{,}997\ \text{gal/yr})(8.33\ \text{lb/gal})(1.14)}{8{,}385\ \text{hr}} = 1{,}968\ \text{lb/hr}$$

The actual annual average utilization rate for M.R. Young Station Unit 2 (using the results of Equation 1.15) is:

$$\text{Actual Utilization} = \frac{(390\ \text{lb/hr})}{(1{,}968\ \text{lb/hr})} = 0.198\ (19.8\%)$$

If the actual utilization of urea at Coal Creek Station is less than predicted by Equation 1.13 (as it is at M.R. Young 2), the expected urea feed rate (50% solution) could be:

Possible Usage = [(326 lb/hr)/(0.152)] * [(0.267)/(0.152)] = 2,892 lb/hr

The Integrated Planning Model (IPM) also estimates the amount of urea required for the SNCR system to achieve the desired emissions reduction. To reduce the NO_x emission rate from 0.153 lb/10^6 Btu to 0.122 lb/10^6 Btu (20% reduction), the IPM estimates that 800 lb/hr of urea (1,600 lb/hr of 50% solution) is required. This estimate is based on a normalized stoichiometric rate (NSR) of 1.0 and a utilization factor of 15%. If the NSR is adjusted to 1.335 as calculated from Equation 1.14, the urea usage (50% solution) would be 2,136 lb/hr. This is very similar to GRE's estimate of 2,310 lb/hr.

Minnkota, in their email, pointed out that the urea feed rate is dependent on a number of factors such as boiler cleanliness and coal quality. Generally, Coal Creek Station burns coal of lower quality (i.e. lower heat content) than M.R. Young Station. Based on the above, it appears that Great River Energy's (URS) estimate of reagent usage of 2,310 lb/hr is reasonable.

TB:csc

Bachman, Tom A.

From: Kevin Thomas [kthomas@minnkota.com]
Sent: Thursday, March 08, 2012 2:56 PM
To: Bachman, Tom A.
Subject: FW: SNCR

Tom,

We used 1,737,997 gallons of 50% urea in Unit 2 in 2011.

-----Original Message-----
From: Bachman, Tom A. [mailto:tbachman@nd.gov]
Sent: Wednesday, March 07, 2012 7:52 AM
To: Kevin Thomas
Subject: RE: SNCR

Kevin:

Can you tell me how many gallons (total) of 50% urea solution were used in Unit 2 in 2011?

Thanks!

Tom Bachman, P.E.
Sr. Env. Engr.
ND Dept. of Health
(701) 328-5188

-----Original Message-----
From: Kevin Thomas [mailto:kthomas@minnkota.com]
Sent: Wednesday, February 22, 2012 7:26 AM
To: Bachman, Tom A.
Subject: RE: SNCR

Let me know if you need any additional information.

Kevin Thomas, P.E.
Senior Environmental Engineer
Minnkota Power Cooperative, Inc.
Phone (701)794-8711
Fax (701)794-7258

From: "Bachman, Tom A." <tbachman@nd.gov>

To: 'Kevin Thomas' <kthomas@minnkota.com>

Date: 02/22/2012 07:21 AM

Subject: RE: SNCR

Thanks Kevin!

Tom Bachman, P.E.
Sr. Env. Engr.
ND Dept. of Health
(701) 328-5188

-----Original Message-----
From: Kevin Thomas [mailto:kthomas@minnkota.com]
Sent: Tuesday, February 21, 2012 3:38 PM
To: Bachman, Tom A.
Cc: Craig Bleth; John Graves
Subject: SNCR

Tom,

From a quick look at our Urea flow data compared to generator output we are injecting from 2 to 8 gallon per minute at about 470 MW. The wide range is a function of a number of factors such as boiler cleanliness and coal quality. I did also find a short period where we were injecting 10 gallon per minute at about 335 MW. The Urea we inject is 50 percent solution.
The typical slip we have measured is down around 1.5 ppm which is actually below the detection limit. As we discussed the performance guarantee for ammonia slip is 5 ppm. We have not tested any of our fly ash for any ammonia compounds.

Kevin Thomas, P.E.
Senior Environmental Engineer
Minnkota Power Cooperative, Inc.
Phone (701)794-8711
Fax (701)794-7258

Unit Level Emissions Quick Report
February 24, 2012

Your query will return data for 7 facilities and 12 units.

You specified: **Year(s):** 2011 **Program:** ARP **State(s):** ND

State	Facility Name	Facility ID (ORISPL)	Unit ID	Associated Stacks	Year	Program(s)	Operating Time	# of Months Reported	SO_2 Tons	Avg. NO_x Rate (lb/mmBtu)	NO_x Tons	CO_2 Tons	Heat Input (mmBtu)
ND	Antelope Valley	6469	B1		2011	ARP	6,148	12	5,176.2	0.34	4,284.4	2,634,366.8	24,197,378
ND	Antelope Valley	6469	B2		2011	ARP	8,558	12	8,730.3	0.34	6,263.3	3,922,343.5	36,027,754
ND	Coal Creek	6030	1		2011	ARP	7,583	12	7,161.2	0.20	4,397.7	4,683,023.6	43,014,802
ND	Coal Creek	6030	2		2011	ARP	8,364	12	7,905.6	0.15	3,579.8	5,110,647.9	46,942,626
ND	Coyote	8222	B1		2011	ARP	8,124	12	13,423.6	0.73	13,018.8	3,873,508.9	35,579,248
ND	Leland Olds	2817	1		2011	ARP	6,632	12	13,218.8	0.25	1,457.1	1,268,737.0	11,653,716
ND	Leland Olds	2817	2		2011	ARP	7,191	12	25,571.4	0.30	3,515.7	2,575,970.9	23,660,990
ND	Milton R Young	2823	B1		2011	ARP	7,592	12	4,049.2	0.51	4,765.1	2,017,791.5	18,534,017
ND	Milton R Young	2823	B2		2011	ARP	8,385	12	1,868.6	0.32	6,705.5	4,535,979.9	41,664,019
ND	R M Heskett	2790	B2		2011	ARP	7,394	12	1,989.6	0.40	934.7	518,718.3	4,764,553
ND	Stanton	2824	1	MS1E, MS1W	2011	ARP	8,414	12	2,256.2	0.24	1,078.2	931,458.0	8,881,160
ND	Stanton	2824	10		2011	ARP	8,162	12	144.0	0.31	755.1	503,368.5	4,799,507
Total									**91,494.7**		**50,755.2**	**32,575,914.5**	**299,719,768**

NORTH DAKOTA
UTILITY BOILERS
ACTUAL NO_x EMISSIONS
($LB/10^6$ BTU)

COMPANY	PLANT	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
BASIN ELECTRIC POWER COOP.	AVS 1	0.34	0.33	0.33	0.34	0.39	0.38	0.36	0.39	0.38	0.35
BASIN ELECTRIC POWER COOP.	AVS 2	0.30	0.35	0.33	0.34	0.35	0.32	0.37	0.37	0.34	0.35
BASIN ELECTRIC POWER COOP.	LELAND OLDS 1	0.27	0.29	0.29	0.31	0.31	0.31	0.34	0.30	0.29	0.25
BASIN ELECTRIC POWER COOP.	LELAND OLDS 2	0.62	0.61	0.58	0.57	0.50	0.50	0.53	0.47	0.31	0.30
MINNKOTA POWER COOP.	M.R. YOUNG 1	0.79	0.82	0.84	0.84	0.80	0.84	0.81	0.75	0.54	0.51
MINNKOTA POWER COOP.	M.R. YOUNG 2	0.81	0.77	0.81	0.83	0.81	0.86	0.46	0.40	0.41	0.32
OTTERTAIL POWER CO.	COYOTE	0.72	0.72	0.74	0.69	0.67	0.69	0.77	0.77	0.70	0.73
MONTANA DAKOTA UTILITIES	HESKETT 1	0.41	0.41	0.40	0.41	0.41	0.42	0.42	0.42	0.41	
MONTANA DAKOTA UTILITIES	HESKETT 2	0.31	0.29	0.28	0.25	0.27	0.36	0.36	0.36	0.37	0.39
GREAT RIVER ENERGY	STANTON 1	0.43	0.44	0.39	0.30	0.31	0.24	0.25	0.26	0.26	0.24
GREAT RIVER ENERGY	STANTON 10	0.35	0.34	0.31	0.30	0.26	0.25	0.30	0.26	0.25	0.31
GREAT RIVER ENERGY	COAL CREEK 1	0.21	0.20	0.21	0.22	0.24	0.26	0.25	0.25	0.21	0.20
GREAT RIVER ENERGY	COAL CREEK 2	0.22	0.22	0.24	0.24	0.25	0.20	0.18	0.20	0.17	0.15

IPM SNCR COST
COAL CREEK STATION
RETROFIT FACTOR = 1.0

Variable	Designation	Units	Value	Calculation
Boiler Type			TANGENTIAL	User Input
Unit Size	A	MW	601.5	User Input
Retrofit Factor	B		1	User Input "Average" = 1.0
Heat Rate	C	Btu/kw-hr	10000	User Input
NOx Rate	D	lb/MMbtu	0.153	User Input
SO2 rate	E	lb/MMBtu	2	User Input
Type of Coal			lignite	User Input
Coal Factor	F		1.07	Bit. = 1.0; PRB = 1.06; Lignite = 1.07
Heat Rate Factor	G		1	C/10,000
Heat Input	H	Btu/hr	6.015E+09	A*C*1000
Capacity Factor	I		87	User Input
NOx Removal Eff.	J	%	20	User Input
NOx Removed	K	lb/hr	1.841E+02	$D*H/10^6*J/100$
Urea Rate (100%)	L	lb/hr	8.003E+02	K/UF/46*30 UF=0.25 FOR CFB OR D>0.3; OTHERWISE 0.15
Water Required	M	lb/hr	7202.308696	L*9
Aux. Power	N	%	0.05	
Dilution Water Rate	O	1000 gph	0.864277043	M*0.12/1000
Urea Cost 50% Soln.	P	$/ton	250	User Input
Aux. Power Cost	Q	$/kwh	0.06	User Input
Dilution Water Cost	R	$/kgal	3	User Input
Op. Labor Rate	S	$/hr	60	User Input
Capital Cost Calculation				
BMS	2,995,735			SNCR (Injectors, blowers, DCS, Reagent System) Cost
BMA	0			Air Heater Modifications
BMB	4,171,636			Balance of the Plant Cost (Piping, Including Site Upgrades)
BM	7,167,371			Total Bare Module Cost including retrofit factor
Total Project Cost				

IPM SNCR COST
COAL CREEK STATION
RETROFIT FACTOR = 1.0

A1	716,737			Engineering and Construction Management Costs (10% of BM)
A2	716,737			Labor Adjustment (10% of BM)
A3	716,737			Contractor Profit and Fees (10% of BM)
CECC	9,317,582			Capital, Engineering, and Construction Cost Subtotal (BM+A1+A2+A3)
B1	465,879			Owner's Cost (5% of CECC)
TPC	9,783,461			Total Project Cost (CECC + B1) (2009 dollars)

TPC (2011 dollars) = (9,783,461)(1.05) = $10,272,634

Coal Creek Station NOx BART Options - LCALGRD Sensitivity
98th Percentile Delta-deciview (24-hour)

Met. Data	Location	LNC3+ Nox		LNC3+ & SNCR Nox		Delta (SNCR Improvement)	
		LCALGRD=F	LCALGRD=T	LCALGRD=F	LCALGRD=T	LCALGRD=F	LCALGRD=T
2000	TRNP North	0.92	0.89	0.84	0.82	0.08	0.07
	TRNP South	0.83	0.83	0.75	0.76	0.08	0.07
	TRNP Elkhorn	0.62	0.51	0.58	0.49	0.04	0.02
	Lostwood NWA	0.94	0.76	0.86	0.72	0.08	0.04
2001	TRNP North	1.00	0.90	0.92	0.85	0.08	0.05
	TRNP South	0.96	0.82	0.85	0.76	0.11	0.06
	TRNP Elkhorn	0.92	0.79	0.81	0.70	0.11	0.09
	Lostwood NWA	1.81	1.69	1.71	1.57	0.10	0.12
2002	TRNP North	2.17	1.74	1.96	1.58	0.21	0.16
	TRNP South	1.76	1.63	1.56	1.46	0.20	0.17
	TRNP Elkhorn	1.49	1.28	1.34	1.18	0.15	0.10
	Lostwood NWA	1.48	1.35	1.33	1.25	0.15	0.10
						Avg.=0.116	0.088

6/27/2012

COAL CREEK STATION
UNITS 1 AND 2
NO_X BART ANALYSIS

YEAR	UNIT	LNC3+		SNCR+LNC3+		DIFFERENCE	
		90TH PCTL. DELTA-DV	98TH PCTL. DELTA-DV	90TH PCTL. DELTA-DV	98TH PCTL. DELTA-DV	90TH PCTL. DELTA-DV	98TH PCTL. DELTA-DV
2000	TRNP-SU	0.238	0.918	0.216	0.837	0.022	0.081
2001	TRNP-SU	0.199	1.001	0.181	0.921	0.018	0.080
2002	TRNP-SU	0.423	2.165	0.380	1.960	0.043	0.205
AVERAGE	*TRNP-SU*	*0.287*	*1.361*	*0.259*	*1.239*	*0.028*	*0.122*
2000	TRNP-NU	0.243	0.826	0.222	0.749	0.021	0.077
2001	TRNP-NU	0.257	0.955	0.254	0.848	0.003	0.107
2002	TRNP-NU	0.286	1.756	0.265	1.561	0.021	0.195
AVERAGE	*TRNP-NU*	*0.262*	*1.179*	*0.247*	*1.053*	*0.015*	*0.126*
2000	ELKHORN RANCH	0.164	0.622	0.151	0.584	0.013	0.038
2001	ELKHORN RANCH	0.150	0.923	0.140	0.814	0.010	0.109
2002	ELKHORN RANCH	0.263	1.493	0.245	1.339	0.018	0.154
AVERAGE	*ELKHORN RANCH*	*0.192*	*1.013*	*0.179*	*0.912*	*0.014*	*0.100*
2000	LOSTWOOD W.A.	0.421	0.943	0.382	0.861	0.039	0.082
2001	LOSTWOOD W.A.	0.424	1.805	0.387	1.711	0.037	0.094
2002	LOSTWOOD W.A.	0.285	1.479	0.277	1.329	0.008	0.150
AVERAGE	*LOSTWOOD W.A.*	*0.377*	*1.409*	*0.349*	*1.300*	*0.028*	*0.109*
OVERALL AVERAGE		*0.279*	*1.241*	*0.258*	*1.126*	*0.021*	*0.114*

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Coal Creek Station - LNC3+ NOx - Year 2000 Met. Data

Title lines from CALPUFF (POSTUTIL) output file:

Coal Creek Station (Units 1+2) - LNC3+ NOx - Calpuff 5.711a
Year 2000 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	% of Modeled Extinction by Species %_SO4	%_NO3	%_PMC	%_PMF
TRNP SOUTH UNIT												
Largest Delta-DV	2.477	4.711	2.234	2000	72	53	107	2.80	51.37	46.79	0.64	1.20
98th %tile Delta-DV	0.916	3.149	2.234	2000	75	56	110	2.80	54.95	43.59	0.21	1.24
90th %tile Delta-DV	0.238	2.387	2.149	2000	184	48	102	2.40	81.60	16.07	0.79	1.54

Number of days with Delta-Deciview > 0.50: 17
Number of days with Delta-Deciview > 1.00: 7
Max number of consecutive days with Delta-Deciview > 0.50: 2

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP NORTH UNIT												
Largest Delta-DV	2.235	4.468	2.234	2000	74	67	56	2.80	62.02	36.80	0.15	1.03
98th %tile Delta-DV	0.826	3.060	2.234	2000	54	84	113	2.80	55.74	42.49	0.61	1.16
90th %tile Delta-DV	0.243	2.371	2.127	2000	110	63	52	2.30	14.51	71.20	5.99	8.30

Number of days with Delta-Deciview > 0.50: 17
Number of days with Delta-Deciview > 1.00: 6
Max number of consecutive days with Delta-Deciview > 0.50: 1

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP ELKHORN RANCH												
Largest Delta-DV	2.297	4.531	2.234	2000	74	90	72	2.80	60.82	38.01	0.16	1.01
98th %tile Delta-DV	0.622	2.728	2.106	2000	265	90	72	2.20	66.24	31.51	0.68	1.57
90th %tile Delta-DV	0.164	2.397	2.234	2000	56	90	72	2.80	59.92	38.16	0.59	1.33

Number of days with Delta-Deciview > 0.50: 10
Number of days with Delta-Deciview > 1.00: 2
Max number of consecutive days with Delta-Deciview > 0.50: 1

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
LOSTWOOD NWA												
Largest Delta-DV	3.216	5.491	2.275	2000	47	99	81	2.90	56.36	42.40	0.40	0.84
98th %tile Delta-DV	0.943	3.218	2.275	2000	72	97	79	2.90	55.21	43.59	0.42	0.78
90th %tile Delta-DV	0.421	2.696	2.275	2000	62	99	81	2.90	46.68	51.70	0.40	1.21

Number of days with Delta-Deciview > 0.50: 28
Number of days with Delta-Deciview > 1.00: 5
Max number of consecutive days with Delta-Deciview > 0.50: 2

:ALBART - Summary of Visibility Results for 24-hr Delta-Deciview

:oal Creek Station - LNC3+ NOx - Year 2001 Met. Data

·itle lines from CALPUFF (POSTUTIL) output file:

:oal Creek Station (Units 1+2) - LNC3+ NOx - Calpuff 5.711a
'ear 2001 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
;ART Protocol Receptors (99)

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	% of Modeled Extinction by Species %_SO4	%_NO3	%_PMC	%_PMF
·RNP SOUTH UNIT												
Largest Delta-DV	2.270	4.504	2.234	2001	64	52	106	2.80	62.43	36.71	0.28	0.58
98th %tile Delta-DV	1.001	3.255	2.255	2001	12	48	102	2.90	58.19	40.57	0.49	0.75
90th %tile Delta-DV	0.199	2.475	2.276	2001	330	53	107	3.00	14.74	74.95	4.56	5.74

Number of days with Delta-Deciview > 0.50: 19
Number of days with Delta-Deciview > 1.00: 8
Max number of consecutive days with Delta-Deciview > 0.50: 2

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
·RNP NORTH UNIT												
Largest Delta-DV	2.996	5.230	2.234	2001	64	82	71	2.80	62.12	36.83	0.36	0.69
98th %tile Delta-DV	0.955	3.082	2.127	2001	98	84	113	2.30	38.08	57.13	1.96	2.84
90th %tile Delta-DV	0.257	2.363	2.106	2001	234	82	71	2.20	93.61	1.77	1.91	2.70

Number of days with Delta-Deciview > 0.50: 22
Number of days with Delta-Deciview > 1.00: 6
Max number of consecutive days with Delta-Deciview > 0.50: 3

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
TRNP ELKHORN RANCH												
Largest Delta-DV	2.268	4.501	2.234	2001	64	90	72	2.80	63.21	35.93	0.29	0.57
98th %tile Delta-DV	0.923	3.050	2.127	2001	92	90	72	2.30	40.81	56.71	0.82	1.65
90th %tile Delta-DV	0.150	2.277	2.127	2001	101	90	72	2.30	69.03	30.18	0.18	0.60

Number of days with Delta-Deciview > 0.50: 14
Number of days with Delta-Deciview > 1.00: 5
Max number of consecutive days with Delta-Deciview > 0.50: 2

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
LOSTWOOD NWA												
Largest Delta-DV	3.910	6.186	2.275	2001	64	91	73	2.90	53.36	45.25	0.38	1.01
98th %tile Delta-DV	1.805	3.950	2.145	2001	259	97	79	2.30	70.36	27.48	0.69	1.47
90th %tile Delta-DV	0.424	2.591	2.167	2001	275	93	75	2.40	53.17	41.71	1.62	3.50

Number of days with Delta-Deciview > 0.50: 30
Number of days with Delta-Deciview > 1.00: 16
Max number of consecutive days with Delta-Deciview > 0.50: 3

CALBART - Summary of Visibility Results for 24-hr Delta-Deciview

Coal Creek Station - LNC3+ NOx - Year 2002 Met. Data

Title lines from CALPUFF (POSTUTIL) output file:

Coal Creek Station (Units 1+2) - LNC3+ NOx - Calpuff 5.711a
Year 2002 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
BART Protocol Receptors (99)

TRNP SOUTH UNIT

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	% of Modeled Extinction by Species %_SO4	%_NO3	%_PMC	%_PMF
Largest Delta-DV	3.716	5.950	2.234	2002	78	46	46	2.80	54.69	44.10	0.23	0.98
98th %tile Delta-DV	2.165	4.420	2.255	2002	26	47	101	2.90	47.10	51.10	0.67	1.13
90th %tile Delta-DV	0.423	2.657	2.234	2002	79	53	107	2.80	48.79	49.86	0.17	1.18

Number of days with Delta-Deciview > 0.50: 32
Number of days with Delta-Deciview > 1.00: 20
Max number of consecutive days with Delta-Deciview > 0.50: 3

TRNP NORTH UNIT

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	% of Modeled Extinction by Species %_SO4	%_NO3	%_PMC	%_PMF
Largest Delta-DV	5.674	7.907	2.234	2002	73	89	118	2.80	48.83	49.18	0.79	1.19
98th %tile Delta-DV	1.756	3.990	2.234	2002	50	58	47	2.80	40.72	56.95	0.71	1.62
90th %tile Delta-DV	0.286	2.541	2.255	2002	30	82	71	2.90	61.70	37.57	0.15	0.58

Number of days with Delta-Deciview > 0.50: 25
Number of days with Delta-Deciview > 1.00: 15
Max number of consecutive days with Delta-Deciview > 0.50: 4

TRNP ELKHORN RANCH

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	% of Modeled Extinction by Species %_SO4	%_NO3	%_PMC	%_PMF
Largest Delta-DV	4.687	6.920	2.234	2002	73	90	72	2.80	52.40	45.85	0.64	1.11
98th %tile Delta-DV	1.493	3.768	2.276	2002	336	90	72	3.00	43.31	54.36	1.02	1.31
90th %tile Delta-DV	0.263	2.369	2.106	2002	271	90	72	2.20	49.87	44.74	2.47	2.92

Number of days with Delta-Deciview > 0.50: 19
Number of days with Delta-Deciview > 1.00: 12
Max number of consecutive days with Delta-Deciview > 0.50: 2

LOSTWOOD NWA

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	% of Modeled Extinction by Species %_SO4	%_NO3	%_PMC	%_PMF
Largest Delta-DV	3.119	5.394	2.275	2002	74	97	79	2.90	56.69	41.97	0.43	0.91
98th %tile Delta-DV	1.479	3.646	2.167	2002	301	91	73	2.40	44.63	53.03	0.74	1.59
90th %tile Delta-DV	0.285	2.496	2.211	2002	172	97	79	2.60	76.39	14.48	3.02	6.11

Number of days with Delta-Deciview > 0.50: 24
Number of days with Delta-Deciview > 1.00: 12
Max number of consecutive days with Delta-Deciview > 0.50: 3

ALBART - Summary of Visibility Results for 24-hr Delta-Deciview

oal Creek Station - LNC3+ & SNCR NOx - Year 2000 Met. Data

itle lines from CALPUFF (POSTUTIL) output file:

oal Creek Station (Units 1+2) - LNC3+ & SNCR NOx - Calpuff 5.711a
ear 2000 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
ART Protocol Receptors (99)

RNP SOUTH UNIT

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	% of Modeled Extinction by Species %_SO4	%_NO3	%_PMC	%_PMF
Largest Delta-DV	2.260	4.493	2.234	2000	72	53	107	2.80	56.96	40.99	0.71	1.34
98th %tile Delta-DV	0.837	3.070	2.234	2000	75	56	110	2.80	60.39	38.01	0.24	1.36
90th %tile Delta-DV	0.216	2.343	2.127	2000	101	46	46	2.30	52.59	44.08	0.85	2.47

Number of days with Delta-Deciview > 0.50: 16
Number of days with Delta-Deciview > 1.00: 7
Max number of consecutive days with Delta-Deciview > 0.50: 2

RNP NORTH UNIT

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
Largest Delta-DV	2.080	4.314	2.234	2000	74	67	56	2.80	67.16	31.56	0.16	1.12
98th %tile Delta-DV	0.749	2.982	2.234	2000	36	82	71	2.80	47.93	49.67	0.66	1.74
90th %tile Delta-DV	0.222	2.370	2.149	2000	183	85	114	2.40	83.40	12.91	1.19	2.50

Number of days with Delta-Deciview > 0.50: 14
Number of days with Delta-Deciview > 1.00: 6
Max number of consecutive days with Delta-Deciview > 0.50: 1

RNP ELKHORN RANCH

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
Largest Delta-DV	2.134	4.367	2.234	2000	74	90	72	2.80	66.03	32.70	0.18	1.10
98th %tile Delta-DV	0.584	2.690	2.106	2000	265	90	72	2.20	70.76	26.84	0.73	1.68
90th %tile Delta-DV	0.151	2.385	2.234	2000	56	90	72	2.80	64.94	32.97	0.64	1.44

Number of days with Delta-Deciview > 0.50: 10
Number of days with Delta-Deciview > 1.00: 2
Max number of consecutive days with Delta-Deciview > 0.50: 1

OSTWOOD NWA

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
Largest Delta-DV	2.971	5.246	2.275	2000	47	99	81	2.90	61.80	36.84	0.44	0.92
98th %tile Delta-DV	0.861	3.137	2.275	2000	72	97	79	2.90	60.69	38.00	0.46	0.85
90th %tile Delta-DV	0.382	2.614	2.232	2000	204	96	78	2.70	55.31	42.05	0.94	1.71

Number of days with Delta-Deciview > 0.50: 26
Number of days with Delta-Deciview > 1.00: 4
Max number of consecutive days with Delta-Deciview > 0.50: 2

:ALBART - Summary of Visibility Results for 24-hr Delta-Deciview

:oal Creek Station - LNC3+ & SNCR NOx - Year 2001 Met. Data

'itle lines from CALPUFF (POSTUTIL) output file:

:oal Creek Station (Units 1+2) - LNC3+ & SNCR NOx - Calpuff 5.711a
'ear 2001 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
;ART Protocol Receptors (99)

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	% of Modeled Extinction by Species %_SO4	%_NO3	%_PMC	%_PMF
'RNP SOUTH UNIT												
Largest Delta-DV	2.115	4.349	2.234	2001	64	52	106	2.80	67.57	31.50	0.31	0.63
98th %tile Delta-DV	0.921	3.175	2.255	2001	12	48	102	2.90	63.53	35.12	0.54	0.81
90th %tile Delta-DV	0.181	2.309	2.127	2001	148	49	103	2.30	47.16	46.49	2.83	3.51

Number of days with Delta-Deciview > 0.50: 19
Number of days with Delta-Deciview > 1.00: 4
Max number of consecutive days with Delta-Deciview > 0.50: 2

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
'RNP NORTH UNIT												
Largest Delta-DV	2.793	5.027	2.234	2001	64	82	71	2.80	67.35	31.51	0.39	0.75
98th %tile Delta-DV	0.848	2.975	2.127	2001	98	84	113	2.30	43.13	51.45	2.21	3.21
90th %tile Delta-DV	0.254	2.488	2.234	2001	62	82	71	2.80	73.51	25.51	0.25	0.73

Number of days with Delta-Deciview > 0.50: 19
Number of days with Delta-Deciview > 1.00: 6
Max number of consecutive days with Delta-Deciview > 0.50: 3

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
'RNP ELKHORN RANCH												
Largest Delta-DV	2.116	4.349	2.234	2001	64	90	72	2.80	68.31	30.76	0.31	0.62
98th %tile Delta-DV	0.814	2.941	2.127	2001	92	90	72	2.30	46.51	50.68	0.94	1.88
90th %tile Delta-DV	0.140	2.268	2.127	2001	101	90	72	2.30	73.67	25.50	0.19	0.64

Number of days with Delta-Deciview > 0.50: 11
Number of days with Delta-Deciview > 1.00: 4
Max number of consecutive days with Delta-Deciview > 0.50: 2

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
.OSTWOOD NWA												
Largest Delta-DV	3.599	5.874	2.275	2001	64	91	73	2.90	58.95	39.52	0.42	1.11
98th %tile Delta-DV	1.711	3.856	2.145	2001	259	97	79	2.30	74.59	23.12	0.73	1.56
90th %tile Delta-DV	0.387	2.555	2.167	2001	275	93	75	2.40	58.24	36.15	1.77	3.83

Number of days with Delta-Deciview > 0.50: 28
Number of days with Delta-Deciview > 1.00: 15
Max number of consecutive days with Delta-Deciview > 0.50: 3

:ALBART - Summary of Visibility Results for 24-hr Delta-Deciview

:oal Creek Station - LNC3+ & SNCR NOx - Year 2002 Met. Data

'itle lines from CALPUFF (POSTUTIL) output file:

:oal Creek Station (Units 1+2) - LNC3+ & SNCR NOx - Calpuff 5.711a
'ear 2002 Calmet Met. Data - RUC2d Mesoscale Data - Monthly NH3
;ART Protocol Receptors (99)

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	% of Modeled Extinction by Species %_SO4	%_NO3	%_PMC	%_PMF
'RNP SOUTH UNIT												
Largest Delta-DV	3.428	5.661	2.234	2002	78	46	46	2.80	60.21	38.47	0.25	1.08
98th %tile Delta-DV	1.960	4.215	2.255	2002	26	47	101	2.90	52.58	45.42	0.74	1.26
90th %tile Delta-DV	0.380	2.613	2.234	2002	79	53	107	2.80	54.52	43.97	0.19	1.32

Number of days with Delta-Deciview > 0.50: 30
Number of days with Delta-Deciview > 1.00: 20
Max number of consecutive days with Delta-Deciview > 0.50: 3

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
'RNP NORTH UNIT												
Largest Delta-DV	5.219	7.453	2.234	2002	73	89	118	2.80	54.42	43.37	0.89	1.33
98th %tile Delta-DV	1.561	3.795	2.234	2002	50	58	47	2.80	46.27	51.09	0.81	1.84
90th %tile Delta-DV	0.265	2.519	2.255	2002	30	82	71	2.90	66.84	32.37	0.17	0.63

Number of days with Delta-Deciview > 0.50: 23
Number of days with Delta-Deciview > 1.00: 14
Max number of consecutive days with Delta-Deciview > 0.50: 4

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
'RNP ELKHORN RANCH												
Largest Delta-DV	4.323	6.557	2.234	2002	73	90	72	2.80	57.93	40.14	0.70	1.23
98th %tile Delta-DV	1.339	3.614	2.276	2002	336	90	72	3.00	48.67	48.71	1.15	1.47
90th %tile Delta-DV	0.245	2.351	2.106	2002	255	90	72	2.20	71.86	17.95	3.51	6.68

Number of days with Delta-Deciview > 0.50: 18
Number of days with Delta-Deciview > 1.00: 11
Max number of consecutive days with Delta-Deciview > 0.50: 2

	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	SEQ RECEP	ND RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
.OSTWOOD NWA												
Largest Delta-DV	2.881	5.156	2.275	2002	74	97	79	2.90	62.13	36.39	0.47	1.00
98th %tile Delta-DV	1.329	3.497	2.167	2002	301	91	73	2.40	50.03	47.35	0.83	1.78
90th %tile Delta-DV	0.277	2.488	2.211	2002	172	97	79	2.60	78.74	11.85	3.11	6.30

Number of days with Delta-Deciview > 0.50: 24
Number of days with Delta-Deciview > 1.00: 11
Max number of consecutive days with Delta-Deciview > 0.50: 3

BART COSTS

WRAP ANNEX TO GRAND CANYON VISIBILITY TRANSPORT REPORT (JUNE 1999)[a]:

LOW COST: < $500/TON
MODERATE COST: $500 - $3000/TON
HIGH COST: > $3000/TON

[a] ***Cited in The Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations; Proposed Rule; F.R. Vol.69, No.87 May 5,2004 p.25198.***

INFLATION ADJUSTMENT:

JUNE 1999 CPI (1967 DATUM) = 497.9
DECEMBER 2006 CPI (1967 DATUM) = 604.5

ADJUSTMENT = (604.5-497.9) / 497.9
= 0.214 or 21.4%

ADJUSTED BART COSTS:

LOW COST: < $607/TON
MODERATE COST: $607 - $3642/TON
HIGH COST: > $3642

SUGGESTED BART COST CEILING:

COST EFFECTIVESNESS: $3650/TON
INCREMENTAL COST: $6500/TON [b]

[b] ***In March 2006, the Department determined that an incremental cost of $6450/ton for the control of NOx at the Northern Sun facility was excessive when determining BACT.***

UPDATE
AUGUST 2011

CPI - December 2006 (1982-84 Datum) = 201.8

CPI - August 2011 (1982-84 Datum) = 226.9

Adjustment = (226.9 – 201.8) / 201.8
= 0.124 or 12.4%

Adjusted Cost Effectiveness = ($3,650/ton)(1.124) = $4,103/ton

Adjusted Incremental Cost Effectiveness = ($6,500/ton)(1.124)
= $7,306/ton

Suggested BART Ceiling (August 2011):

Cost Effectiveness = $4,100/ton
Incremental Cost = $7,300/ton

NORTH DAKOTA
DEPARTMENT *of* HEALTH

ENVIRONMENTAL HEALTH SECTION
Gold Seal Center, 918 E. Divide Ave.
Bismarck, ND 58501-1947
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www.ndhealth.gov

January 19, 2012

FILE

Ms. Mary Jo Roth
Manager, Environmental Services
Great River Energy
12300 Elm Creek Boulevard
Maple Grove, MN 55369-4718

Re: Coal Creek NO_x BART Determination

Dear Ms. Roth:

This letter is a follow-up to our telephone call on January 10, 2012. As indicated, the Department has reviewed the report submitted by Great River Energy (GRE), on November 21, 2011 entitled "Coal Creek Station Units 1 and 2, Best Available Retrofit Technology Refined Analysis for NO_x Emissions" (Revised NO_x Report). The Department is in the process of re-evaluating its Best Available Retrofit Technology (BART) Determination for NO_x from GRE's Coal Creek Station, as a result of errors found to exist in the BART-related submittals previously provided by GRE. The Department fully intends to exercise and preserve its regulatory discretion and authority with respect to its Regional Haze SIP. As such and in order for GRE to meet its obligations under North Dakota regulations, the Department requests GRE to promptly address the following issues with its Report:

1. The Coal Creek Station has a rating greater than 750 MW. Therefore, NDAC 33-15-25-03 requires that you comply with the requirements in EPA's BART Guidelines (40 CFR 51, Appendix Y). The BART Guidelines state "The baseline emissions rate should represent a realistic depiction of anticipated annual emissions for the source. In general, for the existing sources subject to BART, you will estimate the anticipated annual emissions based upon actual emissions from a baseline period." The Department requests that GRE include a review of the last five years of operation in GRE's analysis of baseline emissions (or heat input). If changes to the facility affect the historic baseline (such as DryFining™), please include an explanation of any adjustment in your analysis. All tables should provide a consistent baseline emission rate (see Table A-2 versus Tables A-1, A-4 to A-10).

2. GRE's Report included a document developed by Golder Associates entitled "Fly Ash Storage and Ammonia Mitigation Technology Evaluation" which states "Based on a review of the recent load profile of CCS, historic information on marketable fly ash at CCS, and an estimate of the reliability of the SNCR and ASM systems, approximately

30% of the fly ash now sent to the sales silos is assumed to have ammonia concentrations which make it untreatable if an SNCR system is installed." The Eastlake Station also uses an ammonia slip mitigation (ASM) system and only 15% is untreatable. The Department understands that the Eastlake Station is able to blend ammoniated ash with ash that does not contains ammonia; an option that will not be available to the Coal Creek Station. In order for the Department to further evaluate the Report, please confirm and more fully explain this and any other differences between Coal Creek Station's operation and Eastlake Station's operation in order to evaluate GRE's 30% untreatable ash figure.

3. In Table 3.1, Cost Summary, the "Annualized Operating Cost" for Unit 1 SNCR + LNC3+ (30% lost ash sales) is listed at \$6.81 million. However, Table A-1 lists \$7.62 million for this scenario. Further, there are also inconsistent annualized operating costs in Table 3.1 versus Table A-1 for Unit 1 SNCR (30% lost ash sales) and Unit 2 SNCR (30% lost ash sales). Please address these inconsistencies.

4. The "Pollution Control Cost" in Table 3.1 and Table A-1 for all three scenarios of Unit 1 SNCR + LNC3+ do not appear to be correct. Please evaluate these asserted costs and correct as may be necessary, including with respect to the asserted incremental costs.

5. In Table A-6 and A-9 of the Report,

   a. A project contingency of 42% and 41% are listed, respectively. However, it appears GRE actually used 15% (which is consistent with EPA's Control Cost Manual). The 42% and 41% should be revised. This is also an issue with other tables in GRE's Report. Please evaluate these considerations and address any errors or mislabeling.

   b. The cost for "SW Disposal" is not consistent with the cost separately listed in Table 2.3.2 and the Golder Report. Given the inconsistency, please verify which number is correct and revise the Report to reflect this correction.

   c. The cost of "Lost Ash Sales" is inconsistent with Table 2.3.4 and the Golder Report. Given the inconsistency, please verify which number is correct and revise the Report to reflect this correction.

6. In order to be technically complete, GRE must provide a detailed explanation of Table 3.3.1, Visibility Improvement.

   a. Unit 1 has a baseline emission rate in Table 3.1 of 0.20 lb/10^6 Btu (annual average). Table 3.3.1 lists a 24-hr maximum emission rate of 0.20 lb/10^6 Btu. A 24-hr maximum emission rate should be larger than an annual average emission rate.

   b. The "Avg. Improvement" column indicates improvement for baseline conditions. Under the BART Guidelines, no improvement would be shown for baseline conditions.

c. The amount of improvement should be based on three years of meteorological data. The results from all three years must be submitted. Please explain whether it represent a 98th percentile value or some other value.

7. The Department appreciates GRE's prompt attention to the issues noted above and also suggests GRE closely review all tables and text for accuracy and consistency with the supporting documents.

The Department requests that GRE provide a revised Report no later than February 20, 2012.

If you have any questions, please contact Tom Bachman of my staff at (701)328-5188.

Sincerely,

Terry L. O'Clair

Terry L. O'Clair, P.E.
Director
Division of Air Quality

TLO/TB:saj
xc: Carl Daly, EPA
Margaret Olson, Ass't Attorney General
Paul Seby, Special Ass't Attorney General

NORTH DAKOTA
DEPARTMENT *of* HEALTH

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FILE

February 28, 2012

Ms. Mary Jo Roth
Manager, Environmental Services
Great River Energy
1200 Elm Creek Boulevard
Maple Grove, MN 55369-4718

Re: Coal Creek NO_x BART Analysis

Dear Ms. Roth:

The North Dakota Department of Health (Department) is in receipt of Great River Energy's (GRE) "Coal Creek Station Units 1 and 2; Best Available Retrofit Technology Refined Analysis for NO_x Emissions; November 2011; Updated February 10, 2012" (Refined NO_x Analysis).

GRE's Refined NO_x Analysis was submitted in response to the Department's November 3, 2011 request that GRE provide additional information regarding the Regional Haze NO_x BART analysis for the Coal Creek Station. The Department's request came after GRE informed the Department that the Coal Creek Station NO_x BART analysis previously submitted contained errors.

The information requested by the Department is necessary for the Department to further review and consider the installation of NO_x control technologies at the Coal Creek Station – including Selective Non-Catalytic Reduction (SNCR) technology.

The Department's initial review of GRE's Refined NO_x Analysis indicates that certain material information remains lacking, along with discrepancies in the visibility analysis and cost information set forth in the Analysis. On February 23, 2012, Tom Bachman and I spoke with you and Deb Nelson regarding the Department's initial review and concerns with the Refined NO_x Analysis. Mr. Bachman also had further discussions with Deb Nelson and BARR Engineering Company on February 27, 2012, regarding these concerns. During these calls, the Department raised the following specific questions/areas of concern in need of GRE's further attention:

1. The visibility modeling GRE performed for the year 2000 is not accurate when compared to the modeling results for the years 2001 and 2002. Specifically, GRE's year 2000 modeling analysis indicates that greater visibility improvement is achieved with the use of a lesser emission control technology than when a more stringent control technology is used. In order for the Department to complete its analysis, GRE must correct the year 2000 visibility modeling.

2. Tables A-5 to A-10 present a summary of the cost/economic analysis of the various control options and the marketability of fly ash that could be contaminated with ammonia if SNCR were to be used at the Coal Creek Station. These tables appear to contain calculated costs that do not match values calculated from the data in the tables. As such, please verify the following costs and data in the tables:

   a. General Facilities
   b. Engineering and Home Office
   c. Process Contingency
   d. Project Contingency
   e. Pre Production Cost
   f. Electricity
   g. SW Disposal
   h. Ammonia Mitigation
   i. Lost Ash Sales
   j. Urea
   k. Capital Recovery

Further, as the Department indicated during our February 23 call, GRE must review its consideration and application of the EPA Pollution Control Cost Manual (2002) to certain data presented in its Refined NO_x Analysis. Specifically, while the EPA Control Cost Manual establishes 5% as the default value for Process Contingencies; GRE used 6%. Before the Department can consider GRE's deviation from the Manual's default value for Process Contingencies, GRE must set forth and explain its rationale for doing so. Additionally, the "Prepaid Royalties" cost item, identified under Capital Costs in Tables A-5 to A-10, does not appear in the EPA Control Cost Manual. An explanation for Prepaid Royalties must therefore be included, especially since GRE listed as zero "Royalty Allowance" under Capital Costs in the tables. Also, Table A-10 still lists Project Contingency at 41%. Because it appears 15% was actually used, the 41% label should be corrected. In addition, all text within the Refined NO_x Analysis should be checked to verify that it is consistent with any revised pollution control costs and visibility results.

Only once the Department has received this updated information from GRE will the Department be able to proceed with conducting and completing its analysis of the Refined NO_x Analysis. In any event, the Department will promptly proceed to conclude its NOx BART determination for the Coal Creek Station. As such, GRE is directed to submit its revised information within ten (10) days of receipt of this letter.

Sincerely,

Tom Bachman

for Terry L. O'Clair, P.E.
Director
Division of Air Quality

TLO/TB:saj
xc: Carl Daly; EPA Region 8

Appendix D

Visibility Impact Tables

Summary of Modeling Inputs

Description		Stack Velocity	PM10		PM2.5 (fine)	PM (coarse)	SO_2		NOx		
		Emission Rate Input									
NOx Control	Units	m/s (ft/s)	% reduction	lb/hr	lb/hr	lb/hr	% reduction	lb/hr	% reduction	lb/hr	30-Day Rolling lb/MMBtu
Pre-BART Protocol	1	25.9 (85)	NA - base	249.2	101.9	147.3	NA - base	5733.5	NA - base	1772.3	NA - base
	1& 2	25.9 (85)	NA - base	465.3	190.3	275.0	NA - base	10702.8	NA - base	3594.7	NA - base
LNC3+	1	16.8(55)	0%	249.2	101.9	147.3	69%	1756.4	31%	1227.6	0.19
	1& 2	16.8(55)	0%	465.3	190.3	275.0	67%	3514.8	32%	2456.5	0.19
LNC3+ with Tuning	1	16.8(55)	0%	249.2	101.9	147.3	69%	1756.4	39%	1083.1	0.17
	1& 2	16.8(55)	0%	465.3	190.3	275.0	67%	3514.8	40%	2167.5	0.17
SNCR	1	16.8(55)	0%	249.2	101.9	147.3	69%	1756.4	49%	902.6	0.14
	1 & 2	16.8(55)	0%	465.3	190.3	275.0	67%	3514.8	50%	1806.3	0.14
SNCR with LNC3+	1	16.8(55)	0%	249.2	101.9	147.3	69%	1756.4	56%	776.2	0.12
	1& 2	16.8(55)	0%	465.3	190.3	275.0	67%	3514.8	57%	1553.4	0.12

Year 2000 Modeling Results

Description		Average Improv-ement	Visibility Impairment											
			TRNP South Unit			TRNP North Unit			TRNP Elkhorn Ranch			Lostwood WA		
NOx Control	Units		Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV	Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV	Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV	Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV
Pre-BART Protocol	1	--	24	0.299	1.229	21	0.318	0.941	18	0.212	0.777	37	0.503	1.183
	1& 2	--	41	0.553	2.176	41	0.586	1.836	35	0.401	1.391	58	0.945	2.157
LNC3+	1	59%	7	0.125	0.494	6	0.124	0.446	2	0.088	0.314	7	0.215	0.499
	1& 2	59%	17	0.217	0.860	16	0.235	0.959	10	0.186	0.596	28	0.376	0.954
LNC3+ with Tuning	1	61%	7	0.119	0.467	6	0.118	0.416	2	0.082	0.300	6	0.207	0.469
	1& 2	56%	18	0.251	0.970	18	0.245	0.909	11	0.175	0.627	29	0.426	0.983
SNCR	1	86%	0	0.041	0.157	0	0.042	0.138	0	0.029	0.103	1	0.069	0.166
	1 & 2	86%	5	0.080	0.310	4	0.083	0.290	2	0.056	0.209	3	0.140	0.326
SNCR with LNC3+	1	65%	6	0.106	0.410	6	0.105	0.352	2	0.072	0.270	4	0.180	0.417
	1& 2	58%	17	0.235	0.918	17	0.236	0.860	10	0.163	0.605	26	0.409	0.924

Year 2001 Modeling Results

Description		Average Improv-ement	Visibility Impairment											
			TRNP South Unit			TRNP North Unit			TRNP Elkhorn Ranch			Lostwood WA		
NOx Control	Units		Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV	Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV	Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV	Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV
Pre-BART Protocol	1	--	21	0.251	1.209	27	0.372	1.154	16	0.192	1.056	40	0.503	1.183
	1& 2	--	34	0.466	2.181	46	0.694	2.094	27	0.365	1.949	56	0.945	2.157
LNC3+	1	58%	8	0.116	0.509	9	0.142	0.547	8	0.076	0.505	21	0.215	0.499
	1& 2	56%	19	0.230	0.986	25	0.282	1.069	14	0.151	0.984	34	0.215	0.499
LNC3+ with Tuning	1	60%	7	0.108	0.482	8	0.136	0.512	6	0.076	0.473	18	0.207	0.469
	1& 2	58%	19	0.214	0.936	24	0.270	1.002	13	0.151	0.923	33	0.207	0.469
SNCR	1	62%	7	0.101	0.453	7	0.133	0.467	4	0.074	0.433	16	0.192	0.486
	1 & 2	60%	19	0.202	0.884	21	0.267	0.917	12	0.147	0.847	33	0.192	0.486
SNCR with LNC3+	1	64%	6	0.096	0.437	6	0.127	0.436	4	0.069	0.405	15	0.180	0.417
	1& 2	62%	18	0.194	0.854	20	0.253	0.858	12	0.137	0.793	31	0.180	0.417

Year 2002 Modeling Results

Description		Average Improv-ement	Visibility Impairment											
			TRNP South Unit			TRNP North Unit			TRNP Elkhorn Ranch			Lostwood WA		
NOx Control	Units		Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV	Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV	Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV	Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV
Pre-BART Protocol	1	--	38	0.540	2.559	30	0.385	2.113	23	0.310	1.703	32	0.385	1.814
	1& 2	--	50	0.971	4.475	45	0.706	3.557	42	0.581	3.039	45	0.707	3.190
LNC3+	1	57%	22	0.219	1.181	15	0.158	0.987	12	0.136	0.789	13	0.178	0.832
	1& 2	54%	32	0.433	2.218	26	0.313	1.880	18	0.269	1.524	26	0.350	1.601
LNC3+ with Tuning	1	59%	20	0.207	1.140	15	0.151	0.918	12	0.129	0.746	13	0.165	0.783
	1& 2	56%	32	0.410	2.145	26	0.298	1.755	18	0.256	1.443	25	0.325	1.510
SNCR	1	63%	20	0.193	1.088	14	0.138	0.850	11	0.123	0.692	12	0.148	0.722
	1 & 2	60%	32	0.382	2.055	24	0.273	1.601	17	0.243	1.342	24	0.292	1.397
SNCR with LNC3+	1	64%	20	0.186	1.052	14	0.131	0.813	11	0.118	0.654	11	0.141	0.680
	1& 2	61%	30	0.371	1.991	24	0.260	1.536	17	0.234	1.271	23	0.279	1.318

Average Incremental Control Comparison for 98th % Δ-dV

Description		Year 2000			Year 2001			Year 2002			Year 2000-2002 Average		
NOx Control	Units	Average Impairment	Improvement from Protocol	Incremental Improvement	Average Impairment	Improvement from Protocol	Incremental Improvement	Average Impairment	Improvement from Protocol	Incremental Improvement	Average Impairment	Improvement from Protocol	Incremental Improvement
Pre-BART Protocol	1	1.033	NA	NA	1.151	NA	NA	2.047	NA	NA	1.410	NA	NA
	1& 2	1.890	NA	NA	2.095	NA	NA	3.565	NA	NA	2.517	NA	NA
LNC3+	1	0.438	0.594	0.594	0.515	0.636	0.636	0.947	1.100	1.100	0.634	0.777	0.777
	1& 2	0.842	1.048	1.048	0.885	1.211	1.211	1.806	1.760	1.760	1.178	1.339	1.339
LNC3+ with Tuning	1	0.413	0.620	0.025	0.484	0.667	0.031	0.897	1.151	0.051	0.598	0.812	0.036
	1& 2	0.872	1.018	-0.030	0.833	1.263	0.052	1.713	1.852	0.093	1.139	1.378	0.038
SNCR	1	0.141	0.892	0.272	0.460	0.691	0.024	0.838	1.209	0.059	0.480	0.931	0.118
	1 & 2	0.284	1.606	0.589	0.784	1.312	0.049	1.599	1.967	0.115	0.889	1.628	0.251
SNCR with LNC3+	1	0.362	0.670	-0.221	0.424	0.727	0.036	0.800	1.248	0.038	0.529	0.882	-0.049
	1& 2	0.827	1.063	-0.543	0.731	1.365	0.053	1.529	2.036	0.070	1.029	1.488	-0.140

Appendix E

Low-Baseline NOx SNCR Demonstration (EPRI Study)

This appendix contains confidential business information and is being submitted under separate seal.
Copyrighted material is not currently available for public release.

Appendix F

URS SNCR Evaluation Supplement

URS

March 30, 2012

Debra Nelson
Great River Energy
12300 Elm Creek Boulevard
Maple Grove, MN 55369

RE: URS Response to EPA FIP Exchange

Dear Debra:

Great River Energy (GRE) contracted URS Energy & Construction (URS) to conduct a review of the costs and performance capability of Selective Non-Catalytic Reduction (SNCR) at their Coal Creek Station (CCS) Units 1 & 2. This review was requested to provide:

- A site-specific rough order of magnitude estimate with a stated accuracy of ±30% for the 2011 capital cost required for installation of SNCR onto the Coal Creek units
- Site-specific operating and maintenance costs for SNCR operation at Coal Creek
- The level of NOx reduction expected when using SNCR on these units.

Cost Estimating Methodology - The basis for the cost estimates was stated to be the EPRI IECCOST model, which URS previously developed for the Electric Power Research Institute. This model provides site-specific cost estimates for all types of emissions control system installations, including individual systems that are designed to remove SO_2, NOx, Hg, and particulate matter. It also evaluates costs for multi-pollutant control systems, producing conceptual cost estimates that are site-specific based on the plant location, current operating characteristics, fuels burned, etc.

EPRI IECCOST Model development has continued for more than ten years; during that period URS has installed all of the commercial systems at utility installations, and become intimately familiar with all emissions control technologies. Consequently URS is very familiar with the relationship between the vendor island costs and the Total Capital Requirement for an emissions control retrofit. This extensive project experience also identified the performance capabilities and emission rate guarantees for the various technologies through review of bid documents and budgetary quote submittals under real world conditions.

The model is updated and escalated continuously as new projects are completed, calibrating the cost estimating results against actual project costs and performance. The economic model used for these calculations is IECCOST Version 3.1 that will be published by EPRI later in 2012.

URS Capabilities and Qualifications - URS is an engineering and construction company that has provided emissions control technology assessments, economic analyses, balance of plant designs, construction, construction management and startup assistance to utility and other industrial clients since the 1970's. During this period, URS participated in more than 30 SNCR projects at multiple sites using systems supplied by multiple vendors.

Total Capital Requirement Cost Estimates - URS is not a technology supplier. The supplier is typically responsible for installation of only their process island and system performance guarantees. The installation of the balance of plant (BOP) equipment, construction management, foundations, utility tie-ins (electrical, water, air, instrumentation and controls interface,

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URS

interconnecting piping, new flue gas emissions monitoring equipment, boiler and air heater modifications, retrofit difficulty due to existing plant access and congestion issues, et al) typically falls outside of the scope of supply for the SNCR vendor. Published cost estimates and vendor proposals in many cases do not consider these BOP cost impacts on the Total Capital Requirement for the installation of emissions control equipment. URS's project experience provides a basis for the assessment of these BOP costs that must be added to the vendor supplied equipment's installed costs to determine the true total capital cost of an installation.

Retrofit Factor - A site visit was made to the Coal Creek plant by one of the URS air quality control engineering staff. Based on his assessment of the site and the location for installation of the SNCR equipment, the retrofit difficulty for this plant was established to be moderately difficult due the constraints provided by existing equipment at the plant. Based on previous industry assessments of the cost impacts of retrofit difficulty, a retrofit factor of 1.6 was established for this moderately difficult SNCR installation. Previous industry surveys by Radian and Kellogg (EPA-450/3-74-015 – "Factors Affecting Ability to Retrofit FGD Systems" & EPA R2-72-100 – "Applicability of SO_2-Control Processes to Power Plants" and the EPA/600/S7-90/008 – "Verification of Simplified Procedure for Site-Specific SO_2 and NOx Control Cost Estimates") attempted to quantify the retrofit cost impacts compared to new equipment installations. These surveys established retrofit factors based on retrofit difficulty that are multiplied times the new plant installed cost estimates to determine the retrofit installed cost. The site assessment by the URS staff resulted in the moderately difficult retrofit assessment, which was translated in the capital cost estimate as a 60% adder to the new equipment installation cost to account for decreasing productivity due to movement of parts and materials around existing equipment and structures, limited access to construction sites due to overhead, underground and side obstructions by existing equipment, crane access, etc.

SNCR Expected Performance – SNCR system performance is directly impacted by the flue gas temperature at the point of urea/ammonia injection, and by the current concentration of NOx in the outlet flue gas. Injection outside the correct temperature window results in significant reductions in reduction efficiency. The lower the current NOx concentration in the outlet flue gas, the lower the reduction efficiency that can be achieved (reduced driving force for the NOx reduction reactions). The performance claims in published articles are typically short term, optimized test results, and are typically inflated compared to the performance guarantees that are actually offered for actual installations. Given the relatively low NOx concentrations in the Coal Creek flue gas, the reduction capabilities of SNCR were set at values in the 20-30% range based on data from other recent projects. The urea feed rate used in the calculation of operating costs

For comparison, recent FuelTech papers (one of the major SNCR vendors) stated that larger utility boilers (such as exist at Coal Creek at 605MW) have reported lower performance mainly due to the size of the units, inaccessible areas for injection, and load following control issues. NOx reductions in the range of 20 – 30% are common for units that start with NOx emission rates of 0.15-0.25 lbs NOx/MMBtu. Urea injection rates to obtain these reduction efficiencies varied from site to site, but fell in the range of 1.1-1.5 normalized stoichiometric ratio while maintaining acceptable ammonia slip rates. All-in costs for these systems were stated to be in the range of $10-20/kW. The injection rates assumed for this URS analysis of SNCR for Coal Creek used NSR injection rates that varied from 1.3-1.5 over the range of control evaluated of 20-30% NOx reduction. All of these performance values and estimated capital costs fall in the ranges stated in the supplier papers.

URS

If you have any additional questions, please contact me.

Sincerely,

Robert J. Keeth
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URS Energy & Construction, Inc.
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Appendix G

Golder Fly Ash Evaluation Supplement

Golder Associates

April 2, 2012 Project No. 113-82161

Diane Stockdill
Great River Energy
Coal Creek Station
2875 Third Street SW
Underwood, North Dakota 58576

RE: SNCR IMPACT TO FLY ASH MARKETABILITY AND MANAGEMENT COSTS

Dear Diane:

1.0 BACKGROUND

Golder Associates Inc. (Golder) submitted a report to Great River Energy (GRE) on November 15, 2011, providing a third party review of Headwater's ammonia slip mitigation (ASM) technology. Additionally, the review included a detailed engineering estimate of potential disposal costs associated with fly ash impacted by ammonia slip from selective non-catalytic reduction (SNCR) emission controls at GRE's Coal Creek Station (CCS).

This report was included as part of GRE's submittal of November 21, 2011 to the U.S. EPA Region 8 (EPA), with comments responding to the Proposed Rule for the Approval and Promulgation of Implementation Plans: North Dakota Regional Haze State Implementation Plan, Federal Implementation Plan for Interstate Transport of Pollution Affecting Visibility and Regional Haze (Docket ID No. EPA-R08-OAR-2010-0406).

The EPA provided a prepublication version of the "final rule" to GRE on March 2, 2012, which included EPA's response to various comments including those in GRE's November 21, 2011 submittal:

- Section V: Issues Raised by Commenters and EPA's Responses;
- Part E: Comments on BART Determination;
- Subpart 2: CCS Units 1 and 2;
- Item d: CCS Coal Ash had several comments; and
- EPA responses addressing the potential for SNCR to impact fly ash sales and the cost of this impact.

Below are Golder's responses to the EPA's comments on our November 15, 2011 report concerning the potential impact of SNCR controls to fly ash marketability at CCS and the potential cost impact if fly ash requires ASM technology and is less marketable and therefore, placed in greater quantities into disposal facilities.

2.0 SNCR IMPACT TO FLY ASH MARKETABILITY

The potential impact to fly ash marketability is a function of the SNCR ammonia slip adsorption onto the fly ash particles, and the acceptable (allowable) ammonia levels in fly ash by the fly ash end users.

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2.1 Ammonia Adsorption onto Fly Ash

Based on available literature, the adsorption of ammonia onto fly ash from SNCR emission controls is highly variable and dependent upon factors such as SNCR operation, fuel type/fuel mix, boiler configuration, ash content, ash mineralogy, ash alkalinity, ash sulfur content, and temperature. Limited published data are available for ammonia levels in fly ash for coal-fired power plants utilizing SNCR emissions controls, with no published information being found for energy generation facilities burning lignite coal.

In a 2007 EPRI study on the handling, disposal, and sale of ammoniated fly ash (EPRI 2007), responses from eight units utilizing SNCRs were discussed. All the units fired a PRB/eastern bituminous coal blend, were predominantly smaller units, were predominantly wall-fired, and had actual ammonia slip up to 5 parts per million (ppm). Only four units had tested levels of ammonia in the fly ash, with the measured levels ranging from less than 100 ppm to over 200 ppm. Several references attempt to relate the amount of ammonia slip to the ammonia levels in fly ash and suggest that a 2 ppm ammonia slip may result in fly ash ammonia levels from less than 50 ppm to several hundred ppm (Murarka 2003, Bittner 2001, Hinton 2012, Larrimore 2002). In addition, when explaining ash sales impacts at CCS, Sahu (2011) references a figure created by Larrimore (2002) that indicates ammonia slip levels above 2 ppm can lead to "restricted use" of fly ash and ammonia slip levels above 4 ppm may lead to "unmarketable" fly ash for use in ready mix.

2.2 Allowable Ammonia Present In Fly Ash

The amount of "allowable" ammonia present in fly ash destined for beneficial use varies depending on ash marketer preferences and the ultimate end use. Higher concentrations of ammonia present in fly ash are a result of ammonia slip in SCR or SNCR systems (EPRI 2007). Fly ash impacted with elevated levels of ammonia results in ammonia being released into the air when water is added. At low levels, ammonia is a nuisance; however, at higher exposure levels, ammonia can cause irritation of the eyes, throat, and nose as well as difficulty breathing (NIOSH 2011). Strength characteristics do not appear to be affected by the presence of ammonia in fly ash (Rathbone and Robl 2001).

Elevated concentrations of ammonia in fly ash contribute to releases into the environment during placement (with the presence of water), and a reluctance of fly ash marketers and users (i.e. Headwaters Resources, Lafarge, etc.) to buy fly ash for sales to the construction industry. EPRI (2007) explains that the "...industry rule-of-thumb indicates that ammonia contamination on fly ash that is destined for concrete/cement utilization must have less than 100 ppm ammonia to be useable." Headwaters indicated (January 11, 2010) that they "...quit shipping anything over 100 ppm..." in reference to the Eastlake facility, which has had an SNCR system since 2007. Eastlake has attempted to decrease ammonia content in the fly ash to less than 50 ppm using ASM to improve fly ash marketability. Lafarge (January 26, 2010) has found "...when the ammonia levels exceed 40 part per million in the fly ash that the consumer notices the ammonia and finds it to be objectionable." Additional references have generally found that approximately 100 ppm is the maximum "acceptable" ammonia level in fly ash (Bittner et al. 2001, Giampi 2000, Bittner and Gasiorowski 2005). Other sources cite 100 ppm as an acceptable allowable ammonia level in fly ash for enclosed spaces, but allow a higher limit of 200 ppm in well ventilated areas (Brendel et al. 2000, Larrimore 2002).

The amount of ammonia in fly ash can be related to the ammonia off-gassed during placement. Both NIOSH and OSHA have health-based exposure limits for ammonia in the air. NIOSH has a recommended exposure limit (REL) of 25 ppm and OSHA's permissible exposure limit (PEL) is 50 ppm. A "comfortable" threshold of 10 ppm ammonia is referenced by Rathbone and Robl (2001). Rathbone and Robl (2001) evaluated the relationship between ammonia in fly ash and the corresponding amount in air using laboratory and field-scale test methods:

$$NH_{3\,ash} = \frac{(NH_{3\,water})(Water - to - Cement\ ratio)}{(Fly\ Ash\ Content)}$$

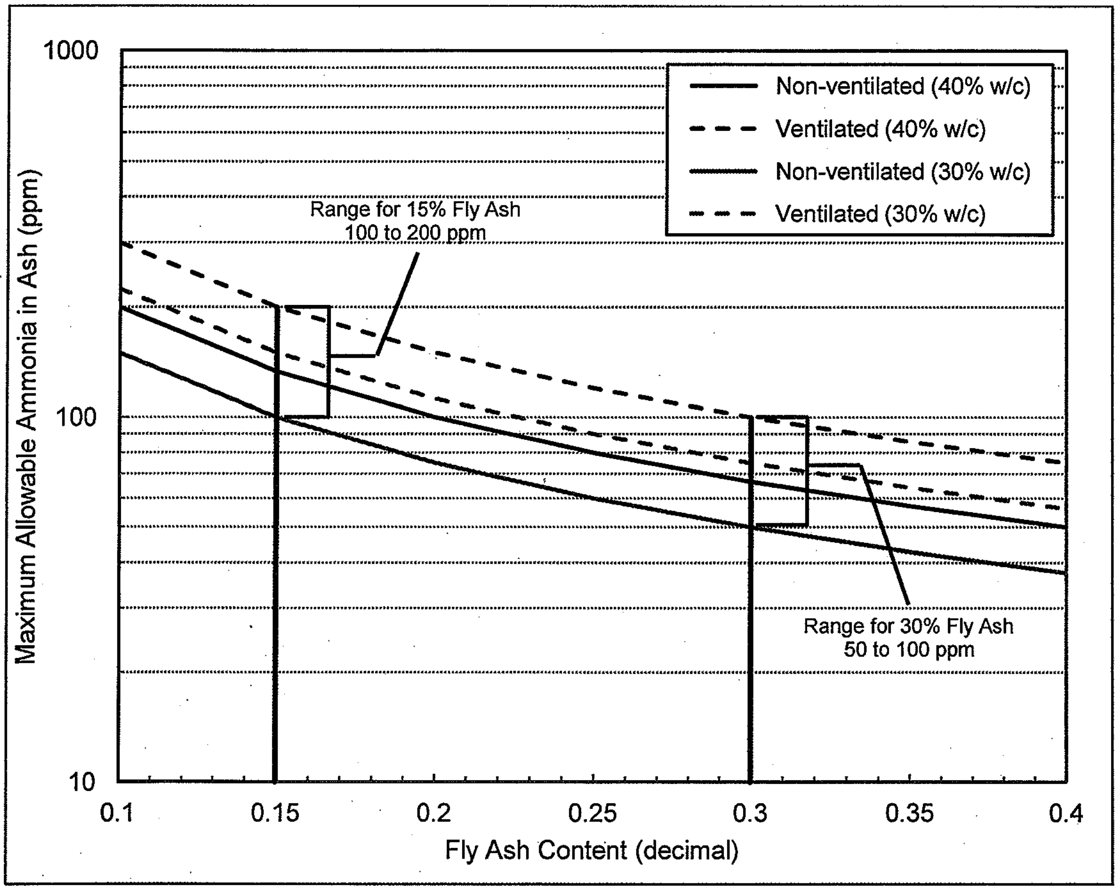
The lab and field scale testing found allowable ammonia levels in the concrete water prior to setting (for 10 ppm in the air), to be approximately 50 mg/l for non-ventilated spaces and 75 mg/l for well ventilated spaces.

Fly ash from CCS is a desirable high quality material and has been used extensively in North Dakota, Minnesota, Colorado, and as far as California. In a review of fly ash uses in North Dakota, the Energy & Environmental Research Center (EERC) stated:

> "NDDOT uses fly ash in almost all concrete projects at a replacement rate of 30%. A replacement rate between 15% and 30% is specified by most state DOTs (if they specify fly ash use at all), making NDDOT's specification on the higher end compared to other states. For mass pours, a replacement rate of 40% is allowed and is more typical." (EERC 2011)

Based on these uses of CCS fly ash, the above relationship was used to evaluate the maximum allowable ammonia content in fly ash for 15% and 30% fly ash mixtures, for water cement ratios between 30% and 40%, and for well-ventilated and non-ventilated areas. Results of the calculations are shown in the following table and the figure below.

Condition	**Ammonia in Air***	**Water/Cement Ratio**	**Allowable Ammonia Content in Fly Ash (15% fly ash mixture)**	**Allowable Ammonia Content in Fly Ash (30% fly ash mixture)**
	ppm	**-**	**ppm**	**ppm**
Ventilated	10	0.4	200	100
Non-Ventilated	10	0.4	133	67
Ventilated	10	0.3	150	75
Non-Ventilated	10	0.3	100	50
*Practical limit based on experience (Rathbone and Robl 2001)				



2.3 Marketability Conclusions

When ammoniated fly ash is used in concrete, the ammonia can be released into the air during placement and may cause irritation to individuals placing the concrete. The amount of ammonia released into the air is a function of fly ash content, the water/cement ratio of the concrete batch, and the ammonia concentration in the ash. Generally, industry experience indicates that fly ash used for concrete should have less than 100 ppm ammonia to prevent handling issues from limiting the marketability of the ash. Based on the use of CCS fly ash as a high percentage cement replacement (30%), a calculated allowable ammonia level in the fly ash may range between 50 ppm and 100 ppm. When discussing ash sales impacts at CCS, Sahu (2011) cites Larrimore (2002) in concluding that 2 ppm ammonia slip can result in 100 ppm ammonia in ash. According to Larrimore (2002), 4 ppm ammonia slip can result in 200 ppm ammonia in ash, a potentially unmarketable level of ammonia for use in ready mix. Because the ash marketer and ready mix user may not know the exact use of fly ash when it is purchased and placed in a silo, the practical limit for CCS fly ash is 50 ppm or less to allow its use in a wide variety of applications. This limit is also supported by the anecdotal comments from both Headwaters and Lafarge.

Definitive information is not available for the levels of ammonia that could be present in the fly ash at CCS due to SNCR ammonia slip. However, review of available literature indicates a reasonably high probability that ammonia concentrations would be in the range that is problematic for marketers and end users of CCS fly ash. Therefore, it is prudent for engineering costs evaluations to assume ammonia levels in CCS fly ash will be higher than the acceptable ammonia levels for CCS fly ash destined for beneficial use, and therefore to assume that CCS fly ash will be disposed or will require treatment with ASM technology to be sold for beneficial use.

3.0 SNCR COST IMPACT TO FLY ASH MANAGEMENT

Golder previously provided a detailed engineering cost estimate for the potential impact to fly ash management as a result of SNCR emissions controls at CCS. Based on the EPA responses, supporting information and clarifications are provided below.

3.1 Fly Ash Disposal Facility Design Basis

The previous evaluation indicated that each cost estimate was prepared assuming that fly ash will be disposed of in a new landfill with a design based on RCRA Subtitle D practices. This may have been taken as a speculative/highly conservative estimate based on impending coal combustion residue (CCR) regulations being developed by the EPA (see EPA response to comment on page 111 of rule prepublication).

In actuality, the assumed design is based on current North Dakota Department of Health (NDDH) regulations (NDDH, http://www.legis.nd.gov/information/acdata/html/33-20.html), which are in-line with RCRA Subtitle D practices. In the early 1990s the NDDH revised its Solid Waste Management and Land Protection rules adopting environmentally sound controls such as composite liners, leachate collection systems, surface water controls, and ground water monitoring.

3.2 Fly Ash Disposal Unit Cost Estimate

Disposal costs of $11 to $18 per ton were estimated based on site-specific designs for the disposal of fly ash at CCS. These disposal costs were based on a detailed engineering cost estimate for CCS including costs from landfill development to post-closure care. In the EPA's responses (page 110), they indicated "we find a disposal cost of $5/ton is reasonable in the improbable event that some ash would need to be disposed."

The cost estimate of $5/ton deemed reasonable by the EPA is not supported by an engineering cost estimate, is not supported by industry information, and is not supported by recent work published by the EPA.

In 2010, the EPA estimated baseline (i.e. current) CCP disposal costs in their Regulatory Impact Analysis for EPA's Proposed RCRA Regulation of Coal Combustion Residues (CCR) Generated by the Electric Utility Industry (EPA 2010). In Chapter 3 of that report, the EPA provided a cost estimate for the management of CCRs and estimated a range of $2/ton to $80/ton with an average of $59/ton. In discussion of these results, the report indicates that $2/ton is reflective of unlined, near-plant impoundments in states with low regulatory requirements, and the high end of $80/ton is reflective of off-site commercial disposal in landfills. Fly ash disposal facilities at CCS are clay- or composite-lined, engineered impoundments and landfills located at varying distances from the plant. North Dakota has comprehensive regulatory requirements in place for ash disposal facilities.

The EPA report further references information from the American Coal Ash Association (ACAA) to validate its cost estimate. The ACAA routinely collects ash disposal and beneficial use information from its members and has developed estimates for the disposal of CCPs. From the ACAA website and referenced in the EPA report:

> "As one can see, a variety of factors enter into determining disposal costs. The lowest cost occurs when a disposal site is located near the power plant and the material being disposed can be easily handled. If the material can be piped, rather than trucked, costs are usually lower. In these types of situations, cost may be as low as $3.00 to $5.00 per ton. In other areas, when distance is far away and the material must be handled several times due to its moisture content or volume, costs could range from $20.00 to $40.00 a ton. In some areas, the costs are even higher. If new sites are required and extensive permitting processes take place, the total cost of the facility may be increased, resulting in higher disposal costs over time." (ACAA, http://acaa.affiniscape.com/displaycommon.cfm?an=1&subarticlenbr=5#Q13)

The disposal of fly ash at CCS does not fall at either cost extreme (unlined impoundment or off-site commercial disposal), and the engineering estimate of $11 to $18 per ton appears well within the EPA's cost estimate and industry practice.

3.3 Lost Fly Ash Sales Revenue

Part of the cost impact to fly ash management is the loss of fly ash sales revenue currently being generated. Based on information from GRE, the 2010 average fly ash sales price per ton was $41.00 with 30% of the sales price going to GRE ($12.30/ton) as revenue and 70% of the sales price going to the fly ash marketer Headwaters ($28.70/ton).

EPA commented that GRE should use $5/ton rather than the updated value of $12.30/ton, and suggested that the lost revenue price included lost revenue to other parties. Based on follow-up discussions with GRE, it was confirmed that the $41/ton is the 2010 average FOB Coal Creek Station sales price and the $12.30/ton portion attributed to GRE does not include lost revenue to other parties. Based on this confirmation, the $12.30/ton rather than the $5/ton is more appropriate for the conditions at Coal Creek Station.

3.4 Cost Impact Conclusions

The fly ash disposal cost estimate is based on an engineering design reflective of the practice in North Dakota, and Golder's engineering estimate of $11 to $18 per ton for fly ash disposal appears to be well within the EPA's cost estimate and consistent with industry practice. Further, the lost fly ash sales revenue of $12.30/ton reported in the cost impact evaluation is reflective of current conditions at CCS.

The disposal and lost revenue cost estimates are valid, and based on the uncertainty with respect to ammonia levels in fly ash, the previous evaluation with respect to fly ash management cost is reasonable.

GOLDER ASSOCIATES INC.

Ron R. Jorgenson
Principal

Todd Stong, P.E.
Senior Engineer

TJS/RRJ/kcs

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Great River Energy's
Legal and Technical Review Of
U.S. EPA's BART Determination for Coal Creek Station

I. INTRODUCTION

On March 2, 2012, EPA issued its *Approval and Promulgation of Implementation Plans; North Dakota; Regional Haze State Implementation Plan; Federal Implementation Plan for Interstate Transport of Pollution Affecting Visibility and Regional Haze*, 76 Fed. Reg. ____(April __, 2012) ("FIP"). EPA largely upheld the North Dakota Department of Health's ("NDDH's") SIP with two exceptions: the NOx Best Available Retrofit Technology ("BART") requirement for Great River Energy's Coal Creek Station ("CCS"), and Reasonable Progress requirements for Basin Electric's Antelope Valley Station. Below, GRE addresses EPA's FIP and its rationale for requiring selective non-catalytic reduction ("SNCR") at CCS. In particular, GRE explains that EPA failed to rationally apply the Clean Air Act's ("CAA's") five-factor BART analysis and GRE responds to key EPA arguments for rejecting NDDH's BART determination.

In rejecting NDDH's BART determination for CCS, EPA made numerous errors, including the following:

- Conducted an improper cost analysis by ignoring the existing controls in use at CCS, including LNC3+ and DryFining™;

- Failed to analyze, or ignored, the incremental cost of SNCR compared to existing and planned controls at CCS, including LNC3+ and DryFining;

- Ignored the demonstrated lack of visibility benefits resulting from its requirement to install SNCR at CCS; and

- Rejected, without validated support, the likelihood of ammonia slip and fly ash contamination.

Beyond these errors, EPA purported to reject NDDH's BART determination for CCS because NDDH relied on cost analyses that contained an error in one component of the costs – the cost of ash contamination and disposal. While objecting to this one component, EPA rejected NDDH's entire BART analysis and NDDH's valuation of the other four, equally important, factors in the BART determination.

The foregoing errors, as well as EPA's failure to give any credence to the values that NDDH's placed on the other BART factors, demonstrate that EPA did not conduct a valid BART analysis for CCS. EPA failed to comply with the CAA requirements and the Agency's own guidelines.

II. EPA's "COST OF CONTROLS" ANALYSIS IS INCONSISTENT WITH THE STATUTE AND EPA'S OWN GUIDANCE

EPA's principal basis for rejecting NDDH's BART determination was NDDH's reliance on purportedly incorrect information regarding the cost associated with ammonia contamination of merchantable fly ash resulting from using SNCR. GRE has addressed the cost issue that EPA raised and has reflected those changes in GRE's Supplemental Best Available Retrofit Technology Refined Analysis for NOx Emissions, April 5, 2012 ("BART Supplement"). EPA asserts, incorrectly, that there should be no ammonia slip or fly ash contamination from using SNCR.[1] However, EPA's own cost analysis is seriously flawed and inconsistent with both the CAA and its own Guidance. EPA made two significant errors in conducting its cost analysis of SNCR. First, it ignored the emission controls already installed and in use that have significantly reduced NOx emissions at CCS. Second, EPA failed to examine the incremental, or marginal, costs of SNCR beyond the existing and planned controls at CCS.

A. <u>EPA Failed to Consider Existing Pollution Controls in Use at CCS and Current Emissions in Performing Its Cost Analysis</u>

Under CAA §169A, the State (or EPA Administrator) must take into consideration five factors in determining BART. One of the five factors is "any existing pollution control technology in use at the source." 42 U.S.C. § 7491(g)(2). EPA completely disregarded this obligation and, instead, relied on 9-year-old emissions data in its cost analysis. The effect of using the inaccurate, inflated emissions data is to distort EPA's cost numbers and make SNCR seem more cost-effective than it is.

EPA relied on emissions data from 2003 and 2004 in its cost analysis. EPA did this notwithstanding its acknowledgement that current emissions are significantly lower. *See* FIP at 20. Since 2004, GRE has made multiple improvements in the combustion and emissions at CCS, including: (1) installing new, adjustable SOFA nozzles in Unit 1 in 2005; (2) installing expanded over-fire air registers in Unit 2 in 2007; (3) installing close coupled over-fire air (CCOFA) on Unit 2 in 2010; and (4) installing DryFining at both units in 2010. All of these measures had beneficial impacts on NOx formation and emissions, reducing emission rates at Unit 2 from 0.22 lbs/mmBtu in 2004 to 0.153 currently. For Unit 1, emissions were reduced from 0.22 in 2004 to 0.20 lbs/mmBtu in 2010.

EPA's failure to acknowledge these installed controls is inconsistent with the plain language of the statute and EPA's own BART guidance. "[B]aseline emissions rate should represent a realistic depiction of anticipated annual emissions for the source." *See* 69 Fed. Reg. 25224. EPA's reliance on 2003 - 2004 emissions from CCS is not a "realistic depiction" of CCS's current or anticipated emissions. By using incorrect emissions data, EPA created and relied on admittedly inaccurate cost effectiveness numbers, the very grounds on which it rejected NDDH's BART determination.

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[1] EPA's assertion is addressed below in Section IV, and by Golder Associates in Exhibit G to the BART Supplement.

EPA's explanation for using inaccurate emission data is both irrational and inapposite to CCS. EPA argues that using emissions resulting from existing emission controls (as required by the statute) would "reward sources that install lesser controls in advance of a BART determination in an effort to avoid more stringent controls." FIP at 95. Whatever EPA's policy considerations, GRE did not install such controls to "game" the BART process. The DryFining technology involved a multi-year, $270 million investment in partnership with the Department of Energy to improve the emissions resulting from coal combustion. The installation of new SOFA nozzles and LNC3+ was done as part of DryFining and in cooperation with the NDDH to achieve better combustion and lower NOx emissions. There is nothing in the record to suggest any of this was done to avoid more stringent BART. It was not.

EPA's statement that these controls were "voluntary" and, thus, EPA need not consider them in evaluating BART is nonsensical. There is nothing in the statute that says voluntarily installed emission controls can or should be ignored. The statute says that EPA must take into consideration "*existing pollution control technology in use at the source*." EPA cannot simply assume emissions that do not exist to bolster its goal of making SNCR appear more cost effective than it is. Further, this is a policy decision beyond EPA's authority. Congress expressly requires EPA to consider existing controls when determining BART. *See* 42 U.S.C. § 7491(g)(2); *St. Mary's Hosp. of Rochester, Minnesota v. Leavitt*, 535 F.3d 802, 806 (8th Cir. 2008) ("The plain meaning of a statute controls, if there is one, regardless of an agency's interpretation."). Although that may result in companies having to do less under BART, that may be precisely what Congress intended. Encouraging sources to install controls voluntarily – as CCS did – results in achieving emission reductions and visibility improvements earlier than might otherwise be required. EPA's policy would discourage companies from ever voluntarily reducing emissions; in other words, EPA is pursuing the "no good deed goes unpunished" theme of regulation.[2]

Finally, EPA acknowledges that it refused to use accurate, current emission rates from CCS because using the lower emission levels would "skew the 5-factor BART analysis by reducing the emissions reductions from combinations of control options and increasing the cost effectiveness values." FIP at 98. This admission lays bare the inaccuracy of the Agency's cost effectiveness assertions and the inappropriateness of EPA's BART determination for CCS.

B. <u>EPA Failed to Properly Calculate and Consider the Incremental Cost of SNCR in Making Its BART Determination</u>

EPA also failed to consider the incremental cost of SNCR in contravention of its own regulations and guidance. EPA guidelines direct the states as follows. "In addition to the average cost effectiveness of a control option, you *should* also calculate incremental cost effectiveness. You *should* consider the incremental cost effectiveness in combination with the total cost effectiveness in order to justify elimination of a control option. *See* 69 Fed. Reg. 25224 (emphases added); 70 Fed. Reg. 39127 ("We *continue* to believe that *both* average and

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[2] By EPA's logic, GRE should have done nothing over the past nine years while waiting for a BART determination. This would have postponed any NOx reductions from approximately 2005 until 2018 (five years after BART is determined).

incremental costs provide information useful for making control determinations.") (emphases added).

To justify SNCR, EPA inexplicably ignored half of its own "cost of controls" analysis. Instead, EPA looked only at the total cost of installing both LNC3+ *and* SNCR (as opposed to SNCR alone) and compared that total cost to the emission reductions achieved using both technologies. As discussed above, the emission reductions from LNC3+ (in addition to the DryFining) already have been achieved at Unit 2 and the LNC3+ is planned for Unit 1. The cost of LNC3+ is a small fraction of the costs of SNCR, yet it generates most of the NOx emission reductions. By combining the two costs into one control option, EPA further distorts the cost-effectiveness of SNCR. If EPA had looked at the cost-effectiveness of SNCR alone (i.e., incremental cost), it would have to admit that the emission rate would decline by only 0.023 lbs/mmBtu: from 0.153 lbs/mmBtu to EPA's proposed rate of 0.13 lbs/mmBtu.

The impact of EPA's error is dramatic. Even if we accepted EPA's unfounded assumption that there would be no fly ash contamination resulting from SNCR, the incremental cost of using SNCR would be $8,534 per ton for Unit 1 and $4,688 per ton for Unit 2. EPA's estimate that the cost effectiveness is under $2,500 per ton is misleading because the cost-efficient reductions come from the use of LNC3+, a technology already installed at Unit 2 and planned for Unit 1.[3] *See* BART Supplement, Table 3.1. SNCR cannot be justified on the basis of achieving such a small incremental reduction in NOx emissions at such high costs, particularly in light of the other factors that weigh against SNCR.

III. EPA Failed to Properly Consider the Lack of Visibility Benefits Resulting From the Installation of SNCR

The flaws in EPA's BART analysis were not limited to only cost-related considerations. EPA also failed to give serious consideration to other statutory factors that Congress required to be part of any BART analysis, especially the lack of any demonstrable visibility benefit resulting from SNCR. The modeling on which both NDDH and EPA relied demonstrates that there would be no discernable visibility improvement resulting from installation of SNCR. *See* 76 Fed. Reg. 58,622. The degree of predicted visibility improvement, approximately 0.105 deciviews, is only one tenth of the level that EPA asserts is perceivable by the human eye. Given the many sources of variability of inputs to CALPUFF's visibility analysis versus actual impacts, a difference of 0.1 deciviews between options may reflect no real difference at all. *See* attached Memorandum from Andrew Skoglund, Barr Engineering, to William Bumpers (April 4, 2012).

EPA made no effort in its final rule to dispute that there will be no real improvement in visibility resulting from SNCR. Instead, EPA surprisingly states that "perceptibility of visibility improvement is not a test for the suitability of BART controls." FIP at 112. While EPA later acknowledges that deciview improvements is one of the five factors, it then says that the "Guidelines provide flexibility in determining the weight and significance to be assigned to each factor" and that achieving a perceptible benefit of 0.5 deciview is not a prerequisite for selecting

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[3] The significantly higher incremental costs associated with Unit 1 are due to lower utilization and associated emissions at Unit 1 compared to Unit 2.

BART. FIP at 112. While Congress made clear that the state has great discretion in deciding the weight to accord each factor, EPA has effectively eliminated any import associated with the one factor (visibility) that is the central focus of the regional haze rule. EPA is simply imposing controls and costs on CCS notwithstanding that EPA cannot predict with any confidence that there will be any visibility improvement. This is contrary to the entire objective of the statute.

EPA's only attempt to justify ignoring the lack of visibility benefits resulting from its proposed BART was to note that NDDH was satisfied with a similarly small improvement at another source. *See* 76 Fed. Reg. 58,623. But this explanation completely ignores NDDH's source-specific determination for CCS that an estimated 0.1 deciview improvement did not justify the large costs of SNCR. *See* 76 Fed. Reg. 58,624. EPA's attempt to cherry pick the visibility level from a separate BART analysis ignores NDDH's valuation of all of the other four factors, including a much lower cost, that affected the determination.

Even the theoretical improvement of 0.105 deciviews is likely exaggerated. EPA criticizes the modeling that GRE provided because the various control scenarios were modeled together; that is, the NOx control options were modeled along with the SO_2 reductions. But EPA has repeatedly recognized that its modeling requirements overstate real-world visibility improvements by five to seven times. *See, e.g.,* EPA North Dakota Proposed FIP, Technical Support Document, B-41; FIP at 55. EPA's justification is that modeling based on "current degraded visibility conditions would result in a smaller relative benefit than would a comparison relative to natural background visibility." FIP at 55.[4] Importantly, EPA admits that it undertook no independent modeling of the prescribed emission reductions, so EPA cannot state that SNCR will result in *any* visibility improvement, FIP at 99.

IV. EPA's Conclusion that SNCR Will Result In No Fly Ash Contamination Is Unrealistic

The principal basis EPA cites for rejecting NDDH's BART determination is that NDDH had relied on costs provided by GRE for installation of SNCR that included one incorrect value – the cost of disposing of contaminated fly ash.[5] *See* 76 Fed. Reg. 58,603-04. GRE has corrected that value.[6] As discussed above, even if we assumed that there would be zero contamination of the fly ash, the marginal cost of SNCR ($4,688 per ton for Unit 2 and $8,534 per ton for Unit 1) coupled with the lack of any visibility benefit cannot justify SNCR. But EPA's assertion in the FIP that there will be no wastage of fly ash is not supportable. Exhibit G to the BART Supplement is a report from Golder Associates, addressing EPA's assertion that SNCR would not result in any fly ash contamination and reaffirming the expected costs of fly ash disposal. As demonstrated by Golder Associates and below (1) EPA's assertion that CCS could maintain ammonia slip to below 2 ppm is unsupported and almost certainly wrong; and (2) even at 2 ppm

[4] Put differently, EPA does not allow modeling of what is expected to actually happen because that would confirm EPA's approach results in little or no real-world visibility improvements.
[5] GRE had initially included FOB price of ash. The value was not in error, but GRE agreed that the FOB price was not the correct value for the BART cost analysis.
[6] Golder Associates concludes that a cost of $12.30 per ton is the expected cost of lost fly ash sales resulting from ammonia contamination. BART Supplement, Exhibit G at 6.

ammonia slip, a significant amount of CCS's fly ash would become unmerchantable and require disposal.

In EPA's proposed BART determination, EPA recognized that using SNCR could, and likely would, result in some contamination of GRE's merchantable fly ash at CCS. *See* 76 Fed. Reg. 58,620-21. Consequently, EPA assigned costs to SNCR associated with the lost sales and increased disposal costs associated with the contaminated fly ash. *Id.* In the final FIP, EPA asserts that SNCR at CCS would not contaminate any fly ash because "current technology has made it possible to control ammonia slip from SNCR to levels . . . in a range of 2 ppm or less." *See* FIP at 102. In making this remarkable assertion, EPA relies essentially on a single case study – the "Andover Report." *See* FIP at 102 n.32. The Andover Report provides virtually no support for EPA's claims.

The Andover Report's results cannot be relied on to make any operating assumptions about CCS. It states upfront that "[e]xperience with the TDLAS method on coal power plants has had mixed success – and unfortunately, *far more failures than successes*." Andover Report at page 5 (emphasis added). In the course of examining this technology further, the Andover Report analyzes the use of SNCR at the CP Crane station in Baltimore. The CP Crane station consists of two, 200MW cyclone boilers. It is subject to the Maryland Healthy Air Act, a law that imposes a company-wide, NOx tonnage limitation on power plant owners. CP Crane is one of multiple plants owned and operated by Constellation Energy in Maryland. Constellation installed NOx controls on all of its plants in Maryland, installing SCR on its larger, base load plants, and installing SNCR on CP Crane. GRE contacted Constellation about EPA's assertions. Constellation officials informed GRE that the plant conducted four, one-hour performance tests when commissioning the system,[7] on which the Andover Report is based. Since this commissioning test, Constellation has rarely run the SNCR at CP Crane. Constellation's plant is not subject to a short term NOx rate limit, is not subject to an ammonia slip limit and Constellation does not monitor the ammonia slip. The SNCR system has process monitors but they are not certified. The initial NOx rate at these cyclone burners is approximately 0.4 lbs/mmBtu. Because there is no enforceable NOx rate, the level of ammonia injection is completely discretionary. Constellation does not know what its actual ammonia slip rate is, or would be if the SNCR were actually being utilized. Thus, Mr. Staudt's paper, which is based on the initial, short-term, commissioning test, in no way represents a reasoned basis for EPA's assertions that ammonia slip can be held consistently below 2 ppm or that there will be no fly ash loss as a result of installing SNCR at CCS.[8]

In response to EPA's FIP, Golder Associates ("Golder") has re-examined the literature on the impact of ammonia on fly ash, including the studies referenced by Dr. Sahu in the FIP. *See* FIP at 102 n.35. Golder demonstrates that there is no literature that supports EPA's contention that no fly ash wastage is expected. To the contrary, even if ammonia slip could be limited to 2 ppm on a constant basis – something that has never been demonstrated – ammonia

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[7] This short-term commissioning test is hardly an indication of what can be achieved at a much larger facility over a longer term and a wider range of operating levels.

[8] EPA's reference to the Big Brown plant in Texas is similarly unpersuasive. According to EIA data and Luminant, Big Brown landfills approximately one third of its fly ash.

concentration in fly ash could be as high as 100 ppm, which Golder concludes would significantly limit the sale of CCS's fly ash. BART Supplement, Exhibit G at 3-4.

Golder also addresses EPA's criticism of the costs assigned for disposing of contaminated fly ash. BART Supplement, Exhibit G at 5-6. Golder points out that its costs are based on NDDH Solid Waste Management and Land Protection regulations (NDDH, http://www.legis.nd.gov/information/acdata/html/33-20.html). NDDH's rules require controls such as composite liners, leachate collection systems, surface water controls, and ground water monitoring. As a result, Golder estimates the cost of fly ash disposal to be between \$11 and \$18 per ton. Golder also demonstrates that EPA's estimate of \$5 per ton is not supported by any analysis and is inconsistent with EPA's own regulatory impact analysis from 2010, which estimated a range of \$2 to \$80 per ton, with an average cost of \$59 per ton. BART Supplement, Exhibit G at 5. Golder also confirms that the cost of lost fly ash sales for GRE is \$12.30 per ton. BART Supplement, Exhibit G at 6.

Perhaps recognizing the fundamental weakness of its assertion, EPA noted that even if SNCR did cause some ammonia contamination, "three possible systems" could be used to cure the problem. *See* FIP at 102 n.35. EPA did not even bother to analyze whether any of these technologies might actually work at CCS. The manufacturer of one of those technologies stated that "[t]he limited current experience in commercial application and lack of research is not adequate for Headwaters to be able to provide any guarantee that the process can be successfully applied to treat lignite ash at the Coal Creek Station." *See* July 15, 2011 Email from Rafic Minkara, PhD., PE (Headwaters) to John Weeda (GRE), forwarded to Gail Fallon and Carl Daly (EPA) on July 15, 2011. Despite the manufacturer's lack of confidence as to whether its own technology would work, EPA asserted its "consultants are aware of no technical reason that ASM technology would not be effective to mitigate ammonia on fly ash from lignite." *See* FIP at 102 n.35. EPA cites nothing to justify its conclusion that the technology in question should work when the technology's own creator refused to support the conclusion. Making bald assertions that are unsupported at best, and flatly contradicted at worst, by evidence in the record is textbook arbitrary and capricious.

III. EPA'S CONSIDERATION OF THE OTHER FACTORS WAS IRRATIONAL

A. Other Cost Errors

1. EPA Arbitrarily Rejected URS's Cost Data

EPA's disregard of construction cost analysis of SNCR at CCS is unfounded. URS is a leading engineering and construction company that has participated in the construction and installation of SNCR projects at more than 30 coal-fired power plants. EPA's criticism that URS is not an SNCR vendor, and thus unable to opine on the costs of installing SNCR at CCS is arbitrary and capricious. *See* FIP at 121-124. As URS states:

> URS is not a technology supplier. The supplier is typically responsible for installation of only their process island and system performance guarantees. The installation of the balance of plant (BOP) equipment, construction management, foundations, utility tie-ins (electrical, water, air, instrumentation and controls

> interface, interconnecting piping, new flue gas emissions monitoring equipment, boiler and air heater modifications, retrofit difficulty due to existing plant access and congestion issues, et al) typically falls outside of the scope of supply for the SNCR vendor. Published cost estimates and vendor proposals in many cases do not consider these BOP cost impacts on the Total Capital Requirement for the installation of emissions control equipment. URS's project experience provides a basis for the assessment of these BOP costs that must be added to the vendor supplied equipment's installed costs to determine the true total capital cost of an installation.

See Letter from URS to Debra Nelson, March 30, 2012, BART Supplement, Exhibit F.

URS also has reconfirmed the basis for the retrofit factor of 1.6 based on the difficulty of installation at CCS. *See* BART Supplement, Exhibit F. URS also further explains the basis for its skepticism regarding SNCR's effectiveness when the initial NOx emission rates are in the lower range, similar to the NOx rate at CCS Unit 2. *See* BART Supplement, Exhibit F. EPA simply had no reasoned basis for disregarding URS's cost and performance analysis. EPA repeatedly refers to information from SNCR-designer Fuel Tech, but EPA's information appears to have been gleaned largely from a promotional website rather than site-specific analysis. *See* FIP at 20 n.2, 97 n.29. EPA's claim that its "consultant" received some sort of input from a SNCR vendor is so vague as to render it useless. *See* FIP at 102 n.34. The record does not show that EPA asked Fuel Tech to evaluate whether its technology would work at CCS. In any event, the follow up analysis provided by URS demonstrates that its cost analysis is well grounded.

2. EPA Provided No Rational Basis for Departing From its Guidelines' Presumptive Values

EPA's FIP ignored the Agency's own Guidelines, which require careful consideration of EPA's presumptive emissions limits. EPA's Guidelines explain that "we believe that States should carefully consider the specific NOx rate limits for different categories of coal-fired utility units, differentiated by boiler design and type of coal burned, set forth below as likely BART limits." *See* 70 Fed. Reg. 39134. EPA went on to note that "States have the ability to consider the specific characteristics of the source at issue and to find that the presumptive limits would not be appropriate for that source." However, EPA's BART analysis does not even acknowledge the existence of its own presumptive emissions limits much less reflect "careful" consideration of them. *See* 76 Fed. Reg. 58620-23. Furthermore, EPA offers no explanation why a departure from them is appropriate in this particular case, particularly where no visibility benefit would result from doing so. EPA cannot ignore its own Guidelines and nonetheless claim to have undertaken a legally-adequate BART analysis. EPA certainly would not allow a state to do so.

B. Energy and Non-Air Quality Environmental Impacts of Compliance

The CAA also requires consideration of the energy and non-air quality environmental impacts resulting from the use of relevant control technologies. This includes the energy requirements of the technology, the local availability of necessary fuels, and the generation of solid or hazardous wastes as a result of applying a control technology. *See* 70 Fed. Reg. 39,169. As already discussed above, EPA assumed contrary to all reasonable evidence that no fly ash

would be contaminated due to SNCR. EPA was therefore able to avoid considering the non-air environmental impacts arising from the creation of hundreds of thousands of tons of solid waste (and perhaps hazardous wastes depending on EPA's consideration of how to regulate fly ash). EPA's unsupported conclusion about fly ash therefore prevented EPA from properly considering two factors – the cost of controls and non-air environmental impacts.

IV. CONCLUSION

EPA rejected NDDH's entire BART analysis principally because of a purported error in a single cost component: the cost of contaminated fly ash. EPA then utilized flawed cost analysis and inaccurate emissions data to justify installation of SNCR. EPA effectively ignored all of the other BART factors, especially the lack of any measurable visibility improvement that might result from investing tens of millions of dollars to install and operate SNCR. GRE has provided NDDH with a revised BART analysis, including a refined cost analysis that examines the average and incremental cost, and cost-effectiveness of various levels of NOx emissions control. In light of the lack of any discernable visibility improvement at any Class I area, NDDH would be justified in supporting its initial BART determination at any cost level, including EPA's artificially low average cost per ton of $2500 per ton. The actual incremental cost of SNCR will be $4,688 per ton and, for Unit 1, will be $8,534 per ton, even if no costs are assigned to the loss of merchantable fly ash. The costs are significantly higher, and other environmental impacts worse, if fly ash contamination were to result from using SNCR. The documentation demonstrates this is very likely.

NDDH's initial BART determination was in compliance with the statutory obligations. With the refined BART analysis, and updated cost information, NDDH can make its own BART determination, assigning its own values to the five BART factors and should not accept EPA's usurpation of NDDH's authority.

Memorandum

To: William Bumpers, Baker Botts L.L.P.
From: Andrew Skoglund
Subject: CALPUFF Visibility Impact Variations
Date: 4/4/2012
Project: 34280013.01
c: Mary Jo Roth, Debra Nelson - GRE; Joel Trinkle, Laura Brennan - Barr

CALPUFF is the USEPA's preferred model for assessing visibility impacts at Class I Areas resulting from long range (50 – 300 km) plume transport. CALPUFF is a multi-source model which accounts for plume advection and atmospheric chemical reactions to estimate the concentrations of primary chemical species (ammonium nitrate, ammonium sulfate, elemental carbon, organic carbon, fine particulate and soil) known to cause haze (i.e., visibility impairment). Plumes in CALPUFF are transported using sophisticated meteorological data and plume transformations from atmospheric chemical reactions occur due to interactions of plume pollutants, background atmospheric pollutants (ozone and ammonia) and meteorological variables – most importantly water vapor as represented by relative humidity.

Visibility impairment is calculated as a function of the light scattering properties of atmospheric particles and gases. An increase in light scattering particles decreases the visual range as measured in deciviews. The EPA estimates that a sensitive observer may be able to detect a variation of 0.5 deciviews, with 1.0 deciviews being a more accepted threshold for distinguishable difference in visual impairment. Modeled visibility impacts of 0.1 deciviews are therefore indistinguishable to the human eye.

Calpuff modeled visibility impacts are reported in the model output files to thousandths of deciviews. However, this level of sensitivity overstates the potential accuracy of the model when compared to real-world observations. Assessments of the CALPUFF modeling suite versus real-world monitoring data demonstrate the potential for significant differences between modeled and actual concentrations. There are many model inputs which play a role in impact variability, ranging from background chemistry data to emissions data entered into the model.

Visibility calculations are directly affected by the background chemistry input to the model. While ozone is input to the model based on hourly observations from available monitoring locations within the modeling domain, ammonia inputs are calculated monthly average values. The use of monthly ammonia background concentrations in the model, allows for consistency between modeling runs, but is a simplification of the actual conditions and impacts to visibility. Variation in ammonia background can have a measurable effect on the chemical transformations in the model, and in turn on modeled visibility impacts. The background values for visibility impairing pollutants (ammonium nitrate, ammonium sulfate, elemental carbon, organic carbon, fine particulate, and soil.) are based on projected values of pristine or natural conditions. These also are input as monthly average background levels. Variability in actual backgrounds, while demonstrating definite seasonal changes, is not limited to changing by calendar month.

Additionally, the fixed nature of the modeled emissions utilized in BART analyses does not reflect actual operations of a facility. Few facilities will operate at their maximum 24-hour rate 365 days per year. The emission rates and parameters for the potential modeled scenarios use assumed emissions and fixed stack parameters (e.g. exhaust temperature, airflow) for scenarios not already in operation at a facility. Final design may yield variations in these parameters, an additional source of impact variability. There is the possibility for considerable variation in actual emissions versus the modeled maximum rates used for BART analysis. It could be expected that small changes to the source parameter assumptions would result in small changes to the model results. Therefore, if the assumed stack flow rate or temperature for the EPA BART controls were misrepresented by 10 - 20% from potential as-built values, it could be possible that the deciview difference would be on the order of 0.1 deciviews – i.e., within the sensitivity of the model.

Inasmuch as the BART modeling analysis methodology is proscriptive (e.g., model each facility individually, use background monthly ammonia values, etc…), the CALPUFF results from one model run to the next can be useful in a relative sense and not in an absolute sense (i.e., the CALPUFF model results are not expected to reflect observed values). However, the difference in results from any two modeling runs needs to be understood in context of the parameter estimated. For the BART analysis, the parameter of interest is deciviews and the human perceptibility threshold is 0.5 deciviews. On this basis, differences in model run results of less than 0.5 deciviews are not significant.

For the CCS modeling analysis, the model run differences are 1) baseline – current controls compared to 2) baseline – EPA BART controls. In both cases, the relative model results (baseline – controls) show a fairly large difference (up to 2 deciviews), giving some confidence in the modeling results that controls would result in perceptible improvements to visibility. However, the EPA's contention that the 0.1 deciview difference between 1) and 2) is actionable based on modeling, ignores the fact that 0.1 is the difference between two large numbers.

Given the many sources of variability of input to CALPUFF's visibility analysis versus actual impacts, a difference of 0.1 deciviews between options may reflect no real difference at all.

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VIA E-MAIL
AND U.S. MAIL

July 15, 2011

Received
Air Quality
JUL 2011

Mr. Terry L. O'Clair
Director, Division of Air Quality
North Dakota Department of Health
Gold Seal Center
918 E. Divide, 2nd Floor
Bismarck, ND 58501-1947

RE: BART Revisions and Proposed NOx Testing

Dear Mr. O'Clair:

In response to recent correspondence from EPA, Great River Energy (GRE) has reevaluated the Coal Creek Station (CCS) NOx technology options, as originally presented in the BART Emission Control Cost Analysis Table A-1a. After making minor corrections to some erroneous calculations and updates to the capital costs, the analysis shows that Selective Non-Catalytic Reduction (SNCR) technology is not cost effective.

In addition, Great River Energy is committing to additional NOx optimization studies to better improve upon emissions reductions. It is our firm position that SNCR should not be required, based upon cost effectiveness thresholds as well as the relatively minor deciview improvements associated with the emission controls. Finally, Great River Energy has strong reservations about the feasibility of the ash mitigation technology, which will negatively impact ash sales. Given the limited timeframe to respond to recent EPA correspondence, Great River Energy has not been able to fully investigate the ash mitigation feasibility. We have, however, contacted the developer of the technology, Headwaters Resources. Headwaters has not conducted any research on application of this technology to lignite. Its inadequate experience with commercial application and the lack of research on lignite means that Headwaters is unable to provide any guarantee that the process can be successfully applied to treat lignite ash. Therefore, Headwaters does not recommend application of this technology at CCS. Consequently, it has not been included in the revised analysis.

Revised Cost and Emission Information

Great River Energy has updated the cost and emission information (see attachments). Most notably, Great River Energy has updated the SNCR capital cost based upon the recent revision to the IEC Cost model (Rev 3, Nov 2010). In the initial analysis, data from the 1998 cost model was used and was escalated to 2006 dollars. In order to remain consistent with other BART Analyses and other cost estimates, GRE has de-escalated the 2010 SNCR cost to 2006 dollars. With respect to emission information, Great River Energy noticed that the baseline NOx emission values did not use the highest two-year period from the baseline due to formatting error. This minor error was corrected.

Proposed NOx Optimization Study

Great River Energy recognizes the value of reducing emissions and supports NDDH's goal of lowering emissions, as demonstrated by our willingness to install emissions reduction technology (i.e., LNB3/SOFA "Option 2") well in advance of any regulatory requirement. In addition to these existing reductions, Great River Energy will commit to an evaluation and testing of NOx emissions to determine what emission reductions can now be achieved utilizing the novel DryFining™, multi-pollutant control technology.

As you are well aware, Great River Energy voluntarily installed DryFining as an innovative patented technology. The development of the DryFining coal drying technology has taken over ten years. The system provides a means of beneficiating low-rank feedstock in a manner that results in more efficient power plant operation and reduced emissions. During its development, Great River Energy believed that the DryFining system would provide additional NOx reductions. However, with no operating experience, GRE could not predict with certainty NOx emissions reductions and could not include them as part of the Final BART Analysis, which was submitted to NDDH in late 2007. In December 2009, the $285 million DryFining system was placed in service.

Throughout 2010 and 2011, Great River Energy has continued to modify and finalize the design of this new technology. DryFining design changes are now final. The NOx, SO_2 and mercury emissions have been lowered. As one example, Unit 2's 2011 year-to-date NOx emissions are 0.146 lbs/mmBtu. This represents a 28% reduction from pre-DryFining emissions. Note that CCS Unit 2 has also installed LNB/OFA Option 2 from the BART table, in advance of the BART requirements. CCS has already demonstrated it can achieve 30-day rolling average emissions below the presumptive BART limit of 0.17 lbs/mmBtu.

Not only are Unit 2's year-to-date average emissions at 0.146 lbs/mmBtu, CCS has also operated at levels below 0.14 lbs/mmBtu on a short-term basis. CCS would need to conduct additional tuning and testing to determine whether this lower level is achievable on a 30-day rolling average basis.

To determine additional and achievable emissions reductions utilizing Option 2 and DryFining on Unit 2, Great River Energy proposes to complete a NOx optimization study. The scope of NOx optimization will include a comprehensive evaluation of NOx emissions and controls. The details of the testing program will be further determined as system experts and consultants are able to review and make recommendations for a testing protocol. The DryFining process is currently removing 8.5% of the feedstock moisture with a long term goal of 12% moisture removal. Great River Energy expects additional reductions as a result of the change in feedstock moisture. Additional testing is likely to include such things as boiler tuning and adjustments such as excessive air levels, an evaluation of computerized boiler optimization system benefits with DryFining, and burner, nozzle and SOFA designs associated with DryFining.

The preliminary timeline for testing is as follows:

- Develop testing protocol – 2011
- Testing NOx emissions at 12% moisture removal – 2011
- Engineering evaluation – 2012
- Purchase, install and calibrate carbon monoxide monitor – 2012
- Install additional thermocouples – 2013
- Perform NOx testing – 2012-2014
- Final report – December 2014

Progress reports will be communicated to the NDDH and a final written report will be prepared and delivered no later than December 2014. Based on the results of this testing and evaluation, CCS will commit to an achievable NOx emission limit that is lower than the presumptive BART value of 0.17 lb/mmBtu that is currently in the NDDH State Implementation Plan (SIP).

In summary, Great River Energy has revised the cost and emission tables to demonstrate SNCR is not cost effective. If EPA moves forward by requiring SNCR, Great River Energy is very concerned about the technical feasibility of the ash mitigation technology and, in fact, the technology developer does not guarantee or recommend the application of this technology at CCS. Therefore, as another demonstration of our commitment to emission reductions and improvement to regional haze, Great River Energy offers to complete a NOx optimization study. If these NOx reductions are incorporated into the BART analysis, it would further demonstrate that SNCR is not cost effective. We would appreciate any questions or comments that you may have on the revised analysis and proposed NOx optimization study.

GRE believes this approach is appropriately within the NDDH's authority. We request that NDDH take action to remove CCS from a proposed FIP and include this approach in the North Dakota SIP.

Please contact me if you have any questions (763-445-5212).

Sincerely,

GREAT RIVER ENERGY

for Debra Nelson

Mary Jo Roth
Manager, Environmental Services

Attachments

c: Tom Bachman, NDDH
Deb Nelson, GRE
Diane Stockdill, GRE

Great River Energy Coal Creek
BART Emission Control Cost Analysis

Table A-1a: Cost Summary

PM/PM_{10} Control Cost Summary Baseline 0.030 lb/MMBtu

Case	Control Technology	Controlled Emissions lb/MMBtu	Control Eff %	Controlled Emissions T/yr	Incremental Ranking	Emission Reduction T/yr	Installed Capital Cost $	Annualized Operating Cost $/yr	Pollution Control Cost $/ton	CT Class [1]	Annual Incremental Cost $/ton	See Table XX for additional information
1	PM Polishing WESP	0.015	50%	388.7	1	387.1	$7,232,000	$1,919,536	$4,959	D	NA-Base	A-4
2	PM Baghouse	0.015	50%	388.7	--	387.1	$37,370,845	$7,674,855	$19,829	I	NA	A-5
3	Dry ElectroStatic Precipitator (ESP)	0.015	50%	388.7	--	387.1	$38,510,903	$10,061,861	$25,996	I	NA	A-6

SO_2 Control Cost Summary Baseline 2.12 lb/MMBtu

Case	Control Technology	Designed Emissions lb/MMBtu	Control Eff %	Controlled Emissions T/yr	Incremental Ranking	Emission Reduction T/yr	Installed Capital Cost MM$	Annualized Operating Cost MM$/yr	Pollution Control Cost $/ton	CT Class [1]	Annual Incremental Cost $/ton	See Table XX for additional information
1	Scrubber Replacement	0.042	98%	1097.1	3	16237.0	$196.52	$29.81	$1,836	D	$8,354	A-7
2	Scrubber Mod. + Coal Dryer	0.128	94%	3318.8	2	14015.3	$74.02	$11.25	$803	D	$281	A-8
3	Spray Dry Baghouse	0.212	90%	5485.7	--	11848.5	$178.98	$28.97	$2,445	I	NA	A-9
4	Existing Scrubber + Coal Dryer	0.358	83%	9287.2	1	8046.9	$69.00	$9.57	$1,189	D	NA-Base	A-10
5	DSI Baghouse	0.635	70%	16457.0	--	877.2	$48.75	$12.54	$14,298	I	NA	A-11

NO_x Control Cost Summary Baseline 0.22 lb/MMBtu

Case	Control Technology	Designed Emissions lb/MMBtu	Control Eff %	Controlled Emissions T/yr	Incremental Ranking	Emission Reduction T/yr	Installed Capital Cost MM$	Annualized Operating Cost MM$/yr	Pollution Control Cost $/ton	CT Class [1]	Annual Incremental Cost $/ton	See Table XX for additional information
1	Low Temperature Oxidation (LoTOx)	0.022	90%	557	5	5015.1	$44.32	$58.21	$11,608	D	$24,061	A-12
2	Selective Catalytic Reduction (SCR) w/Reheat	0.044	80%	1114	4	4457.9	$70.44	$44.81	$10,051	D	$21,474	A-13 and A-14
3	Selective Non-Catalytic Reduction (SNCR)	0.110	50%	2786	3	2786.2	$12.72	$8.91	$3,198	D	$8,181	A-15
4	SOFA/LNB #2	0.151	32%	3799	2	1773.0	$4.91	$0.62	$350	D	$557	A-16
5	SOFA/LNB #1	0.171	23%	4306	1	1266.4	$2.63	$0.34	$267	D	NA-Base	A-17

[1] Control Technology Classification- D=Dominant, I=Inferior. Only dominant costs are used to calculate incremental cost effectiveness.

Great River Energy Coal Creek
BART Emission Control Cost Analysis
Table A-13: NOx Control - Selective Catalytic Reduction SCR

Operating Unit: **Unit 1 or 2**

Emission Unit Number	NA		Stack/Vent Number	NA		**Chemical Engineering Chemical Plant Cost Index**	
Desgin Capacity	6,019	MMBtu/hr	Standardized Flow Rate	965,316	scfm @ 32° F	1998/1999	390
Expected Utiliztion Rate	100%		Temperature	330	Deg F	2005	465
Expected Annual Hours of Operation	8,612	Hours	Moisture Content	15.3%		Inflation Adj	1.19
Annual Interest Rate	5.5%		Actual Flow Rate	2,488,000	acfm		
Expected Equipment Life	20	yrs	Standardized Flow Rate	1,550,000	scfm @ 330° F		
			Dry Std Flow Rate	1,312,850	dscfm @ 330° F		

CONTROL EQUIPMENT COSTS

Capital Costs			Duty MMBtu/hr	Control Eff	NOx in lb/MMBtu		Year	
Direct Capital Costs	EPRI Correlation		6019	80.0%	0.22		1998	40,951,514
Purchased Equipment (A1)							2005	48,826,805
Purchased Equipment Total (B)	0%	of control device cost (A)					SCR Only	**48,826,805**
Installation - Standard Costs	15%	of purchased equip cost (B)					SCR Only	8,788,825
Installation - Site Specific Costs								0
Installation Total								0
Total Direct Capital Cost, DC								0
Total Indirect Capital Costs, IC	0%	of purchased equip cost (B)						0
Total Capital Investment (TCI) = DC + IC							SCR + Reheat	**70,440,281**
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.					SCR + Reheat	38,808,410
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost					SCR + Reheat	5,998,573
Total Annual Cost (Annualized Capital Cost + Operating Cost)							SCR + Reheat	**44,806,984**

Emission Control Cost Calculation

Pollutant	Max Emis Lb/Hr	Annual T/Yr	Cont Eff %	Exit Conc	Conc Units	Cont Emis T/yr	Reduction T/yr	Cont Cost $/Ton Rem
PM10	180.2	775.8				775.8	-	NA
Total Particulates	181.1	779.7				779.7	-	NA
Nitrous Oxides (NOx)	1,294.2	5,572.4	80%			1114.5	4,457.9	10,051
Sulfur Dioxide (SO_2)	4,025.8	17,334.1				17334.1	-	NA

Notes & Assumptions

1
2 Estimated Equipment Cost per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 2
3 Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 2
4 Capital Cost per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 2 Eq 2.36 -2.43
5 Reagent Use per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 2 Eq 2.32 - 2.35
6 SCR Catalyst Volume per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 2 Eq 2.18 - 2.24
7 SCR Reactor Size per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 2 Eq 2.25 - 2.31
8 SCR Catalyst Replacement per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 2 Eq 2.50 - 2.53
9 SCR Electrical Demand per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 2 Eq 2.48
10 SCR Maintenance Costs EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 2 Eq 2.46
Presumptive BART limits use as basis for emission reductions in NOx control cost analysis (e.g. NOX limit for lignite is 0.29lb NOx /MMBTU) Using emission reduction feasible in recent BACT determinations (70% or higher) can significantly reduce the $/ton control cost down to values
11 approaching the BART economic feasibility values for presumptive BART.
12 Reheat cost based on 180 F temperature from scrubber exhaust
13 Process, emissions and cost data listed above is for one unit.
For units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal

Great River Energy Coal Creek
BART Emission Control Cost Analysis
Table A-13: NOx Control - Selective Catalytic Reduction SCR

CAPITAL COSTS		
Direct Capital Costs		
Purchased Equipment (A) (1)		
Purchased Equipment Costs (A) - Absorber + packing + auxillary equipment, EC		**48,826,805**
Instrumentation	10% of control device cost (A)	NA
ND Sales Taxes	0.0% of control device cost (A)	NA
Freight	5% of control device cost (A)	NA
Purchased Equipment Total (A)		**48,826,805**
Indirect Installation		
General Facilities	5% of purchased equip cost (A)	2,441,340
Engineerin & Home Office	10% of purchased equip cost (A)	4,882,681
Process Contingency	5% of purchased equip cost (A)	2,441,340
Total Indirect Installation Costs (B)	20% of purchased equip cost (A)	**9,765,361**
Project Contingeny (C)	15% of (A + B)	**8,788,825**
Total Plant Cost D	A + B + C	**67,380,991**
Allowance for Funds During Construction (E)	0 for SNCR	**0**
Royalty Allowance (F)	0 for SNCR	**0**
Pre Production Costs (G)	2% of (D+E))	**1,347,620**
Inventory Capital	Reagent Vol * $/gal	**48,174**
Intial Catalyst and Chemicals	0 for SNCR	**0**
Total Capital Investment (TCI) = DC + IC	D + E + F + G +H + I	**68,776,786**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost		**NA**
OPERATING COSTS		
Direct Annual Operating Costs, DC		
Operating Labor		
Operator	NA	-
Supervisor	NA	-
Maintenance		
Maintenance Total	1.50 % of Total Capital Investment	1,031,652
Maintenance Materials	NA % of Maintenance Labor	-
Utilities, Supplies, Replacements & Waste Management		
Electricity	0.05 $/kwh, 5,180 kW-hr, 8611.575 hr/yr, 100% utilization	2,258,130
NA	NA	-
NA	NA	-
NA	NA	-
NA	NA	-
NA	NA	-
NA	NA	-
SW Disposal	5.00 $/ton, 47 ton/hr, 8611.575 hr/yr, 100% utilization	2,023,720
NA	NA	-
NA	NA	-
Lost Ash Sales	5.00 $/ton, 47 ton/hr, 8611.575 hr/yr, 100% utilization	2,023,720
NA	NA	-
NA	NA	-
Ammonia	0.92 $/lb, 1,420 lb/hr, 8611.575 hr/yr, 100% utilization	11,246,699
NA	NA	-
SCR Catalyst	500.00 $/ft3, 0 ft3, 8611.575 hr/yr, 100% utilization	1,394,223
NA	NA	-
Total Annual Direct Operating Costs		**19,978,143**
Indirect Operating Costs		
Overhead	NA of total labor and material costs	NA
Administration (2% total capital costs)	NA of total capital costs (TCI)	NA
Property tax (1% total capital costs)	NA of total capital costs (TCI)	NA
Insurance (1% total capital costs)	NA of total capital costs (TCI)	NA
Capital Recovery	0.0837 for a 20- year equipment life and a 5.5% interest rate	5,755,195
Total Annual Indirect Operating Costs	Sum indirect oper costs + capital recovery cost	**5,755,195**
Total Annual Cost (Annualized Capital Cost + Operating Cost)		**25,733,339**

Great River Energy Coal Creek
BART Emission Control Cost Analysis
Table A-13: NOx Control - Selective Catalytic Reduction SCR

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Catayst				
Equipment Life	24,000	hours		
FCW	0.3157			
Rep part cost per unit	500	$/ft^3	# of Layers	12
Replacement Factor	12	.ayers replaced per year =		1
Amount Required	8,834	ft^3		
Catalyst Cost	4,416,933			
Y catalyst life factor	3	Years		
Annualized Cost	**1,394,223**			

SCR Capital Cost per EPRI Method			**40,951,514**				
Duty	6,019	MMBtu/hr	Catalyst Area	2,904	ft^2	361	f(h SCR)
Q flue gas	2,787,396	acfm	Rx Area	3,339		-24	f(h NH_3)
NOx Cont Eff	80%	(as faction)	Rx Height	57.8	ft	-728	f(h New) new= -728, Retrofit = 0
NOx in	0.22	lb/MMBtu	n layer	12	layers	Y	Bypass? Y or N
Ammina Slip	2	ppm	h layer	13.2	ft	127	f(h Bypass)
Fuel Sulfur	0.67	wt % (as %)	n total	13	layers	25,441,531	f(vol catalyst)
Temperature	330	Deg F	h SCR	90	ft		f(h SCR)
Catalyst Volume	**106,006**	ft^3	New/Retrofit	N	N or R		

Electrical Use				
Duty	6,019	MMBtu/hr		kW
NOx Cont Eff	80%	(as faction)	Power	5,179.7
NOx in	0.22	lb/MMBtu		
n catalyst layers	13	layers		
Press drop catalyst	1	in H_2O per layer		
Press drop duct	3	in H_2O		
Total				5179.7

Reagent Use & Other Operating Costs			Ammonia Use			
NOx in	0.22	lb/MMBtu	412	lb/hr Neat		
Efficiency	80%		29%	solution	56.0	lb/ft^3 Density
Duty	6,019	MMBtu/hr	1420	lb/hr	189.6	gal/hr
		Volume 14 day inventory	63,719	gal	$48,174	Inventory Cost

Operating Cost Calculations — **Annual hours of operation:** **8,612**; **Utilization Rate:** **100%**

	Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
	Operating Labor							
	Op Labor	37	$/Hr	0.0	hr/8 hr shift	0	0	$/Hr, 0.0 hr/8 hr shift, 8611.575 hr/yr
	Supervisor	15%	of Op.			NA	-	15% of Operator Costs
	Maintenance							
	Maintenance Total	1.5	% of Total Capital Investment				1,031,652	% of Total Capital Investment
	Maint Mtls	0	% of Maintenance Labor			NA	0	0% of Maintenance Labor
	Utilities, Supplies, Replacements & Waste Management							
	Electricity	0.051	$/kwh	5179.7	kW-hr	44,605,471	2,258,130	$/kwh, 5,180 kW-hr, 8611.575 hr/yr, 100% utilization
	Natural Gas	6.85	$/kscf	0	scfm	0	0	$/kscf, 0 scfm, 8611.575 hr/yr, 100% utilization
	Water	0.31	$/kgal	0.0	gph	0	0	$/kgal, 0 gph, 8611.575 hr/yr, 100% utilization
	Cooling Water	0.27	$kgal	0.0	gpm	0	0	$kgal, 0 gpm, 8611.575 hr/yr, 100% utilization
	Comp Air	0.31	$/kscf	0.0	scfm/kacfm**	0	0	$/kscf, 0 scfm/kacfm**, 8611.575 hr/yr, 100% utilization
	WW Treat Neutralizatioi	1.64	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 8611.575 hr/yr, 100% utilization
	WW Treat Biotreatemei	4.15	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 8611.575 hr/yr, 100% utilization
	SW Disposal	5.00	$/ton	47.0	ton/hr	404,744	2,023,720	$/ton, 47 ton/hr, 8611.575 hr/yr, 100% utilization
	Haz W Disp	273	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8611.575 hr/yr, 100% utilization
	Waste Transport	0.55	$/ton-mi	0.0	ton/hr	0	0	$/ton-mi, 0 ton/hr, 8611.575 hr/yr, 100% utilization
	Lost Ash Sales	5.00	$/ton	47.0	ton/hr	404,744	2,023,720	$/ton, 47 ton/hr, 8611.575 hr/yr, 100% utilization
1	Lime	90.00	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 8611.575 hr/yr, 100% utilization
7	Ammonia	0.92	$/lb	1420	lb/hr	12,224,673	11,246,699	$/lb, 1,420 lb/hr, 8611.575 hr/yr, 100% utilization
5	Oxygen	15	kscf	0.0	kscf/hr	0	0	kscf, 0 kscf/hr, 8611.575 hr/yr, 100% utilization
1	SCR Catalyst	500	$/ft3	0	ft^3	0	1,394,223	$/ft3, 0 ft3, 8611.575 hr/yr, 100% utilization
1	Filter Bags	160.00	$/bag	0	bags	0	0	$/bag, 0 bags, 8611.575 hr/yr, 100% utilization

** Std Air use is 2 scfm/kacfm

*annual use rate is in same units of measurement as the unit cost factor

Great River Energy Coal Creek
BART Emission Control Cost Analysis
Table A-15: NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal

Operating Unit: **Unit 1 or 2**

						Chemical Engineering Chemical Plant Cost Index	
Emission Unit Number	NA		Stack/Vent Number	NA			
Desgin Capacity	6,019	MMBtu/hr	Standardized Flow Rate	965,316	scfm @ 32° F		
Expected Utiliztion Rate	100%		Temperature	330	Deg F	1998/1999	390
Expected Annual Hours of Operation	8,612	Hours	Moisture Content	15.3%		2005	465
Annual Interest Rate	5.5%		Actual Flow Rate	2,488,000	acfm	Inflation Adj	1.19
Expected Equipment Life	20	yrs	Standardized Flow Rate	1,550,000	scfm @ 330° F		
			Dry Std Flow Rate	1,312,850	dscfm @ 330° F		

CONTROL EQUIPMENT COSTS

Capital Costs			Duty MMBtu/hr	Control Eff	NOx in lb/MMBtu		Year	
Direct Capital Costs	EPRI Correlation, 1998 $'s		6019	50.0%	0.22		1998	3,627,729
Purchased Equipment (A)		[13]contingencies and installation costs included (indexed to 2006$)					2009	12,395,598
Purchased Equipment Total (B)	0%	of control device cost (A)						**12,395,598**
Installation - Standard Costs	15%	of purchased equip cost (B)						0
Installation - Site Specific Costs								0
Installation Total								0
Total Direct Capital Cost, DC								0
Total Indirect Capital Costs, IC	0%	of purchased equip cost (B)						0
Total Capital Investment (TCI) = DC + IC								**12,715,834**
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.						7,845,209
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost						1,064,053
Total Annual Cost (Annualized Capital Cost + Operating Cost)								**8,909,261**

Emission Control Cost Calculation

Pollutant	Max Emis Lb/Hr	Annual T/Yr	Cont Eff %	Exit Conc	Conc Units	Cont Emis T/yr	Reduction T/yr	Cont Cost $/Ton Rem
PM10	180.2	775.8				775.8	-	NA
Total Particulates	181.1	779.7				779.7	-	NA
Nitrous Oxides (NOx)	1,294.2	5,572.4	50.0%			2786.2	2,786.2	3,198
Sulfur Dioxide (SO_2)	4,025.8	17,334.1				17334.1	-	NA

Notes & Assumptions

1
2 Estimated Equipment Cost per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1
3 Capital Cost per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.19
4 Reagent Use per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.22
5 Water use per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.25
6 Additional Fuel Use per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.29
7 SNCR Electrical Demand per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.23
8 SNCR Maintenance Costs EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.21
9 Lignite Coal Assumptions 6,054 Btu/lb (wet) Ash 6.2% 42% moisture $10.20/ton delivered
10 Control Efficiency = % reduction needed to meet presumptive BART of 0.29 lb/MMBtu
Presumptive BART limits use as basis for emission reductions in NOx control cost analysis (e.g. NOX limit for lignite is 0.29lb NOx /MMBTU) Using emission reduction feasible in recent BACT determinations (70% or higher) can significantly reduce the $/ton control cost down to values
11 approaching the BART economic feasibility values for presumptive BART.
12 Process, emissions and cost data listed above is for one unit.
For units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal
13 Values obtained from IECCOST Model V.3, Issued November 5, 2010. ($25.47/kW at 550,000kW)

Great River Energy Coal Creek
BART Emission Control Cost Analysis
Table A-15: NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) (1)			
Purchased Equipment Costs (A) - Absorber + packing + auxillary equipment, EC			**0**
Instrumentation	10%	of control device cost (A)	NA
ND Sales Taxes	0.0%	of control device cost (A)	NA
Freight	5%	of control device cost (A)	NA
Purchased Equipment Total (A)			**0**
Indirect Installation			
General Facilities	5%	of purchased equip cost (A)	0
Engineerin & Home Office	10%	of purchased equip cost (A)	0
Process Contingency	5%	of purchased equip cost (A)	0
Total Indirect Installation Costs (B)	20%	of purchased equip cost (A)	**0**
Project Contingeny (C)	15%	of (A + B)	**0**
Total Plant Cost D		A + B + C + SNCR Costs	**12,395,598**
Allowance for Funds During Construction (E)		0 for SNCR	**0**
Royalty Allowance (F)		0 for SNCR	**0**
Pre Production Costs (G)	2%	of (D+E))	**247,912**
Inventory Capital		Reagent Vol * $/gal	**72,324**
Intial Catalyst and Chemicals		0 for SNCR	**0**
Total Capital Investment (TCI) = DC + IC		D + E + F + G +H + I	**12,715,834**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**12,715,834**

OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	NA		-
Supervisor	NA		-
Maintenance			
Maintenance Total	15.00	% of Total Capital Investment	1,907,375
Maintenance Materials	NA	% of Maintenance Labor	-
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.05	$/kwh, 81 kW-hr, 8611.575 hr/yr, 100% utilization	35,387
NA	NA		-
Water	0.31	$/kgal, 510 gph, 8611.575 hr/yr, 100% utilization	1,360
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
SW Disposal	5.00	$/ton, 47 ton/hr, 8611.575 hr/yr, 10% ash landfill	2,023,720
NA	NA		-
NA	NA		-
Lost Ash Sales	5.00	$/ton, 47 ton/hr, 8611.575 hr/yr, 10% Non-saleable	2,023,720
NA	NA		-
NA	NA		-
Urea	405.00	$/ton, 1 ton/hr, 8611.575 hr/yr, 100% utilization	1,853,646
NA	NA		-
NA	NA		-
NA	NA		-
Total Annual Direct Operating Costs			**7,845,209**
Indirect Operating Costs			
Overhead	NA	of total labor and material costs	NA
Administration (2% total capital costs)	NA	of total capital costs (TCI)	NA
Property tax (1% total capital costs)	NA	of total capital costs (TCI)	NA
Insurance (1% total capital costs)	NA	of total capital costs (TCI)	NA
Capital Recovery	0.0837	for a 20- year equipment life and a 5.5% interest rate	1,064,053
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**1,064,053**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**8,909,261**

Great River Energy Coal Creek
BART Emission Control Cost Analysis
Table A-15: NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Catayst		<- Enter Equipment Name to Get Cost
Equipment Life	5	years
CRF	0.2342	
Rep part cost per unit	500	$/ft³
Amount Required	12	ft³
Packing Cost	6,300	Cost adjusted for freight & sales tax
Installation Labor	945	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:		<- Enter Equipment Name to Get Cost	
Equipment Life	2	years	
CRF	0.0000		
Rep part cost per unit	160	$/ft³	
Amount Required	0	Cages	
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax	See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs
Installation Labor	0	10 min per bag, Labor + Overhead (68% = $29.65/hr)	
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	EPA CCM list replacement times from 5 - 20 min per bag.
Annualized Cost	**0**		

Electrical Use			
NOx in	0.22	lb/MMBtu	kW
NSR	1.24		
Power			81.2
Total			81.2

Reagent Use & Other Operating Costs				Urea Use			
NOx in	0.22	lb/MMBtu		531	lb/hr Neat		
Efficiency	50%			50%	solution	71.0	lb/ft³ Density 50% Solution
Duty	6,019	MMBtu/hr		1063	lb/hr	112.0	gal/hr
		Volume 14 day inventory		37,632	gal	$72,324	Inventory Cost
Water Use	510	gal/hr	Inject at 10% solution				
						10.74	wt % ash
Fuel Use	8.61	MMBtu/hr				37.30	% Coal Moisture Content
						0.73	% Coal Sulfur Content
Ash Generation	147.83	lb/hr				6,257	Btu/lb of coal

Operating Cost Calculations — **Annual hours of operation:** **8,612** — **Utilization Rate:** **100%**

	Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
	Operating Labor							
	Op Labor	37	$/Hr	0.0	hr/8 hr shift	0	0	$/Hr, 0.0 hr/8 hr shift, 8611.575 hr/yr
	Supervisor	15%	of Op.			NA	-	15% of Operator Costs
	Maintenance							
	Maintenance Total	15	% of Total Capital Investment				1,907,375	% of Total Capital Investment
	Maint Mtls	0	% of Maintenance Labor			NA	0	0% of Maintenance Labor
	Utilities, Supplies, Replacements & Waste Management							
	Electricity	0.051	$/kwh	81.2	kW-hr	699,012	35,387	$/kwh, 81 kW-hr, 8611.575 hr/yr, 100% utilization
	Natural Gas	6.85	$/kscf	0	scfm	0	0	$/kscf, 0 scfm, 8611.575 hr/yr, 100% utilization
	Water	0.31	$/kgal	509.5	gph	4,388	1,360	$/kgal, 510 gph, 8611.575 hr/yr, 100% utilization
	Cooling Water	0.27	$kgal	0.0	gpm	0	0	$kgal, 0 gpm, 8611.575 hr/yr, 100% utilization
	Comp Air	0.31	$/kscf	0.0	scfm/kacfm**	0	0	$/kscf, 0 scfm/kacfm**, 8611.575 hr/yr, 100% utilization
	WW Treat Neutralization	1.64	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 8611.575 hr/yr, 100% utilization
	WW Treat Biotreatement	4.15	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 8611.575 hr/yr, 100% utilization
	SW Disposal	5.00	$/ton	47.0	ton/hr	404,744	2,023,720	$/ton, 47 ton/hr, 8611.575 hr/yr, 10% ash landfill
	Haz W Disp	273	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8611.575 hr/yr, 100% utilization
	Waste Transport	0.55	$/ton-mi	0.0	ton/hr	0	0	$/ton-mi, 0 ton/hr, 8611.575 hr/yr, 100% utilization
	Lost Ash Sales	5.00	$/ton	47.0	ton/hr	404,744	2,023,720	$/ton, 47 ton/hr, 8611.575 hr/yr, 10% Non-saleable
1	Lime	90.00	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 8611.575 hr/yr, 100% utilization
3	Urea	405	$/ton	0.5315	ton/hr	4,577	1,853,646	$/ton, 1 ton/hr, 8611.575 hr/yr, 100% utilization
5	Oxygen	15	kscf	0.0	kscf/hr	0	0	kscf, 0 kscf/hr, 8611.575 hr/yr, 100% utilization
1	SCR Catalyst	500	$/ft3	0	ft³	0	0	$/ft3, 0 ft3, 8611.575 hr/yr, 100% utilization
1	Filter Bags	160.00	$/bag	0	bags	0	0	$/bag, 0 bags, 8611.575 hr/yr, 100% utilization

** Std Air use is 2 scfm/kacfm

*annual use rate is in same units of measurement as the unit cost factor

Great River Energy Coal Creek
BART Emission Control Cost Analysis
Table A-16: NOx Control - Foster Wheeler Low NOx Burner / Over Fire Air Option #2

Operating Unit: Unit 1 or 2

Emission Unit Number	NA		Stack/Vent Number	NA	
Desgin Capacity	6,019	MMBtu/hr	Standardized Flow Rate	965,316	scfm @ 32° F
Expected Utiliztion Rate	100%		Temperature	330	Deg F
Expected Annual Hours of Operation	8,612	Hours	Moisture Content	15.3%	
Annual Interest Rate	5.5%		Actual Flow Rate	2,488,000	acfm
Expected Equipment Life	20	yrs	Standardized Flow Rate	1,550,000	scfm @ 330° F
			Dry Std Flow Rate	1,312,850	dscfm @ 330° F

CONTROL EQUIPMENT COSTS

Capital Costs			
Direct Capital Costs			
Purchased Equipment (A)			1,000,000
Purchased Equipment Total (B)	5%	of control device cost (A)	**1,050,000**
Installation - Standard Costs	0%	of purchased equip cost (B)	2,000,000
Installation - Site Specific Costs			NA
Installation Total			2,000,000
Total Direct Capital Cost, DC			3,050,000
Total Indirect Capital Costs, IC	20%	of purchased equip cost (B)	0
Total Capital Investment (TCI) = DC + IC			**4,913,299**
Operating Costs			
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.	7,966
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	612,453
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**620,419**

Emission Control Cost Calculation

Pollutant	Max Emis Lb/Hr	Annual T/Yr	Cont Eff %	Exit Conc	Conc Units	Cont Emis T/yr	Reduction T/yr	Cont Cost $/Ton Rem
PM10	180.2	775.8				775.8	-	NA
Total Particulates	181.1	779.7				779.7	-	NA
Nitrous Oxides (NOx)	1,294.2	5,572.4	32%			3799.3	1,773.0	350
Sulfur Dioxide (SO_2)	4,025.8	17,334.1				17334.1	-	NA

Notes & Assumptions

1. Sept 2005 Cost Estimate from Foster Wheeler, Option 1. Assumed price listed is for one unit. Costs in spreadsheet are for one unit
2. Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 2 (Used PM Scrubber which has lowest installed cost multiplier)
3. Assumed 0.1 hr/shift operatior and maintenance labor for LNB
4. Presumptive BART limits use as basis for emission reductions in NOx control cost analysis (e.g. NOX limit for lignite is 0.29lb NOx /MMBTU) Using emission reduction feasible in recent BACT determinations (70% or higher) can significantly reduce the $/ton control cost down to values approaching the BART economic feasibility values for presumptive BART.
5. Process, emissions and cost data listed above is for one unit.
6. For units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal

Great River Energy Coal Creek
BART Emission Control Cost Analysis
Table A-16: NOx Control - Foster Wheeler Low NOx Burner / Over Fire Air Option #2

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) (1)			1,000,000
Purchased Equipment Costs (A) - Absorber + packing + auxillary equipment, EC			
Instrumentation	0%	of control device cost (A)	0
Sales Taxes	0.0%	of control device cost (A)	0
Freight	5%	of control device cost (A)	50,000
Purchased Equipment Total (B)	5%		1,050,000
Installation			
Foundations & supports		of purchased equip cost (B)	0
Handling & erection		of purchased equip cost (B)	0
Electrical	10%	of purchased equip cost (B)	105,000
Piping		of purchased equip cost (B)	0
Insulation	15%	of purchased equip cost (B)	157,500
Painting		of purchased equip cost (B)	0
Installation Subtotal Standard Expenses (1)			2,000,000
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Site Specific - Other		Site Specific	NA
Total Site Specific Costs			NA
Installation Total			2,000,000
Total Direct Capital Cost, DC			3,050,000
Indirect Capital Costs			
Engineering, supervision	5%	of purchased equip cost (B)	
Construction & field expenses	10%	of purchased equip cost (B)	
Contractor fees	0%	of purchased equip cost (B)	
Start-up	1%	of purchased equip cost (B)	
Performance test	1%	of purchased equip cost (B)	
Model Studies	NA	of purchased equip cost (B)	NA
Contingencies	3%	of purchased equip cost (B)	
Total Indirect Capital Costs, IC	20%	of purchased equip cost (B)	0
Ozone Generator, Installed Cost			0
Total Capital Investment (TCI) = DC + IC		2010 Actual Total costs of Installation indexed to 2006 $	4,913,299
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			4,913,299
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	NA		-
Supervisor	NA		-
Maintenance			
Maintenance Labor	37.00	$/Hr, 0.1 hr/8 hr shift, 8611.575 hr/yr	3,983
Maintenance Materials	100%	of maintenance labor costs	3,983
Utilities, Supplies, Replacements & Waste Management			
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
Total Annual Direct Operating Costs			7,966
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	4,779
Administration (2% total capital costs)	2%	of total capital costs (TCI)	98,266
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	49,133
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	49,133
Capital Recovery	0.0837	for a 20- year equipment life and a 5.5% interest rate	411,142
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	612,453
Total Annual Cost (Annualized Capital Cost + Operating Cost)			620,419

See Summary page for notes and assumptions

Great River Energy Coal Creek
BART Emission Control Cost Analysis
Table A-16: NOx Control - Foster Wheeler Low NOx Burner / Over Fire Air Option #2

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Parts & Equipment:		
Equipment Life	5	years
CRF	0.0000	
Rep part cost per unit	500	$/ft^3
Amount Required	0	ft^3
Packing Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:			
Equipment Life	3		
CRF	0.3707		
Rep part cost per unit	160	$ each	
Amount Required	0	Number	
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax	
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr	OAQPS list replacement times from 5 - 20 min per bag.
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	
Annualized Cost	**0**		

Electrical Use							
	Flow acfm		D P in H2O	Efficiency	Hp	kW	
Blower, Scrubber	2,488,000		0	0.7	-	0.0	EPA Cost Cont Manual 6th ed Section 5.2 Chapter 1 Eq 1.48
	Flow	Liquid SPGR	D P ft H2O	Efficiency	Hp	kW	
Circ Pump	000 gpm	1	0	0.7	-	0.0	EPA Cost Cont Manual 6th ed Section 5.2 Chapter 1 Eq 1.49
H2O WW Disch	0 gpm	1	0	0.7	-	0.0	EPA Cost Cont Manual 6th ed Section 5.2 Chapter 1 Eq 1.49
			lb/hr O_3				
LTO Electric Use	4.5 kW/lb O_3					0	
Other							
Total						0.0	

Reagent Use & Other Operating Costs					
Ozone Needed	1.8	lb O3/lb NOx	- lb/hr O3		
Oxygen Needed	10%	wt O2 to O3 conversion		0 lb/hr O2	0 scfh O2
LTO Cooling Water	150	gal/lb O3	0 gpm		
Liquid/Gas ratio	0.0	* L/G = Gal/1,000 acf			
Circulating Water Rate	0	gpm			
Water Makeup Rate/WW Disch =	20%	of circulating water rate =	0 gpm		
Scrubber Cost	10	$/scfm Gas	$0	Incremental cost per BOC. Need to increase vessel size over standard absorber.	
Ozone Generator	$350	lb O3/day	$0 Installed	Installed cost factor per BOC.	

Operating Cost Calculations — Annual hours of operation: **8,612**; Utilization Rate: **100%**

	Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
	Operating Labor							
	Op Labor	0	$/Hr	0.1	hr/8 hr shift	108	0	$/Hr, 0.1 hr/8 hr shift, 8611.575 hr/yr
	Supervisor	15%	of Op.			NA	-	15% of Operator Costs
	Maintenance							
	Maint Labor	37.00	$/Hr	0.1	hr/8 hr shift	108	3,983	$/Hr, 0.1 hr/8 hr shift, 8611.575 hr/yr
	Maint Mtls	100	% of Maintenance Labor			NA	3,983	100% of Maintenance Labor
	Utilities, Supplies, Replacements & Waste Management							
	Electricity	0.051	$/kwh	0.0	kW-hr	0	0	$/kwh, 0 kW-hr, 8611.575 hr/yr, 100% utilization
	Natural Gas	6.85	$/kscf	0	scfm	0	0	$/kscf, 0 scfm, 8611.575 hr/yr, 100% utilization
	Water	0.31	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 8611.575 hr/yr, 100% utilization
	Cooling Water	0.27	$kgal	0.0	gpm	0	0	$kgal, 0 gpm, 8611.575 hr/yr, 100% utilization
	Comp Air	0.31	$/kscf	0	kscfm	0	0	$/kscf, 0 kscfm, 8611.575 hr/yr, 100% utilization
	WW Treat Neutralizatioi	1.64	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 8611.575 hr/yr, 100% utilization
	WW Treat Biotreatemei	4.15	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 8611.575 hr/yr, 100% utilization
	SW Disposal	5.00	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8611.575 hr/yr, 100% utilization
	Haz W Disp	273	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8611.575 hr/yr, 100% utilization
	Waste Transport	0.55	$/ton-mi	0.0	ton/hr	0	0	$/ton-mi, 0 ton/hr, 8611.575 hr/yr, 100% utilization
	Lost Ash Sales	5.00	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8611.575 hr/yr, 100% utilization
1	Lime	90.0	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 8611.575 hr/yr, 100% utilization
2	Caustic	305.21	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 8611.575 hr/yr, 100% utilization
5	Oxygen	15	kscf	0.0	kscf/hr	0	0	kscf, 0 kscf/hr, 8611.575 hr/yr, 100% utilization
1	SCR Catalyst	500	$/ft3	0	ft^3	0	0	$/ft3, 0 ft3, 8611.575 hr/yr, 100% utilization
1	Filter Bags	160.00	$/bag	0	bags	0	0	$/bag, 0 bags, 8611.575 hr/yr, 100% utilization

*annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

Great River Energy Coal Creek
BART Emission Control Cost Analysis
Table A-17: NOx Control - Foster Wheeler Low NOx Burner / Over Fire Air Option #1

Operating Unit: Unit 1 or 2

Emission Unit Number	NA		Stack/Vent Number	NA	
Desgin Capacity	6,019	MMBtu/hr	Standardized Flow Rate	965,316	scfm @ 32° F
Expected Utiliztion Rate	100%		Temperature	330	Deg F
Expected Annual Hours of Operation	8,612	Hours	Moisture Content	15.3%	
Annual Interest Rate	5.5%		Actual Flow Rate	2,488,000	acfm
Expected Equipment Life	20	yrs	Standardized Flow Rate	1,550,000	scfm @ 330° F
			Dry Std Flow Rate	1,312,850	dscfm @ 330° F

CONTROL EQUIPMENT COSTS

Capital Costs			
Direct Capital Costs			
Purchased Equipment (A)			500,000
Purchased Equipment Total (B)	5%	of control device cost (A)	**525,000**
Installation - Standard Costs	0%	of purchased equip cost (B)	2,000,000
Installation - Site Specific Costs			NA
Installation Total			2,000,000
Total Direct Capital Cost, DC			2,525,000
Total Indirect Capital Costs, IC	20%	of purchased equip cost (B)	105,000
Total Capital Investment (TCI) = DC + IC			**2,630,000**
Operating Costs			
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.	7,966
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	330,056
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**338,022**

Emission Control Cost Calculation

Pollutant	Max Emis Lb/Hr	Annual T/Yr	Cont Eff %	Exit Conc	Conc Units	Cont Emis T/yr	Reduction T/yr	Cont Cost $/Ton Rem
PM10	180.2	775.8				775.8	-	NA
Total Particulates	181.1	779.7				779.7	-	NA
Nitrous Oxides (NOx)	1,294.2	5,572.4	23%			4305.9	1,266.4	267
Sulfur Dioxide (SO_2)	4,025.8	17,334.1				17334.1	-	NA

Notes & Assumptions

1 Sept 2005 Cost Estimate from Foster Wheeler, Option 1. Assumed price listed is for one unit. Costs in spreadsheet are for one unit
2 Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 2 (Used PM Scrubber which has lowest installed cost multiplier)
3 Assumed 0.1 hr/shift operatior and maintenance labor for LNB
4 Presumptive BART limits use as basis for emission reductions in NOx control cost analysis (e.g. NOX limit for lignite is 0.29lb NOx /MMBTU) Using emission reduction feasible in recent BACT determinations (70% or higher) can significantly reduce the $/ton control cost down to values approaching the BART economic feasibility values for presumptive BART.
5 Process, emissions and cost data listed above is for one unit.
6 For units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal

Great River Energy Coal Creek
BART Emission Control Cost Analysis
Table A-17: NOx Control - Foster Wheeler Low NOx Burner / Over Fire Air Option #1

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) (1)			**500,000**
Purchased Equipment Costs (A) - Absorber + packing + auxillary equipment, EC			
Instrumentation	0%	of control device cost (A)	0
Sales Taxes	0.0%	of control device cost (A)	0
Freight	5%	of control device cost (A)	25,000
Purchased Equipment Total (B)	5%		525,000
Installation			
Foundations & supports		of purchased equip cost (B)	0
Handling & erection		of purchased equip cost (B)	0
Electrical		of purchased equip cost (B)	0
Piping		of purchased equip cost (B)	0
Insulation		of purchased equip cost (B)	0
Painting		of purchased equip cost (B)	0
Installation Subtotal Standard Expenses (1)			2,000,000
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Site Specific - Other		Site Specific	NA
Total Site Specific Costs			NA
Installation Total			2,000,000
Total Direct Capital Cost, DC			2,525,000
Indirect Capital Costs			
Engineering, supervision	5%	of purchased equip cost (B)	26,250
Construction & field expenses	10%	of purchased equip cost (B)	52,500
Contractor fees	0%	of purchased equip cost (B)	0
Start-up	1%	of purchased equip cost (B)	5,250
Performance test	1%	of purchased equip cost (B)	5,250
Model Studies	NA	of purchased equip cost (B)	NA
Contingencies	3%	of purchased equip cost (B)	15,750
Total Indirect Capital Costs, IC	20%	of purchased equip cost (B)	105,000
Total Capital Investment (TCI) = DC + IC			2,630,000
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			2,630,000
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	NA		-
Supervisor	NA		-
Maintenance			
Maintenance Labor	37.00	$/Hr, 0.1 hr/8 hr shift, 8611.575 hr/yr	3,983
Maintenance Materials	100%	of maintenance labor costs	3,983
Utilities, Supplies, Replacements & Waste Management			
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
Total Annual Direct Operating Costs			7,966
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	4,779
Administration (2% total capital costs)	2%	of total capital costs (TCI)	52,600
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	26,300
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	26,300
Capital Recovery	0.0837	for a 20- year equipment life and a 5.5% interest rate	220,077
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	330,056
Total Annual Cost (Annualized Capital Cost + Operating Cost)			338,022

See Summary page for notes and assumptions

Great River Energy Coal Creek
BART Emission Control Cost Analysis
Table A-17: NOx Control - Foster Wheeler Low NOx Burner / Over Fire Air Option #1

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Parts & Equipment:		
Equipment Life	5	years
CRF	0.0000	
Rep part cost per unit	500	$/ft^3
Amount Required	0	ft^3
Packing Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:			
Equipment Life	3		
CRF	0.3707		
Rep part cost per unit	160	$ each	
Amount Required	0	Number	
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax	
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr	OAQPS list replacement times from 5 - 20 min per bag.
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	
Annualized Cost	**0**		

Electrical Use							
	Flow acfm		D P in H2O	Efficiency	Hp	kW	
Blower, Scrubber	2,488,000		0	0.7	-	0.0	EPA Cost Cont Manual 6th ed Section 5.2 Chapter 1 Eq 1.48
	Flow	Liquid SPGR	D P ft H2O	Efficiency	Hp	kW	
Circ Pump	000 gpm	1	0	0.7	-	0.0	EPA Cost Cont Manual 6th ed Section 5.2 Chapter 1 Eq 1.49
H2O WW Disch	0 gpm	1	0	0.7	-	0.0	EPA Cost Cont Manual 6th ed Section 5.2 Chapter 1 Eq 1.49
			lb/hr O_3				
LTO Electric Use	4.5	kW/lb O_3				0	
Other							
Total						0.0	

Reagent Use & Other Operating Costs						
Ozone Needed	1.8	lb O3/lb NOx	-	lb/hr O3		
Oxygen Needed	10%	wt O2 to O3 conversion		0 lb/hr O2	0 scfh O2	
LTO Cooling Water	150	gal/lb O3	0 gpm			
Liquid/Gas ratio	0.0	* L/G = Gal/1,000 acf				
Circulating Water Rate	0	gpm				
Water Makeup Rate/WW Disch =	20%	of circulating water rate =	0 gpm			
Scrubber Cost	10	$/scfm Gas	$0	Incremental cost per BOC. Need to increase vessel size over standard absorber.		
Ozone Generator	$350	lb O3/day	$0 Installed	Installed cost factor per BOC.		

Operating Cost Calculations — Annual hours of operation: **8,612** — Utilization Rate: **100%**

	Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
	Operating Labor							
	Op Labor	0	$/Hr	0.1	hr/8 hr shift	108	0	$/Hr, 0.1 hr/8 hr shift, 8611.575 hr/yr
	Supervisor	15%	of Op.			NA	-	15% of Operator Costs
	Maintenance							
	Maint Labor	37.00	$/Hr	0.1	hr/8 hr shift	108	3,983	$/Hr, 0.1 hr/8 hr shift, 8611.575 hr/yr
	Maint Mtls	100	% of Maintenance Labor			NA	3,983	100% of Maintenance Labor
	Utilities, Supplies, Replacements & Waste Management							
	Electricity	0.051	$/kwh	0.0	kW-hr	0	0	$/kwh, 0 kW-hr, 8611.575 hr/yr, 100% utilization
	Natural Gas	6.85	$/kscf	0	scfm	0	0	$/kscf, 0 scfm, 8611.575 hr/yr, 100% utilization
	Water	0.31	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 8611.575 hr/yr, 100% utilization
	Cooling Water	0.27	$kgal	0.0	gpm	0	0	$kgal, 0 gpm, 8611.575 hr/yr, 100% utilization
	Comp Air	0.31	$/kscf	0	kscfm	0	0	$/kscf, 0 kscfm, 8611.575 hr/yr, 100% utilization
	WW Treat Neutralizatio	1.64	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 8611.575 hr/yr, 100% utilization
	WW Treat Biotreateme	4.15	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 8611.575 hr/yr, 100% utilization
	SW Disposal	5.00	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8611.575 hr/yr, 100% utilization
	Haz W Disp	273	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8611.575 hr/yr, 100% utilization
	Waste Transport	0.55	$/ton-mi	0.0	ton/hr	0	0	$/ton-mi, 0 ton/hr, 8611.575 hr/yr, 100% utilization
	Lost Ash Sales	5.00	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8611.575 hr/yr, 100% utilization
1	Lime	90.0	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 8611.575 hr/yr, 100% utilization
2	Caustic	305.21	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 8611.575 hr/yr, 100% utilization
5	Oxygen	15	kscf	0.0	kscf/hr	0	0	kscf, 0 kscf/hr, 8611.575 hr/yr, 100% utilization
1	SCR Catalyst	500	$/ft3	0	ft^3	0	0	$/ft3, 0 ft3, 8611.575 hr/yr, 100% utilization
1	Filter Bags	160.00	$/bag	0	bags	0	0	$/bag, 0 bags, 8611.575 hr/yr, 100% utilization

*annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

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VIA EMAIL
AND U.S. MAIL

February 10, 2012

Mr. Terry O'Clair
Director, Division of Air Quality
North Dakota Department of Health
918 E. Divide Ave.
Bismarck, ND 58501-1947

RE: Coal Creek Station NOx BART Determination

Dear Mr. O'Clair:

This letter and enclosed document "*Coal Creek Station Units 1 and 2; Best Available Retrofit Technology Refined Analysis for NOx Emissions; November 2011; Updated February 10, 2012*" provide Great River Energy's (GRE) response to North Dakota Department of Health (NDDH) comments discussed on January 10, 2012, and provided in your letter dated January 19, 2012.

GRE recognizes there were a number of inadvertent errors and inconsistencies in the November 21 submittal. We have now reviewed the entire report, responded to all of NDDH's comments, and had an independent review conducted by a consultant not connected with our analysis.

Enclosed is an updated version of the BART refined analysis report ("Updated Report") initially submitted on November 21, 2011, now dated February 10, 2012. It is important to note that correction of the inadvertent errors and related revised analysis do not change the conclusions of the previous report – specifically, that the presumptive NOx limit of 0.17 lb/mmBtu is both cost effective and results in significant visibility improvements in North Dakota's Class I areas.

The updated report addresses all of NDDH's comments. In addition, we are providing a brief explanation, below, of our response to each of the items detailed in your January 19, 2012, letter to GRE.

Item 1. *The Department requests that GRE include a review of the last five years of operation in GRE's analysis of baseline emissions (or heat input). If changes to the facility affect the historic baseline (such as DryFining™), please include an explanation of any adjustment in your analysis. All tables should provide a consistent baseline emission rate (see Table A-2 versus Tables A-1, A-4, to A-10).*

As indicated in the January 19 letter, the BART Guidelines (40 CFR 51, Appendix Y) state "The baseline emissions rate should represent a realistic depiction of anticipated annual emissions for the source. In general, for the existing sources subject to BART, you will estimate the anticipated annual emissions based upon actual emissions from a baseline period." To accurately depict the anticipated annual emissions for the units at CCS, a new baseline must be established taking into consideration the DryFining™ technology and installed combustion controls in Unit 2 (LNC3+). The DryFining process is designed to remove moisture from the coal prior to introduction of the coal into the final stage of grinding and conveyance into the boiler. DryFining, having been funded under a DOE grant (DE-FC26-04NT41763), was required to conduct performance tests which demonstrated a heat input reduction of approximately 2 to 3 percent. By removing the moisture prior to introduction into the pulverizers, less primary air is required to "dry" and convey the coal through the pulverizers, making air available for staging (over-fire air NOx control) in other areas of the boiler. This drier coal will not require the same amount of heat input into the boiler because wet coal expends some of its heat input to vaporize the moisture in the coal. Thus a drier coal will not require that additional coal which is typically used to vaporize the moisture. DryFining is currently obtaining a moisture reduction in the coal of approximately eight percent. Further tuning is continuing so the units will meet a required reduction of 12% by 2016, which is needed to achieve the SO_2 BART limit through full scrubbing.

Item 2. *GRE's Report included a document ... which states "Based on a review of the recent load profile of CCS, historic information on marketable fly ash at CCS, and an estimate of the reliability of the SNCR and ASM systems, approximately 30% of the fly ash now sent to the sales silos is assumed to have ammonia concentrations which make it untreatable if an SNCR system is installed." The Eastlake Station also uses an ammonia slip mitigation (ASM) system and only 15% is untreatable. The Department understands that the Eastlake Station is able to blend ammoniated ash with ash that does not contain ammonia; an option that will not be available to the Coal Creek Station. In order for the Department to further evaluate the Report, please confirm and more fully explain this and any other differences between Coal Creek Station's operation and Eastlake Station's operation in order to evaluate GRE's 30% untreatable ash figure.*

It is not possible to determine exactly what percent of ash sales would be lost based on the installation of the SNCR and ammonia mitigation technologies at Coal Creek Station. There are no plants in the country with both of these technologies operating together on a lignite-fired unit. In fact, the vendor responsible for the ammonia mitigation technology will not guarantee the technology's performance at CCS.

As pointed out by NDDH, Coal Creek Station's situation is, indeed, different from that of Eastlake Station. Eastlake is the only plant in the U.S. that has operated with the discussed ammonia mitigation technology and it mixes its ammoniated ash with a non-ammoniated ash prior to sale, thus providing the ability to sell up to approximately 85% of its ash. There are additional differences between CCS operations and those of Eastlake as discussed in the Updated Report.

The 30% lost ash sales figure for Coal Creek Station reflects a reasonable and optimistic (i.e., conservative) outcome that can be justified based on our understanding of plant operations and the ash markets in which we compete for sales. We consider a 30% scenario to be a very optimistic view of the future that relies on the successful implementation of a technology that cannot currently be guaranteed by the vendor and has never been installed on lignite-fired units.

Item 3. *In Table 3.1, Cost Summary, the "Annualized Operating Cost" for Unit 1 SNCR + LNC3+ (30% lost ash sales) is listed at $6.81 million. However, Table A-1 lists $7.62 million for this scenario. Further, there are also inconsistent annualized operating costs in Table 3.1 versus Table A-1 for Unit 1 SNCR (30% lost ash sales) and Unit 2 SNCR (30% lost ash sales). Please address these inconsistencies.*

Table 3.1 has been updated to represent the same data presented in the appendices.

Item 4. *The "Pollution Control Cost" in Table 3.1 and Table A-1 for all three scenarios of Unit 1 SNCR + LNC3+ do not appear to be correct. Please evaluate these asserted costs and correct as may be necessary, including with respect to the asserted incremental costs.*

In the original table we had added the pollution control costs from Case 1 for Unit 1 (LNC3+) and the pollution control costs for Case 1 for Unit 2 (SNCR). Although seemingly correct we have changed this to be calculated from the Annualized Operating Cost (MM$/yr) and the Emission Reduction (T/yr). The Annualized Operating Cost has been derived from Unit 1 - Case 1 and Unit 2 - Case 1 in the table. The incremental cost was recalculated because Case 2 for Unit 1 is deemed an inferior control technology using the least cost envelope evaluation.

Item 5.a. *In Tables A-6 and A-9 of the Report, a project contingency of 42% and 41% are listed, respectively. However, it appears GRE actually used 15% (which is consistent with EPA's Control Cost Manual). The 42% and 41% should be revised. This is also an issue with other tables in GRE's Report. Please evaluate these considerations and address any errors or mislabeling.*

The project contingency percentage was mislabeled and has been corrected.

Item 5.b. *In Tables A-6 and A-9 of the Report, the cost for "SW Disposal" is not consistent with the cost separately listed in Table 2.3.2 and the Golder Report. Given the inconsistency, please verify which number is correct and revise the Report to reflect this correction.*

The data provided in the Golder Report was calculated on a specific set of operating parameters. The future actual emissions calculated for the BART analysis utilizes the Golder Report to determine the cost associated with the additional ash disposed (beyond current disposal amounts) due to the future installation of SNCR technology. GRE calculated the cost to dispose of additional ash – above and beyond what we are currently disposing (Table 2.3.2 Disposal Cost Summary: Incremental Increase in Disposal Cost Compared to Scenario A ($/ton)). This was done to capture the additional costs associated with the SNCR control technology installation.

Item 5.c. *In Tables A-6 and A-9 of the Report, the cost of "Lost Ash Sales" is inconsistent with Table 2.3.4 and the Golder Report. Given the inconsistency, please verify which number is correct and revise the Report to reflect this correction.*

The data provided in the Golder Report was calculated on a specific set of operating parameters. The future actual lost ash sales are calculated based on the future projected operating conditions defined for our baseline period. In reviewing the underlying calculations for the total dollars associated with lost ash sales we did find an error in the calculation which caused the value of lost ash sales to be approximately twice that of what it should have been. This has been corrected.

Item 6.a. *Provide a detailed explanation of Table 3.3.1, Visibility Improvement. Unit 1 has a baseline emission rate in Table 3.1 of 0.20 lb/10^6 Btu (annual average). Table 3.3.1 lists a 24-hr maximum emission rate of 0.20 lb/10^6 Btu. A 24-hr maximum emission rate should be larger than an annual average emission rate.*

Table 3.3.1 was confusing as presented in the original report. The original intent of the table was to illustrate that the incremental deciview improvement for each of the modeling runs was less than is perceptible to the human eye. We have modified the table to present this information in a more clear manner.

Item 6.b. *Provide a detailed explanation of Table 3.3.1, Visibility Improvement. The "Avg. Improvement" column indicates improvement for baseline conditions. Under the BART Guidelines, no improvement would be shown for baseline conditions.*

The original table was missing a notation that the baseline improvement values were illustrative to indicate improvements which have already occurred since the 2007 submittal. Table 3.3.1 has been modified to clearly represent the improvement in visibility.

Item 6.c. *Provide a detailed explanation of Table 3.3.1, Visibility Improvement. The amount of improvement should be based on three years of meteorological data. The results from all three years must be submitted. Please explain whether it represents a 98th percentile value or some other value.*

Table 3.3.1 has been modified to show each of the three years of visibility improvement derived from the visibility tables. These tables are included in a new Appendix D.

Item 7. *The Department ... suggests GRE closely review all tables and text for accuracy and consistency with the supporting documents.*

GRE has taken additional steps to review and verify data in the appendices, including an independent review by a consultant not connected with our analysis.

We submit the enclosed February 10, 2012, updated report which we believe addresses all of NDDH's comments and continues to support the conclusion that 0.17 lb/mmBtu is the appropriate NOx BART emissions limit for our Coal Creek Station Units 1 and 2.

If you have any questions, please contact me or Deb Nelson of my staff.

Sincerely,

Mary Jo Roth

Mary Jo Roth
Manager, Environmental Services

Enclosure

c: Tom Bachman, NDDH
Deb Nelson, GRE
Diane Stockdill, GRE

GREAT RIVER ENERGY®

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April 5, 2012

Mr. Terry O'Clair
Director, Division of Air Quality
North Dakota Department of Health
918 E. Divide Ave.
Bismarck, ND 58501-1947

RE: Coal Creek NOx BART Analysis

Dear Mr. O'Clair:

We are herewith responding to your letter of February 28, 2012, in which you requested that Great River Energy ("GRE") provide additional information to assist the North Dakota Department of Health ("NDDH") with its ongoing Best Available Retrofit Technology ("BART") determination for Coal Creek Station ("CCS"). You requested that GRE address some issues with its year 2000 visibility modeling, verify certain costs and data related to various pollution control options, and address some inconsistencies between GRE's cost analysis and the U.S. EPA's Control Cost Manual for certain cost components.

Enclosed is GRE's Supplemental Best Available Retrofit Technology Refined Analysis for NOx Emissions, April 5, 2012 ("BART Supplement"), which provides a supplemental BART analysis that addresses the issues raised in the February 28, 2012 letter (as well as issues raised in your January 19, 2012 letter). In particular, GRE asked Barr Engineering to rerun the visibility modeling analysis as requested by NDDH. The revised visibility modeling, reflected in both Table 3.2 and Appendix D of the BART Supplement, demonstrates that the incremental visibility improvement of adding SNCR to Units 1 and 2 is essentially non-existent at only 0.106 deciviews. The BART Supplement also includes additional cost information from URS addressing your questions about the EPA Control Cost Manual and URS's departures from assumptions that EPA makes about costs. Barr Engineering also has included the cost/economic analyses regarding the impact of ammonia contamination on fly ash marketability and disposal costs based upon information provided by Golder Associates. Those costs are reflected in Table 3.1 of the BART Supplement. The costs reflect the expected costs depending on whether 0%, 30% or 100% of the fly ash becomes unmarketable due to ammonia contamination. Barr Engineering concluded that, even if no costs are attributable to ammonia contamination, installing SNCR on to already existing or planned controls would reduce NOx emissions at Unit 2 at a rate of $4,688/ton and $8,534/ton at Unit 1. Thus, SNCR remains well outside the range of cost-effective control technologies.

Since your February 28, 2012, letter, the U.S. EPA has issued its *Approval and Promulgation of Implementation Plans; North Dakota; Regional Haze State Implementation Plan; Federal Implementation Plan for Interstate Transport of Pollution Affecting Visibility and Regional Haze*, 76 Fed. Reg. ______(April __, 2012) ("EPA FIP"). In the EPA FIP, the Agency rejected NDDH's BART determination for CCS and imposed a NOx emission limitation of 0.13 lbs/mmBtu, based on EPA's determination that a combination of low-NOx burners and selective non-catalytic reduction ("SNCR") is BART.

GRE's analysis of the EPA FIP, EPA's basis for rejecting the NDDH BART for CCS, and EPA's own BART determination is also enclosed. See *Legal and Technical Review of U.S. EPA's BART Determination for Coal Creek Station* ("FIP Analysis"). The FIP Analysis concludes that EPA's rejection of NDDH's BART determination is ill-founded and EPA's own BART determination is severely flawed and inconsistent with the Clean Air Act and EPA's own regional haze regulations. EPA rejected NDDH's BART because of its cost analysis, primarily NDDH's reliance on certain cost values resulting from ammonia contamination of fly ash. GRE has corrected that value. EPA also questioned the retrofit factor for SNCR at CCS, but gave no basis for rejecting the factor applied by URS, GRE's consultant. On the basis of these two issues, EPA rejected NDDH's BART determination and substituted its own judgment for NDDH's regarding all five BART factors. The FIP Analysis addresses EPA's critique of the prior cost analysis and demonstrates that the cost of SNCR remains prohibitively high, particularly in light of the other four BART factors.

The FIP Analysis also examines EPA's own BART determination and concludes that it is severely flawed. EPA's cost analysis failed to consider the existing NOx controls at CCS in conducting its cost analysis and expressly ignored the incremental costs of installing SNCR beyond the existing and planned LNC3+ burner controls at CCS. Both of these decisions directly violate the statute and are inconsistent with EPA's guidelines and regulations. The effect of these two decisions is to greatly distort the actual cost-effectiveness of SNCR. Second, EPA utterly ignored the lack of any demonstrated visibility improvement that would result from investing tens of millions of dollars to install and operate SNCR. The EPA visibility modeling indicates that the greatest potential visibility benefit resulting from installation of SNCR would be 0.105 dv, which is only one-tenth the level that EPA asserts is discernable by the human eye. Additionally, given the many sources of variability of inputs to CALPUFF's visibility analysis versus actual impacts, a difference of around 0.1 dv between options may reflect no real difference at all.

The FIP Analysis also demonstrates that EPA's conclusion that SNCR can be operated in a manner to avoid any fly ash contamination is unsupported. EPA's assertion that SNCR can be operated with a 2 ppm ammonia slip or less is not supported by the literature and studies EPA cites. Further, Golder Associates demonstrates that, even at a 2 ppm threshold, there will be significant fly ash wastage due to ammonia contamination. Consequently, the actual costs of utilizing SNCR will almost certainly be even higher and EPA's disregard of the collateral environmental impact of its BART selection is unjustifiable.

GRE's revised BART analysis provided today includes a refined cost analysis that examines the average and incremental cost, and cost-effectiveness, of various levels of NOx emissions control as well as a revised visibility impact analysis of various levels of control. In light of the lack of any discernable visibility improvement at any Class I area, NDDH would be justified in supporting its initial BART determination at any cost level, including EPA's artificially low average cost of less than $2,500 per ton. The actual incremental cost of SNCR will be in excess of $4,500 per ton for Unit 2 and over $8,000 per ton for Unit 1, even if no costs are assigned to the loss of merchantable fly ash. The actual costs will be even higher.

GRE greatly appreciates NDDH's continued work on the CCS BART. Please do not hesitate to contact me or my staff if you would like to discuss any of these matters in greater detail.

Sincerely,

Mary Jo Roth

Mary Jo Roth
Manager, Environmental Services

Enclosures

c: William M. Bumpers, Esq.
Eric Olsen, GRE
Deb Nelson, GRE

resourceful. naturally.
engineering and environmental consultants
BARR

TRANSMITTAL LETTER

To:	Mary Jo Roth (GRE)	**Date:**	April 5, 2012
c:	Deb Nelson (GRE), Diane Stockdill (GRE), Joel Trinkle (Barr)		
Project #:	34280013.01	**Re:**	GRE CCS Supplemental NOx Analysis
Sent by:	Laura Brennan	**Phone:**	952.832.2615

We are sending you:

___	Correspondence	X	Reports	___	Plans
___	Copy of Letter	___	Specifications	___	Other:

These are transmitted as checked below:

___	For approval	X	As requested	___	Other:
___	For your use	___	For review and comment:		

Description:

This report is a revised version of the original November 2011 report titled "Best Available Retrofit Technology Refined Analysis for NOx Emissions" submitted by GRE to the NDDH. The report reflects the collaborative effort of Barr and GRE with assistance from other technical consultants to develop an appropriate control strategy for Coal Creek's Units 1 and 2. Barr assisted with the development and update of cost estimates for various control scenarios, incorporating GRE's work with URS and Golder into the technical discussion at GRE's direction.

The Refined NOx Analysis is prepared in response to comments from the NDDH provided in letters dated January 19, 2012 and February 28, 2012. The conclusions and text of the analysis are not markedly changed in responding to NDDH's comments. The changes in this report primarily focus on updated modeling results and clarifications to cost calculations, as described below.

In response to an anomaly identified in Appendix D of GRE's submittal, GRE has revised the visibility tables that were presented in that submittal. A review of the modeling output files for the year 2000 SNCR run in question concluded that the values presented in the original table were consistent with the output files. The original modeling runs had been conducted in 2006 and 2007 for the initial BART evaluation, and the intermediate data files were no longer available to identify whether the apparent error was the result of an incomplete annual model run or some other contributing factor. In order to be responsive to NDDH's request for clarification of the data, the model was re-run. The modeling files had not previously been reopened for the NOx refined analysis efforts in 2011 and 2012. Accordingly, GRE also took the opportunity to more closely

realign the NOx emission rates and stack-related modeling input parameters with the scenarios described in the report for all scenarios in all years as opposed to the approximations from previously modeled scenarios shown in the November 2011 tables.

The new results more closely align with the expected reductions for each control scenario and follow the trend originally illustrated in the year 2001 and 2002 tables for the February 10, 2012 submittal. The revised modeling runs support the conclusions presented in the GRE NOx analysis, and have only resulted in minor revisions to Table 3.3.1 and Appendix D.

In this revised report, NDDH also provides several comments with respect to alignment of calculations and clarity of documentation provided in the Appendix A cost calculations. Footnotes and documentation are appropriately updated. Additionally, the calculation alignment is clarified through the inclusion of additional significant digits. Neither of these updates result in changes to the final cost tables included within the report text.

Should you have any questions regarding this transmittal or the revisions herein, please contact Laura Brennan at 952.832.2615.

GREAT RIVER ENERGY®

A Touchstone Energy® Cooperative

Coal Creek Station Units 1 and 2

Supplemental Best Available Retrofit Technology Refined Analysis for NOx Emissions

November 2011; Updated April 5, 2012

Coal Creek Station Supplemental BART Refined Analysis for NOx Emissions

November 2011; Updated April 5, 2012

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1.0 Introduction

In December 2007, GRE submitted its final Best Available Retrofit Technology (BART) evaluation for Regional Haze controls to the North Dakota Department of Health (NDDH). The NDDH incorporated the proposed emission limitations for Coal Creek Station (CCS) Units 1 and 2 into their proposed State Implementation Plan (SIP), and issued a draft Permit-to-Construct (PTC) for these BART limits. As part of their review on North Dakota's draft and final SIP, EPA requested supplemental data and documentation on Coal Creek's BART controls. These requests started in February 2010, and continued through June 2011 and July 2011. GRE provided the requested information.

On September 21, 2011, EPA proposed a Federal Implementation Plan (FIP), which would override certain NDDH determinations, particularly with respect to required NOx controls for certain coal-fired utility units. On November 3, 2011, NDDH requested that GRE provide a supplemental BART analysis that is focused on NOx control options at Coal Creek Station. In particular, GRE has performed more refined analyses on selective non-catalytic reduction (SNCR) cost assumptions, achievable control levels and the overall impacts to ash re-use on Coal Creek's Units 1 and 2. This supplemental analysis is being provided to address questions from the NDDH per its letters of January 19, 2012 and February 28, 2012.

Based on the supplemental analyses, Great River Energy still asserts that use of its state-of-the-art coal drying technology, DryFining™, in conjunction with second generation combustion control low NOx burners with separated overfire air (LNC3+), meets EPA's presumptive BART NOx limit of 0.17 lb/MMBtu, and is consistent with cost effective thresholds as set by North Dakota and ultimately approved by EPA through their partial approval of the North Dakota SIP. When all factors are adequately considered, including ammoniated ash impacts, SNCR is not considered cost effective for Coal Creek and would not result in perceptible visibility improvements in the affected Class I areas.

This supplemental analysis summarizes updated SNCR cost and emission assessments and supplemental information provided by URS Energy and Construction (URS). It also provides an updated ash implication assessment and supplemental information as provided by Golder Associates (Golder). (see Appendices F and G, respectively) The updated ash implications are then integrated with the updated SNCR cost and emission estimates to more accurately demonstrate that SNCR is not cost effective, by either EPA established thresholds or NDDH established thresholds.

1.1 Initial BART Analysis and EPA Guidance

In preparing the initial BART analysis and subsequent revisions, Great River Energy developed a combination of detailed engineering and screening level analyses, which were ultimately used by NDDH to make their BART determinations. From the BART preamble, EPA sets presumptive levels based on their cost effective assessments and deciview reductions, and essentially rule out post combustion NOx controls for electric generating units greater than 750MW, subject to the state's determination. Great River Energy's screening level analyses on SNCR and ash impacts initially supported EPA's presumptive determination. Great River Energy continues to concur with EPA's establishment of a presumptive NOx emission limit at 0.17 lb/MMBtu.

Specifically, in its final rule publication of 40 CFR Part 51, Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations, EPA establishes presumptive NOx levels based on combustion controls, and not SNCR:

> *In today's action, EPA is setting presumptive NOx limits for EGUs larger than 750 MW. EPA's analysis indicates that the large majority of the units can meet these presumptive limits at relatively low costs. Because of differences in individual boilers, however, there may be situations where the use of such controls would not be technically feasible and/or cost-effective. For example, certain boilers may lack adequate space between the burners and before the furnace exit to allow for the installation of over-fire air controls. Our presumption accordingly may not be appropriate for all sources. As noted, the NOx limits set forth here today are presumptions only in making a BART determination, States have the ability to consider the specific characteristics of the source at issue and to find that the presumptive limits would not be appropriate for that source.* (emphasis added)

> *For all types of boilers other than cyclone units, the limits in Table 2 are based on the use of current combustion control technology. Current combustion control technology is generally, but not always, more cost-effective than post-combustion controls such as SCRs. For cyclone boilers, SCRs were found to be more cost-effective than current combustion control technology; thus the NOx limits for cyclone units are set based on using SCRs. SNCRs are generally not cost-effective except in very limited applications and therefore were not included in EPA's analysis. The types of current combustion control technology options assumed include low NOx burners, over-fire air, and coal reburning.*

We are establishing presumptive NOx limits in the guidelines that we have determined are cost-effective for most units for the different categories of units below, based on our analysis of the expected costs and performance of controls on BART-eligible units greater than 200 MW. We assumed that coal-fired EGUs would have space available to install separated over-fire air. Based on the large number of units of various boiler designs that have installed separated over-fire air, we believe this assumption to be reasonable. It is possible, however, that some EGUs may not have adequate space available. In such cases, other NOx combustion control technologies could be considered such as Rotating Opposed Fire Air (''ROFA''). The limits provided were chosen at levels that approximately 75 percent of the units could achieve with current combustion control technology. The costs of such controls in most cases range from just over $100 to $1000 per ton. Based on our analysis, however, we concluded that approximately 25 percent of the units could not meet these limits with current combustion control technology. However, our analysis indicates that all but a very few of these units could meet the presumptive limits using advanced combustion controls such as rotating opposed fire air (''ROFA''), which has already been demonstrated on a variety of coal-fired units. Based on the data before us, the costs of such controls in most cases are less than $1500 per ton. (emphasis added)

The advanced combustion control technology we used in our analysis, ROFA, is recently available and has been demonstrated on a variety of unit types. It can achieve significantly lower NOx emission rates than conventional over-fire air and has been installed on a variety of coal-fired units including T-fired and wall-fired units. We expect that not only will sources have gained experience with and improved the performance of the ROFA technology by the time units are required to comply with any BART requirements, but that more refinements in combustion control technologies will likely have been developed by that time. As a result, we believe our analysis and conclusions regarding NOx limits are conservative. For those units that cannot meet the presumptive limits using current combustion control technology, States should carefully consider the use of advanced combustion controls such as ROFA in their BART determination (emphasis added).[1]

There are several key concepts from EPA's preamble. First, Coal Creek is unique in that it has installed DryFining™ as a novel multi-pollutant control technology. This is important because it enhances the effectiveness of the NOx combustion controls. Second, Coal Creek re-uses the vast

[1] Federal Register / Vol. 70, No. 128 / Wednesday, July 6, 2005 / Page 39134-39135.

majority of its fly ash rather than disposing of it. Any negative impacts to fly ash, such as adding ammonia, will have both operational risks and cost implications for Great River Energy that must be included in any cost-effectiveness determination. Third, EPA has made its cost-effectiveness determination in setting presumptive BART NOx levels and has given states the authority to determine if more stringent requirements are needed based on their review.

In reviewing EPA's preamble discussion, it was clear to GRE that the EPA did not expect BART control scenarios for tangentially-fired units, such as Coal Creek Station's Units 1 and 2, to include post combustion add-on controls such as selective catalytic reduction (SCR) and SNCR. As such, in the initial BART evaluation, GRE focused on supporting this determination through the use of screening level cost data, and comparing those screening costs to cost effectiveness thresholds.

Based on the direction provided in the BART preamble and guidance, along with an analysis of cost effectiveness thresholds implemented in other EPA regulatory programs,[2] GRE proposed a cost effectiveness range of $1,300 to $1,800 (2006$) per ton of NOx removed. Guidance provided by NDDH presented higher cost per ton thresholds than EPA's in setting the presumptive level.

GRE's BART NOx determination for CCS Units 1 and 2 was consistent with EPA's preamble and confirmed that advanced combustion controls and an emission limit of 0.17 lb/MMBtu represented BART. SNCR was found to be cost ineffective based on screening level analysis, and presented additional operational and non-environmental impacts that were not exhaustively discussed in the December 2007 BART analysis but are provided herein.

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[2] http://www.ndhealth.gov/AQ/RegionalHaze/Regional%20Haze%20Link%20Documents/Appendix%20C/Coal%20Creek/Coal%20Creek%20BART%20Analysis.pdf (Appendix B).

2.0 Refined NOx Control Evaluation at CCS

This section will first establish that Coal Creek is unique, such that site specific evaluations are more appropriate than relying on general screening level assumptions to determine emission reductions and associated costs. It will then summarize the evaluation of site specific SNCR NOx reductions by URS, as well as ash impacts from the ammonia associated with this control.

2.1 Unique Aspects of Unit 1 and 2 NOx Controls

As discussed in the following sections, Coal Creek Station is neither average nor typical. EPA Guidelines, provided to States in identifying appropriate Regional Haze control requirements and provided in EPA's Pollution Control Cost Manual (2002), are developed in order to assist State authorities in making regulatory determinations. These guidelines are not to be viewed as regulatory requirements. They are best suited for evaluating average or typical installations. Units 1 and 2 are uniquely designed and employ a state-of-the-art lignite fuel enhancement technology, or DryFining™. This means that any accurate analysis of add-on NOx controls must be site specific and not rely upon general guidelines, which might apply to a normal facility.

2.1.1 DryFining™ Technology

GRE has a long track record of being innovative and going beyond minimum environmental requirements. DryFining™ is a $270 million, multi-pollutant technology. It reduces coal moisture and impurities while increasing the heat content of Fort Union lignite, which has the highest moisture of any coal in the US. The operation of DryFining™ has afforded CCS Units 1 and 2 significant reductions across the spectrum of emissions. Sulfur dioxide and mercury emissions have been reduced by more than 40%. Carbon dioxide emissions have been reduced by 4%. NOx emissions – the subject of the EPA FIP and this evaluation – have been reduced by more than 20%.

GRE expected that some additional NOx reductions would result from the implementation of DryFining™. It was estimated that the reduction in coal moisture, and corresponding increase in coal heat content, would result in less coal into the furnace, and more air available elsewhere in the furnace, which can be utilized to reduce NOx emissions. However, this NOx reduction benefit was not quantified in the original BART analysis. At the time of the final BART analysis (December 2007), DryFining™ had not yet operated, and the exact degree of control was unknown for this innovative strategy. Because DryFining™ has been in place for nearly two years, NOx emissions are

reduced. Consequently, current (baseline) NOx emissions that are used in Section 3.1 have been updated to reflect the URS control cost analysis and are inclusive of DryFining™, with low NOx burner technology as applicable.

2.1.2 NOx Combustion Control Considerations

GRE's proposed BART NOx control strategy includes the use of DryFining™ along with advanced combustion controls. As a result of the installation of the proposed advanced combustion controls on Unit 2, GRE has gained a better understanding of anticipated NOx control levels and costs.

The size and arrangement of the furnace box on CCS Units 1 and 2 is unique. It is literally a one-of-a-kind furnace box, sized specifically for the high moisture Fort Union lignite. Given a larger firebox, relative to other lower-moisture, higher-heat-content coal-fired units, there is a correspondingly higher complexity and higher cost to NOx combustion controls. There is a greater distance across the furnace through which the air must penetrate, thus increasing the size and type of wall nozzles, along with increased nozzle staging complexity throughout the wall sections. When an advanced combustion air system is added to a larger firebox, it requires additional wall openings, and redesign to wall water tubes, further increasing costs.

Since the time of the initial BART submittal, GRE has gained direct operational experience on the performance of these advanced combustion controls and DryFining™. Prior to the installation of DryFining™, most of the available primary air was needed to convey, grind, and dry the coal in the pulverizers due to the high moisture in the coal. Consequently, the maximum performance for the LNC3+ control installed on Unit 2 could not be fully realized upon initial installation. The Unit 2 LNC3+ installation includes larger registers to increase available primary air. Since a significant amount of that primary air was used to dry and pulverize the "unrefined" high moisture coal, there was not sufficient air available for the larger registers to act as a form of overfire air. With DryFining™, there is additional air available to be routed to the larger registers, which reduces NOx emissions. As a result, Units 1 and 2 currently operate with annual average NOx emissions of 0.200 and 0.153 lb/MMBtu, respectively. Unit 2's lower annual average NOx emission rate is directly attributable to the larger registers, which are tentatively anticipated for Unit 1 in 2014.

2.1.3 Site Specific SNCR Expected Control Levels

Portions of Coal Creek Station's December 2007 submittal of the NOx BART analysis were based on screening level data presented in the EPA Pollution Control Cost Manual (2002). Since EPA has proposed to reject North Dakota's SIP largely on their assessment of SNCR's screening level, cost

effectiveness, it is imperative to more accurately portray SNCR costs. With respect to SNCR specifically, EPA acknowledges in its cost manual:

> *SNCR system design is a proprietary technology. Extensive details of the theory and correlations that can be used to estimate design parameters such as the required [normal stoichiometric ratio] NSR are not published in the technical literature. Furthermore, the design is highly site-specific. In light of these complexities, SNCR system design is generally undertaken by providing all of the plant- and boiler-specific data to the SNCR system supplier, who specifies the required NSR and other design parameters based on prior experience and computational fluid dynamics and chemical kinetic modeling.*[3](emphasis added)

As discussed above, GRE has established that Coal Creek is unique due to its boiler size, DryFining™, and existing NOx combustion controls. Therefore, only a site specific evaluation, by a competent engineering and construction company (URS) familiar with SNCR engineering and installation costs, should be used to estimate emission reductions and associated costs. URS is a leading engineering consultant, with significant experience in installing SNCR technology, having managed the design and installation of several dozen SNCR pollution control systems throughout the world. This experience qualifies URS to make site-specific recommendations on SNCR design.

URS completed a site inspection, evaluated the unique aspects of Coal Creek, and provided their refined analysis (see Appendix B).

URS has determined that the removal efficiency for Coal Creek Unit 1 with an inlet NOx concentration of 0.22 lb/MMBtu would not be 50% as anticipated from the EPA Pollution Control Cost Manual (2002), and as used in GRE's original BART analysis. Rather, URS estimates a removal rate of approximately 30% removal for Unit 1. With respect to Unit 2, and an inlet concentration of 0.15 to 0.16 lb/MMBtu, URS estimates the removal efficiency would be approximately 20%.

EPA has raised concerns with respect to utilizing a new baseline period in determining the removal efficiencies for SNCR vs. DryFining™ with LNC3+. At the time of the 2007 BART analysis, GRE had no experience with the DryFining™ technology and was unable to determine the removal efficiencies possible with the LNC3+ and DryFining™ projects combined relative to NOx emissions.

[3] EPA Pollution Control Cost Manual (2002); Section 4.2 Chapter 1.3.

In an effort to evaluate existing installed technologies, GRE incorporated actual DryFining™ operating experience and performance subsequent to the 2007 analysis. This information must be considered in the revised analysis in order to capture the actual realized removal efficiencies of the DryFining™ and LNC3+ technologies as existing installed pollution control technologies. GRE notes that since the submittal of the 2007 BART analysis, GRE has lowered its Unit 2 NOx emissions from the baseline level of 0.22 lb/MMBtu to 0.153 lb/MMBtu on an annual average basis. This equates to an emissions reduction of 30.5% from the previously utilized 2007 baseline.

In addition to GRE's experience operating CCS with LNC3+ in combination with the DryFining™ technology, resulting in lower NOx emission levels, a relatively new study has been completed for a facility with low-baseline NOx emissions[4] (Appendix E). This EPRI study addressed applicability of and anticipated removal efficiencies for SNCR for units with low-baseline NOx emissions. The study's findings suggest that SNCR performance is significantly decreased at baseline NOx emission levels less than 100 ppm[5]. The demonstrated low removal efficiencies (~10% reduction) are much lower than GRE's suggested removal efficiency for the SNCR technology (20%) applied in this analysis. Similarly, the low removal efficiencies are also much lower that the removal efficiency of 25%+ suggested in EPA's proposed FIP.

The study concludes that for low-baseline NOx applications, at levels around 75 ppm4, anticipated removal efficiency for SNCR is in the range of 8%-12%. If GRE takes into account the data from this study in place of the removal efficiency recommended by URS, the cost effectiveness would be well outside the range deemed cost effective. GRE's anticipated SNCR removal efficiency of 20% is likely higher than the technology will be able to achieve starting from a baseline of 0.153 lb NOx/MMBtu or 88 ppm (DryFining™ with LNC3+ installed). GRE continues to use a removal efficiency of 20% in its analysis based on the SNCR technology evaluation conducted by URS, but notes that this value may in fact be conservatively optimistic.

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[4] *Low-Baseline NOx Selective Non-Catalytic Reduction Demonstration*: *Joppa Unit 3*. EPRI, Palo Alto, CA: 2009, 1018665. GRE asserts a business confidentiality claim and asserts this report is confidential business information subject to the protections set forth in Air Pollution Control Rules for the State of North Dakota at 33-15-01-16 and 40 CFR Part 2.

[5] Current NOx concentrations for CCS Unit 1 and Unit 2 are 110 ppm and 88 ppm, respectively (determined on a 12-month rolling average basis).

Given these lower projected emission rates, and the lower "baseline" emission rates from installed controls, the cost evaluation has been revised, accordingly, in Section 3.1.

Rather than relying on the original screening level analyses, GRE finds it imperative to provide this updated information to North Dakota to make their well-informed cost effectiveness determinations.

2.2 Revision of Baseline NOx Emissions

The BART Guidelines (40 CFR 51, Appendix Y) state "The baseline emissions rate should represent a realistic depiction of anticipated annual emissions for the source. In general, for the existing sources subject to BART, you will estimate the anticipated annual emissions based upon actual emissions from a baseline period." To accurately depict the anticipated annual emissions for the units at CCS a new baseline must be established taking into consideration the DryFining™ technology and installed combustion controls in Unit 2 (LNC3+). The DryFining™ process is designed to remove moisture and segregate dense material from the coal prior to introduction of the coal into the final stage of grinding and conveyance into the boiler. DryFining™ having been funded under a DOE collaborative agreement (DE-FC26-04NT41763) was required to conduct performance tests which demonstrated a heat input reduction of approx. 2-3%. Having removed the moisture prior to the introduction into the pulverizers lends to less primary air required to "dry" and convey the coal through the pulverizers, making air available for staging (Over-fired air NOx control) in other areas in the boiler. This drier coal will not require the same amount of heat input into the boiler because wet coal expends some of its heat input to vaporize the moisture in the coal and its heating value has increased per pound so fewer pounds are needed. Thus a drier coal will not require that additional coal typically lost to vaporizing the moisture and reduced heating value. DryFining™ is currently obtaining a moisture reduction in the coal of approximately 8%. Future tuning is continuing and will meet a required reduction of 12% by 2016, which is needed for the SO_2 BART analysis to achieve full scrubbing.

In order to make its cost effectiveness determination, North Dakota must not only have site specific control cost, but also accurate emission reduction estimates. Clearly, with the installation of both LNC3, LNC3+, and DryFining™, Coal Creek's NOx emissions are greatly reduced with respect to "baseline" values previously provided. In this section, in light of recently refined analysis, GRE will update baseline emissions to be used in making the cost effectiveness determination.

Based on the timing of the original analysis, the initial BART evaluation used baseline emission rates for approximately the same time period that was used to determine the visibility baseline, which was

a 5-year period of emission inventory data from 2000 to 2004. It is necessary to update the baseline emissions for Units 1 and 2 for this technology evaluation in order to reflect current conditions and unit performance. Both units utilize "low NOx coal-and-air nozzles with close-coupled and separated overfire air," which is referred to as LNC3. Since the time of the initial evaluation, NOx controls in the form of larger registers,[6] advancing the LNC3 controls (LNC3+),[7] have been added to Unit 2, which means that the two units have different baselines for the purpose of estimating future emission reductions. For Unit 1, the revised baseline is 0.200 lb/MMBtu, as an annual average. For Unit 2, the revised baseline is 0.153 lb/MMBtu, as an annual average, as also described in Section 2.1.2. These new "baseline" emission rates are lower than the initial BART baseline of 0.22 lb/MMBtu.

2.2.1 Circumferential Cracking in Boiler Tubes

Following the installation of LNC3+ technology at Unit 2, CCS has determined that an emission rate of 0.15 lb/MMBtu for LNC3+ is not a sustainable 30-day rolling average control level due to circumferential cracking. In other words, the 0.15 lb/MMBtu on a 30-day rolling basis is at the edge of this technology's capabilities. While GRE may intermittently achieve this rate on a monthly or perhaps more easily as an annual average, it is not the basis for a 30-day rolling limit.

As background, in 2008 GRE lowered NOx emissions from Unit 2 by expanding the OFA registers. This diverted more of the combustion air from the burners of the boiler to an area about 30 feet higher in the boiler. In doing so, the flame temperatures were lowered, which reduced the production of NOx generated by the combination of oxygen and nitrogen gas burned under high temperatures. NOx emissions were lowered, but there was an unexpected side effect. This low NOx emission rate caused circumferential cracks in the boiler tubes between the burner front and the over-fired air registers.

The phenomenon of circumferential cracking has several interrelated contributing factors including high surface temperatures (>900°F bare tubes, >1100°F weld overlays) (which exposes the boiler tubes to high wall temperatures and high temperature fluctuations, which produces numerous thermal fatigue cracks in the boiler walls), frequent and severe thermal spikes (>100°F), and corrosive

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[6] Larger registers allow for a greater ability to tune combustion staging and thus control NOx emissions.

[7] LNC3 is the acronym used by EPA to describe a specific type of restrictive combustion control. To differentiate between the controls installed on Unit 1 and the additional controls installed on Unit 2 (both are versions of LNC3), the acronyms LNC3 and LNC3+ are used for each unit, respectively.

conditions/deposits. Low NOx burner systems with overfire air ports produce longer flames and increase the chance of flame impingement and local overheating of the boiler walls.

In 2009, Coal Creek Station began to experience unscheduled outages on Unit 2 due to failures from the circumferential cracking described above. To understand and correct this problem, Great River Energy engaged the Electric Power Research Institute (EPRI) to assist in evaluating the causes and potential remedies for this problem. To date, corrective actions have included detailed examinations of the boiler tubes to detect the extent of the cracking, the installations of additional temperature monitors to determine boiler wall temperatures, the replacement of damaged boiler tubes, and continued tuning of the boiler to minimize the circumferential cracking in the zone of concern. While not eliminating the problem, these efforts have greatly reduced the problem of unscheduled outages caused by circumferential cracking. Based on our analysis, it is not clear how to completely and consistently eliminate this problem, while operating at or near 0.15 lb/MMBtu on a 30-day rolling basis. Efforts continue to further reduce this circumferential cracking problem while balancing our desire to operate at lower NOx emission levels.

The only examples of tangentially-fired units with emissions lower than the 0.17 lb/MMBtu NOx presumptive level are facilities with post combustion NOx controls, such as SNCR. Further, a majority of these SNCR controlled sources operate well above the 0.17 lb/MMBtu, as annual averages, as detailed in the Cross State Air Pollution Rule and illustrated in Figure 2.2. Consequently, GRE presumes it cannot safely and consistently operate below 0.17 lb/MMBtu as a 30-day rolling limit, without installing SNCR.

2.2.2 Load Variability

In addition to circumferential cracking, this assessment must also consider load variability and its impacts on NOx emissions. The NOx emission limits proposed in the original BART evaluation for Units 1 and 2 did not consider that Coal Creek's units would experience significant load variability. GRE has historically operated as a baseload unit, without much load swinging. In May 2011, Midwest Independent Transmission System Operator (MISO) began cycling CCS in the real-time market. In September 2011, GRE greatly increased the cycling range of CCS in response to current market prices in the MISO market. This is important because load swinging significantly impacts expected NOx control performance. While base load NOx emissions can be tuned due to relatively stable load, the swinging load cannot be finely tuned but must still be accounted for when assessing compliance with emission limits.

Table 2.1 illustrates the variability experienced during recent load swinging. It is different on Units 1 and 2, due to different NOx controls. Based on changing market conditions, load variability is expected to continue as an operational scenario for Units 1 and 2 for the foreseeable future. As such, any emission limit must account for this additional variability in emissions. It is clear from Table 2.1 that the BART NOx presumptive emission rate of 0.17 lb/MMBtu is achievable, including load variability, and also reflecting the maximum NOx emission reductions from LNC3+ and DryFining™, as demonstrated through Unit 2.

Table 2.1 Coal Creek Station NOx Emission Rates During Load Variability

Scenario Description		NOx Emissions (lb/MMBtu)			
		Unit 1		Unit 2	
		Min	Max	Min	Max
Overall - Nov. 2010 to Nov. 2011	30-day Rolling	0.179	0.219	0.14	0.169
Load Variability – May – November 2011	30-day Rolling	0.186	0.219	0.146	0.166
	Hourly Average	0.206		0.16	
Load Variability – September – November 2011	30-day Rolling	**0.207**	**0.219**	**0.163**	**0.166**
	Hourly Average	0.218		0.17	

In addition, GRE provides a chart (Figure 2.1) showing Unit 2's 30-day rolling average NOx emission rate, with notes on tuning emphasis and load variability, as further support of the 0.17 lb/MMBtu emission limit.

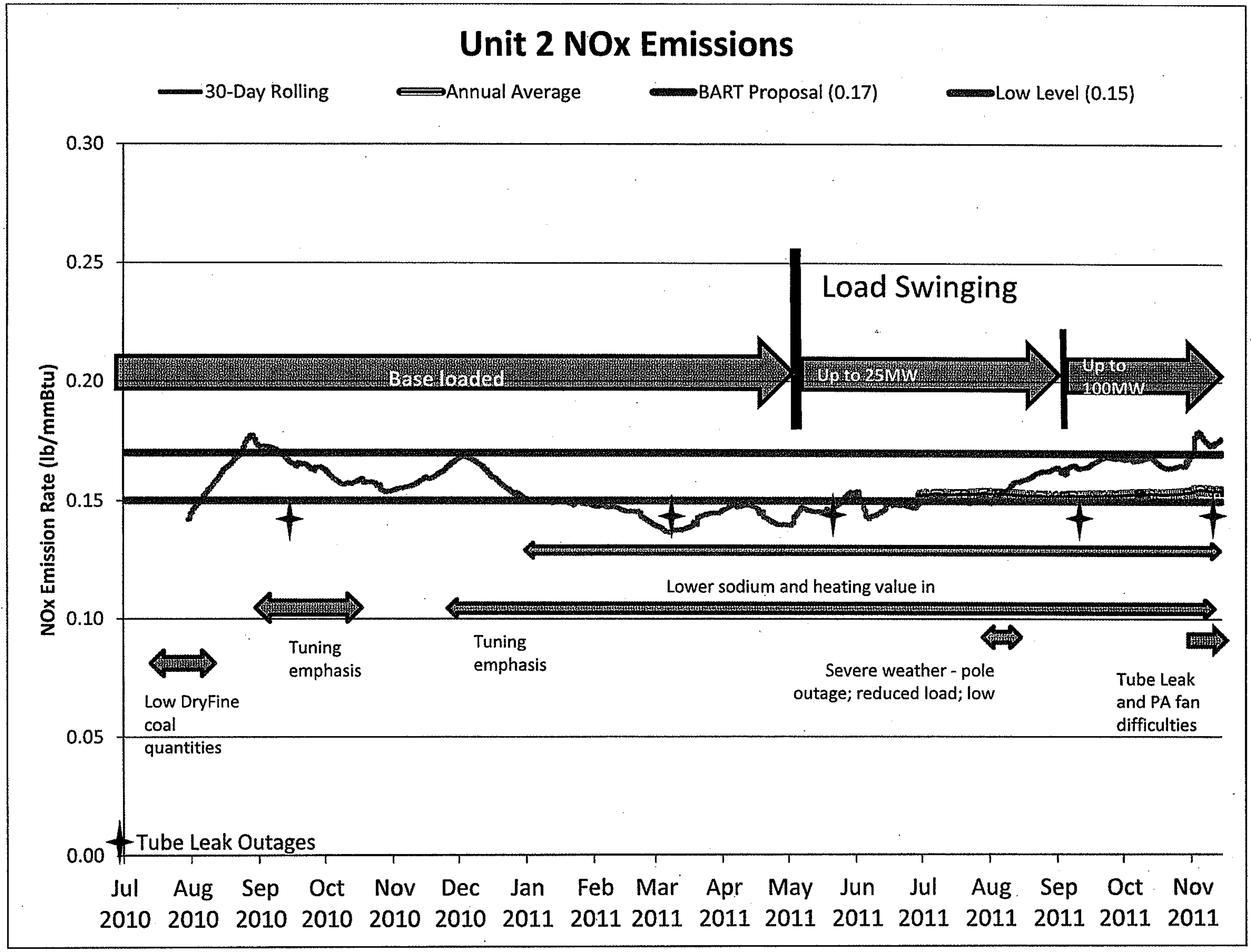

Figure 2.1 Unit 2 30-Day Rolling NOx Emission Averages

2.2.3 Evaluation of SNCR Effectiveness in CSAPR

Interestingly, the Coal Creek presumptive NOx BART emission rates are consistent with annual average emissions as modeled by EPA in CSAPR. By reviewing existing units of similar design, data from the docket for the proposed Cross State Air Pollution Rule (Docket ID EPA-HQ-OAR-2009-0491) illustrates that there are currently no tangentially-fired utility electricity generating units with LNC3 combustion controls and SNCR post combustion controls that operate at or below the presumptive BART limit of 0.17 lb/MMBtu for NOx (Figure 2.2), as annual averages. If the data set is expanded to include LNC3 ("low NOx coal-and-air nozzles with separated overfire air (LNC2[8])") and "low NOx burners and overfire air (OFA)" as illustrated in Figure 2.3, only four supercritical[9] emission units operate below the presumptive NOx limit of 0.17 lb/MMBtu. None of the facilities included in the CSAPR database operate at or below the proposed FIP limit of 0.12 lb/MMBtu. All of the facilities analyzed use SNCR to effectively achieve the Coal Creek presumptive NOx emission limit of 0.17 lb/MMBtu. To state it differently, Coal Creek effectively achieves presumptive BART with DryFining™ rather than SNCR.

[8] LNC2 and LNC3 are various types of low NOx burner design.

LNC2 = Low NOx burner with separated OFA

LNC3 = Low NOx burner with close-coupled and separated OFA

[9] For a subcritical boiler (standard operational design consistent with CCS Units 1 and 2), steam to power the turbine is derived by heating liquid water to its saturation point and then isothermally heating of the system causing the phase change from liquid water to steam (boiling). In contrast, a supercritical steam generating unit operates at such a high pressure that liquid water does not boil and is instead converted to a supercritical fluid, an intermediate fluid having properties of both liquid water and steam. Operation of supercritical units is typically more thermally efficient than operation of subcritical units, resulting in less fuel combusted for the same energy output and, consequently, lower emissions.

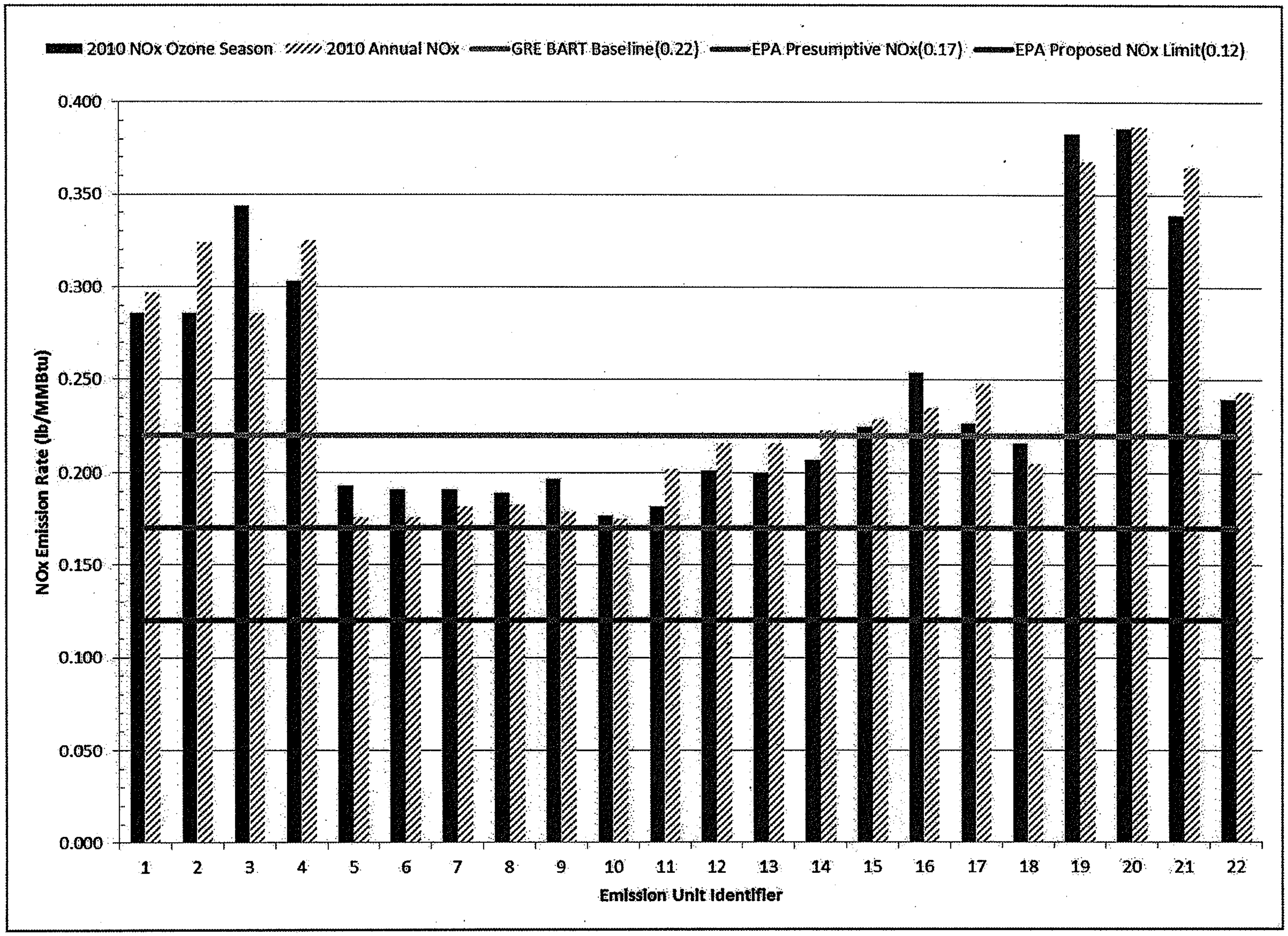

Figure 2.2 **2010 NOx Emission Rates from CSAPR Rule Data for Units with SNCR and LNC3/OFA NOx Control**

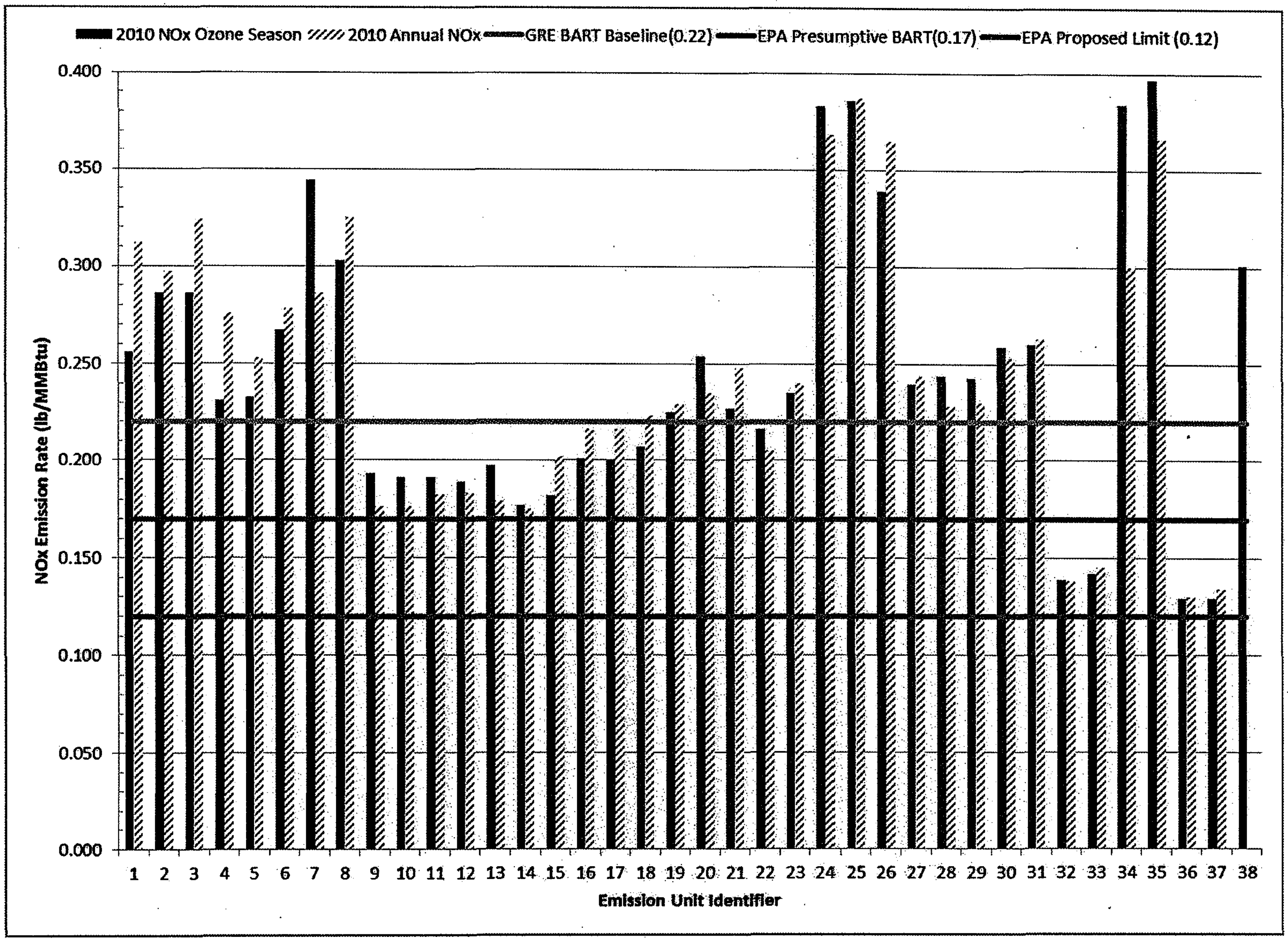

Figure 2.3 **2010 NOx Emission Rates from CSAPR Rule Data for Units with SNCR and LNC2/LNC3/OFA NOx Control**

2.2.4 Ash Cost Considerations

The EPA indicated in its proposed FIP that GRE fly ash sales and disposal values provided in previous submittals were in error and, when corrected, resulted in SNCR being cost effective. Great River Energy had previously submitted two estimates: $5/ton and $36/ton (2006$). Contrary to our Summer 2011 submittal, these values were not necessarily in error, but instead represented different assumptions on economic impacts of lost ash sales and associated disposal costs. Therefore, rather than rely upon these screening level values as previously submitted, GRE contracted with Golder Associates to provide a more refined analysis of ash impacts associated with the installation of SNCR. The following discussion and attached "Fly Ash Storage and Ammonia Slip Mitigation Technology Evaluation" (Appendix C) provides a more comprehensive assessment of ash implications associated with SNCR installation.

To provide some additional background on the previously submitted values, the $36/ton value represented the total freight on board (FOB) Coal Creek Station price that was paid by the end user. The $5/ton dollar per ton figure represented what GRE received as a portion of the FOB price prior to December 1, 2011.

Both of the values ($5/ton and $36/ton) attempted to capture lost revenue from decreased ash sales. In each case, an additional $5/ton cost was added as GRE's cost to dispose of the unsalable ash. This additional $5/ton disposal value was the result of a screening level analysis and had not taken into account all of the internal costs associated with ash disposal. This disposal value also had not accounted for anticipated cost increases based on changing ash disposal regulations, nor did it take into account various ash disposal levels as could be anticipated due to lost fly ash sales.

GRE and Headwaters Resources, Inc (HRI), GRE's strategic partner in the sales and distribution of fly ash, have invested heavily into fly ash sales infrastructure including terminals and storage facilities, conveying equipment, scales and train car shuttles. HRI financed GRE's portion of the infrastructure through a per ton payment on fly ash sales. The current ash sales contract requires payments to GRE that total 30% of the $41 (2011$) FOB price or $12.30 per ton (2011$) of ash that is delivered.

Considerable effort has been taken to clarify the impacts that SNCR installation will have on GRE's ash management methods, overall disposal costs and reduction in ash sales revenues. In short, Great River Energy firmly believes, and EPA acknowledges in its proposed FIP, that SNCR may have a detrimental impact to ash sales. The Golder analysis represents these risk ranging from a worst case

100% lost fly ash sales, to an optimistic 30% lost sales, as shown in their Scenarios B and C, respectively. For the sole purpose of defining a baseline, a hypothetical Scenario A "No Ash Impacts," has also been included as a reference point.

2.2.5 SNCR's Impact on Ash Management Options

Fly ash from CCS is used throughout the Upper Midwest to replace a portion of Portland cement in concrete production, making the concrete more durable and longer lasting. Ash generated at Coal Creek Station has chemical and physical properties that make it an extremely desirable ash in the concrete market. Coal Creek Station currently generates approximately 525,000 tons of fly ash per year. Approximately 415,000 tons of that ash is sold as a Portland cement replacement. Coal Creek fly ash has been used in many large-scale projects such as construction of the new Interstate-35W Bridge after its collapse.

The beneficial use of fly ash also has a strong positive economic benefit to Great River Energy, and the regional economy. We started selling fly ash nearly three decades ago. In that time, we have grown this activity into a sizable annual revenue stream. The addition of SNCR will have a negative impact on the marketability, value and perception of Coal Creek Station's fly ash. The addition of ammonia into the combustion process leaves an ammonia residue on the ash that can cause aesthetic and worker safety issues during the use of the ash. The residual ammonia in the ash eventually off-gases and creates odors which are offensive, are potentially dangerous to human health, and can even pose an explosion risk. Section 1-2 of EPA's Pollution Control Cost Manual recognizes this fact and states the following:

> *Ammonia sulfates also deposit on the fly ash that is collected by particulate removal equipment. The ammonia sulfates are stable until introduced into an aqueous environment with an elevated pH levels. Under these conditions, ammonia gas can release into the atmosphere. These results in an odor problem or, in extreme instances, a health and safety concern. Plants that burn alkali coal or mix the fly ash with alkali materials can have fly ash with high pH. In general, fly ash is either disposed of as waste or sold as a byproduct for use in processes such as concrete admixture. <u>Ammonia content in the fly ash greater than 5 ppm can result in off-gassing which would impact the</u>*

salability of the ash as a byproduct and the storage and disposal of the ash by landfill.[10] (emphasis added)

The range of residual ammonia left with the fly ash can vary with each installation of SNCR. Ammonia slip of only 5 ppm, generally accepted as the minimum that can be achieved with SNCR, can render fly ash unmarketable. (URS, Appendix B) Even in those systems where residual ammonia is generally low, there will be times of increased ammonia slip based on plant operations. As the plant output varies due to market demand or startup/shutdown activity, varying levels of ammonia will be used to control NOx and, consequently, the levels in the ash will change. Variable ammonia levels in the ash create additional complexity to both sales and/or treatment, and will result in increased disposal.

2.2.6 Ammonia Mitigation Technology

Great River Energy is committed to ash re-use due to its economic and environmental benefits. Therefore, we anticipate additional capital and operating costs to treat the ash in order to ideally preserve a percentage of ash sales. With respect to ammoniated ash treatment, Ammonia Slip Mitigation (ASM) technology refers to a variety of technologies that have been designed to improve the marketability of ammoniated ash. These technologies fall into two rough categories, combustion or carbon burn out (CBO) and chemical treatment. CBO is the process of running the ash through an additional combustion unit that would combust and burn out the residual carbon and ammonia that is with the ash. This is a capital intensive technology that also has high operating costs. The second category of ASM technology is generally referred to as chemical treatment. These treatment technologies involve creating a chemical or physical reaction that results in the off-gassing of the residual ammonia. These treatment technologies are generally less costly than CBO. For purposes of this more refined analysis, GRE contracted with Golder Associates to provide a detailed cost estimate of one particular chemical treatment technology as a potentially cost effective option. The detailed cost estimate can be found in Appendix C.

Even with a cost effective ASM technology installed, there will be times when the residual ammonia levels in the ash are too high to treat. Ammonia injection rates will vary during periods of startup and shutdown, in addition to variable load operation, in order to maintain compliance with the BART limits. Variable ammonia injection rates and associated changes in ash concentrations will result in

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frequent testing and periodic rejection of ash for on-site disposal. Further, variable ammoniated ash levels will put GRE's generated ash in a very vulnerable position with respect to competitors in the fly ash marketplace, reducing ash sales and increasing on-site disposal.

2.2.7 Ash Disposal Scenario Cost Summaries

Appendix C contains a technical assessment and cost analysis of ammonia slip mitigation technology and ash disposal under RCRA Subtitle D design standards. To address the uncertainty regarding costs associated with ammoniated ash management and disposal, a range of costs is presented. These costs are based on three scenarios described below. Table 2.2 shows the volumes of ash produced, sold and disposed of in each scenario. For a more detailed description please see Appendix C.

Scenario A (current ash sales levels) – This scenario is the base case with fly ash sales equal to the average sales over the past few years. The scenario assumes that fly ash will be disposed of in a new landfill with a design based on RCRA Subtitle D practices, and has a 20-year disposal capacity. No post processing of the fly ash is required to maintain 100% marketability. (Golder 2011) This hypothetical scenario is not considered to be a possible option for future ash management costs but serves as a point of reference for understanding future impacts.

Scenario B (No ash sales) – This "worst case" scenario assumes that the ammonia slip impact of SNCR makes fly ash at CCS completely unsalable. The scenario also assumes that fly ash will be disposed of in a new landfill with a design based on RCRA Subtitle D practices, and has a 20-year disposal capacity. (Golder 2011)

***Scenario C* (30% sales reduction, ASM costs)** – This "realistic" scenario assumes that Headwater's ASM technology will be viable for ammonia-impacted fly ash at CCS. However, sales will be reduced from current sales levels due to load swing impacts on ammonia slip, market conditions, and other factors previously identified. The scenario also assumes that fly ash will be disposed of in a new landfill with a design based on RCRA Subtitle D practices, and has a 20-year disposal capacity. (Golder 2011)

Table 2.2 Fly Ash Sales and Disposal Tons

	Scenario A (Current Sales)	Scenario B (No Sales)	Scenario C (Reduced Sales, ASM)
Fly Ash Produced (ton/yr)	525,000	525,000	525,000
Fly Ash Sold (ton/yr)	415,000	0	290,500
Fly Ash Disposed (ton/yr)	110,000	525,000	234,500

It is clear in EPA's proposed FIP that the installation of SNCR may negatively impact ash sales[11].

Our knowledge of the ash marketplace, SNCR systems, and treatment technologies confirm that the installation of SNCR will have a detrimental impact on the salability of fly ash. GRE believes that Scenario A, which represents no impact to ash sales, is extremely unlikely. Nevertheless, we present it as a point of reference for better quantifying the ash impacts from SNCR installation.

GRE believes that scenario B (zero ash sales) is a likely outcome, but we hope that through investment in ASM technology we will be able to preserve some of the ash sales. To model partial ash sales, we created Scenario C. Scenario C assumes an investment in ASM technology and a reduction of ash sales by 30%.

It is not possible to determine exactly what percent of ash sales would be lost based on the installation of the SNCR and ammonia mitigation technologies at Coal Creek Station. There are no plants in the country with both of these technologies operating together on a lignite-fired unit. In fact, the vendor responsible for the ammonia mitigation technology will not guarantee the technology's performance at Coal Creek Station.

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[11] Federal Register / Vol. 76, No. 183 / Wednesday, September 21, 2011 / Page 58620.

"Regarding this value for fly ash sales, North Dakota concluded that SCR and SNCR use at Coal Creek would likely result in NH_3 in the fly ash due to NH_3 slip which would negatively affect fly ash salability. According to Great River Energy and North Dakota, fly ash that is currently beneficially used in the production of concrete would, instead, be landfilled. While we have opted to agree that fly ash will not be saleable for the SNCR and SCR options for purposes of our cost analyses, we are seeking comment on this issue, particularly related to the levels of NH_3 that fly ash marketers deem problematic, and the availability, applicability, and cost of applying NH_3 mitigation techniques to fly ash derived from lignite coal."

Across the country there are examples of plants that have SCR or SNCR and sell most of their ash, however, there are also others that sell none of their ash. It is a very site-specific scenario and depends on the type of coal, type of combustion, type of ash collection, plant operation (cycling % load), type of ammonia mitigation technology (if any), and how the SNCR or SCR system has been designed, installed and implemented. Each and every site is very different.

For the sake of modeling the costs related to lost ash sales we determined it was important to model a middle ground between 0% lost ash sales and 100% lost ash sales. There is a strong possibility that all ash sales will be lost and a zero chance that 100% ash sales will be maintained; some middle option needed to be considered. We looked across the industry to determine the best scenario for a moderate outcome. The 30% lost ash sales figure reflects a reasonable and optimistic (i.e., conservative) outcome that can be justified based on our understanding of plant operations and the ash markets in which we compete for sales.

The only plant (Eastlake) in the U.S. operating with the discussed ammonia mitigation technology operates under a very different scenario. This plant mixes the ammoniated ash with a non-ammoniated ash prior to sales. Thus, Eastlake is able to sell up to approximately 85% of its ash. However, Coal Creek Station is unlike the Eastlake plant. Increased load variation at CCS, adjusting plant output to match the MISO market in which we operate, can lead to upsets in the SNCR system and higher levels of ammonia in the ash.

The addition of ammonia mitigation technology and additional handling and processing steps will also increase the cost of ash to the end users. As our price point in the market increases, we will face increased competition and will lose some sales to competing ash sources.

In addition, consistency is a prized trait for a fly ash that is marketed to the cement industry. The addition of SNCR will have a detrimental impact on the consistency of the market product. Decreased consistency will lead to lower demand for the ash and will result in some lost sales to competing ash sources.

Predicting exactly what impact all of these factors will have on our ash sales is not possible. Based on our investigation and knowledge, and that of the experts we consulted, we concluded it is very likely that we will lose 50% or more of our ash sales. We chose to model 30% loss in sales as a conservative scenario that likely underestimates the real impact of this technology on ash sales.

Furthermore, in our modeling scenarios, we assumed that the future regulation of coal ash would not be subject to RCRA Subtitle C requirements. Consistent with our comments to EPA's docket during its Coal Combustion Residuals rulemaking, we believe Subtitle C regulation of coal ash is unwarranted and unnecessary. Nevertheless, EPA has proposed it as one option for a final rule. Subtitle C regulation of coal ash would significantly increase our cost to handle and dispose of our ash. Subtitle C regulation has not been included in our scenarios.

In summary, we consider a 30% scenario to be a very optimistic view of the future that relies on the successful implementation of a technology that cannot currently be guaranteed by the vendor and has never been installed on lignite-fired units. This scenario also quantifies increased disposal costs, in addition to some GRE-specific economic benefit from preserved ash sales. None of the scenarios attempt to capture economic impacts to GRE's strategic partners or other regional entities, but these impacts are mentioned in Section 3.2 and should also be taken into consideration when making a final BART determination.

2.2.8 Ash Management Costs

There are three major cost categories to be considered in each of these scenarios;

- Fly ash disposal cost estimates,
- Ammonia slip mitigation costs, and
- Lost fly ash sales revenue

Each cost area is summarized below. For a more detailed assessment, see Appendix C.

2.2.9 Fly Ash Disposal Cost Estimates

Given significant uncertainty with pending regulatory requirements such as RCRA Subtitles C and D, with ammonia slip treatment technologies, and with market reactions to ammoniated ash, Great River Energy has developed essentially three scenarios that attempt to capture a range of possibilities associated with SNCR installation. For all three scenarios, a 20-year disposal capacity and a RCRA Subtitle D design is assumed. It is also assumed that the landfill will be built on property not currently owned by GRE, as GRE does not currently have a suitable location for siting a Subtitle D landfill. For this cost estimate, it is assumed that property just west of the plant property would be purchased for the new facility. Landfill size is based on a 20-year fly ash disposal capacity. For the three scenarios, this varies between 2.2 million and 10.5 million tons of capacity. For each scenario, Golder developed a simplified landfill footprint that would provide the 20-year fly ash disposal capacity.

The cost estimate includes costs for the life of the disposal facility including engineering, design, and permitting; construction; and operations and maintenance, including closure and post-closure care. Golder used actual costs from similar projects at CCS, local contractor rates, RS Means manuals (RS Means 2010), and professional judgment to develop this cost estimate. Sources and assumptions are documented. Some general assumptions for the cost estimate include:

- All costs are estimated in 2011 dollars.
- Capital costs are annualized based on a 20-year life and 5.5% interest rate.
- Existing fly ash processing equipment (silos, unloaders, etc.) is not included. Disposal costs begin once the haul trucks are loaded with fly ash.
- Existing fly ash sales infrastructure (silos, scales, rail facilities) and operations and maintenance are not included.
- Disposal costs only include fly ash disposal and not facility airspace or operations and maintenance for other coal combustion products produced at CCS. (Golder 2011)

Table 2.3 Disposal Cost Summary (2011$)

	Scenario A (Current Sales)	Scenario B (No Sales)	Scenario C (Reduced Sales, ASM)
Fly Ash Disposed (ton/yr)	110,000	525,000	234,500
Total Disposal Cost ($/ton)	$18.06	$11.18	$13.91
Annual Disposal Cost ($/yr)	$1,987,000	$5,870,000	$3,262,000
Annual Increase in Disposal Cost Compared to Scenario A ($/yr)	-	$3,883,000	$1,275,000
Incremental Increase in Disposal Cost Compared to Scenario A ($/ton) *	-	$7.40	$5.44

*These values are used in the BART analysis as they represent the only the incremental costs above the baseline costs which would be incurred with or without the installation of SNCR.

2.2.10 Ammonia Slip Mitigation Costs

Post-processing of ammonia slip impacted fly ash by Headwater's ASM technology is proposed as an option to maintain fly ash sales. This post-processing is only being applied to the sold fly ash tonnage in Scenario C. Depending upon the plant power profile and how the fly ash distribution system is setup, it is likely that additional tons of fly ash will be treated and disposed, but these potential cost impacts are not included. The cost impact for ASM post-processing is shown in Table 2.4. (Golder 2011)

Table 2.4 ASM Post-Processing Costs (Golder 2011)

	Scenario A (Current Sales)	Scenario B (No Sales)	Scenario C (Reduced Sales, ASM)
ASM Unit Rate Capital and O&M ($/ton sold)	$0.00	$0.00	$5.61
ASM Annual Capital and O&M ($/yr)	$0	$0	$1,629,000

2.2.11 Lost Fly Ash Sales Revenue

The current fly ash sales are supported by a large investment in capital infrastructure as well as a large operations and maintenance contingency. Changes to the quantity of fly ash marketed and sold will have a direct impact on fly ash management costs, as the revenue currently used to offset fly ash management will be lost. The lost fly ash sales revenue is based on the 2010 average price per ton FOB of $41.00; with 30% of the sale price going to GRE as revenue. The cost impact of the potential loss in fly ash sales in shown in Table 2.5. (Golder 2011)

Table 2.5 Lost Fly Ash Sales (Golder 2011)

	Scenario A (Current Sales)	Scenario B (No Sales)	Scenario C (Reduced Sales, ASM)
Lost Fly Ash Sales Revenue ($/ton lost sales)	$12.30	$12.30	$12.30
Annual Lost Fly Ash Sales Revenue ($/yr)	$0	$5,105,000	$1,531,000

2.2.12 Total Fly Ash Management Costs

The combination of the ASM post-processing, fly ash disposal, and lost fly ash sales revenue is shown in Table 2.6. This table represents the total economic impact of SNCR installation on GRE's fly ash management in two likely scenarios; a total loss of ash sales and a 30% reduction in ash sales.

Table 2.6 Total Fly Ash Management Costs (Golder 2011)

	Scenario A (Current Sales)	Scenario B (No Sales)	Scenario C (Reduced Sales, ASM)
Total (Disposal + Post Processing + Lost Sales)			
Annual Cost ($/yr)	$1,987,000	$10,975,000	$6,422,000
Unit Cost ($/ton produced)	$3.79	$20.91	$12.23
Additional Cost (Scenario B/C - Scenario A)			
Fly Ash Management Cost ($/yr)	-	$8,988,000	$4,435,000
Fly Ash Management Cost ($/ton produced)	-	$17.12	$8.45

2.2.13 BART Analysis Ash Disposal Cost Summary[12]

While the exact impacts to Coal Creek Station's ash are unknown, mandating SNCR will leave GRE in a vulnerable position where we would expect to incur significantly higher costs from lost ash sales and increased landfilling. Based on the detailed technical review discussed above and included as Appendix C, GRE proposes a range of ash disposal costs and lost ash sales revenue figures in the BART analysis. None of the scenarios consider the significant cost impact of potential RCRA Subtitle C regulation in the future.

Scenario B represents the highest cost scenario with a total annual additional cost of $8,988,000. The total cost includes lost ash sales revenue of $5,105,000 (Table 2.5) and an additional annual ash disposal cost of $3,883,000 or $7.40 per ton disposed (Table 2.3).

Scenario C represents an optimistically low cost scenario with a total annual additional cost of $4,435,000. The total cost includes lost ash sales revenue of $1,531,000 (Table 2.5) and an additional annual ash disposal cost of $1,275,000 or $5.44 per ton disposed (Table 2.3). Scenario C also includes a Ammonia Slip Mitigation cost of $5.61 per ton of ash reused for an additional annual cost of $1,629,000 (Table 2.4).

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[12] All costs within this section are presented in 2011$.

3.0 Integrated NOx Control and Ash Impact Impacts Analyses

This section will integrate the revised baseline emissions, the refined URS SNCR Analysis and the Golder Ash Impact Analysis. It will then provide a summary table with associated cost per ton and incremental cost per ton values.

3.1 SNCR Control Cost Analysis

As discussed in Section 2.1.3, baseline NOx emissions are adjusted to reflect existing controls. Based on the updated baseline, Table 3.1 summarizes the anticipated control costs for additional NOx controls. It includes more refined SNCR costs for CCS Units 1 and 2 (See URS Report Appendix B). It also includes cost scenarios from the Golder Associates Fly Ash Storage and Ammonia Slip Mitigation Technology Evaluation (See Appendix C). It should be noted that the controlled NOx emission concentrations and mass rates have been evaluated on an annual average basis and are not representative of anticipated operation on a shorter scale averaging period (30-day rolling or 24-hour rolling), consistent with BART guidance that costs be normalized to the expected annual emissions reduction. The 30-day rolling limits are intended to be inclusive of unit startup and shutdown as well as variability in load. Consequently, associated BART limits must be higher than stated annual averages used for estimating cost effectiveness (e.g., LNC3+ is evaluated at 0.153 lb NOx/MMBtu on an annual average basis with an anticipated 30-day rolling limit of 0.17 lb NOx/MMBtu). Costs are valued on a present (2011) dollars basis.

Considerable effort has been taken to clarify the impacts that SNCR installation will have on GRE's ash management methods, overall disposal costs and reduction in ash sales revenues. In short, Great River Energy firmly believes, and EPA acknowledges in its proposed FIP, that SNCR may have a detrimental impact to ash sales. The Golder analysis represents these risk ranging from a worst case 100% lost fly ash sales, to an optimistic 30% lost sales, as shown in their Scenarios B and C, respectively. For the sole purpose of defining a baseline, a hypothetical Scenario A "No Ash Impacts," has also been included as a reference point.

Table 3.1 Control Cost Summary (2011$)

Unit ID	Control Description	NOx Emissions (lb/MMBtu)	Control Eff. From Baseline (%)	Emission Reduction from Baseline (T/yr)	Installed Capital Cost ($MM)	Annualized Operating Cost ($MM)	Pollution Control Cost ($/ton)	Incremental Cost $/ton
Unit 1	SNCR, LNC3+, 100% Lost Ash Sales (Scenario B)					$8.878	$5,821	$19,125
	SNCR, LNC3+, 30% Lost Ash Sales (Scenario C)	0.122	33%	1,525.2	$17.873	$6.602	$4,329	$13,762
	SNCR, LNC3+, No Ash Impacts (Scenario A)					*$4.384*	*$2,875*	*$8,534*
	SNCR, 100% Lost Ash Sales (Scenario B)					$8.795	$7,629	
	SNCR, 30% Lost Ash Sales (Scenario C)	0.150	25%	1,152.8	$12.176	$6.519	$5,655	NA – Inferior Control
	SNCR, No Ash Impacts (Scenario A)					*$4.301*	*$3,731*	
	LNC3+	0.153	24%	1,100.9	$6.079	$0.763	$693	$693
	Baseline (LNC3)	0.200	NA-Base	NA-Base	NA-Base	NA-Base	NA-Base	NA-Base
Unit 2	SNCR, 100% Lost Ash Sales (Scenario B)					$8.115	$10,505	$10,505
	SNCR, 30% Lost Ash Sales (Scenario C)	0.122	20%	772.5	$11.794	$5.839	$7,559	$7,559
	SNCR, No Ash Impacts (Scenario A)					*$3.621*	*$4,688*	*$4,688*
	Baseline – LNC3+	0.153	NA-Base	NA-Base	NA-Base	NA-Base	NA-Base	NA-Base

Scenario A (No Ash Impacts) is provided for reference only and does not represent a feasible control option.

Below is provided the least cost envelope illustrated graphically. Only dominant controls falling within the least cost envelope were further analyzed for incremental feasibility. Inferior technologies are deemed not cost effective.

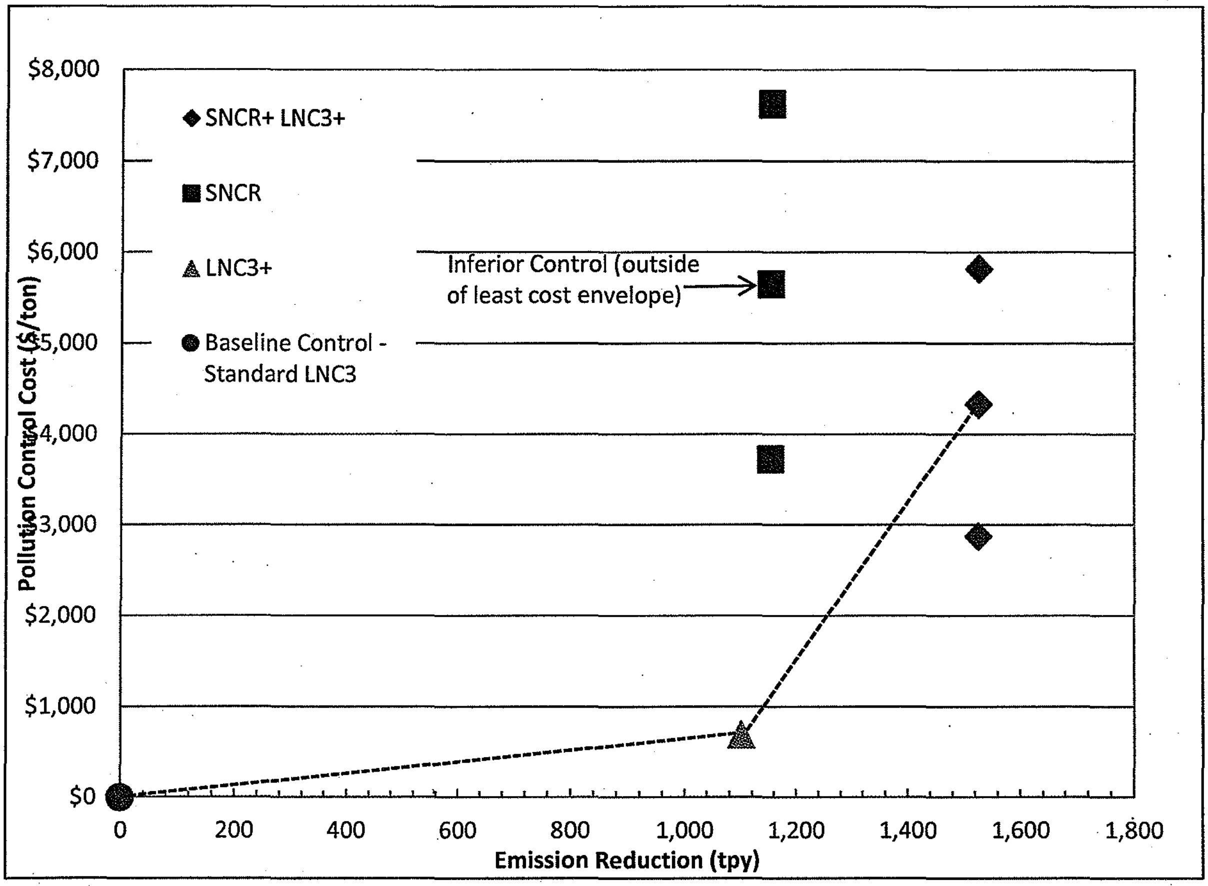

Figure 3.1 **Incremental NOx Analysis**
The remaining feasible technologies are illustrated on the basis of annualized emission reduction in tons per year and total annualized cost in millions of dollars per year.

This refined economic impacts analysis confirms GRE's original conclusion that SNCR is not a cost effective NOx control option. From Table 3.1, it would appear as if Unit 1 SNCR – No Ash Impacts would be cost effect on a dollar per ton basis according to the State of ND thresholds, but in understanding that this scenario is considered hypothetical since some level of ash impacts are expected, and the incremental cost per ton is an order of magnitude higher than anything deemed cost effective. The disparity in the incremental costs occurs due to the fact that the DryFining™ with LNC3+ technology could achieve the associated emissions reduction indicated for the SNCR technology. As highlighted, the "most realistic" or optimistic scenario is 30% lost ash sales, with cost exceeding $4,000 (2011$) per ton of NOx controlled. This value is higher than EPA's determination of economic infeasibility for SCR for CCS at around $4,000/ton (2011$) of NOx removed stated in the FIP.

Although not directly incorporated into GRE's capital and operating control costs presented above, NDDH must also consider additional impacts, such as indirect and stranded cost components discussed in Section 3.2 and Section 3.3.

3.2 Additional Impacts

GRE provides these additional impact considerations not found in the original BART analysis as important to North Dakota in making its final BART determination.

1. The use of DryFining™ technology that has already been implemented for use at both units at a cost of $270 million. GRE has made a significant investment to achieve multi-pollutant emission reductions and visibility improvements in the region.

2. At the time of this submittal, GRE has already installed LNC3+ combustion controls at Unit 2. In 2011 dollars, this was at a cost of over $6 million and has already resulted in NOx reductions. The same system is currently tentatively scheduled to be installed on Unit 1 during the 2014 outage.

3. Ash infrastructure investments of over $31 million have been made to date for management and sale of Coal Creek Station's ash. Over $7 million of the total investment have been made by GRE, directly.

4. The DryFining™ technology provides a dual emission improvement for the total BART analysis. In order to achieve 100% scrubbing for the SO_2 analysis GRE must reduce the moisture, related air flow and therefore the total mass of flue gas travelling through the absorbers in the scrubber. DryFining™ will be implemented to its fullest extent by the BART compliance deadline.

3.2.1 Regional Impact from Ash Sales Revenue

The BART analysis does not take into account additional regional economic impacts resulting from the reduction or elimination of CCS ash sales. In order to estimate these regional impacts, one can use the freight on board (FOB) price of the ash at $41 (2011$), and subtract GRE's share of that revenue at $12.30 (2011$). Therefore, SNCR installation would reduce or eliminate ash sales, eliminating an additional $28.70/ton (2011$) from the local and regional economy. This could result in a loss of as much as $11,910,500 (2011$) per year from the local and regional economy. In addition to these regional economic impacts, there are other impacts that must also be considered.

3.2.2 Fly Ash is Important to the National Economy

Fly ash is an important part of the regional and national economy. The National Association of Manufacturers reported in 2010 that Coal Combustion Residuals (CCRs) contribute $6-11 billion annually to the U.S. economy through revenues from sales for beneficial use, avoided cost of disposal, and savings from use as a sustainable building material.[13] The beneficial use of fly ash and other CCRs are directly responsible for a large number of jobs throughout the country. A 2011 report by Veritas found that "Approximately 10.6 million tons of coal combustion residuals were used in concrete-related products during 2009. Those products provided employment for 240,100 manufacturing workers, 78,480 foundation, structure, and building exterior workers and many of the 102,350 nonresidential building construction workers during 2010." (Veritas 2011[14])

3.2.3 Fly Ash is Important to Regional and National Infrastructure

The American Road and Transportation Builders Association[15] completed a report in 2011 that highlighted the importance of fly ash as a component of road and bridge construction across the country. Their research found that the elimination of fly ash as a construction material would increase the average annual cost of building roads, runways and bridges in the United States by nearly $5.23 billion. This total includes $2.5 billion in materials price increases, $930 million in additional repair work and $1.8 billion in bridge work. The additional costs would total $104.6 billion over 20 years.

3.2.4 Environmental Benefits of Ash Reuse

The use of fly ash as a replacement for cement has many environmental benefits. As a result of the increased use of fly ash, less land is disturbed for quarrying raw materials, less land is taken out of production for landfills, and less carbon dioxide (CO_2) is emitted into the atmosphere to make cement. Using one ton of fly ash instead of Portland cement reduces up to one ton of greenhouse gas emissions. Inversely, by contaminating the ash with ammonia, and increasing ash disposal, there will be a corresponding 1-to-1 ton increase in CO_2 emissions from using more Portland cement. These CO_2 emissions are not trivial.

[13] Report available at: http://www.regulations.gov/#!documentDetail;D=EPA-HQ-RCRA-2009-0640-6992.

[14] Available at: http://www.recyclingfirst.org/pdfs/101.pdf.

[15] Available at: http://www.artba.org/mediafiles/study2011flyash.pdf.

3.2.5 Additional Ash Management Cost Considerations

The ash management costs detailed in this report are considered to be conservative figures from reasonable assumptions that most likely underestimate GRE's future expenditures on ash management.

The ash analysis envisions that all future disposal facilities will be designed and constructed to RCRA subtitle D standards. EPA is currently proceeding with an ash disposal rulemaking that will create uniform national disposal standards under RCRA subtitle D, the far more stringent Subtitle C (Hazardous Waste), or some hybrid approach that takes some requirements from each Subtitle D and C. The cost of complying with a Subtitle C rule would vastly exceed the amounts discussed in this report. This analysis reasonably assumes Subtitle D.

The ash disposal costs discussed above are portrayed as three scenario costs: a baseline which represents current ash sales figures; a scenario where all ash must be disposed of; and a scenario where ash sales are reduced by 30% from the baseline. There is significant uncertainty regarding specific impacts to beneficial reuse if SNCR were installed. The zero ash sales scenario (Scenario B) is very possible and is an outcome that we hope to avoid. Scenario C captures a "hybrid" estimate of the future where some ash is beneficially used and some additional ash must be disposed. For the hybrid scenario, we chose a 30% reduction in sales. This 30% estimate is an optimistic figure of preserved ash sales at 70%. It is quite possible that the amount of ash requiring disposal could easily represent a 50%, 70% or larger reduction in fly ash sales. For this reason, Scenario C is likely to produce ash management costs that are lower than will actually be encountered.

As discussed above, there are a variety of different Ammonia Slip Mitigation (ASM) technologies available. Most of these technologies have only been installed at a small number of generating units and, to GRE's knowledge, no lignite-fired unit is currently operating SNCR and ASM technology.[16] Of all ASM technologies that were investigated, the Headwaters technology was the least expensive. If the Headwaters ASM technology fails to function properly on lignite, it is likely that we would incur significantly larger costs to preserve the beneficial reuse of some portion of our fly ash.

[16] It is important to note that Headwaters ASM technical staff have stated that this technology has not been tested on a lignite unit and they would not guarantee any level of performance if installed at CCS.

The EPA Pollution Control Cost Manual (2002) does not allow GRE to include in our BART analysis the value of previously purchased assets that would be rendered useless by the elimination or reduction of fly ash sales. GRE and its strategic partner, Headwaters Resources, have invested $31 million on ash storage, transportation and distribution infrastructure.

3.3 SNCR Visibility Impacts

It is known that NOx contributes to ammonium nitrate formation, which is predominantly a winter "haze" contributor. For purposes of valuing the welfare effects of recreational visibility, it is important to consider that the North Dakota national parks are generally not in high use during the winter season. If required to install SNCR, GRE will pay an extreme price per deciview resulting in imperceptible improvements for a time of year when the parks are generally not used.

To satisfy EPA's proposed Federal Implementation Plan, Coal Creek Station would need to install SNCR technology to reach a NOx emissions level that is 29% lower than EPA's presumptive BART. Yet, the extensive modeling performed as part of the BART analysis concludes that the installation of SNCR, at an emission rate of 0.12 lb/mmBtu, will have an imperceptible improvement in visibility, ranging from 0.05 deciview (dV) to 0.18 dV in the Class I areas near the facility. This is far less than one-half of what EPA has determined to be perceptible to the human eye (0.50 dV)[17]. As such, it is not justifiable for GRE to incur the added cost of SNCR without any appreciable improvement in visibility.

It is worth noting that SNCR will result in ammonia emissions to the atmosphere. Ammonia is a listed state toxic in North Dakota, and is viewed as a contributor to regional haze because it can bond with sulfur dioxide and nitrogen oxides to form ammonium sulfate and ammonium nitrate aerosols Consequently, GRE does not believe that SNCR is a cost effective technology for improving visibility.

3.3.1 CCS Modeled Visibility Impacts

Under EPA's modeling guidelines, it is necessary to develop a 24-hour maximum anticipated emission rate for each control technology in order to assess visibility impacts. GRE assumes that on a 30-day rolling basis, combustion and post-combustion NOx controls can experience emissions that

[17] Federal Register / Vol. 76, No. 183 / Wednesday, September 21, 2011.
FR discusses State's ability to consider potential impacts for VOC and ammonia although full analyses may not be required.

are approximately 10% higher than their annual design basis. Similarly, for assessing a 24-hour maximum emission rate, GRE assumes emissions will be up to 20% higher than the annual design rate for a given control.

GRE presented a full evaluation of anticipated cost per unit visibility impairment (Δ-dV) in its final BART analysis (Dec 2007). Pollutant interaction has an impact on modeled visibility impairment and, as such, GRE believes that modeling changes to NOx emission rates alone will not provide visibility modeling results that are representative of actual emission controls. This may overstate visibility improvement as compared to modeling NOx, SO_2 and fine PM together. However, for the purpose of illustrating the relative visibility impacts of SNCR and LNC3+, an analysis of the difference in modeled impacts is presented in Table 3.2.

An incremental cost per deciview analysis is also included in Table 3.2. This comparison relies on the annualized operating costs presented in Table 3.1, and represents the difference in annualized capital costs between the two controls compared to the change in average visibility impairment for the 98th percentile over the three modeled years for the same controls.

Table 3.2 Difference in Impairment and Incremental Cost for LNC3+ with Tuning and SNCR with LNC3+

Unit ID	2000 (dV)	2001 (dV)	2002 (dV)	Average (dV)	Incremental Cost per dV (MM$/dV)[1]
Unit 1	0.031	0.044	0.093	0.056	$103.81
Unit 1 & 2	0.062	0.083	0.172	0.106	$110.26

[1] Incremental cost comparison (2011$) of LNC3+ with SNCR with LNC3+ at 30% lost ash sales.

The visibility analysis demonstrates that SNCR will not result in actual improvement to visibility in North Dakota's affected Class I areas, and potential modeled improvements will come at a prohibitive incremental cost exceeding $100 million (2011$) per deciview. Utilities in North Dakota only contribute ~6% to total NOx emissions in the State. Consequently, any additional utility NOx reductions will not have an appreciable effect on visibility improvement. Additional details regarding modeling inputs and visibility impairment is presented in Appendix D.

4.0 Conclusions

Great River Energy provided BART Determinations utilizing the 5 step process in 2007. Until now, Great River Energy has provided screening level analyses and assumptions with respect to SNCR installation. Due to EPA's proposed FIP, and its assertion that SNCR is cost effective for Coal Creek Station, Great River Energy responds with more refined analyses in three primary areas. This refined analysis reevaluates the last two steps of the BART Determination process for LNC3+ and SNCR technology at Coal Creek Station.

First, URS provides a site specific evaluation of SNCR effectiveness at Coal Creek Station, which results in lower projected emissions reductions from this control. These emission estimates clearly change the basis for any cost effective determination. Consideration for startup and shutdown emissions, circumferential cracking and load variations should also factor into this determination as discussed in Section 2.2.

Second, URS reviewed and updated both capital and operating costs for SNCR, based on their expertise and site specific investigation. These values were relatively consistent with values presented to EPA in June and July 2011, but are somewhat higher than the screening values presented in the original BART analysis.

Third, Golder Associates conducted a detail ash impact analysis associated with a range of costs from contaminating the fly ash with ammonia from SNCR. While the exact impacts to Coal Creek Station's ash management and sales are unknown, mandating SNCR will leave GRE in a vulnerable position where we would expect to incur significantly higher costs from lost ash sales and increased landfilling. Based on a detailed technical review GRE would expect to incur additional ash annual costs somewhere between $4,435,000 and $8,988,000 (2011$).

The final two steps of the BART Determination include Step 4 - "Evaluate Impacts and Document Results" and Step 5 – "Evaluate Visibility Impacts". In evaluating the impacts of Unit 1's technologies it was concluded that installation of SNCR alone (without LNC3+) is an economic inferior technology and therefore is not further evaluated incrementally. When the SNCR and LNC3+ technologies were evaluated together for Unit 1 and Unit 2 they were deemed not cost effective on an incremental basis and therefore not an appropriate BART technology. GRE included the visibility tables for the associated LNC3+, and SNCR cases presented in Table 3.1. The final conclusion for the visibility impacts is that based on our refined analysis the state Class I areas would not see any

perceptible improvement in visibility by requiring a level of NOx control above LNC3+ for CCS, and additional reductions would be cost prohibitive on a dollar per deciview basis (Table 3.2).

When the three refined analyses of the final two steps of the BART Determination process are combined and evaluated, it clearly demonstrates that the presumptive NOx limit of 0.17 lb/mmBtu is both cost effective and results in significant visibility improvements in North Dakota's Class I areas.

On strictly a cost effective basis, SNCR can be ruled not cost effective for Unit 2, especially when the GRE specific risks and costs associated with this technology are included. On an incremental cost effectiveness basis, SNCR can be ruled not cost effective for Unit 1, also considering the GRE specific risks and costs associated with this technology. As noted, there are additional economic and visibility impacts associated with SNCR that further preclude it from consideration.

Appendix A

Pollution Control Cost Evaluations

Great River Energy Coal Creek Station
BART Supplement - NOx Emission Control Cost Analysis

Table A-1: Cost Summary

NO_x Control Cost Summary - Unit 1

Case	Control Technology [1]	Annual Designed Emissions lb/MMBtu	Control Eff % from Baseline [3]	Controlled Emissions T/yr	Emission Reduction T/yr	Installed Capital Cost MM$	Annualized Control Cost MM$/yr	Pollution Control Cost $/ton	Annual Incremental Cost $/ton [4]	See Table XX for additional Information
3 [2]	SNCR + LNC3+ - 100% Lost Ash Sales	0.122	33%	3,086.2	1,525.2	$17.873	$8.878	$5,821	$19,125	A-4, A-10
	SNCR + LNC3+ - 30% Lost Ash Sales						$6.602	$4,329	$13,762	A-4, A-9
	SNCR + LNC3+ - No Ash Impacts						*$4.384*	*$2,875*	*$8,534*	*A-4, A-8*
2	SNCR - 100% Lost Ash Sales	0.150	25%	3,458.5	1,152.8	$12.176	$8.795	$7,629	NA - Inferior Control	A-7
	SNCR - 30% Lost Ash Sales						$6.519	$5,655	NA - Inferior Control	A-6
	SNCR - No Ash Impacts						*$4.301*	*$3,731*	*NA - Inferior Control*	*A-5*
1	LNC3+	0.153	24%	3,510.5	1,100.9	$6.079	$0.763	$693	$693	A-4
0	Baseline Control - Standard LNC3	0.200	NA-Base	4,611.4	NA-Base	NA-Base	NA-Base	NA-Base	NA-Base	A-3

NO_x Control Cost Summary - Unit 2

Case	Control Technology [1]	Annual Designed Emissions lb/MMBtu	Control Eff % from Baseline [3]	Controlled Emissions T/yr	Emission Reduction T/yr	Installed Capital Cost MM$	Annualized Control Cost MM$/yr	Pollution Control Cost $/ton	Annual Incremental Cost $/ton [4]	See Table XX for additional Information
1	SNCR - 100% Lost Ash Sales	0.122	20%	3,089.8	772.5	$11.794	$8.115	$10,505	$10,505	A-10
	SNCR - 30% Lost Ash Sales					$11.794	$5.839	$7,559	$7,559	A-9
	SNCR - No Ash Impacts					*$11.794*	*$3.621*	*$4,688*	*$4,688*	*A-8*
0	Baseline Control - LNC3+	0.153	NA-Base	3,862.3	NA-Base	NA-Base	NA-Base	NA-Base	NA-Base	A-3

[1] Ash impact scenarios align with November 2011 Golder report.
No Ash Impacts - Golder Scenario A; *Scenario provided for reference only and does not represent a feasible outcome*
30% Lost Ash Sales - Golder Scenario C
100% Lost Ash Sales - Golder Scenario B

[2] Capital costs for combined control scenario on Unit 1 are calculated using LNC3+ costs for Unit 1 (scenario 1) and SNCR costs for Unit 2, as unit 2 presently has LNC3+ installed.

[3] Calculated on a mass basis.

[4] Incremental costs calculated as the difference in annualized operating cost divided by the difference in emission reduction for the next lowest level of dominant control.

Great River Energy Coal Creek Station

BART Supplement - NOx Emission Control Cost Analysis

Table A-2: Emission Inventory Data / Baseline Emission Rate for BART Control Cost Analysis

Equipment Information: GRE Coal Creek Unit I				6015	MMBtu/hr		Baseline Emis	
Year (12-Month Avg. Period)	Jul 2010 - Jun 2011	Aug 2010 - Jul 2011	Sep 2010 - Aug 2011	Oct 2010 - Sep 2011	Nov 2010 -Oct 2011		Unit 1	Unit 2
Hours of Operation	7,700	7,700	7,635	7,599	7,629		7,653	8,410
Fuels Used:								
Quanity of Lignite - Tons	3,356,248	3,352,605	3,296,938	3,268,966	3,282,270		3,311,405	3,688,805
Percent Sulfur in Coal (Average)	0.64%	0.65%	0.65%	0.66%	0.61%		0.64%	0.64%
BTU per Unit of Coal (Average)	6,415	6,448	6,482	6,517	6,003		6,373	6,373
Heat Input	4.410E+07	4.422E+07	4.356E+07	4.320E+07	4.346E+07		43,708,554	47,761,077
MMBtu/hr	5,727	5,743	5,705	5,685	5,697		5,712	5,679
% of Capacity	95.2%	95.5%	94.8%	94.5%	94.7%		95.0%	94.3%
NOx lb/MMBtu	0.200	0.200	0.199	0.200	0.203		0.200	0.153
Total Stack Emissions:								
NOx Emitted Tons Per Year:	4,416.3	4,412.0	4,333.1	4,330.2	4,402.3		4,378.8	3,642.5
NOx Emitted Lb Per Hour:	1,204.8	1,200.3	1,196.7	1,205.8	1,218.5		1205.2	918.5
Stack Emissions --- Lignite:								
NOX CEM Annual Average lb/MMBtu	0.201	0.200	0.200	0.201	0.203		0.201	0.153

Equipment Information: GRE Coal Creek Unit II				6022	MMBtu/hr
Year	Jul 2010 - Jun 2011	Aug 2010 - Jul 2011	Sep 2010 - Aug 2011	Oct 2010 - Sep 2011	Nov 2010 -Oct 2011
Hours of Operation	8,430	8,430	8,397	8,401	8,390
Fuels Used:					
Quanity of Lignite - Tons	3,730,674	3,718,253	3,676,481	3,672,436	3,646,178
Percent Sulfur in Coal (Average)	0.64%	0.65%	0.65%	0.66%	0.61%
BTU per Unit of Coal (Average)	6,415	6,448	6,482	6,517	6,003
Heat Input	4.810E+07	4.799E+07	4.757E+07	4.764E+07	4.751E+07
MMBtu/hr	5,706	5,692	5,665	5,671	5,662
% of Capacity	94.9%	94.6%	94.2%	94.3%	94.1%
NOx lb/MMBtu	0.152	0.153	0.152	0.152	0.153
Total Stack Emissions:					
NOx Emitted Tons Per Year:	3,662.4	3,666.8	3,610.4	3,626.8	3,646.1
Stack Emissions --- Lignite:					
NOX CEM Annual Average lb/MMBtu	0.152	0.153	0.152	0.153	0.154

Great River Energy Coal Creek Station

BART Supplement - NOx Emission Control Cost Analysis

Table A-3: Summary of Utility, Chemical and Supply Costs

Operating Unit: Unit 1 or 2   Study Year 2011

From Golder Report

Item	Unit Cost	Units	Reference Cost	Year	Data Source	Notes
Operating Labor	37.00	$/hr	25.86	2002	Stone & Webster 2002 Cost Estimate; confirmed by GRE	
Maintenance Labor	37.00	$/hr	26.25	2002	Stone & Webster 2002 Cost Estimate; confirmed by GRE	
Electricity	0.0604	$/kwh	0.049	2004	DOE Average Retail Price of Industrial Electricity, 2004	http://www.eia.doe.gov/emeu/aer/txt/ptb0810.html
Water	0.31	$/kgal	0.79	2002	Stone & Webster 2002 Cost Estimate; confirmed by GRE	
Cooling Water	0.32	$kgal	0.23	1999	EPA Air Pollution Control Cost Manual, 6th ed. Section 3.1 Ch 1	Ch 1 Carbon Adsorbers, 1999 $0.15 - $0.30 Avg of 22.5 and 7 yrs and 3% inflation
Compressed Air	0.37	$/kscf	0.25	1998	EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1	Example problem; Dried & Filtered, Ch 1.6 '98 cost adjusted for 3% inflation
Wastewater Disposal Neutralization	1.96	$/kgal	1.50	2002	EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 2 Chapter 2.5.5.5	Section 2 lists $1- $2/1000 gal. Cost adjusted for 3% inflation Sec 6 Ch 3 lists $1.30 - $2.15/1,000 gal
Wastewater Disposal Bio-Treat	4.96	$/kgal	3.80	2002	EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 5.2 Chapter 1	Ch 1 lists $1.00 - $6.00 for municipal treatment, $3.80 is average. Cost adjusted for 3% inflation
Solid Waste Disposal - No Impact	0.000	$/ton	0.00	2011	Assume no chang in GRE landfill cost for ash	Fly ash disposal of 0 net tons
Solid Waste Disposal - 30% Lost	5.438	$/ton	5.438	2011	Golder Fly Ash Management Evaluation - Nov. 2011	Cost per ton of $13.91/ ton for 234,500 tons less existing cost of $18.06/tons for 110,000 tons
Solid Waste Disposal - 100% Lost	7.396	$/ton	7.396	2011	Golder Fly Ash Management Evaluation - Nov. 2011	Cost per ton of $11.18/ ton for 525,000 tons less existing cost of $18.06/tons for 110,000 tons
Hazardous Waste Disposal	326.19	$/ton	250.00	2002	EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 2 Chapter 2.5.5.5	Section 2 lists $200 - $300/ton Used $250/ton. Cost adjusted for 3% inflation
Waste Transport	0.65	$/ton-mi	0.500	2002	EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 3	Example problem. Cost adjusted for 3% inflation
Ash Sales	12.300	$/ton	12.300	2011	Golder Fly Ash Management Evaluation - Nov. 2011	$/ton received for sale of ash; this amount is lost if ash cannot be sold
Ammonia Mitigation	5.610	$/ton	5.610	2011	Golder Fly Ash Management Evaluation - Nov. 2011	
Chemicals & Supplies						
Lime	90.00	$/ton	72.19	2005	GRE per Diane Stockdill 12/6/05 email	Cost adjusted for 3% inflation
Caustic	364	$/ton	305.21	2005	GRE per Diane Stockdill 12/6/05 email	Cost adjusted for 3% inflation
Urea	500	$/ton	500	2011	URS SNCR Report - November 2011	
Oxygen	17.91	kscf	15.00	2005	Get cost from Air Prod Website	Cost adjusted for 3% inflation
EPA Urea	179.1	$/ton				
Ammonia	1	$/lb	0.92	2005	GRE per Diane Stockdill	Cost adjusted for 3% inflation
Other						
Sales Tax	0	%			GRE per Diane Stockdill 12/6/05 email	
Interest Rate	5.50%	%			GRE per Diane Stockdill 12/6/05 email	Estimated prime rate plus 3%

Please note, for units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal

Future Operating Scenario for BART Cost Analysis

Operating Information	Unit 1	Unit 2	Units		Data Source	Notes
Annual Op. Hrs	7,652.6	8,409.6	Hours		July 2010 to October 2011 Coal Creek Emission Data	
Utilization Rate	100.0%	100.0%			GRE per Diane Stockdill 12/6/05 email	
Equipment Life	20	20	yrs			Engineering Estimate
Coal Ash	11.70	11.70	wt % ash		2010 Coal Creek Emission Inventory	
Coal Sulfur	0.64	0.64	% Coal Sulfur Content		July 2010 to October 2011 Coal Creek Emission Data	
Coal Heating Value	6,373	6,373	Btu/lb of coal		July 2010 to October 2011 Coal Creek Emission Data	
Design Capacity	6,015	6,022	MMBtu/hr			
ID Fan Flow Rates	Assumes coal drying with DryFining™					
Standardized Flow Rate	866293.7	866293.7	scfm @ 32º F			
Temperature	330.0	330.0	Deg F		GRE per G. Riveland 4/5/06 email	
Moisture Content	13.3%	13.3%			GRE per G. Riveland 4/5/06 email	
Actual Flow Rate	2,234,300	2,234,300	acfm		GRE per G. Riveland 4/5/06 email	
Standardized Flow Rate	1,391,000	1,391,000	scfm @ 330º F		GRE per G. Riveland 4/5/06 email	
Dry Std Flow Rate	1,205,997	1,205,997	dscfm @ 330º F			
NOx Pollutant Data						
Max Emis (lb/hr)	1,205.2	918.5			July 2010 to October 2011 Coal Creek Emission Data	
Max Emis (tpy)	4,611.4	3,862.3				
Baseline Emiss (lb/MMBtu)	0.200	0.153				

Great River Energy Coal Creek Station
BART Supplement - NOx Emission Control Cost Analysis
Table A-4: Unit 1 NOx Control - Foster Wheeler LNC3+

Operating Unit: Unit 1

Emission Unit Number	EU-1		Stack/Vent Number	SV-1		CEPCI	
Desgin Capacity	6,015	MMBtu/hr	Standardized Flow Rate	866,294	scfm @ 32º F	2005	468.2
Expected Utiliztion Rate	100%		Temperature	330	Deg F	2011	588.9
Expected Annual Hours of Operation	7,652.6	Hours	Moisture Content	13.3%		Inflation Factor	1.26
Annual Interest Rate	5.5%		Actual Flow Rate	2,234,300	acfm		
Expected Equipment Life	20	yrs	Standardized Flow Rate	1,391,000	scfm @ 330º F		
Baseline NOx	0.200	lb/MMBtu	Dry Std Flow Rate	1,205,997	dscfm @ 330º F		

CONTROL EQUIPMENT COSTS

Capital Costs								
Direct Capital Costs								
Purchased Equipment (A)								1,257,796
Purchased Equipment Total (B)								1,958,057
Installation - Standard Costs								1,958,057
Installation - Site Specific Costs								NA
Installation Total								3,729,632
Total Direct Capital Cost, DC								5,687,689
Total Indirect Capital Costs, IC								391,611
Total Capital Investment (TCI) = DC + IC								**6,079,300**
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.						7,079
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost						756,131
Total Annual Cost (Annualized Capital Cost + Operating Cost)								**763,210**

Emission Control Cost Calculation

Pollutant	Max Emis Lb/Hr	Pre-control Annual T/Yr	Cont Eff %	Exit Conc	Conc Units	Cont Emis T/yr	Reduction T/yr	Cont Cost $/Ton Rem
Nitrogen Oxides (NOx)	1,205.2	4,611.4	24%			3510.5	1,100.9	693

Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 2 (Used PM Scrubber which has lowest installed cost multiplier)

Notes & Assumptions

1 Sept 2005 Cost Estimate from Foster Wheeler, Option 2, inflated to 2011 dollars. Ratio based on actual cost for Unit 2 instalaltion.
2 Total capital investment reflects actual installed costs for Unit 2 installation, infllated to 2011 dollars.
3 Assumed 0.1 hr/shift operatior and maintenance labor for LNB
4 Process, emissions and cost data listed above is for one unit.
5 For units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal

Great River Energy Coal Creek Station

BART Supplement - NOx Emission Control Cost Analysis

Table A-4: Unit 1 NOx Control - Foster Wheeler LNC3+

CAPITAL COSTS		
Direct Capital Costs		
Purchased Equipment (A) (1)		1,257,796
Instrumentation		
Sales Taxes		
Freight		
Purchased Equipment Total (B)		1,958,057
Installation		
Foundations & supports		
Handling & erection		
Electrical		
Piping		
Insulation		
Painting		
Installation Subtotal Standard Expenses (1)		1,958,057
Site Preparation, as required	Site Specific	NA
Buildings, as required	Site Specific	NA
Site Specific - Other	Site Specific	NA
Total Site Specific Costs		NA
Installation Total		3,729,632
Total Direct Capital Cost, DC		5,687,689
Indirect Capital Costs		
Engineering, supervision	5% of purchased equip cost (B)	97,903
Construction & field expenses	10% of purchased equip cost (B)	195,806
Contractor fees	0% of purchased equip cost (B)	0
Start-up	1% of purchased equip cost (B)	19,581
Performance test	1% of purchased equip cost (B)	19,581
Model Studies	NA of purchased equip cost (B)	NA
Contingencies	3% of purchased equip cost (B)	58,742
Total Indirect Capital Costs, IC	20% of purchased equip cost (B)	391,611
Ozone Generator, Installed Cost		0
Total Capital Investment (TCI) = DC + IC (2)		6,079,300
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost		6,079,300
OPERATING COSTS		
Direct Annual Operating Costs, DC		
Operating Labor		
Operator	NA	-
Supervisor	NA	-
Maintenance		
Maintenance Labor	37.00 $/Hr, 0.1 hr/8 hr shift, 7652.6 hr/yr	3,539
Maintenance Materials	100% of maintenance labor costs	3,539
Utilities, Supplies, Replacements & Waste Management		
NA	NA	-
NA	NA	-
NA	NA	-
NA	NA	-
NA	NA	-
NA	NA	-
NA	NA	-
NA	NA	-
NA	NA	-
NA	NA	-
NA	NA	-
NA	NA	-
NA	NA	-
Total Annual Direct Operating Costs		7,079
Indirect Operating Costs		
Overhead	60% of total labor and material costs	4,247
Administration (2% total capital costs)	2% of total capital costs (TCI)	121,586
Property tax (1% total capital costs)	1% of total capital costs (TCI)	60,793
Insurance (1% total capital costs)	1% of total capital costs (TCI)	60,793
Capital Recovery	0.0837 for a 20-year equipment life and a 5.5% interest rate	508,712
Total Annual Indirect Operating Costs	Sum indirect oper costs + capital recovery cost	756,131
Total Annual Cost (Annualized Capital Cost + Operating Cost)		763,210

Great River Energy Coal Creek Station
BART Supplement - NOx Emission Control Cost Analysis
Table A-4: Unit 1 NOx Control - Foster Wheeler LNC3+

Capital Recovery Factors	
Primary Installation	
Interest Rate	5.50%
Equipment Life	20 years
CRF	0.0837

Replacement Parts & Equipment:		
Equipment Life	5 years	
CRF	0.0000	
Rep part cost per unit	0 $/ft^3	
Amount Required	0 ft^3	
Packing Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	0	Zero out if no replacement parts needed
Annualized Cost	0	

Replacement Parts & Equipment:			
Equipment Life	3		
CRF	0.3707		
Rep part cost per unit	0 $ each		
Amount Required	0 Number		
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax	
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr	OAQPS list replacement times from 5 - 20 min per bag.
Total Installed Cost	0	Zero out if no replacement parts needed	
Annualized Cost	0		

Electrical Use							
	Flow acfm		ΔP ft H2O	Efficiency	Hp	kW	
Blower, Scrubber	2,234,300		0	0.7	-	0.0	EPA Cost Cont Manual 6th ed Section 5.2 Chapter 1 Eq 1.48
	Flow	Liquid SPGR	ΔP ft H2O	Efficiency	Hp	kW	
Circ Pump	000 gpm	1	0	0.7	-	0.0	EPA Cost Cont Manual 6th ed Section 5.2 Chapter 1 Eq 1.49
H2O WW Disch	0 gpm	1	0	0.7	-	0.0	EPA Cost Cont Manual 6th ed Section 5.2 Chapter 1 Eq 1.49
			lb/hr O_3				
LTO Electric Use	4.5 kW/lb O_3					0	
Other							
Total						0.0	

Reagent Use & Other Operating Costs				
Ozone Needed	1.8 lb O3/lb NOx	- lb/hr O3		
Oxygen Needed	10% wt O2 to O3 conversion		0 lb/hr O2	0 scfh O2
LTO Cooling Water	150 gal/lb O3	0 gpm		
Liquid/Gas ratio	0.0	* L/G = Gal/1,000 acf		
Circulating Water Rate	0 gpm			
Water Makeup Rate/WW Disch =		20% of circulating water rate =	0 gpm	
Scrubber Cost	10 $/scfm Gas	$0	Incremental cost per BOC. Need to increase vessel size over standard absorber.	
Ozone Generator	$350 lb O3/day	$0 Installed	Installed cost factor per BOC.	

Direct Operating Cost Calculations — Annual hours of operation: 7,652.6; Utilization Rate: 100%

Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
Operating Labor							
Op Labor	0	$/Hr	0.1	hr/8 hr shift	96	0	$/Hr, 0.1 hr/8 hr shift, 7652.6 hr/yr
Supervisor	15%	of Op.			NA	-	15% of Operator Costs
Maintenance							
Maint Labor	37.00	$/Hr	0.1	hr/8 hr shift	96	3,539	$/Hr, 0.1 hr/8 hr shift, 7652.6 hr/yr
Maint Mtls	100	% of Maintenance Labor			NA	3,539	100% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.0604	$/kwh	0.0	kW-hr	0	0	$/kwh, 0 kW-hr, 7652.6 hr/yr, 100% utilization
Water	0.3100	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 7652.6 hr/yr, 100% utilization
Cooling Water	0.3208	$kgal	0.0	gpm	0	0	$kgal, 0 gpm, 7652.6 hr/yr, 100% utilization
Comp Air	0.3671	$/kscf	0	kscfm	0	0	$/kscf, 0 kscfm, 7652.6 hr/yr, 100% utilization
WW Treat Neutralization	1.9572	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 7652.6 hr/yr, 100% utilization
WW Treat Biotreatement	4.9581	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 7652.6 hr/yr, 100% utilization
SW Disposal	0.0000	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 7652.6 hr/yr, 100% utilization
Haz W Disp	326.1933	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 7652.6 hr/yr, 100% utilization
Ammonia Mitigation	5.6100	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 7652.6 hr/yr, 100% utilization
Lost Ash Sales	12.3000	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 7652.6 hr/yr, 100% utilization
Lime	90.0000	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 7652.6 hr/yr, 100% utilization
Caustic	364.4367	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 7652.6 hr/yr, 100% utilization
Oxygen	17.9108	kscf	0.0	kscf/hr	0	0	kscf, 0 kscf/hr, 7652.6 hr/yr, 100% utilization

*annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

Great River Energy Coal Creek Station

BART Supplement - NOx Emission Control Cost Analysis

Table A-5: Unit 1 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (Maintain Ash Sales)

Operating Unit: **Unit 1**

Emission Unit Number	EU-1		Stack/Vent Number	SV-1	
Desgin Capacity	6,015	MMBtu/hr	Standardized Flow Rate	866,294	scfm @ 32º F
Expected Utiliztion Rate	100%		Temperature	330	Deg F
Expected Annual Hours of Operation	7,652.6	Hours	Moisture Content	13.3%	
Annual Interest Rate	5.5%		Actual Flow Rate	2,234,300	acfm
Expected Equipment Life	20	yrs	Standardized Flow Rate	1,391,000	scfm @ 330º F
Baseline NOx	0.200	lb/MMBtu	Dry Std Flow Rate	1,205,997	dscfm @ 330º F

CONTROL EQUIPMENT COSTS

Capital Costs								
Direct Capital Costs								
Purchased Equipment (A)								[redacted]
Purchased Equipment Total (B)								8,465,600
Installation - Standard Costs								1,270,000
Installation - Site Specific Costs								1,036,000
Installation Total								1,758,000
Total Capital Investment (TCI) = DC + IC								12,176,084
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.						3,282,068
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost						1,018,887
Total Annual Cost (Annualized Capital Cost + Operating Cost)								4,300,954

Emission Control Cost Calculation

Pollutant	Max Emis Lb/Hr	Pre-control Annual T/Yr	Cont Eff %	Exit Conc	Conc Units	Cont Emis T/yr	Reduction T/yr	Cont Cost $/Ton Rem
Nitrogen Oxides (NOx)	1,205.2	4,611.4	25.0%			3458.5	1,152.8	3,731

Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1

Notes & Assumptions

1. [redacted]
2. SNCR Maintenance Costs EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.21
3. Process, emissions and cost data listed above is for one unit.
4. For units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal
5. Retrofit factor of 60% used by URS based on site visit to Coal Creek Station.
6. SW disposal and fly ash sales data from Nov. 2011 Golder Fly Ash Evaluation, Appendix B2
7. One-time cost for Technology Licensing Fee for the SNCR process is ~0.5% of the Process Capital.

Great River Energy Coal Creek Station
BART Supplement - NOx Emission Control Cost Analysis
Table A-5: Unit 1 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (Maintain Ash Sales)

CAPITAL COSTS		
Direct Capital Costs		
Purchased Equipment		3,700,000
Purchased Equipment Costs		
Instrumentation	10% of purchased equipment cost	370,000
Site Specific and Prime Contractor Markup	28% of purchased equipment cost	1,036,000
Freight	5% of purchased equipment cost	185,000
Purchased Equipment Total	[redacted]	5,291,000
Purchased Equipment Total+ Retrofit Factor (A)		8,465,600
Indirect Installation		
General Facilities	See Notes & Assumptions 1 on pg. 1 of Table	[redacted]
Engineering & Home Office	See Notes & Assumptions 1 on pg. 1 of Table	
Process Contingency	See Notes & Assumptions 1 on pg. 1 of Table	
Total Indirect Installation Costs (B)	See Notes & Assumptions 1 on pg. 1 of Table	1,758,000
Project Contingeny (C)	See Notes & Assumptions 1 on pg. 1 of Table	[redacted]
Total Plant Cost (D)	A + B + C	11,763,600
Allowance for Funds During Construction (E)	0 for SNCR	0
Prepaid Royalties (F)	See Notes & Assumptionss 1 and 7 on pg. 1 of Table	[redacted]
Pre Production Costs (G)	See Notes & Assumptions 1 on pg. 1 of Table	[redacted]
Inventory Capital (H)	Reagent Vol * $/gal	134,484
Intial Catalyst and Chemicals (I)	0 for SNCR	0
Total Capital Investment (TCI) = DC + IC	D + E + F + G +H + I	12,176,084
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost		12,176,084
OPERATING COSTS		
Direct Annual Operating Costs, DC		
Operating Labor		
Operator	NA	-
Supervisor	NA	-
Maintenance		
Maintenance Total	1.50 % of Total Capital Investment	182,641
Maintenance Materials	NA % of Maintenance Labor	-
Utilities, Supplies, Replacements & Waste Management		
Electricity	0.060 See Direct Operating Cost Calculations on last pg.	28,218
Water	0.310 See Direct Operating Cost Calculations on last pg.	8,256
NA	NA	-
NA	NA	-
NA	NA	-
NA	NA	-
NA	NA	-
NA	NA	-
NA	NA	-
NA	NA	-
NA	NA	-
Urea	500.00 See Direct Operating Cost Calculations on last pg.	3,062,953
NA	NA	-
Total Annual Direct Operating Costs		3,282,068
Indirect Operating Costs		
Overhead	NA of total labor and material costs	NA
Administration (2% total capital costs)	NA of total capital costs (TCI)	NA
Property tax (1% total capital costs)	NA of total capital costs (TCI)	NA
Insurance (1% total capital costs)	NA of total capital costs (TCI)	NA
Capital Recovery	0.08368 for a 20- year equipment life and a 5.5% interest rate	1,018,887
Total Annual Indirect Operating Costs	Sum indirect oper costs + capital recovery cost	1,018,887
Total Annual Cost (Annualized Capital Cost + Operating Cost)		4,300,954

See Summary page for notes and assumptions

Great River Energy Coal Creek Station

BART Supplement - NOx Emission Control Cost Analysis

Table A-5: Unit 1 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (Maintain Ash Sales)

Capital Recovery Factors	
Primary Installation	
Interest Rate	5.50%
Equipment Life	20 years
CRF	0.08368

Replacement Catayst		<- Enter Equipment Name to Get Cost
Equipment Life	5 years	
CRF	0.2342	
Rep part cost per unit	0 $/ft^3	
Amount Required	12 ft^3	
Packing Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:		<- Enter Equipment Name to Get Cost	
Equipment Life	2 years		
CRF	0.0000		
Rep part cost per unit	0 $/ft^3		
Amount Required	0 Cages		
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax	See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs
Installation Labor	0	10 min per bag, Labor + Overhead (68% = $29.65/hr)	
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	EPA CCM list replacement times from 5 - 20 min per bag.
Annualized Cost	**0**		

Electrical Use		kW
NOx in	0.20 lb/MMBtu	
NSR	0.60	
Power		[redacted]
Total		61.0

Reagent Use & Other Operating Costs			
NOx in	0.20 lb/MMBtu	Urea Use	[redacted] lb/hr
Efficiency	25%	Volume 14 day inventory	269 ton
Duty	6,015 MMBtu/hr	Inventory Cost	$134,484
Water Use	[redacted] gal/hr		

Direct Operating Cost Calculations

Annual hours of operation: 7,652.6

Utilization Rate: 100%

Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
Operating Labor							
Op Labor	37	$/Hr	0.0	hr/8 hr shift	0	0	$/Hr, 0.0 hr/8 hr shift, 7652.6 hr/yr
Supervisor	15%	of Op.			NA	-	15% of Operator Costs
Maintenance							
Maintenance Total	1.5	% of Total Capital Investment				182,641.26	% of Total Capital Investment
Maint Mtls	0	% of Maintenance Labor			NA	0	0% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.06045	$/kwh	61.00000	kW-hr	466,808.60	28,217.79	$/kwh, 61.0 kW-hr, 7652.6 hr/yr, 100% utilization
Water	0.31000	$/kgal	3480.00000	gph	26,631.05	8,255.62	0.31 $/kgal X 3,480.0 gph/1000 X 7652.6 hr/yr X 100% utilization
Cooling Water	0.32080	$kgal	0.00000	gpm	0	0	$kgal, 0 gpm, 7652.6 hr/yr, 100% utilization
Comp Air	0.36713	$/kscf	0.00000	scfm/kacfm**	0	0	$/kscf, 0.0 scfm/kacfm**, 7652.6 hr/yr, 100% utilization
WW Treat Neutralization	1.95716	$/kgal	0.00000	gpm	0	0	$/kgal, 0.0 gpm, 7652.6 hr/yr, 100% utilization
WW Treat Biotreatement	4.95814	$/kgal	0.00000	gpm	0	0	$/kgal, 0.0 gpm, 7652.6 hr/yr, 100% utilization
SW Disposal	0.00000	$/ton	7.18710	ton/hr	55,000	0	$/ton, 7.2 ton/hr, 7652.6 hr/yr, 100% utilization
Haz W Disp	326.19330	$/ton	0.00000	ton/hr	0	0	$/ton, 0.0 ton/hr, 7652.6 hr/yr, 100% utilization
Ammonia Mitigation	5.61	$/ton	0.00000	ton/hr	0	0	$/ton, 0.0 ton/hr, 7652.6 hr/yr, 100% utilization
Lost Ash Sales	12.3	$/ton	0.00000	ton/hr	0	0	$/ton, 0.0 ton/hr, 7652.6 hr/yr, 100% utilization
Lime	90.0	$/ton	0.00000	lb/hr	0	0	$/ton, 0.0 lb/hr, 7652.6 hr/yr, 100% utilization
Urea	500.0	$/ton	0.80050	ton/hr	6,125.91	3,062,953.15	500 $/ton X 0.8005 ton/hr X 7652.6 hr/yr X 100% utilization
Oxygen	17.91078	kscf	0.00000	kscf/hr	0	0	kscf, 0.0 kscf/hr, 7652.6 hr/yr, 100% utilization

** Std Air use is 2 scfm/kacfm

*annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

Great River Energy Coal Creek Station

BART Supplement - NOx Emission Control Cost Analysis

Table A-6: Unit 1 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (30% Lost Ash Sales)

Operating Unit: Unit 1

Emission Unit Number	EU-1		Stack/Vent Number	SV-1	
Desgin Capacity	6,015	MMBtu/hr	Standardized Flow Rate	866,294	scfm @ 32º F
Expected Utiliztion Rate	100%		Temperature	330	Deg F
Expected Annual Hours of Operation	7,652.6	Hours	Moisture Content	13.3%	
Annual Interest Rate	5.5%		Actual Flow Rate	2,234,300	acfm
Expected Equipment Life	20	yrs	Standardized Flow Rate	1,391,000	scfm @ 330º F
Baseline NOx	0.200	lb/MMBtu	Dry Std Flow Rate	1,205,997	dscfm @ 330º F

CONTROL EQUIPMENT COSTS

Capital Costs		
Direct Capital Costs		
Purchased Equipment (A)		[redacted]
Purchased Equipment Total (B)		8,465,600
Installation - Standard Costs		1,270,000
Installation - Site Specific Costs		1,036,000
Installation Total		1,758,000
Total Capital Investment (TCI) = DC + IC		12,176,084
Operating Costs		
Total Annual Direct Operating Costs	Labor, supervision, materials, replacement parts, utilities, etc.	5,500,243
Total Annual Indirect Operating Costs	Sum indirect oper costs + capital recovery cost	1,018,887
Total Annual Cost (Annualized Capital Cost + Operating Cost)		6,519,129

Emission Control Cost Calculation

Pollutant	Max Emis Lb/Hr	Pre-control Annual T/Yr	Cont Eff %	Exit Conc	Conc Units	Cont Emis T/yr	Reduction T/yr	Cont Cost $/Ton Rem
Nitrogen Oxides (NOx)	1,205.2	4,611.4	25.0%			3458.5	1,152.8	5,655

Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1

Notes & Assumptions

1 [redacted]
2 SNCR Maintenance Costs EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.21
3 Process, emissions and cost data listed above is for one unit.
4 For units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal
5 Retrofit factor of 60% used by URS based on site visit to Coal Creek Station.
6 SW disposal and fly ash sales data from Nov. 2011 Golder Fly Ash Evaluation, Appendix B2
7 One-time cost for Technology Licensing Fee for the SNCR process is ~0.5% of the Process Capital.

Great River Energy Coal Creek Station
BART Supplement - NOx Emission Control Cost Analysis
Table A-6: Unit 1 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (30% Lost Ash Sales)

CAPITAL COSTS		
Direct Capital Costs		
Purchased Equipment		3,700,000
Purchased Equipment Costs		
Instrumentation	10.00% of purchased equipment cost	370,000
Site Specific and Prime Contractor Markup	28.00% of purchased equipment cost	1,036,000
Freight	5.00% of purchased equipment cost	185,000
Purchased Equipment Total	[redacted]	5,291,000
Purchased Equipment Total+ Retrofit Factor (A)		8,465,600
Indirect Installation		
General Facilities	See Notes & Assumptions 1 on pg. 1 of Table	[redacted]
Engineering & Home Office	See Notes & Assumptions 1 on pg. 1 of Table	
Process Contingency	See Notes & Assumptions 1 on pg. 1 of Table	
Total Indirect Installation Costs (B)	See Notes & Assumptions 1 on pg. 1 of Table	1,758,000
Project Contingeny (C)	See Notes & Assumptions 1 on pg. 1 of Table	[redacted]
Total Plant Cost (D)	A + B + C	11,763,600
Allowance for Funds During Construction (E)	0 for SNCR	0
Prepaid Royalties (F)	See Notes & Assumptionss 1 and 7 on pg. 1 of Table	[redacted]
Pre Production Costs (G)	See Notes & Assumptions 1 on pg. 1 of Table	[redacted]
Inventory Capital (H)	Reagent Vol * $/gal	134,484
Intial Catalyst and Chemicals (I)	0 for SNCR	0
Total Capital Investment (TCI) = DC + IC	D + E + F + G +H + I	12,176,084
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost		12,176,084
OPERATING COSTS		
Direct Annual Operating Costs, DC		
Operating Labor		
Operator	NA	-
Supervisor	NA	-
Maintenance		
Maintenance Total	1.50 % of Total Capital Investment	182,641
Maintenance Materials	NA % of Maintenance Labor	-
Utilities, Supplies, Replacements & Waste Management		
Electricity	0.060 See Direct Operating Cost Calculations on last pg.	28,218
Water	0.310 See Direct Operating Cost Calculations on last pg.	8,256
NA	NA	-
NA	NA	-
NA	NA	-
NA	NA	-
SW Disposal	5.44 See Direct Operating Cost Calculations on last pg.	637,648
NA	NA	-
Ammonia Mitigation	5.61 See Direct Operating Cost Calculations on last pg.	814,853
Lost Ash Sales	12.30 See Direct Operating Cost Calculations on last pg.	765,675
NA	NA	-
Urea	500.00 See Direct Operating Cost Calculations on last pg.	3,062,953
NA	NA	-
Total Annual Direct Operating Costs		5,500,243
Indirect Operating Costs		
Overhead	NA of total labor and material costs	NA
Administration (2% total capital costs)	NA of total capital costs (TCI)	NA
Property tax (1% total capital costs)	NA of total capital costs (TCI)	NA
Insurance (1% total capital costs)	NA of total capital costs (TCI)	NA
Capital Recovery	0.08368 for a 20- year equipment life and a 5.5% interest rate	1,018,887
Total Annual Indirect Operating Costs	Sum indirect oper costs + capital recovery cost	1,018,887
Total Annual Cost (Annualized Capital Cost + Operating Cost)		6,519,129

See Summary page for notes and assumptions

Great River Energy Coal Creek Station
BART Supplement - NOx Emission Control Cost Analysis
Table A-6: Unit 1 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (30% Lost Ash Sales)

Capital Recovery Factors	
Primary Installation	
Interest Rate	5.50%
Equipment Life	20 years
CRF	0.08368

Replacement Catayst		<- Enter Equipment Name to Get Cost
Equipment Life	5 years	
CRF	0.2342	
Rep part cost per unit	0 $/ft³	
Amount Required	12 ft³	
Packing Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	0	**Zero out if no replacement parts needed**
Annualized Cost	0	

Replacement Parts & Equipment:		<- Enter Equipment Name to Get Cost	
Equipment Life	2 years		
CRF	0.0000		
Rep part cost per unit	0 $/ft³		
Amount Required	0 Cages		
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax	See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs
Installation Labor	0	10 min per bag, Labor + Overhead (68% = $29.65/hr)	
Total Installed Cost	0	**Zero out if no replacement parts needed**	EPA CCM list replacement times from 5 - 20 min per bag.
Annualized Cost	0		

Electrical Use		kW
NOx in	0.20 lb/MMBtu	
NSR	0.60	
Power		[redacted]
Total		61.0

Reagent Use & Other Operating Costs			
NOx in	0.20 lb/MMBtu	Urea Use	[redacted] lb/hr
Efficiency	25%	Volume 14 day inventory	269 ton
Duty	6,015 MMBtu/hr	Inventory Cost	$134,484
Water Use	[redacted] gal/hr		

Direct Operating Cost Calculations — **Annual hours of operation:** 7,652.6 — **Utilization Rate:** 100%

Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
Operating Labor							
Op Labor	37	$/Hr	0.0	hr/8 hr shift	0	0	$/Hr, 0.0 hr/8 hr shift, 7652.6 hr/yr
Supervisor	15%	of Op.			NA	-	15% of Operator Costs
Maintenance							
Maintenance Total	1.5	% of Total Capital Investment				182,641.26	% of Total Capital Investment
Maint Mtls	0	% of Maintenance Labor			NA	0	0% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.06045	$/kwh	61.00000	kW-hr	466,808.60	28,217.79	0.0604 $/kwh X 61.0 kW-hr X 7652.6 hr/yr X 100% utilization
Water	0.31000	$/kgal	3480.00000	gph	26,631.05	8,255.62	0.3100 $/kgal X 3,480.0 gph/1000 X 7652.6 hr/yr X 100% utilization
Cooling Water	0.32080	$kgal	0.00000	gpm	0	0	$kgal, 0 gpm, 7652.6 hr/yr, 100% utilization
Comp Air	0.36713	$/kscf	0.00000	scfm/kacfm**	0	0	$/kscf, 0.0 scfm/kacfm**, 7652.6 hr/yr, 100% utilization
WW Treat Neutralization	1.95716	$/kgal	0.00000	gpm	0	0	$/kgal, 0.0 gpm, 7652.6 hr/yr, 100% utilization
WW Treat Biotreatement	4.95814	$/kgal	0.00000	gpm	0	0	$/kgal, 0.0 gpm, 7652.6 hr/yr, 100% utilization
SW Disposal	5.43836	$/ton	15.32159	ton/hr	117,250	637,648	5.4384 $/ton X 15.3216 ton/hr X 7652.6 hr/yr X 100% utilization
Haz W Disp	326.19330	$/ton	0.00000	ton/hr	0	0	$/ton, 0.0 ton/hr, 7652.6 hr/yr, 100% utilization
Ammonia Mitigation	5.61	$/ton	18.98048	ton/hr	145,250	814,853	5.61 $/ton X 18.9805 ton/hr X 7652.6 hr/yr X 100% utilization
Lost Ash Sales	12.3	$/ton	8.13449	ton/hr	62,250.0	765,675	12.3 $/ton X 8.1345 ton/hr X 7652.6 hr/yr X 100% utilization
Lime	90.0	$/ton	0.00000	lb/hr	0	0	$/ton, 0.0 lb/hr, 7652.6 hr/yr, 100% utilization
Urea	500.0	$/ton	0.80050	ton/hr	6,125.91	3,062,953.15	500 $/ton X 0.8005 ton/hr X 7652.6 hr/yr X 100% utilization
Oxygen	17.91078	kscf	0.00000	kscf/hr	0	0	kscf, 0.0 kscf/hr, 7652.6 hr/yr, 100% utilization

** Std Air use is 2 scfm/kacfm *annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

Great River Energy Coal Creek Station

BART Supplement - NOx Emission Control Cost Analysis

Table A-7: Unit 1 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (100% Lost Ash Sales)

Operating Unit: Unit 1

Emission Unit Number	EU-1		Stack/Vent Number	SV-1	
Desgin Capacity	6,015	MMBtu/hr	Standardized Flow Rate	866,294	scfm @ 32º F
Expected Utiliztion Rate	100%		Temperature	330	Deg F
Expected Annual Hours of Operation	7,652.6	Hours	Moisture Content	13.3%	
Annual Interest Rate	5.5%		Actual Flow Rate	2,234,300	acfm
Expected Equipment Life	20	yrs	Standardized Flow Rate	1,391,000	scfm @ 330º F
Baseline NOx	0.200	lb/MMBtu	Dry Std Flow Rate	1,205,997	dscfm @ 330º F

CONTROL EQUIPMENT COSTS

Capital Costs			
Direct Capital Costs			
Purchased Equipment (A)			[redacted]
Purchased Equipment Total (B)			8,465,600
Installation - Standard Costs			1,270,000
Installation - Site Specific Costs			1,036,000
Installation Total			1,758,000
Total Capital Investment (TCI) = DC + IC			12,176,084
Operating Costs			
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.	7,775,768
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	1,018,887
Total Annual Cost (Annualized Capital Cost + Operating Cost)			8,794,654

Emission Control Cost Calculation

Pollutant	Max Emis Lb/Hr	Pre-control Annual T/Yr	Cont Eff %	Exit Conc	Conc Units	Cont Emis T/yr	Reduction T/yr	Cont Cost $/Ton Rem
Nitrogen Oxides (NOx)	1,205.2	4,611.4	25.0%			3458.5	1,152.8	7,629

Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1

Notes & Assumptions

1 [redacted]
2 SNCR Maintenance Costs EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.21
3 Process, emissions and cost data listed above is for one unit.
4 For units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal
5 Retrofit factor of 60% used by URS based on site visit to Coal Creek Station.
6 SW disposal and fly ash sales data from Nov. 2011 Golder Fly Ash Evaluation, Appendix B2
7 One-time cost for Technology Licensing Fee for the SNCR process is ~0.5% of the Process Capital.

Great River Energy Coal Creek Station

BART Supplement - NOx Emission Control Cost Analysis

Table A-7: Unit 1 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (100% Lost Ash Sales)

CAPITAL COSTS		
Direct Capital Costs		
Purchased Equipment		3,700,000
Purchased Equipment Costs		
Instrumentation	10.00% of purchased equipment cost	370,000
Site Specific and Prime Contractor Markup	28.00% of purchased equipment cost	1,036,000
Freight	5.00% of purchased equipment cost	185,000
Purchased Equipment Total	[redacted]	5,291,000
Purchased Equipment Total+ Retrofit Factor (A)		8,465,600
Indirect Installation		
General Facilities	See Notes & Assumptions 1 on pg. 1 of Table	[redacted]
Engineering & Home Office	See Notes & Assumptions 1 on pg. 1 of Table	
Process Contingency	See Notes & Assumptions 1 on pg. 1 of Table	
Total Indirect Installation Costs (B)	See Notes & Assumptions 1 on pg. 1 of Table	1,758,000
Project Contingeny (C)	See Notes & Assumptions 1 on pg. 1 of Table	[redacted]
Total Plant Cost (D)	A + B + C	11,763,600
Allowance for Funds During Construction (E)	0 for SNCR	0
Prepaid Royalties (F)	See Notes & Assumptionss 1 and 7 on pg. 1 of Table	[redacted]
Pre Production Costs (G)	See Notes & Assumptions 1 on pg. 1 of Table	[redacted]
Inventory Capital (H)	Reagent Vol * $/gal	134,484
Intial Catalyst and Chemicals (I)	0 for SNCR	0
Total Capital Investment (TCI) = DC + IC	D + E + F + G +H + I	12,176,084
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost		12,176,084
OPERATING COSTS		
Direct Annual Operating Costs, DC		
Operating Labor		
Operator	NA	-
Supervisor	NA	-
Maintenance		
Maintenance Total	1.50 % of Total Capital Investment	182,641
Maintenance Materials	NA % of Maintenance Labor	-
Utilities, Supplies, Replacements & Waste Management		
Electricity	0.060 See Direct Operating Cost Calculations on last pg.	28,218
Water	0.310 See Direct Operating Cost Calculations on last pg.	8,256
NA	NA	-
NA	NA	-
NA	NA	-
NA	NA	-
SW Disposal	7.40 See Direct Operating Cost Calculations on last pg.	1,941,450
NA	NA	-
NA	NA	-
Lost Ash Sales	12.30 See Direct Operating Cost Calculations on last pg.	2,552,250
NA	NA	-
Urea	500.00 See Direct Operating Cost Calculations on last pg.	3,062,953
NA	NA	-
Total Annual Direct Operating Costs		7,775,768
Indirect Operating Costs		
Overhead	NA of total labor and material costs	NA
Administration (2% total capital costs)	NA of total capital costs (TCI)	NA
Property tax (1% total capital costs)	NA of total capital costs (TCI)	NA
Insurance (1% total capital costs)	NA of total capital costs (TCI)	NA
Capital Recovery	0.08368 for a 20- year equipment life and a 5.5% interest rate	1,018,887
Total Annual Indirect Operating Costs	Sum indirect oper costs + capital recovery cost	1,018,887
Total Annual Cost (Annualized Capital Cost + Operating Cost)		8,794,654

See Summary page for notes and assumptions

Great River Energy Coal Creek Station

BART Supplement - NOx Emission Control Cost Analysis

Table A-7: Unit 1 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (100% Lost Ash Sales)

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.08368	

Replacement Catayst		<- Enter Equipment Name to Get Cost
Equipment Life	5	years
CRF	0.2342	
Rep part cost per unit	0	$/ft³
Amount Required	12	ft³
Packing Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	0	**Zero out if no replacement parts needed**
Annualized Cost	0	

Replacement Parts & Equipment:		<- Enter Equipment Name to Get Cost	
Equipment Life	2	years	
CRF	0.0000		
Rep part cost per unit	0	$/ft³	
Amount Required	0	Cages	
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax	See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs
Installation Labor	0	10 min per bag, Labor + Overhead (68% = $29.65/hr)	
Total Installed Cost	0	**Zero out if no replacement parts needed**	EPA CCM list replacement times from 5 - 20 min per bag.
Annualized Cost	0		

Electrical Use			
NOx in	0.20	lb/MMBtu	kW
NSR	0.60		
Power			[redacted]
Total			61.0

Reagent Use & Other Operating Costs					
NOx in	0.20	lb/MMBtu	Urea Use	[redacted]	lb/hr
Efficiency	25%		Volume 14 day inventory	269	ton
Duty	6,015	MMBtu/hr	Inventory Cost	$134,484	
Water Use	[redacted]	gal/hr			

Direct Operating Cost Calculations — **Annual hours of operation:** 7,652.6 — **Utilization Rate:** 100%

Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
Operating Labor							
Op Labor	37	$/Hr	0.0	hr/8 hr shift	0	0	$/Hr, 0.0 hr/8 hr shift, 7652.6 hr/yr
Supervisor	15%	of Op.			NA	-	15% of Operator Costs
Maintenance							
Maintenance Total	1.5	% of Total Capital Investment				182,641.26	% of Total Capital Investment
Maint Mtls	0	% of Maintenance Labor			NA	0	0% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.06045	$/kwh	61.00000	kW-hr	466,808.60	28,217.79	0.0604 $/kwh X 61.0 kW-hr X 7652.6 hr/yr X 100% utilization
Water	0.31000	$/kgal	3480.00000	gph	26,631.05	8,255.62	0.3100 $/kgal X 3,480.0 gph/1000 X 7652.6 hr/yr X 100% utilization
Cooling Water	0.32080	$kgal	0.00000	gpm	0	0	$kgal, 0 gpm, 7652.6 hr/yr, 100% utilization
Comp Air	0.36713	$/kscf	0.00000	scfm/kacfm**	0	0	$/kscf, 0.0 scfm/kacfm**, 7652.6 hr/yr, 100% utilization
WW Treat Neutralization	1.95716	$/kgal	0.00000	gpm	0	0	$/kgal, 0.0 gpm, 7652.6 hr/yr, 100% utilization
WW Treat Biotreatement	4.95814	$/kgal	0.00000	gpm	0	0	$/kgal, 0.0 gpm, 7652.6 hr/yr, 100% utilization
SW Disposal	7.39600	$/ton	34.30207	ton/hr	262,500	1,941,450	7.3960 $/ton X 34.3021 ton/hr X 7652.6 hr/yr X 100% utilization
Haz W Disp	326.19330	$/ton	0.00000	ton/hr	0	0	$/ton, 0.0 ton/hr, 7652.6 hr/yr, 100% utilization
Ammonia Mitigation	5.61	$/ton	0.00000	ton/hr	0	0	$/ton, 0.0 ton/hr, 7652.6 hr/yr, 100% utilization
Lost Ash Sales	12.3	$/ton	27.11497	ton/hr	207,500	2,552,250	12.3 $/ton X 27.1150 ton/hr X 7652.6 hr/yr X 100% utilization
Lime	90.0	$/ton	0.00000	lb/hr	0	0	$/ton, 0.0 lb/hr, 7652.6 hr/yr, 100% utilization
Urea	500.0	$/ton	0.80050	ton/hr	6,125.91	3,062,953.15	500.0 $/ton X 0.8005 ton/hr X 7652.6 hr/yr X 100% utilization
Oxygen	17.91078	kscf	0.00000	kscf/hr	0	0	kscf, 0.0 kscf/hr, 7652.6 hr/yr, 100% utilization

** Std Air use is 2 scfm/kacfm — *annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

Great River Energy Coal Creek Station

BART Supplement - NOx Emission Control Cost Analysis

Table A-8: Unit 2 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (Maintain Ash Sales)

Operating Unit: **Unit 2**

Emission Unit Number	EU-2		Stack/Vent Number	SV-2	
Desgin Capacity	6,022	MMBtu/hr	Standardized Flow Rate	866,294	scfm @ 32º F
Expected Utiliztion Rate	100%		Temperature	330	Deg F
Expected Annual Hours of Operation	8,409.6	Hours	Moisture Content	13.3%	
Annual Interest Rate	5.5%		Actual Flow Rate	2,234,300	acfm
Expected Equipment Life	20	yrs	Standardized Flow Rate	1,391,000	scfm @ 330º F
Baseline NOx	0.153	lb/MMBtu	Dry Std Flow Rate	1,205,997	dscfm @ 330º F

CONTROL EQUIPMENT COSTS

Capital Costs								
Direct Capital Costs								
Purchased Equipment (A)								[redacted]
Purchased Equipment Total (B)								8,236,800
Installation - Standard Costs								1,230,000
Installation - Site Specific Costs								1,008,000
Installation Total								1,702,000
Total Capital Investment (TCI) = DC + IC								**11,793,820**
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.						2,634,116
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost						986,899
Total Annual Cost (Annualized Capital Cost + Operating Cost)								**3,621,015**

Emission Control Cost Calculation

Pollutant	Max Emis Lb/Hr	Pre-control Annual T/Yr	Cont Eff %	Exit Conc	Conc Units	Cont Emis T/yr	Reduction T/yr	Cont Cost $/Ton Rem
Nitrogen Oxides (NOx)	918.5	3,862.3	20.0%			3089.8	772.5	4,688

Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1

Notes & Assumptions

1 [redacted]
2 SNCR Maintenance Costs EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.21
3 Process, emissions and cost data listed above is for one unit.
4 For units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal
5 Retrofit factor of 60% used by URS based on site visit to Coal Creek Station.
6 SW disposal and fly ash sales data from Nov. 2011 Golder Fly Ash Evaluation, Appendix B2
7 One-time cost for Technology Licensing Fee for the SNCR process is ~0.5% of the Process Capital.

Great River Energy Coal Creek Station

BART Supplement - NOx Emission Control Cost Analysis

Table A-8: Unit 2 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (Maintain Ash Sales)

CAPITAL COSTS		
Direct Capital Costs		
Purchased Equipment		3,600,000
Purchased Equipment Costs		
Instrumentation	10.00% of purchased equipment cost	360,000
Site Specific and Prime Contractor Markup	28.00% of purchased equipment cost	1,008,000
Freight	5.00% of purchased equipment cost	180,000
Purchased Equipment Total	[redacted]	5,148,000
Purchased Equipment Total+ Retrofit Factor (A)		8,236,800
Indirect Installation		
General Facilities	See Notes & Assumptions 1 on pg. 1 of Table	[redacted]
Engineering & Home Office	See Notes & Assumptions 1 on pg. 1 of Table	
Process Contingency	See Notes & Assumptions 1 on pg. 1 of Table	
Total Indirect Installation Costs (B)	See Notes & Assumptions 1 on pg. 1 of Table	1,702,000
Project Contingeny (C)	See Notes & Assumptions 1 on pg. 1 of Table	[redacted]
Total Plant Cost (D)	A + B + C	11,428,800
Allowance for Funds During Construction (E)	0 for SNCR	0
Prepaid Royalties (F)	See Notes & Assumptionss 1 and 7 on pg. 1 of Table	[redacted]
Pre Production Costs (G)	See Notes & Assumptions 1 on pg. 1 of Table	[redacted]
Inventory Capital (H)	Reagent Vol * $/gal	97,020
Intial Catalyst and Chemicals (I)	0 for SNCR	0
Total Capital Investment (TCI) = DC + IC	D + E + F + G +H + I	11,793,820
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost		11,793,820
OPERATING COSTS		
Direct Annual Operating Costs, DC		
Operating Labor		
Operator	NA	-
Supervisor	NA	-
Maintenance		
Maintenance Total	1.50 % of Total Capital Investment	176,907
Maintenance Materials	NA % of Maintenance Labor	-
Utilities, Supplies, Replacements & Waste Management		
Electricity	0.060 See Direct Operating Cost Calculations on last pg.	22,367
Water	0.310 See Direct Operating Cost Calculations on last pg.	6,570
NA	NA	-
NA	NA	-
NA	NA	-
NA	NA	-
NA	NA	-
NA	NA	-
NA	NA	-
NA	NA	-
NA	NA	-
Urea	500.00 See Direct Operating Cost Calculations on last pg.	2,428,272
NA	NA	-
Total Annual Direct Operating Costs		2,634,116
Indirect Operating Costs		
Overhead	NA of total labor and material costs	NA
Administration (2% total capital costs)	NA of total capital costs (TCI)	NA
Property tax (1% total capital costs)	NA of total capital costs (TCI)	NA
Insurance (1% total capital costs)	NA of total capital costs (TCI)	NA
Capital Recovery	0.08368 for a 20- year equipment life and a 5.5% interest rate	986,899
Total Annual Indirect Operating Costs	Sum indirect oper costs + capital recovery cost	986,899
Total Annual Cost (Annualized Capital Cost + Operating Cost)		3,621,015

See Summary page for notes and assumptions

Great River Energy Coal Creek Station

BART Supplement - NOx Emission Control Cost Analysis

Table A-8: Unit 2 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (Maintain Ash Sales)

Capital Recovery Factors	
Primary Installation	
Interest Rate	5.50%
Equipment Life	20 years
CRF	0.08368

Replacement Catayst		<- Enter Equipment Name to Get Cost
Equipment Life	5 years	
CRF	0.2342	
Rep part cost per unit	0 $/ft^3	
Amount Required	12 ft^3	
Packing Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:		<- Enter Equipment Name to Get Cost	
Equipment Life	2 years		
CRF	0.0000		
Rep part cost per unit	0 $/ft^3		
Amount Required	0 Cages		
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax	See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs
Installation Labor	0	10 min per bag, Labor + Overhead (68% = $29.65/hr)	
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	EPA CCM list replacement times from 5 - 20 min per bag.
Annualized Cost	**0**		

Electrical Use		
NOx in	0.15 lb/MMBtu	kW
NSR	0.44	
Power		[redacted]
Total		44.0

Reagent Use & Other Operating Costs			
NOx in	0.15 lb/MMBtu	Urea Use	[redacted] lb/hr
Efficiency	20%	Volume 14 day inventory	194 ton
Duty	6,022 MMBtu/hr	Inventory Cost	$97,020
Water Use	[redacted] gal/hr		

Direct Operating Cost Calculations — **Annual hours of operation:** 8,409.6 — **Utilization Rate:** 100%

Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
Operating Labor							
Op Labor	37	$/Hr	0.0	hr/8 hr shift	0	0	$/Hr, 0.0 hr/8 hr shift, 8409.6 hr/yr
Supervisor	15%	of Op.			NA	-	15% of Operator Costs
Maintenance							
Maintenance Total	1.5	% of Total Capital Investment				176,907.30	% of Total Capital Investment
Maint Mtls	0	% of Maintenance Labor			NA	0	0% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.06045	$/kwh	44.00000	kW-hr	370,022.40	22,367.23	0.0604 $/kwh X 44.0 kW-hr X 8409.6 hr/yr X 100% utilization
Water	0.31000	$/kgal	2520.00000	gph	21,192.19	6,569.58	0.3100 $/kgal X 2,520.0 gph/1000 X 8409.6 hr/yr X 100% utilization
Cooling Water	0.32080	$kgal	0.00000	gpm	0	0	$kgal, 0 gpm, 8409.6 hr/yr, 100% utilization
Comp Air	0.36713	$/kscf	0.00000	scfm/kacfm**	0	0	$/kscf, 0.0 scfm/kacfm**, 8409.6 hr/yr, 100% utilization
WW Treat Neutralization	1.95716	$/kgal	0.00000	gpm	0	0	$/kgal, 0.0 gpm, 8409.6 hr/yr, 100% utilization
WW Treat Biotreatement	4.95814	$/kgal	0.00000	gpm	0	0	$/kgal, 0.0 gpm, 8409.6 hr/yr, 100% utilization
SW Disposal	0.00000	$/ton	6.54014	ton/hr	55,000	0	$/ton, 6.5 ton/hr, 8409.6 hr/yr, 100% utilization
Haz W Disp	326.19330	$/ton	0.00000	ton/hr	0	0	$/ton, 0.0 ton/hr, 8409.6 hr/yr, 100% utilization
Ammonia Mitigation	5.61	$/ton	0.00000	ton/hr	0	0	$/ton, 0.0 ton/hr, 8409.6 hr/yr, 100% utilization
Lost Ash Sales	12.3	$/ton	0.00000	ton/hr	0	0	$/ton, 0.0 ton/hr, 8409.6 hr/yr, 100% utilization
Lime	90.0	$/ton	0.00000	lb/hr	0	0	$/ton, 0.0 lb/hr, 8409.6 hr/yr, 100% utilization
Urea	500.0	$/ton	0.57750	ton/hr	4,856.54	2,428,272.00	500.0 $/ton X 0.5775 ton/hr X 8409.6 hr/yr X 100% utilization
Oxygen	17.91078	kscf	0.00000	kscf/hr	0	0	kscf, 0.0 kscf/hr, 8409.6 hr/yr, 100% utilization

** Std Air use is 2 scfm/kacfm — *annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

Great River Energy Coal Creek Station

BART Supplement - NOx Emission Control Cost Analysis

Table A-9: Unit 2 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (30% Lost Ash Sales)

Operating Unit: Unit 2

Emission Unit Number	EU-2		Stack/Vent Number	SV-2	
Desgin Capacity	6,022	MMBtu/hr	Standardized Flow Rate	866,294	scfm @ 32º F
Expected Utiliztion Rate	100%		Temperature	330	Deg F
Expected Annual Hours of Operation	8,409.6	Hours	Moisture Content	13.3%	
Annual Interest Rate	5.5%		Actual Flow Rate	2,234,300	acfm
Expected Equipment Life	20	yrs	Standardized Flow Rate	1,391,000	scfm @ 330º F
Baseline NOx	0.153	lb/MMBtu	Dry Std Flow Rate	1,205,997	dscfm @ 330º F

CONTROL EQUIPMENT COSTS

Capital Costs		
Direct Capital Costs		
Purchased Equipment (A)		[redacted]
Purchased Equipment Total (B)		8,236,800
Installation - Standard Costs		1,230,000
Installation - Site Specific Costs		1,008,000
Installation Total		1,702,000
Total Capital Investment (TCI) = DC + IC		11,793,820
Operating Costs		
Total Annual Direct Operating Costs	Labor, supervision, materials, replacement parts, utilities, etc.	4,852,291
Total Annual Indirect Operating Costs	Sum indirect oper costs + capital recovery cost	986,899
Total Annual Cost (Annualized Capital Cost + Operating Cost)		5,839,190

Emission Control Cost Calculation

Pollutant	Max Emis Lb/Hr	Pre-control Annual T/Yr	Cont Eff %	Exit Conc	Conc Units	Cont Emis T/yr	Reduction T/yr	Cont Cost $/Ton Rem
Nitrogen Oxides (NOx)	918.5	3,862.3	20.0%			3089.8	772.5	7,559

Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1

Notes & Assumptions

1 [redacted]
2 SNCR Maintenance Costs EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.21
3 Process, emissions and cost data listed above is for one unit.
4 For units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal
5 Retrofit factor of 60% used by URS based on site visit to Coal Creek Station.
6 SW disposal and fly ash sales data from Nov. 2011 Golder Fly Ash Evaluation, Appendix B2
7 One-time cost for Technology Licensing Fee for the SNCR process is ~0.5% of the Process Capital.

Great River Energy Coal Creek Station
BART Supplement - NOx Emission Control Cost Analysis
Table A-9: Unit 2 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (30% Lost Ash Sales)

CAPITAL COSTS		
Direct Capital Costs		
Purchased Equipment		3,600,000
Purchased Equipment Costs		
Instrumentation	10.00% of purchased equipment cost	360,000
Site Specific and Prime Contractor Markup	28.00% of purchased equipment cost	1,008,000
Freight	5.00% of purchased equipment cost	180,000
Purchased Equipment Total	[redacted]	5,148,000
Purchased Equipment Total+ Retrofit Factor (A)		8,236,800
Indirect Installation		
General Facilities	See Notes & Assumptions 1 on pg. 1 of Table	[redacted]
Engineering & Home Office	See Notes & Assumptions 1 on pg. 1 of Table	
Process Contingency	See Notes & Assumptions 1 on pg. 1 of Table	
Total Indirect Installation Costs (B)	See Notes & Assumptions 1 on pg. 1 of Table	1,702,000
Project Contingeny (C)	See Notes & Assumptions 1 on pg. 1 of Table	[redacted]
Total Plant Cost (D)	A + B + C	11,428,800
Allowance for Funds During Construction (E)	0 for SNCR	0
Prepaid Royalties (F)	See Notes & Assumptionss 1 and 7 on pg. 1 of Table	[redacted]
Pre Production Costs (G)	See Notes & Assumptions 1 on pg. 1 of Table	[redacted]
Inventory Capital (H)	Reagent Vol * $/gal	97,020
Intial Catalyst and Chemicals (I)	0 for SNCR	0
Total Capital Investment (TCI) = DC + IC	D + E + F + G +H + I	11,793,820
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost		11,793,820
OPERATING COSTS		
Direct Annual Operating Costs, DC		
Operating Labor		
Operator	NA	-
Supervisor	NA	-
Maintenance		
Maintenance Total	1.50 % of Total Capital Investment	176,907
Maintenance Materials	NA % of Maintenance Labor	-
Utilities, Supplies, Replacements & Waste Management		
Electricity	0.060 See Direct Operating Cost Calculations on last pg.	22,367
Water	0.310 See Direct Operating Cost Calculations on last pg.	6,570
NA	NA	-
NA	NA	-
NA	NA	-
NA	NA	-
SW Disposal	5.44 See Direct Operating Cost Calculations on last pg.	637,648
NA	NA	-
Ammonia Mitigation	5.61 See Direct Operating Cost Calculations on last pg.	814,853
Lost Ash Sales	12.30 See Direct Operating Cost Calculations on last pg.	765,675
NA	NA	-
Urea	500.00 See Direct Operating Cost Calculations on last pg.	2,428,272
NA	NA	-
Total Annual Direct Operating Costs		4,852,291
Indirect Operating Costs		
Overhead	NA of total labor and material costs	NA
Administration (2% total capital costs)	NA of total capital costs (TCI)	NA
Property tax (1% total capital costs)	NA of total capital costs (TCI)	NA
Insurance (1% total capital costs)	NA of total capital costs (TCI)	NA
Capital Recovery	0.08368 for a 20- year equipment life and a 5.5% interest rate	986,899
Total Annual Indirect Operating Costs	Sum indirect oper costs + capital recovery cost	986,899
Total Annual Cost (Annualized Capital Cost + Operating Cost)		5,839,190

See Summary page for notes and assumptions

Great River Energy Coal Creek Station
BART Supplement - NOx Emission Control Cost Analysis
Table A-9: Unit 2 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (30% Lost Ash Sales)

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.08368	

Replacement Catayst		<- Enter Equipment Name to Get Cost	
Equipment Life	5	years	
CRF	0.2342		
Rep part cost per unit	0	$\$/ft^3$	
Amount Required	12	ft^3	
Packing Cost	0	Cost adjusted for freight & sales tax	
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)	
Total Installed Cost	0	**Zero out if no replacement parts needed**	
Annualized Cost	0		

Replacement Parts & Equipment:		<- Enter Equipment Name to Get Cost	
Equipment Life	2	years	
CRF	0.0000		
Rep part cost per unit	0	$\$/ft^3$	
Amount Required	0	Cages	
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax	See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs
Installation Labor	0	10 min per bag, Labor + Overhead (68% = $29.65/hr)	
Total Installed Cost	0	**Zero out if no replacement parts needed**	EPA CCM list replacement times from 5 - 20 min per bag.
Annualized Cost	0		

Electrical Use			kW
NOx in	0.15	lb/MMBtu	
NSR	0.44		
Power			[redacted]
Total			44.0

Reagent Use & Other Operating Costs					
NOx in	0.15	lb/MMBtu	Urea Use	[redacted]	lb/hr
Efficiency	20%		Volume 14 day inventory	194	ton
Duty	6,022	MMBtu/hr	Inventory Cost	$97,020	
Water Use	[redacted]	gal/hr			

Direct Operating Cost Calculations — **Annual hours of operation:** 8,409.6 — **Utilization Rate:** 100%

Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
Operating Labor							
Op Labor	37	$/Hr	0.0	hr/8 hr shift	0	0	$/Hr, 0.0 hr/8 hr shift, 8409.6 hr/yr
Supervisor	15%	of Op.			NA	-	15% of Operator Costs
Maintenance							
Maintenance Total	1.5	% of Total Capital Investment				176,907.30	% of Total Capital Investment
Maint Mtls	0	% of Maintenance Labor			NA	0	0% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.06045	$/kwh	44.00000	kW-hr	370,022.40	22,367.23	0.0604 $/kwh X 44.0 kW-hr X 8409.6 hr/yr X 100% utilization
Water	0.31000	$/kgal	2520.00000	gph	21,192.19	6,569.58	0.3100 $/kgal X 2,520.0 gph/1000 X 8409.6 hr/yr X 100% utilization
Cooling Water	0.32080	$kgal	0.00000	gpm	0	0	$kgal, 0 gpm, 8409.6 hr/yr, 100% utilization
Comp Air	0.36713	$/kscf	0.00000	scfm/kacfm**	0	0	$/kscf, 0.0 scfm/kacfm**, 8409.6 hr/yr, 100% utilization
WW Treat Neutralization	1.95716	$/kgal	0.00000	gpm	0	0	$/kgal, 0.0 gpm, 8409.6 hr/yr, 100% utilization
WW Treat Biotreatement	4.95814	$/kgal	0.00000	gpm	0	0	$/kgal, 0.0 gpm, 8409.6 hr/yr, 100% utilization
SW Disposal	5.43836	$/ton	13.94240	ton/hr	117,250	637,648	5.4384 $/ton X 13.9 ton/hr X 8409.6 hr/yr X 100% utilization
Haz W Disp	326.19330	$/ton	0.00000	ton/hr	0	0	$/ton, 0.0 ton/hr, 8409.6 hr/yr, 100% utilization
Ammonia Mitigation	5.61	$/ton	17.27193	ton/hr	145,250	814,853	5.6 $/ton X 17.2719 ton/hr X 8409.6 hr/yr X 100% utilization
Lost Ash Sales	12.3	$/ton	7.40225	ton/hr	62,250	765,675	12.3 $/ton X 7.4023 ton/hr X 8409.6 hr/yr X 100% utilization
Lime	90.0	$/ton	0.00000	lb/hr	0	0	$/ton, 0.0 lb/hr, 8409.6 hr/yr, 100% utilization
Urea	500.0	$/ton	0.57750	ton/hr	4,856.54	2,428,272.00	500.0 $/ton X 0.5775 ton/hr X 8409.6 hr/yr X 100% utilization
Oxygen	17.91078	kscf	0.00000	kscf/hr	0	0	kscf, 0.0 kscf/hr, 8409.6 hr/yr, 100% utilization

** Std Air use is 2 scfm/kacfm — *annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

Great River Energy Coal Creek Station

BART Supplement - NOx Emission Control Cost Analysis

Table A-10: Unit 2 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (100% Lost Ash Sales)

Operating Unit: Unit 2

Emission Unit Number	EU-2		Stack/Vent Number	SV-2	
Desgin Capacity	6,022	MMBtu/hr	Standardized Flow Rate	866,294	scfm @ 32º F
Expected Utiliztion Rate	100%		Temperature	330	Deg F
Expected Annual Hours of Operation	8,409.6	Hours	Moisture Content	13.3%	
Annual Interest Rate	5.5%		Actual Flow Rate	2,234,300	acfm
Expected Equipment Life	20	yrs	Standardized Flow Rate	1,391,000	scfm @ 330º F
Baseline NOx	0.153	lb/MMBtu	Dry Std Flow Rate	1,205,997	dscfm @ 330º F

CONTROL EQUIPMENT COSTS

Capital Costs									
Direct Capital Costs									
Purchased Equipment (A)									[redacted]
Purchased Equipment Total (B)									8,236,800
Installation - Standard Costs									1,230,000
Installation - Site Specific Costs									1,008,000
Installation Total									1,702,000
Total Capital Investment (TCI) = DC + IC									**11,793,820**
Operating Costs									
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.							7,127,816
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost							986,899
Total Annual Cost (Annualized Capital Cost + Operating Cost)									**8,114,715**

Emission Control Cost Calculation

Pollutant	Max Emis Lb/Hr	Pre-control Annual T/Yr	Cont Eff %	Exit Conc	Conc Units	Cont Emis T/yr	Reduction T/yr	Cont Cost $/Ton Rem
Nitrogen Oxides (NOx)	918.5	3,862.3	20.0%			3089.8	772.5	10,505

Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1

Notes & Assumptions

1 [redacted]
2 SNCR Maintenance Costs EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.21
3 Process, emissions and cost data listed above is for one unit.
4 For units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal
5 Retrofit factor of 60% used by URS based on site visit to Coal Creek Station.
6 SW disposal and fly ash sales data from Nov. 2011 Golder Fly Ash Evaluation, Appendix B2
7 One-time cost for Technology Licensing Fee for the SNCR process is ~0.5% of the Process Capital.

Great River Energy Coal Creek Station

BART Supplement - NOx Emission Control Cost Analysis

Table A-10: Unit 2 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (100% Lost Ash Sales)

CAPITAL COSTS		
Direct Capital Costs		
Purchased Equipment		3,600,000
Purchased Equipment Costs		
Instrumentation	10.00% of purchased equipment cost	360,000
Site Specific and Prime Contractor Markup	28.00% of purchased equipment cost	1,008,000
Freight	5.00% of purchased equipment cost	180,000
Purchased Equipment Total	[redacted]	5,148,000
Purchased Equipment Total+ Retrofit Factor (A)		8,236,800
Indirect Installation		
General Facilities	See footnote 1 on pg. 1 of Table	[redacted]
Engineering & Home Office	See footnote 1 on pg. 1 of Table	
Process Contingency	See footnote 1 on pg. 1 of Table	
Total Indirect Installation Costs (B)	See footnote 1 on pg. 1 of Table	1,702,000
Project Contingeny (C)	See footnote 1 on pg. 1 of Table	[redacted]
Total Plant Cost (D)	A + B + C	11,428,800
Allowance for Funds During Construction (E)	0 for SNCR	0
Prepaid Royalties (F)	See footnotes 1 and 7 on pg. 1 of Table	[redacted]
Pre Production Costs (G)	See footnote 1 on pg. 1 of Table	[redacted]
Inventory Capital (H)	Reagent Vol * $/gal	97,020
Intial Catalyst and Chemicals (I)	0 for SNCR	0
Total Capital Investment (TCI) = DC + IC	D + E + F + G +H + I	11,793,820
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost		11,793,820
OPERATING COSTS		
Direct Annual Operating Costs, DC		
Operating Labor		
Operator	NA	-
Supervisor	NA	-
Maintenance		
Maintenance Total	1.50 % of Total Capital Investment	176,907
Maintenance Materials	NA % of Maintenance Labor	-
Utilities, Supplies, Replacements & Waste Management		
Electricity	0.060 See Direct Operating Cost Calculations on last pg.	22,367
Water	0.310 See Direct Operating Cost Calculations on last pg.	6,570
NA	NA	-
NA	NA	-
NA	NA	-
NA	NA	-
SW Disposal	7.40 See Direct Operating Cost Calculations on last pg.	1,941,450
NA	NA	-
NA	NA	-
Lost Ash Sales	12.30 See Direct Operating Cost Calculations on last pg.	2,552,250
NA	NA	-
Urea	500.00 See Direct Operating Cost Calculations on last pg.	2,428,272
NA	NA	-
Total Annual Direct Operating Costs		7,127,816
Indirect Operating Costs		
Overhead	NA of total labor and material costs	NA
Administration (2% total capital costs)	NA of total capital costs (TCI)	NA
Property tax (1% total capital costs)	NA of total capital costs (TCI)	NA
Insurance (1% total capital costs)	NA of total capital costs (TCI)	NA
Capital Recovery	0.08368 for a 20- year equipment life and a 5.5% interest rate	986,899
Total Annual Indirect Operating Costs	Sum indirect oper costs + capital recovery cost	986,899
Total Annual Cost (Annualized Capital Cost + Operating Cost)		8,114,715

See Summary page for notes and assumptions

Great River Energy Coal Creek Station

BART Supplement - NOx Emission Control Cost Analysis

Table A-10: Unit 2 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (100% Lost Ash Sales)

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.08368	

Replacement Catayst		<- Enter Equipment Name to Get Cost
Equipment Life	5	years
CRF	0.2342	
Rep part cost per unit	0	$/ft^3
Amount Required	12	ft^3
Packing Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:		<- Enter Equipment Name to Get Cost	
Equipment Life	2	years	
CRF	0.0000		
Rep part cost per unit	0	$/ft^3	
Amount Required	0	Cages	
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax	See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs
Installation Labor	0	10 min per bag, Labor + Overhead (68% = $29.65/hr)	
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	EPA CCM list replacement times from 5 - 20 min per bag.
Annualized Cost	**0**		

Electrical Use			
NOx in	0.15	lb/MMBtu	kW
NSR	0.44		
Power			[redacted]
Total			44.0

Reagent Use & Other Operating Costs					
NOx in	0.15	lb/MMBtu	Urea Use	[redacted]	lb/hr
Efficiency	20%		Volume 14 day inventory	194	ton
Duty	6,022	MMBtu/hr	Inventory Cost	$97,020	
Water Use	[redacted]	gal/hr			

Direct Operating Cost Calculations — **Annual hours of operation:** **8,409.6** — **Utilization Rate:** **100%**

Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
Operating Labor							
Op Labor	37	$/Hr	0.0	hr/8 hr shift	0	0	$/Hr, 0.0 hr/8 hr shift, 8409.6 hr/yr
Supervisor	15%	of Op.			NA	-	15% of Operator Costs
Maintenance							
Maintenance Total	1.5	% of Total Capital Investment				176,907.30	% of Total Capital Investment
Maint Mtls	0	% of Maintenance Labor			NA	0	0% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.06045	$/kwh	44.00000	kW-hr	370,022.40	22,367.23	0.0604 $/kwh X 44.0 kW-hr X 8409.6 hr/yr X 100% utilization
Water	0.31000	$/kgal	2520.00000	gph	21,192.19	6,569.58	0.31 $/kgal X 2,520.0 gph/1000 X 8409.6 hr/yr X 100% utilization
Cooling Water	0.32080	$kgal	0.00000	gpm	0	0	$kgal, 0 gpm, 8409.6 hr/yr, 100% utilization
Comp Air	0.36713	$/kscf	0.00000	scfm/kacfm**	0	0	$/kscf, 0.0 scfm/kacfm**, 8409.6 hr/yr, 100% utilization
WW Treat Neutralization	1.95716	$/kgal	0.00000	gpm	0	0	$/kgal, 0.0 gpm, 8409.6 hr/yr, 100% utilization
WW Treat Biotreatement	4.95814	$/kgal	0.00000	gpm	0	0	$/kgal, 0.0 gpm, 8409.6 hr/yr, 100% utilization
SW Disposal	7.39600	$/ton	31.21433	ton/hr	262,500	1,941,450	7.3960 $/ton X 31.2 ton/hr X 8409.6 hr/yr X 100% utilization
Haz W Disp	326.19330	$/ton	0.00000	ton/hr	0	0	$/ton, 0.0 ton/hr, 8409.6 hr/yr, 100% utilization
Ammonia Mitigation	5.61	$/ton	0.00000	ton/hr	0	0	$/ton, 0.0 ton/hr, 8409.6 hr/yr, 100% utilization
Lost Ash Sales	12.3	$/ton	24.67418	ton/hr	207,500	2,552,250	12.3 $/ton X 24.6742 ton/hr X 8409.6 hr/yr X 100% utilization
Lime	90.0	$/ton	0.00000	lb/hr	0	0	$/ton, 0.0 lb/hr, 8409.6 hr/yr, 100% utilization
Urea	500.0	$/ton	0.57750	ton/hr	4,856.54	2,428,272.00	500.0 $/ton X 0.5775 ton/hr X 8409.6 hr/yr X 100% utilization
Oxygen	17.91078	kscf	0.00000	kscf/hr	0	0	kscf, 0.0 kscf/hr, 8409.6 hr/yr, 100% utilization

** Std Air use is 2 scfm/kacfm

*annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

Appendix B

SNCR Evaluation for Coal Creek Station

COAL CREEK STATION
SELECTIVE NON-CATALYTIC REDUCTION (SNCR)
COST AND PERFORMANCE REVIEW

UNDERWOOD, MCLEAN COUNTY, NORTH DAKOTA

PROJECT NUMBER 28966-007

GREAT RIVER ENERGY®
A Touchstone Energy Cooperative

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Revision: 0

Status: Final

Introduction

Great River Energy (GRE) contracted URS Energy & Construction (URS) to conduct a review of the costs and performance capability of Selective Non-Catalytic Reduction (SNCR) at their Coal Creek Station (CCS) Units 1 & 2. This review was requested to provide; an estimate of the current capital cost for the installation of SNCR, operating and maintenance costs for SNCR, and the level of NOx reductions that can be achieved by SNCR.

The CCS units are identical 605 MW (gross - nominal) CE tangentially-fired furnaces burning North Dakota lignite. Each unit is equipped with Low NOx Burners (LNB) and Over-Fire Air (OFA). Unit 2's LNBs are 2nd generation technology while Unit 1's are the 1st generation installation. Unit 1 currently has a NOx emission rate of 0.20 lbs/MMBtu while Unit 2's NOx emission rate is 0.16 lbs/MMBtu.

The Final Best Achievable Retrofit Technology (BART) analysis submitted in 2007 was based on an inlet NOx concentration of 0.22 lbs/MMBtu and an SNCR removal efficiency of 50%. The current review uses the existing CCS NOx values presented in the previous paragraph and updated removal efficiencies. The following sections present data on SNCR capabilities and cost.

SNCR Capabilities

SNCR was originally developed in Japan in the 1970s for use on oil- and gas-fired units. Coal plant applications began in the late 1980s in Western Europe. Commercial U.S. installations on coal-fired utility boilers started in the early 1990s. More than 2 GW of capacity have been installed on coal-fired plants worldwide. SNCR requires injection of ammonia or urea into the proper temperature window within the back-pass of the furnace. The ammonia or urea reacts with NOx species to form nitrogen and water. Emission reduction capabilities range from 25% at 5-ppm ammonia slip to 30% at 10-ppm ammonia slip in most commercial installations.

An SNCR system will require the installation of reagent storage and transfer equipment, a multilevel injection grid and the necessary control instrumentation. Due to the elimination of the catalyst used in the SCR process, the SNCR consumption rates for ammonia or urea are typically 3-4 times the rates required for an SCR system on a per mole of NOx basis.

SNCR performance is dependent upon factors that are specific to each source. These factors are; flue gas temperature, flue gas residence time at temperatures within the reaction temperature range, reagent distribution, uncontrolled NOx levels, mixing between the injected reagent and the flue gas, and the CO and O2 concentrations in the flue gas stream. NOx reductions ranging from 25-75% have been reported with SNCR but the higher levels of reduction are only possible with high inlet NOx levels and

optimum temperatures and residence time. Typical SNCR performance for utility boilers is in the range of 20-35% NOx reductions.

The gas temperature at the point of injection is critical to the NOx reduction performance of an SNCR system. This window falls in a range of 1600-2000°F with an optimum temperature of approximately 1800°F. Above this temperature, ammonia begins to thermally decompose and below this temperature, the reaction rate for NOx reduction decreases, resulting in increased ammonia slip. The temperature profile in any given boiler changes with fluctuations in boiler load. Therefore, the optimum injection point will move during cycling operation and multiple injection points will be required. It should also be noted that the longer the ammonia or urea stays within the optimum temperature window, the higher the NOx reduction that is achieved. Residence times in excess of one second are desirable to achieve the maximum reduction efficiency. The minimum residence time is approximately 0.3 seconds for moderate performance. However, most large utility boilers have heat transfer surfaces (pendants and platens) positioned in this flue gas temperature zone. This reduces the effective use of the SNCR system, even when multiple injection levels are installed. In some cases, these internal obstructions will make the application of SNCR impractical.

Figure 1 shows SNCR NOx removal efficiency as a function of Inlet NOx concentration for 55 existing SNCR installations. The data shows the majority of the installations achieving 20-35% reductions in NOx and only a few installations achieving 50% or greater reductions. There is only one installation achieving 50% reduction at an inlet NOx concentration less than 0.4 lb/MMBtu. This single installation is a cyclone boiler burning a PRB/Illinois coal blend and is the only unit in the data set showing greater than 35% reduction for inlet NOx concentrations less than 0.4 lb/MMBtu.

This figure shows that there are no installations operating with Coal Creek's NOx levels that are achieving greater than 20-25% NOx reductions. The figure also shows that the majority of installations are achieving NOx reductions in the range of 20-30%. Based on the available data, from existing installations operating at the CCS inlet NOx levels used in the BART, the highest level of NOx reduction that could be expected is 30%. At the present CCS NOx levels, it is expected that the highest level of NOx reduction that could be expected is 20%.

Another factor to be considered in the application of SNCR is its effect upon fly ash sales. An ammonia slip of only 5 ppm, which is generally accepted as the minimum that can be achieved in an SNCR application, can render the fly ash produced by the unit unmarketable. CCS currently sells 400,000 tons/yr of fly ash. With SNCR, this fly ash will have to be disposed of in a landfill.

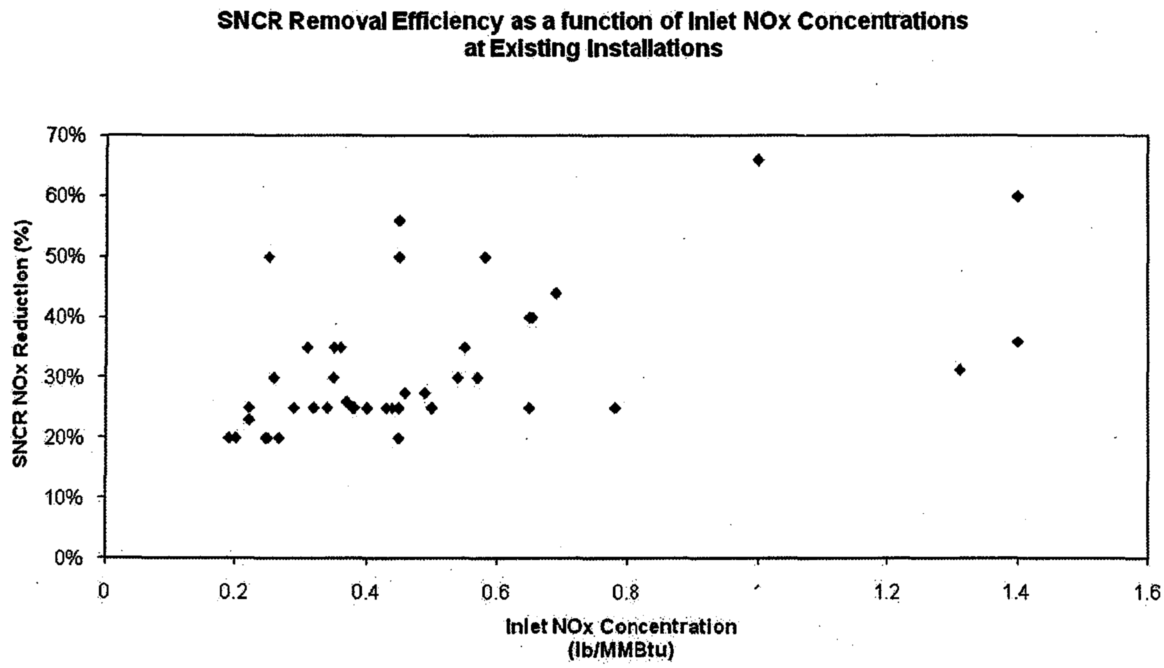

Figure 1 – SNCR Removal Efficiency

SNCR Costs

SNCR capital and operating costs were developed for five (5) different cases utilizing the Electric Power Research Institute's (EPRI) IECCOST model (Rev 3, Nov. 2010) with CCS site specific factors and cost components. The Integrated Emissions Control Cost Model (IECCOST) economic analysis workbook was first published by the Electric Power Research Institute in December 2004. IECCOST produces rough-order-of-magnitude (ROM) cost estimates (stated accuracy of ± 30%) of the installed capital and levelized annual operating costs for Integrated Emission Control (IEC) systems installed on coal-fired power plants. The IECCOST model allows comparison of cost information for conventional and developing SO_2, NOx, particulate, mercury, and integrated emissions control technologies. Costs for utility emission control systems are site-specific, and vary with technology, labor rates, construction conditions and material costs. The site-specific characteristics, operating conditions, process performance requirements and economic criteria serve as input to IECCOST.

IECCOST is able to calculate both new and retrofit plant costs. IECCOST calculates a retrofit factor for each cost area based on site congestion, existence of underground obstructions, soil conditions, seismic zone and state productivity. A series of combustion calculations are carried out based on the ultimate coal analysis provided by the utility and

the operating conditions specified for the boiler(s). The resulting flue gas composition serves as the basis for the calculation of a material balance for the control equipment. The material balance provides data for equipment sizing and calculation of the variable operating costs. The process-specific design criteria, including flue gas flow rate, pollutant removal rate, chemical consumption rate and waste production rate all are incorporated into the production of each process- and site-specific material balance.

The five (5) cases estimated for CCS are:

1. 0.22 lb/MMBtu inlet NOx with 30% reduction
2. 0.20 lb/MMBtu inlet NOx with 25% reduction
3. 0.16 lb/MMBtu inlet NOx with 20% reduction
4. 0.15 lb/MMBtu inlet NOx with 20% reduction
5. 0.22 lb/MMBtu inlet NOx with 50% reduction

These represent the initial BART assessment NOx rate of 0.22 lb/MMBtu with a commercially achievable reduction of 30% for case 1. Cases 2-4 are representative of CCS's existing NOx emission rates and commercially achievable reductions. The final case is the BART assessment case using 2011 dollars. The costs are for a urea-based SNCR system with 14 days of reagent storage. Urea pricing from a source local to CCS was obtained and the current cost of urea is $500/ton delivered to the site. The general plant input data and IECCOST outputs for SNCR capital and operation and maintenance costs are presented in the following section.

IECCOST DATA

Table 1 – Coal Creek Station Data

General Plant Technical Inputs

Total Gross Rating	MW	605
Gross Plant Heat Rate (GPHR)	Btu/KWhr	9,760
Total Net Rating (Less Auxiliary Power)	MW	572.0
Net Plant Heat Rate (NPHR, Without FGD)	Btu/KWhr	10,500
Plant Capacity Factor	%	90%
TECHNICAL INPUTS FOR BOILER:		
Boiler Heat Input	MMBtu/Hr	5,900
Boiler Heat Output	MMBtu/Hr	4,780
Total Air Downstream of Economizer	%	117.0%
Air Heater Leakage (% of econ. flue gas)	%	7.0%
Air Heater Outlet Gas Temp.	°F	300
Inlet Air Temp.	°F	80
Ambient Absolute Pressure	in. Hg	27.9
Pressure After Air Heater	in. H2O	-11
Moisture in Air	lb/lb dry air	0.013
Carbon Loss	%	0.5%
ASH SPLIT		
Fly Ash or Ash Overhead	%	76%
Bottom Ash	%	24%

Table 2 – SNCR Equipment Sizing

SNCR Equipment Sizing and Capacity Calcs			0.22 Inlet & 30% Reduction	0.20 Inlet & 25% Reduction	0.16 Inlet & 20% Reduction	0.15 Inlet & 20% Reduction	0.22 & 50% Reduction
Chosen Reagent			Urea	Urea	Urea	Urea	Urea
Required Reagent Injection	lb/hr		1991	1601	1188	1155	3318
Total Reagent Injection Flowrate	lb/hr		3982	3202	2375	2310	6636
NOx Removed	lb/hr		384	291	186	170	640
NOx Removed	tons/yr		1513	1147	734	670	2522
NOx Emissions	lb/hr		896	873	745	679	640
NOx Emissions	tons/yr		3531	3440	2935	2678	2522
Power Consumption	kW		75	61	45	44	126

Table 3 – Material Costs

SNCR Material Costs			0.22 Inlet & 30% Reduction	0.20 Inlet & 25% Reduction	0.16 Inlet & 20% Reduction	0.15 Inlet & 20% Reduction	0.22 & 50% Reduction
Cost Basis Year			2011	2011	2011	2011	2011
SNCR Equipment Cost	$		$3,800,000	$3,700,000	$3,600,000	$3,600,000	$4,200,000
Installation Factor			1.30	1.30	1.30	1.30	1.30
Installed Equipment Cost	$		$4,970,000	$4,800,000	$4,700,000	$4,700,000	$5,500,000
Prime Contractor's Markup	$		$497,000	$480,000	$470,000	$470,000	$550,000
Total Installed Cost	$		$5,500,000	$5,300,000	$5,100,000	$5,100,000	$6,000,000
Retrofit Factor			1.6	1.6	1.6	1.6	1.6
Total Equipment Cost	$		$8,750,000	$8,500,000	$8,200,000	$8,200,000	$9,600,000
General Facilities	$		$440,000	$420,000	$410,000	$410,000	$480,000
Engineering Fees	$		$875,000	$850,000	$820,000	$820,000	$960,000
Process Contingencies	$		$503,000	$488,000	$472,000	$472,000	$553,000
Project Contingencies	$		$1,580,000	$1,540,000	$1,490,000	$1,490,000	$1,740,000
Total Plant Cost (TPC)	$		$12,145,000	$11,790,000	$11,420,000	$11,400,000	$13,350,000
Total Cash Expended (TCE)	$		$12,145,000	$11,790,000	$11,420,000	$11,400,000	$13,350,000
Allowance for Funds During Constru	$		0	0	0	0	0
Total Plant Investment (TPI)	$		$12,145,000	$11,790,000	$11,420,000	$11,400,000	$13,350,000
Preproduction Costs	$		$243,000	$236,000	$228,000	$227,000	$267,000
Inventory Capital	$		$167,000	$134,000	$100,000	$98,000	$280,000
Initial Catalyst and Chemicals	$		$0	$0	$0	$0	$0
Prepaid Royalties	$		$44,000	$42,000	$41,000	$41,000	$48,000
Total Capital Requirement (TCR)	$		$12,600,000	$12,200,000	$11,800,000	$11,800,000	$13,900,000
Market Demand Escalation	$		$0	$0	$0	$0	$0
Power Outage Penalty	$		$0	$0	$0	$0	$0
Land Cost	$		$0	$0	$0	$0	$0
TCR w/ Market Dem., Power Outag	$		$12,600,000	$12,200,000	$11,800,000	$11,800,000	$13,900,000
	$/kW		21.80	21.10	20.40	20.40	24.00
	Mills/KWh		0.40	0.38	0.37	0.37	0.44

Table 4 – Operation & Maintenance Costs

SNCR O&M Costs			0.22 Inlet & 30% Reduction	0.20 Inlet & 25% Reduction	0.16 Inlet & 20% Reduction	0.15 Inlet & 20% Reduction	0.22 & 50% Reduction
Cost Basis Year			2011	2011	2011	2011	2011
Reagent Type			Urea	Urea	Urea	Urea	Urea
Reagent Consumption	lb/hr		1991	1601	1188	1155	3318
	tons/yr		7848	6310	4681	4553	13080
Water	gpm		72	58	43	42	119
Electricity	kW		75	61	45	44	126
NOx allowances generated	tons/yr		n/a	n/a	n/a	n/a	n/a
Reagent Cost	$/yr		$3,924,000	$3,155,000	$2,340,000	$2,280,000	$6,540,000
Water Cost	$/yr		$410,000	$330,000	$250,000	$240,000	$688,000
Additional Power Costs	$/yr		$24,000	$19,000	$142,000	$13,800	$40,000
NOx Credit	$/yr		$0	$0	$0	$0	$0
Total First Year Variable O&M Cost	$/yr		$4,360,000	$3,500,000	$2,600,000	$2,530,000	$7,270,000
Maintenance	$/yr		$189,000	$183,000	$177,000	$176,000	$210,000
Total First Year Fixed O&M Costs	$/yr		$189,000	$183,000	$177,000	$176,000	$210,000

Attachments

URS SNCR Experience
ICAC White Paper – SNCR for Controlling NOx Emissions – 2000
ICAC White Paper – SNCR for Controlling NOx Emissions – 2008 Update

ATTACHMENTS

The following table presents a listing a URS's SNCR experience. Additionally, a partial listing of the Integrated Emission Control (IEC) Technologies that URS has evaluated for the Electric Power Research Institute (EPRI) follows the SNCR experience list.

NO_X CONTROL EXPERIENCE – SNCR

Client	Project	Unit	Location	Size (MW)	Fuel	ERB	[illegible] or Supplier	[illegible] Retrofit [illegible]	[illegible] Date	Scope
NRG Energy	5 Stations	14 Units	Various	2350	Coal		NA	R	Dec 02	FS, CE
Dayton Power & Light	Total System (6 plants)	15	Various	60-800	Coal		NA	R	1998	FS
Niagara Mohawk	Four Stations	1, 2, 3, 4	NY		Oil, Gas, Coal		NA	R	Dec 94	FS, CE
New York State Electric and Gas	System-wide	10 units	NY	Various	Coal			R	Dec 94	FS, CE
Duquesne Light and Power	System-wide		PA	Various	Coal		NA	R	Dec 93	FS, CE
Atlantic Electric	B. L. England Station			290	Coal		NA	R	Dec 93	FS, CE
Pennsylvania Power & Light	Brunner Island Station	3	PA	790	Coal		NA	R	Dec 93	FS, CE
PEPCO	Various	1, 2, 3, 4, 5, 6	Various	N/A	Coal, Oil, Gas		NA	R	Dec 93	FS, CE
Niagara Mohawk	Huntley Station	6, 7	Syracuse, NY	2 x 420	Coal		NA	R	Apr 93	FS, CE

NO_X CONTROL EXPERIENCE – SNCR

Client	Project	Unit	Location	Size (MW)	Fuel	PRB	Equipment Supplier	New/Retrofit (N/R)	Completion Date	Scope
Inland Steel and Nippon Steel (I/N Tek)	Furnaces and Aux. Boiler Continuous Galvanizing Line (9,000,000 tons/yr capacity)	N/A	IN	N/A	Gas		NA	N	Dec 92	FS, CE
Centerior Energy				72 thru 680	Coal			R	1992	FS, CE
Allegheny Energy Supply	Harrison Station	1, 2, 3	Shinnston, WV	3 x 685	Coal		NA	R	1992	E
San Diego Gas & Electric	System-Wide NO_X Compliance	13 Units	CA	Various	Various		NA	R	1991	PE
Entergy Services, Inc.	System-Wide NO_X Reduction Assessment	54 Units	Various	Various	Various		NA	R		FS
Chevron	El Segundo Refinery		CA		Refinery off-gas		NA	R		FS, CE
AES	Warrior Run	1	Cumberland, MD	180	Coal		NA	N	1998	E, P, C
PEPCO	Various	1, 2, 3, 4, 5, 6	Various	N/A	T-fired oil and coal Wall-fired oil and gas		NA	R	Dec 93	E
Tennessee Valley Authority	Johnsonville	6 units	Johnsonville, TN	6 x 100	Coal		NA	R	Dec 92	E
Los Angeles Dept. of Water & Power	Haynes	1, 2	Long Beach, CA	2 x 230	Gas/Oil		Ammonia injection	R	1992	E, C

NO$_X$ CONTROL EXPERIENCE – SNCR

Client	Project	Unit	Location	Size (MW)	Fuel	PRB	[illegible] or Supplier	New/ Retrofit (R)	Completion Date	Scope
Air Products	Stockton Cogeneration	1	Stockton, CA	50	Coal		NA	N	1988	D, E, CS
Chevron	El Segundo Refinery				Refinery off-gas		NA	R		FS
Texaco	Los Angeles Refinery		Los Angeles, CA	22	Refinery off-gas		NA	R		FS
Air Products	Cambria County	1	Pennsylvania		Waste Coal		NA	N		E, P

Legend:

BE	Bid Evaluation	D	Design	S	Startup
C	Construction	E	Engineering	STG	Steam Turbine Generator
CA	Construction Advisory	FS	Feasibility Study	T	Testing
CE	Cost Estimate	OE	Owner's Engineer	PRB	Powder River Basin Coal
CM	Construction Management	P	Procurement		

Integrated Emission Control Technologies evaluated for EPRI.

Gas Phase Oxidation Systems

Chem-Mod
ECO™
ECO2™
ISCA

Lextran SO2/NOx/Hg
LoTOx

Low-Temperature Multi-Pollutant Control System (MPCS)
THERMALONOx
Plasma/Electron Beam Systems
EBFGT
e-SCRUB™
Pioneer Industrial Technologies (PIT)
Pulsatech
WOWClean

Combustion Modification/Fuel Processing
Ashworth Combustor
Clean Combustion System (CCS)
Coal Tech
Emulsified Fuel Technology
Green Coal
High-Sodium Lignite-Derived Chars
K-Fuel
K-Lean
Lignite Cleaning System
The Mobotec System
N-Viro Fuel
Oxycombustion
Soot Free Catalyst
WRI Coal Processing

Wet Scrubbing Systems
Airborne

Aqueous Foam Air (AFA) Filter
CEFCO
Dry-Wet Hybrid Electrostatic Precipitator (ESP)
DynaWave
Eco Technologies
Envirolution/PureStream Gas-Liquid Contactor
FLU-ACE
Integrated Flue Gas Treatment
Integrated Advanced Tower
Ispra by SRT Group
LABSORB
Membrane Wet ESP
MercOx
PEA
Rapid Absorption Process (RAP)/Dry Absorption Process (DAP)
SkyMine

Dry Technologies
Argonne Spray Dryer
NOxOUT CASCADE / Turbosorp Technology (formerly CDS/SCR)
ClearGas Dry Scrubber
Copper Oxide
EMx (previously SCONOx/SCOSOx)
Indigo MAPS
Kuttner Luehr Filter Technology
Low Temperature Mercury Control (LTMC)
Novacon
PahlmanTM Process
ReACT Technology
SNOX

SOx-NOx-Rox Box (SNRB)
Trona Injection

<u>Other Technologies</u>
Argonne Hg/NOx Process
CANSOLV SO2/CO2 Process
GreenFuel
Integrated Pollutant Removal (IPR)
Low Temperature Sulfur Trioxide Removal System (LT-STRS) / Mitsubishi Mercury Treatment System (Mi-MeTS) (Previously MHI High Efficiency System / HCl Injection)
TIPS
Combined Plasma Scrubbing Technology (CPS)
Consummator
ECOBIK
Aqua Ammonia Process
BioDeNOx
Fungal Bioreactor
Plasma Enhanced ESP
ElectroCore

Appendix C

Fly Ash Storage and ASM Technology Evaluation

REPORT

FLY ASH STORAGE AND AMMONIA SLIP MITIGATION TECHNOLOGY EVALUATION

Great River Energy

Coal Creek Station

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1 Copy – Golder Associates

November 15, 2011 **113-82161**

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EXECUTIVE SUMMARY

Great River Energy (GRE) has requested that Golder Associates Inc. prepare a third-party review of potential ammonia slip mitigation (ASM) technology and cost comparisons for associated RCRA Subtitle D ash storage facility design for their Coal Creek Station (CCS) located in Underwood, North Dakota.

These evaluations are prepared in response to the United States Environmental Protection Agency's (EPA's) proposed Federal Implementation Plan (FIP) for the state of North Dakota. As part of the FIP process, the North Dakota Department of Health (NDDH) has requested that GRE prepare a Best Available Retrofit Technology (BART) analysis for nitrogen oxides (NOx) emissions, specifically evaluating the application of selective non-catalytic reduction (SNCR) emission control technology. Due to the potential for unreacted ammonia in the flue gas downstream of the SNCR (ammonia slip) reacting with sulfur compounds to form ammonia sulfates that deposit in the fly ash, there is concern over the significant impact on current fly ash sales. Therefore, GRE is evaluating an ASM technology at CCS as an option for treating ammonia slip impacted fly ash to allow continued beneficial use and sale of fly ash. This ASM technology is not proven for lignite derived fly ash and is presented as a potential option to reduce the impact of an SNCR on fly ash management. This evaluation includes an ASM technology cost estimation, fly ash disposal cost comparisons, and evaluation of the total cost impact of an SNCR on fly ash management at CCS.

Golder recently visited the Eastlake Station where Headwaters Energy Services' patented ASM technology is currently applied to manage ammonia levels in the fly ash. Based on this operation and Golder's knowledge of CCS and lignite coal-fired power plants, a cost estimate to apply ASM at CCS was prepared. The cost estimate includes costs for the ASM infrastructure including engineering and design, construction, and operations and maintenance. Costs are based on 2011 dollars and capital costs are annualized for a 20-year life and 5.5% interest rate. Existing fly ash sales infrastructure and operations and maintenance are not included in the cost estimate. ASM post-processing costs are estimated to be $5.61 per ton of fly ash treated.

Fly ash that cannot be marketed for beneficial use is disposed of in engineered and permitted facilities at CCS. Golder prepared a cost estimate for three potential operating scenarios: Scenario A – fly ash sales equal to the average sales over the past few years, Scenario B – ammonia slip impact of an SNCR makes fly ash at CCS unsalable, and Scenario C – ASM technology will be viable for ammonia impacted fly ash at CCS allowing a reduced amount of fly ash sales. A summary of the total estimated fly ash disposal costs is shown in the following table.

	Scenario A (Current Sales)	Scenario B (No Sales)	Scenario C (Reduced Sales, ASM)
Fly Ash Disposed (ton/yr)	110,000	525,000	234,500
Disposal Cost ($/ton)	$18.06	$11.18	$13.91
Annual Disposal Cost ($/yr)	$1,987,000	$5,870,000	$3,262,000
Annual Increase in Disposal Cost Compared to Scenario A ($/yr)	-	$3,883,000	$1,275,000

The landfill design included the specific size, location, infrastructure, liner, and cover relevant to each scenario. Costs for each scenario included the specific landfill design, engineering, and permitting costs, land acquisition, infrastructure development, liner construction, post-closure care, construction management and construction quality assurance (CQA), GRE internal costs, project contingencies, and operational costs. Based on the annual disposal cost estimate shown in the table above, the potential impact of an SNCR on the fly ash disposal costs at CCS may be an additional $3.9 million per year if fly ash is no longer marketable or an additional $1.3 million per year if the ASM technology proves successful.

The total cost impact of an SNCR on fly ash management at CCS includes ASM post-processing costs, fly ash disposal costs, and the loss in revenue generated from the sale of fly ash. Golder evaluated this total cost impact for each scenario, and is summarized in the table that follows. Based on this evaluation, the total additional cost impact to fly ash management as a result of an SNCR is between $4.4 and $9.0 million per year.

	Scenario A (Current Sales)	Scenario B (No Sales)	Scenario C (Reduced Sales, ASM)
Total (Disposal + Post Processing + Lost Sales)			
Annual Cost ($/yr)	$1,987,000	$10,975,000	$6,422,000
Unit Cost ($/ton produced)	$3.79	$20.91	$12.23
Additional Cost (Scenario B/C - Scenario A)			
Fly Ash Management Cost ($/yr)	-	$8,988,000	$4,435,000
Fly Ash Management Cost ($/ton produced)	-	$17.12	$8.45

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1.0 INTRODUCTION

Great River Energy (GRE) has requested that Golder prepare a third party review of ammonia slip mitigation technology, and cost comparisons for associated RCRA Subtitle D ash storage facility design for Coal Creek Station (CCS) located in Underwood, North Dakota. These evaluations are prepared in response to the United States Environmental Protection Agency's (EPA's) proposed Federal Implementation Plan (FIP) for the state of North Dakota. Based on the proposed FIP, GRE is evaluating selective non-catalytic reduction (SNCR) control technology to reduce nitrogen oxide (NO_x) emissions from CCS. If SNCR is installed at CCS, there is potential for unreacted ammonia in the flue gas downstream of the SNCR, called ammonia slip, and higher ammonia in fly ash. Due to the significant impact on current ash sales, GRE is evaluating a potential ammonia slip mitigation (ASM) technology patented by Headwaters Energy Services. In addition, GRE is evaluating three potential management scenarios for fly ash based on the potential impact of ammonia concentrations to the sale of fly ash.

Golder performed a third party review and estimated costs associated with implementation of Headwaters' ASM technology as applied to CCS. The review includes an estimate of the capital and operating and maintenance (O&M) costs for implementation of the ASM technology at CCS, with a focus on potential impacts to ash marketing and future sales to assist GRE in determining the feasibility of the ASM technology for operations at CCS. This evaluation is limited in scope given that "Headwaters has not conducted any field scale assessment on application of this technology to lignite derived fly ash. The limited current experience in commercial application and lack of field trials is not adequate for Headwaters to be able to provide any guarantee that the process can be successfully applied to treat lignite ash at the Coal Creek Station," per an email from Rafic Minkara (Headwaters) to John Weeda (GRE) on July 15, 2011.

Golder also prepared a cost comparison for three fly ash storage facility scenarios:

- Scenario 1: CCS's current fly ash sales rate (most fly ash sold);
- Scenario 2: No fly ash sales;
- Scenario 3: Application of ASM technology (allowing for some fly ash sales).

The cost evaluation includes a comparison of capital and O&M costs for each scenario assuming a new facility that meets EPA RCRA Subtitle D type regulations.

1.1 Qualifications

Golder Associates Corporation is an international employee-owned consulting engineering company specializing in the application of earth sciences and engineering to environmental, natural resources, and civil engineering projects. Operating since 1960, our company maintains a network of approximately

160 offices. Current worldwide employment exceeds 7,000 people. The United States operating company, Golder Associates Inc., employs approximately 1,200 people in 51 offices.

This project was conducted by a team based in our Denver, Colorado and Fort Collins, Colorado, offices. The project team was well-suited to perform the proposed services at CCS because of the experience of our technical staff on comparable projects, and our familiarity with the geotechnical and engineering properties of Subtitle D landfill designs. In addition, our team has a firm understanding of the engineering practice and regulatory environment surrounding coal-fired power plants, both in North Dakota and nationally, including ongoing rulemaking efforts by the EPA.

2.0 BACKGROUND

2.1 Regulatory Basis

In order to attain and maintain the National Ambient Air Quality Standards (NAAQS) within a state, state air quality agencies prepare State Implementation Plans (SIP) for EPA approval. If EPA disapproves of the SIP, either partially or fully, EPA will develop a Federal Implementation Plan (FIP) to address the deficiencies in the SIP.

On September 21, 2011, EPA proposed to partially disapprove the North Dakota SIP, specifically addressing regional haze and proposed a FIP to address the deficiency "concerning non-interference with programs to protect visibility in other states"[1]. As part of this process North Dakota Department of Health (NDDH) has requested a Best Available Retrofit Technology (BART) analysis for nitrogen oxides (NOx) emissions. This analysis was submitted by GRE in 2007 and additional evaluations and response to questions were submitted in 2010 and on July 15, 2011 to NDDH. NDDH is requesting additional analyses of selective non-catalytic reduction technology. This report does not include an SNCR evaluation, but provides a cost evaluation to address the potential impact the installation of SNCR would have on the existing GRE fly ash storage and sales.

2.2 SNCR and Ammonia Slip

Selective non-catalytic reduction (SNCR) technology is a post-combustion technology based on the chemical reduction of NOx into molecular nitrogen (N_2) and water vapor (H_2O). A nitrogen based reagent, such as urea, is injected into the post-combustion flue gas. The injection causes mixing of the reagent and flue gas while the heat in the flue gas provides energy for the reaction. The primary byproduct of the reaction is nitrous oxide (N_2O), which is a potent greenhouse gas (GHG).

Unreacted reagent in the flue gas downstream of the SNCR is called slip. This unreacted reagent will appear as ammonia, and reacts with sulfur compounds (from sulfur containing fuels) to form ammonia sulfates which deposit on the fly ash that is collected by the particulate emissions control equipment. The ammonia sulfates are stable in a dry state, but ammonia gas can release if the fly ash becomes wet. Ammonia content in the fly ash greater than 5 parts per million (ppm) (based on Headwaters' experience this level is 35 ppm) can result in release of ammonia gases which impact either the sale or storage and disposal of fly ash.

[1] Federal Register, EPA, 9/21/2011, www.federalregister.gov/articles/2011/9/21/2011-23372

3.0 AMMONIA SLIP MITIGATION

3.1 Background

Headwaters has developed an ammonia slip mitigation (ASM) technology to manage ammonia levels in the fly ash, so that a portion of the fly ash produced can be sold as a concrete additive. The Headwaters' ASM technology was initially developed in 2001 with the first US patent issued in 2004. The first commercial installation of ASM technology was installed at RG&E Russell Station in Rochester, New York in 2004. Russell Station used an SNCR and burned eastern bituminous coal.

The second commercial installation was installed at Eastlake Station in Ohio. Eastlake Station has a 600 megawatt (MW) unit that is fired with a 50/50 blend of Power River Basin (PRB) and eastern bituminous coal while generating approximately 100,000 TPY of fly ash. Headwaters is able to blend, treat, and market approximately 85% of the fly ash produced at Eastlake station. Fly ash is not treated during periods of highly variable ammonia concentrations, typically occurring during SNCR upset or plant load swings.

Currently, there are no commercial applications of ASM technology at a lignite-fired power plant, and Headwaters has not conducted any research on the application of the technology to lignite derived fly ash. Due to the lack of commercial experience with lignite derived fly ash, Headwaters will not provide a guarantee that the ASM technology can be successfully applied to lignite derived fly ash.

3.2 Process Description

The ASM technology mixes approximately 0.5-pound (lb) calcium hypochlorite (Cal-Hypo) with approximately 3,000-lb of fly ash in a hopper. The dose of cal-hypo, which is fed into the hopper using a rotary screw, is based on the ammonia concentration in the fly ash. Typical ammonia range for treatment is 50 to 150 ppm with a dosage of 0.2 to 1.3 lb of Cal-Hypo, resulting in ammonia concentrations after treatment of about 35 to 80 ppm.

Golder visited a current commercial application of ASM technology at the Eastlake Station (Figure 1). Fly ash from the electrostatic precipitator (ESP) is sent to one of two fly ash silos where the fly ash is tested daily to determine ammonia concentrations (Figure 2). If the ammonia concentrations are above 150 ppm, the fly ash is diverted for disposal. Fly ash with ammonia concentrations less than 150 ppm are sent to the third silo, after which it is "dosed" with Cal-Hypo and sent to the fourth silo (Figure 3 through Figure 5). The SNCR at Eastlake cannot keep the ammonia slip consistent, and often over-treats a portion of the fly ash stream. To increase the amount of treatable and marketable fly ash, fly ash with no ammonia from other sources is regularly blended into the Eastlake fly ash to keep the initial ammonia content below 150 ppm. Through the operation of the SNCR and by blending non-ammonia impacted fly ash with Eastlake's ammonia impacted fly ash, Eastlake is able to market approximately 85% of what

they produce because this fly ash is considered "treatable" (i.e., ammonia concentration levels are < 150 ppm). Diagrams of the East Lake Station system provided by Headwaters are shown in Appendix A. Subsequent to these diagrams, Headwaters has added a weigh hopper under the silo as shown in Figure 5.

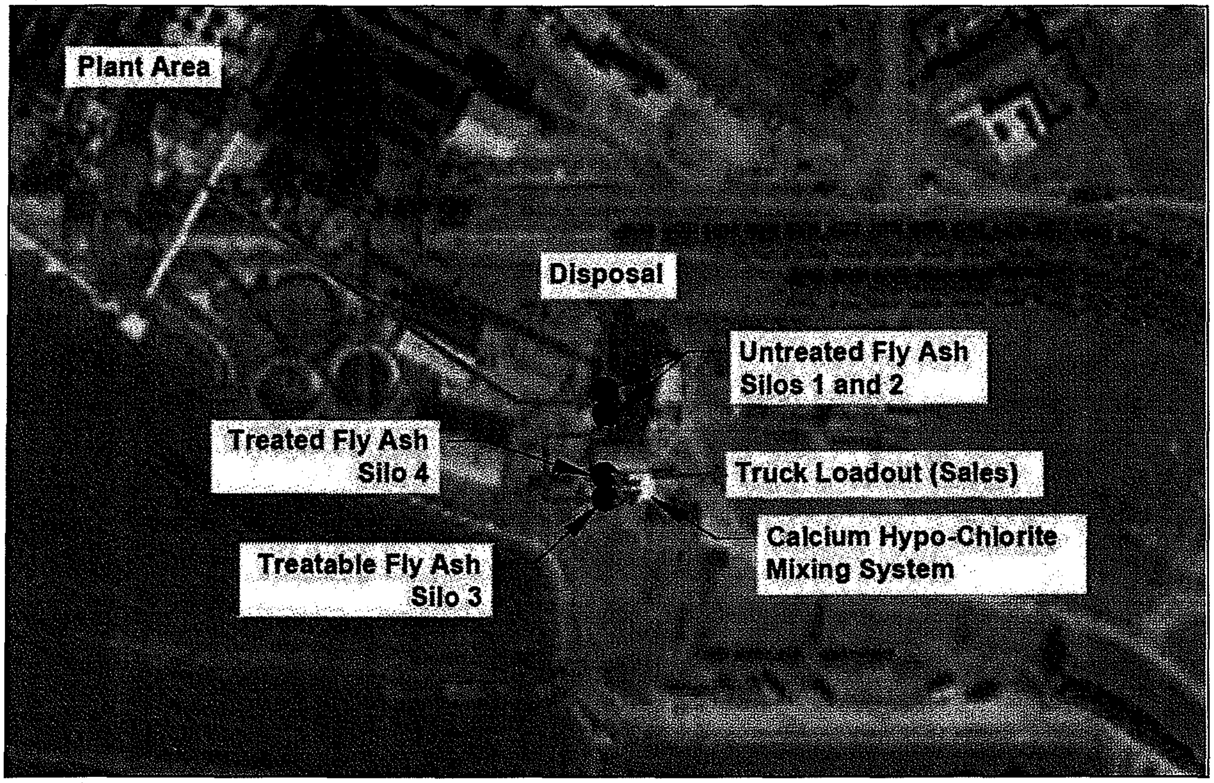

Figure 1: Eastlake Station ASM Schematic

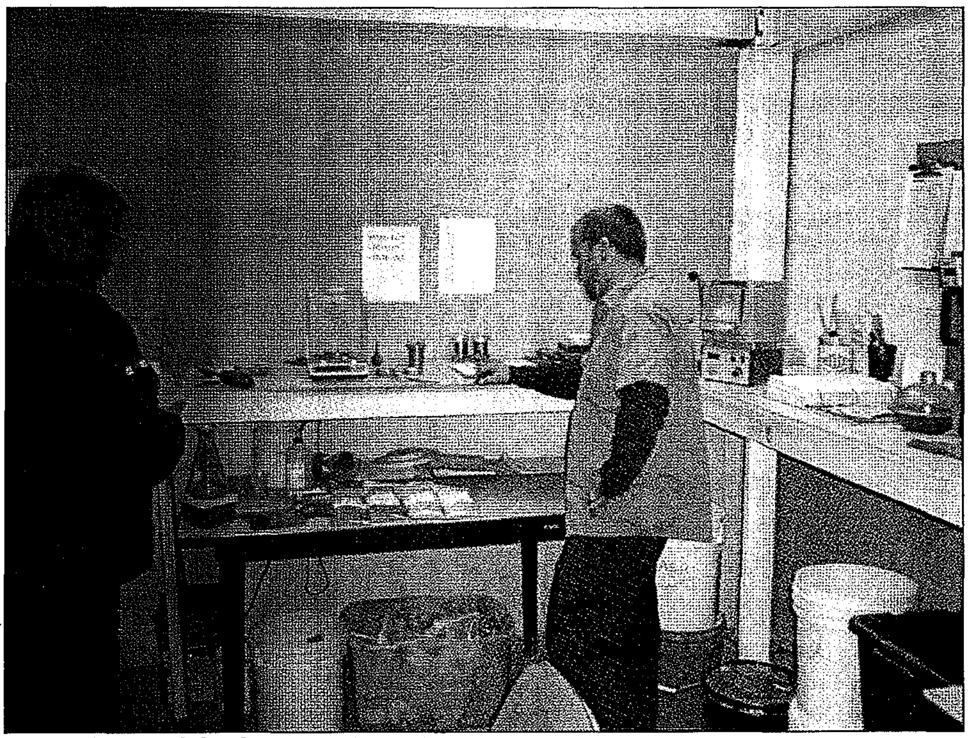

Figure 2: Eastlake Station ASM Lab

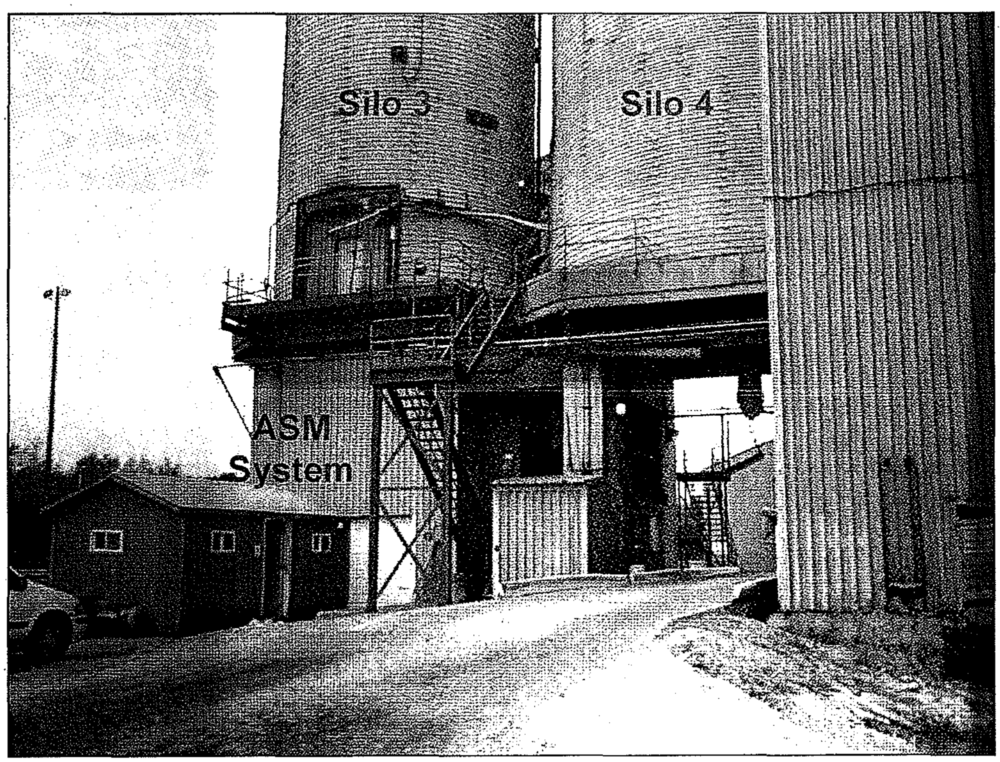

Figure 3: Eastlake Station Silo 3, Silo 4, and ASM Setup

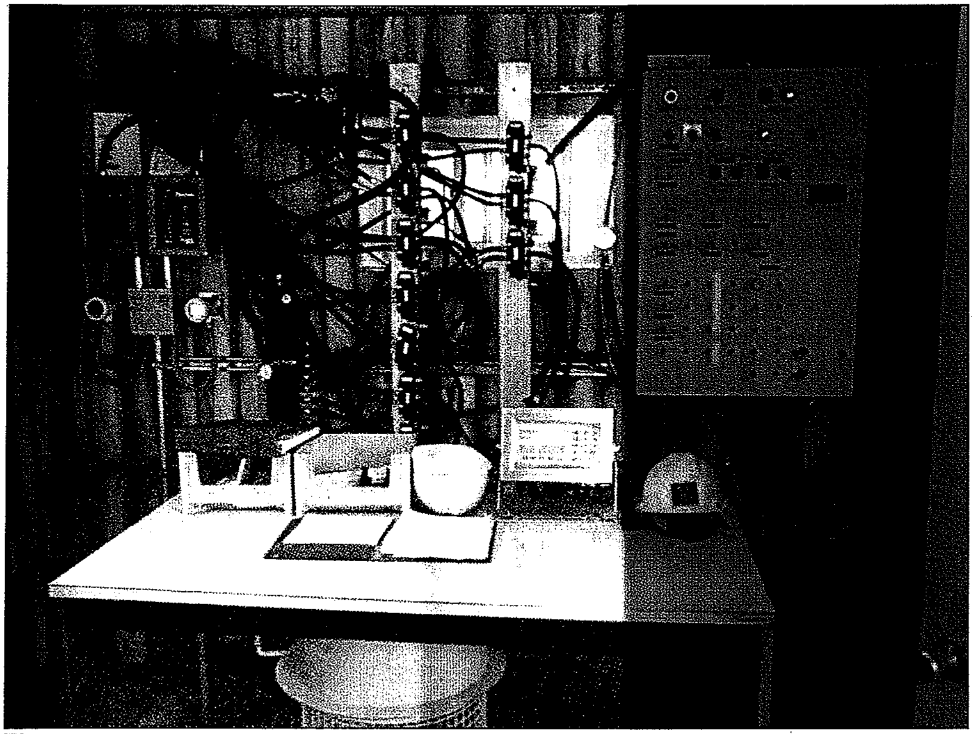

Figure 4: Eastlake Station ASM Control Panel

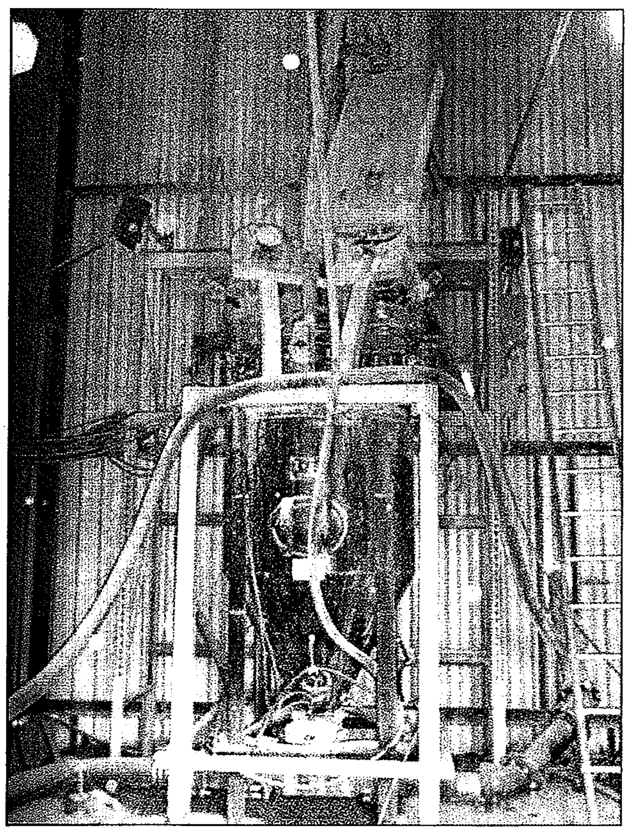

Figure 5: Eastlake Station ASM Mixing Hopper

3.3 Design and Limitations

Based on the Eastlake Station application, ASM is applied to fly ash with ammonia concentration levels less than 150 ppm. Ammonia levels can fluctuate based on plant load variations and SNCR operation. Ammonia concentrations are more consistent at base load conditions and dosing levels are typically based on this condition. Therefore, during load "swings," it can be difficult to properly adjust the amount of ammonia injected into the flue gas resulting in varying concentrations of ammonia in the fly ash. If there is a plant upset condition, it may be several days until the ammonia concentrations in the fly ash being produced are at "treatable" levels again. The concern is two-fold. If the fly ash is not treated with enough Cal-Hypo, objectionable levels of ammonia will be released when the fly ash is mixed with water. Ammonia gas at low levels is an irritant but can be dangerous to life and health at high concentrations. If too much Cal-Hypo is added, chlorine gas will be released when the fly ash is mixed with water. Chlorine gas even at low concentrations is dangerous to life and health.

3.4 ASM Application at CCS

The application of ASM technology at CCS is being evaluated as an option for treating ammonia slip impacted fly ash to allow continued beneficial use and sale of fly ash.

3.4.1 Potential Design at CCS

For cost estimating, a potential layout for the application of ASM at CCS is shown in Figure 6. This potential layout utilizes the existing fly ash infrastructure including the truck load-out silos (91 and 92), the rail load-out silo (93), and the fly ash storage dome (94). To utilize ASM, the layout adds a new truck load-out silo south of Silos 91 and 92, and adds ASM Cal-Hypo feed systems at both the new truck load-out silo and the existing rail load-out silo (93). The general flow of material is treatable fly ash being routed to either the new truck load-out silo, the fly ash dome (94) or the rail load-out silo. From these silos, the fly ash is tested, and then mixed with Cal-Hypo as it is loaded into the trucks or rail cars. Additional testing of the resultant product would also be performed. Fly ash that is expected not to be treatable or saleable is routed to the exiting truck load-out silos (91 and 92) where it will be loaded into haul trucks and disposed at on-site disposal facilities.

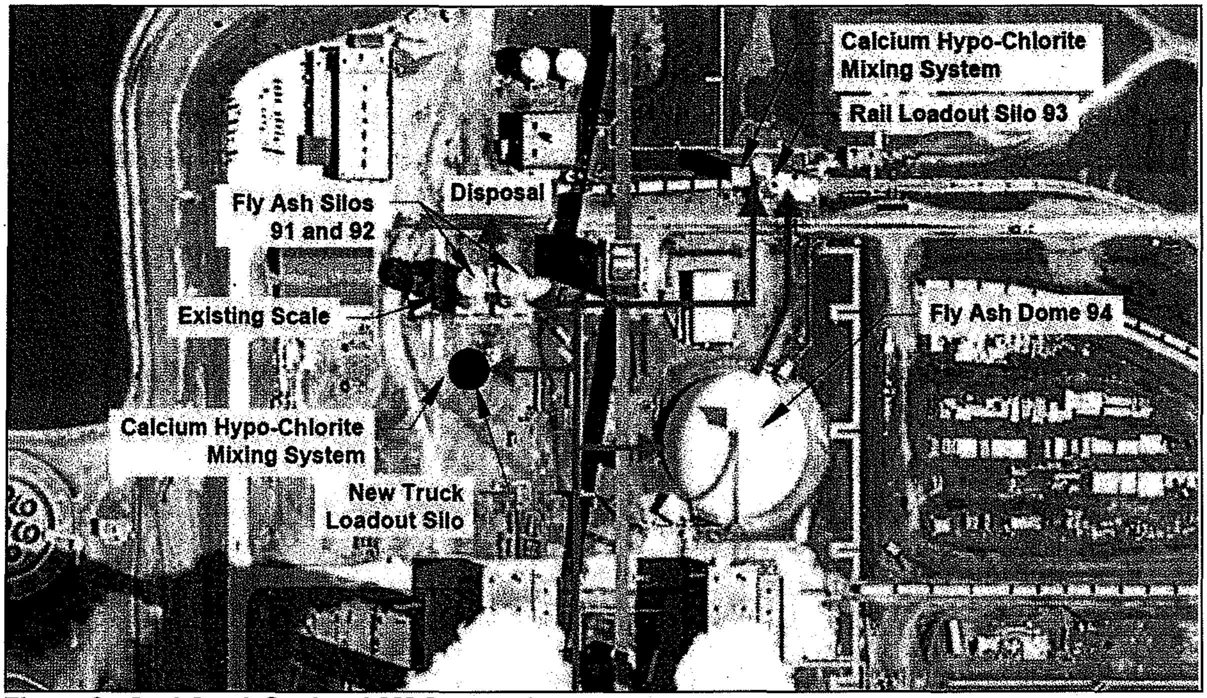

Figure 6: Coal Creek Station ASM Schematic

As discussed earlier, not all of the fly ash coming from the precipitators is expected to be within treatable levels of ammonia. In general, when the power generation units are operating at steady load and the SNCR ammonia injection system is operating properly, the fly ash produced should be treatable using the ASM system and will be collected in the rail load silo (93), the fly ash dome (94), or the new truck loadout silo (95). Conditions under which the ammonia content of the produced fly ash will be questionable include:

- Unit load swings causing variations in ash ammonia concentration (load swings may be due to regional wind penetration or variable load consistent with MISO);
- SNCR ammonia injection feed system problems; and
- Unit startup and shutdown which results in oily ash.

Golder expects that when any of these conditions occur, the fly ash produced will automatically be directed to the disposal silos (91 & 92). Fly ash will not be redirected to the sales silos (93, 94 or 95) until the upset is over and the fly ash collected in the first two rows of the electrostatic precipitator (ESP) has been tested and proven to have less than 150 ppm of ammonia in it.

Based on a review of the recent load profile at CCS, historic information on marketable fly ash at CCS, and an estimate of the reliability of the SNCR and ASM systems, approximately 30% of the fly ash now sent to the sales silos is assumed to have ammonia concentrations which will make it untreatable if an SNCR system is installed.

3.5 Cost Estimate

The cost estimate includes costs for the ASM infrastructure including engineering and design; construction; and operations and maintenance. Golder used actual costs from similar projects, and professional judgment to develop this cost estimate. Sources and assumptions are documented where appropriate. Some general assumptions for the cost estimate include:

- All costs are estimated in 2011 dollars.
- Capital costs are annualized based on a 20-year life and 5.5% interest rate.
- Existing fly ash sales infrastructure (silos, scales, rail facilities) and operations and maintenance are not included.

3.5.1 System Engineering and Design

This item is estimated as 10% of the total construction costs to develop the new facilities. Ten percent is based on Golder's professional judgment.

3.5.2 New Truck Load-Out Silo

The costs for the new truck load-out silo include site preparation, permit application, the silo and handling equipment, dust collection equipment, and feed piping. The costs for this construction are based on the construction of a similar fly ash sales terminal constructed for GRE in 2003. This silo had a 5,000-ton capacity and was used to transfer fly ash from rail cars to trucks (Figure 7). The total estimated cost for this item is $1.6 million and includes the following:

- Silo and truck scale similar to the Irondale, CO unit:
  - Silo slab on grade;
  - Starvrac reclaimer;
  - Truck scale beside the silo on grade;
  - Screw conveyor from discharge of the Starvrac reclaimer;
  - Bucket elevator to overhead;
  - Air slide ;
  - Building with the scale and ASM controls
- Additional items needed at CCS:
  - Feed piping and valves from each of the four fly ash conveying lines;
  - Higher capacity dust collectors to handle the high air flow from ESP.

Details for this cost estimate are included in Appendix B.

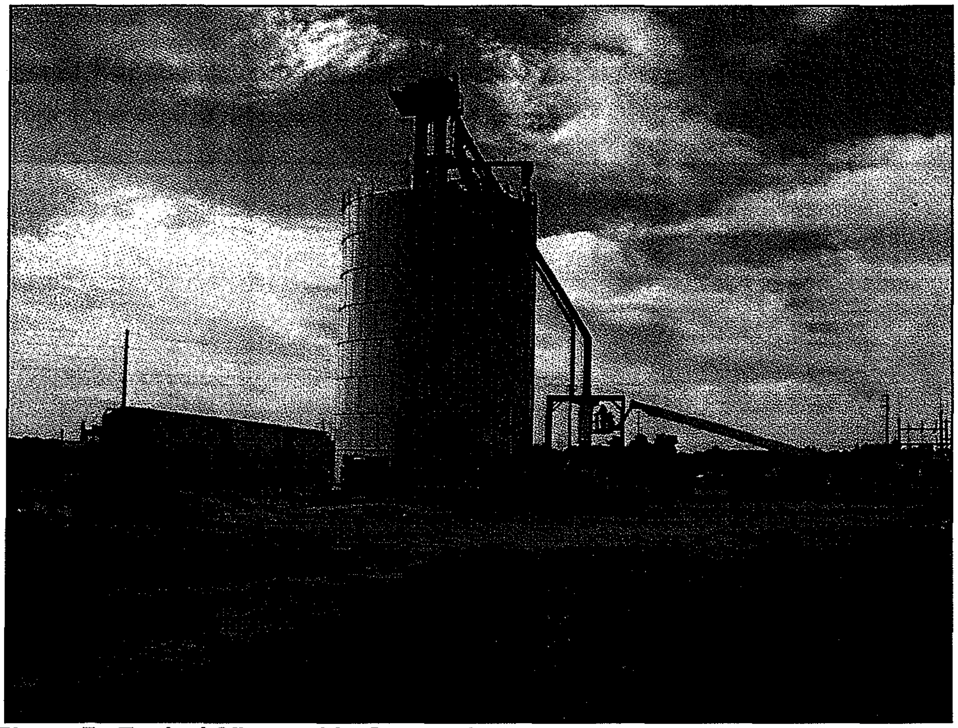

Figure 7: Typical Silo used in Cost Estimate

3.5.3 Cal-Hypo Feed System

The costs for the Cal-Hypo feed systems are estimated at $574,500 and include:

- Rail loadout silo (93):
  - Cal-Hypo storage and conveying building;
  - Day storage hopper for Cal-Hypo on the silo weigh bin floor;
  - Conveying system from the storage building to the day storage hopper;
  - Variable speed screw conveyor to feed Cal-Hypo into existing weigh hopper;
  - ASM system controls
- New truck loadout silo (95):
  - Weigh hopper above truck loadout spout;
  - Cal-Hypo storage and conveying building;
  - Day storage hopper for Cal-Hypo on the silo weigh bin floor;
  - Conveying system from the storage building to the day storage hopper;
  - Variable speed screw conveyor to feed Cal-Hypo into existing weigh hopper;
  - ASM system controls.

3.5.4 GRE Internal Costs

Internal costs for GRE to manage consultants, contractors, and in-house staff is estimated as 10% of the total costs (construction, engineering, permitting, CQA). Ten percent is based on GRE's experience with projects at CCS.

3.5.5 Project Contingency

Due to the order-of-magnitude scope of this cost estimate a contingency of 15% on the construction costs was added.

3.5.6 Operational and Maintenance Costs

ASM post-processing operations and maintenance costs are estimated as an annual cost. Operations costs include the cost of Cal-Hypo, fly ash sampling and testing costs, and labor to operate the system. Maintenance costs include labor and materials to maintain and repair the added equipment at the rail load-out silo (93) and the new truck load-out silo (95).

The estimated cost for this item, based on annual sale/processing of 290,500 tons, is approximately $1.4 million per year. Details for this cost estimate are included in Appendix B.

3.6 ASM Post-Processing Cost Summary

Using the quantities and the unit pricing described above, ASM post-processing costs are estimated as $5.61 per ton of fly ash treated.

4.0 FLY ASH DISPOSAL

Fly ash that cannot be marketed for beneficial use is disposed of in engineered and permitted facilities at CCS. Golder has prepared this order-of-magnitude cost estimate to compare costs between three scenarios defined to assess the potential impact of an SNCR on fly ash sales and disposal at CCS. Summary costs and key inputs are included in Table 1 through Table 3, and Figure 8 through Figure 10, with cost estimate details provided in Appendix B.

4.1 Fly Ash Disposal Scenarios

Three scenarios were evaluated to estimate the annual cost and the cost per ton to dispose of fly ash at CCS. These scenarios include:

- ***Scenario A*** – This scenario is the base case with fly ash sales equal to the average sales over the past few years. The scenario assumes that fly ash will be disposed of in a new landfill with a design based on RCRA Subtitle D practices, and has a 20-year disposal capacity. No post processing of the fly ash is required to make it marketable.
- ***Scenario B*** – This scenario assumes that the ammonia slip impact of an SNCR makes fly ash at CCS unsalable. The scenario also assumes that fly ash will be disposed of in a new landfill with a design based on RCRA Subtitle D practices, and has a 20-year disposal capacity.
- ***Scenario C*** – This scenario assumes that Headwater's ASM technology will be viable for ammonia impacted fly ash at CCS. However, sales will be reduced from current sales due to load swing impacts on ammonia slip, market conditions, and other factors previously identified. The scenario also assumes that fly ash will be disposed of in a new landfill with a design based on RCRA Subtitle D practices, and has a 20-year disposal capacity.

A summary of the fly ash production, sales, and disposal annual tonnages for these scenarios is provided in Table 1.

Table 1: Fly Ash Sales and Disposal Tons

	Scenario A (Current Sales)	Scenario B (No Sales)	Scenario C (Reduced Sales, ASM)
Fly Ash Produced (ton/yr)	525,000	525,000	525,000
Fly Ash Sold (ton/yr)	415,000	0	290,500
Fly Ash Disposed (ton/yr)	110,000	525,000	234,500

The total tonnage of fly ash produced is variable based on items such as plant load, plant efficiency, coal quality, and coal processing. Tonnage used in this analysis is meant to represent a typical or average amount of fly ash produced, sold, and disposed at CCS.

4.2 Landfill Design

For all three scenarios a 20-year disposal capacity and a RCRA Subtitle D design is assumed. It is also assumed that the landfill will be built on property not currently owned by GRE. For this cost estimate, it is assumed that property just west of the plant property would be purchased for the new facility. Figure 8 shows a potential location for these new facilities just west of the plant property and represents the approximate footprint required for Scenario A.

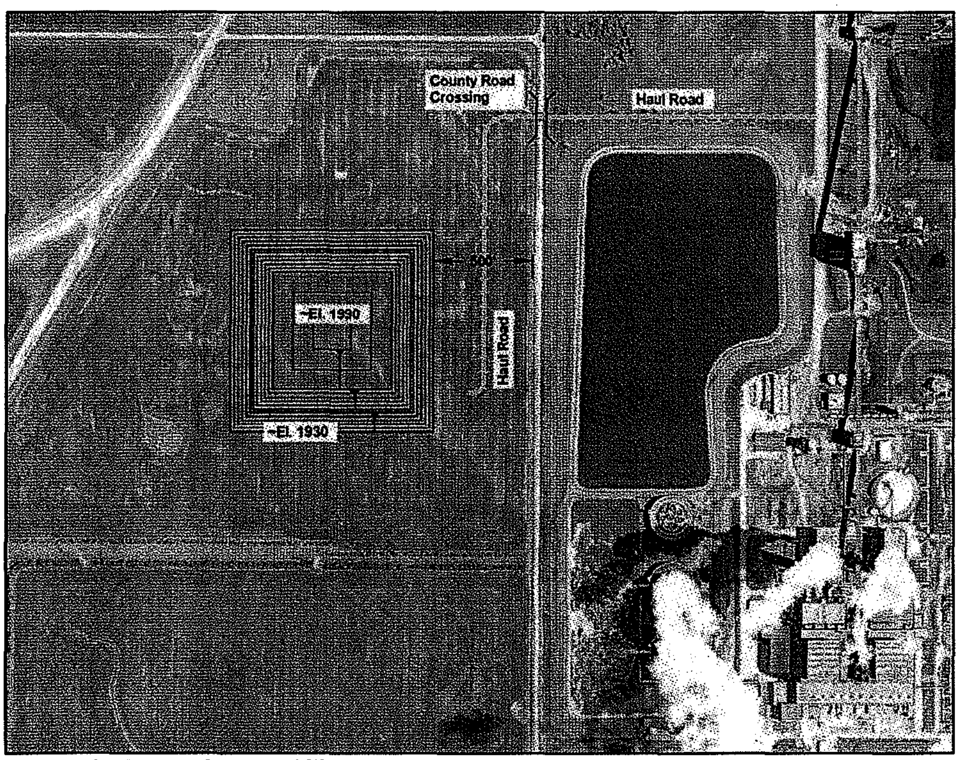

Figure 8: Potential Landfill Location (Scenario A)

4.2.1 Landfill Size

Landfill size is based on a 20-year fly ash disposal capacity. For the three scenarios this varies between 2.2 million and 10.5 million tons of capacity. For each Scenario, Golder developed a simplified landfill footprint that would provide the 20-year fly ash disposal capacity. The simplified landfill design assumes 10 feet of cut, 12-foot high soil berm, 3H:1V soil berm slopes, and 4H:1V fly ash slopes with a 5% crown. Based on preliminary engineering, the landfill capacity ranges between 75,000 and 118,000 cubic yards (cy) per lined acre due to the increased height capacity of a larger footprint facility. Figures showing the size of each Scenario are included in Appendix B.

The amount of cover area in relationship to the liner area has also been estimated based on preliminary engineering as 1.1 acres of cover for every 1 acre of liner.

The amount of land required is assumed to encompass at least a 500-foot buffer beyond this lined footprint to allow for access roads, fencing, support structures, and groundwater monitoring. For the land acquisition purchase estimate, the nearest whole or partial section of land to the required footprint was assumed.

Table 2 provides a summary of the estimated facility liner area, cover area, and site area for the three scenarios.

Table 2: Scenario Landfill Size

	Scenario A (Current Sales)	Scenario B (No Sales)	Scenario C (Reduced Sales, ASM)
Liner Acres (acres)	24.0	73.5	41.0
Cover Area (acres)	26.5	81.0	45.0
Site Area (acres)	160.0	240.0	160.0

4.2.2 Infrastructure Development

With the landfill constructed on a new property, considerable site development is required, which may include a haul truck access road, fencing and gates around the property, power to the new site, monitoring wells up- and down-gradient of the new facility, and a water return pipeline to allow the pumping of excess contact water from the site to the ash water tanks within the plant.

In addition, haul trucks will be required to cross a county road to deliver fly ash from the plant to the new facility. For safety and operational flexibility, a new country road bridge should be constructed to allow haul truck traffic under the county road. This bridge would include the bridge structure as well as the grading and embankment costs associated with the approach on the county road.

4.2.3 Liner

A liner design based on RCRA Subtitle D standards and historic practice at CCS was utilized. The assumed liner system is shown in Figure 9 and consists of (from bottom to top) a compacted clay layer (1×10^{-7} cm/sec maximum permeability), a geomembrane liner, a leachate collection layer consisting of drainage material, piping and sumps, and a protective cover layer.

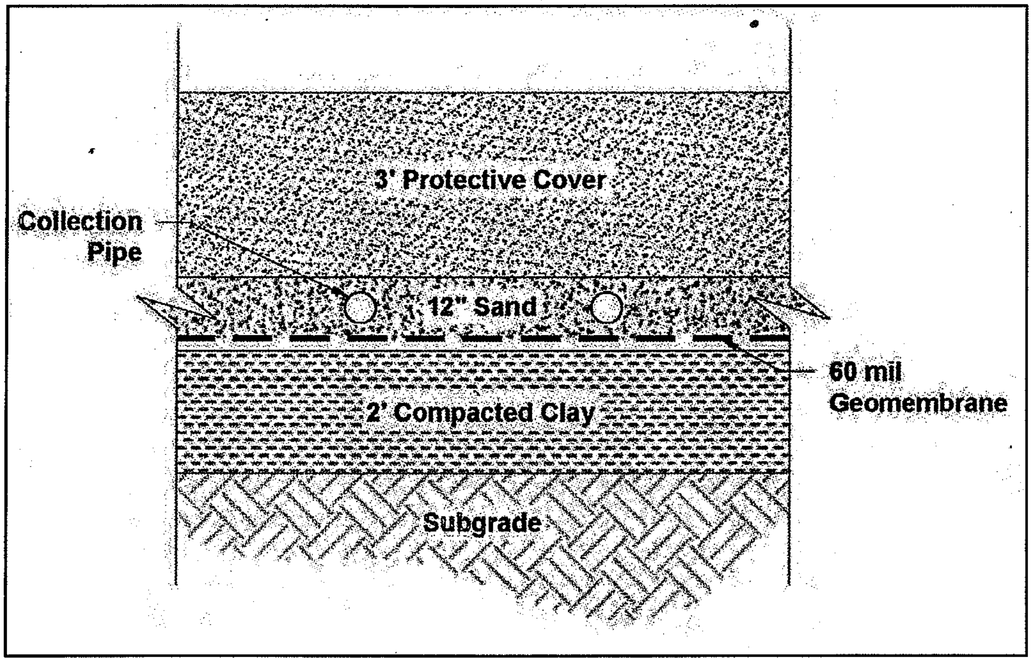

Figure 9: Composite Liner Detail

4.2.4 Cover

The final cover is also design based on RCRA Subtitle D standards and historic practice at CCS. The assumed cover system is shown in Figure 10 and consists of (from bottom to top) a compacted soil layer ($1x10^{-5}$ cm/sec maximum permeability), a textured geomembrane, a drainage layer consisting of drainage material and piping, and a vegetation layer. The drainage layer over the geomembrane is required to control the head on the liner and the resulting stability of growth medium. In addition, the cover will utilize terrace channels and armored down-chute channels to manage surface water runoff and reduce erosion.

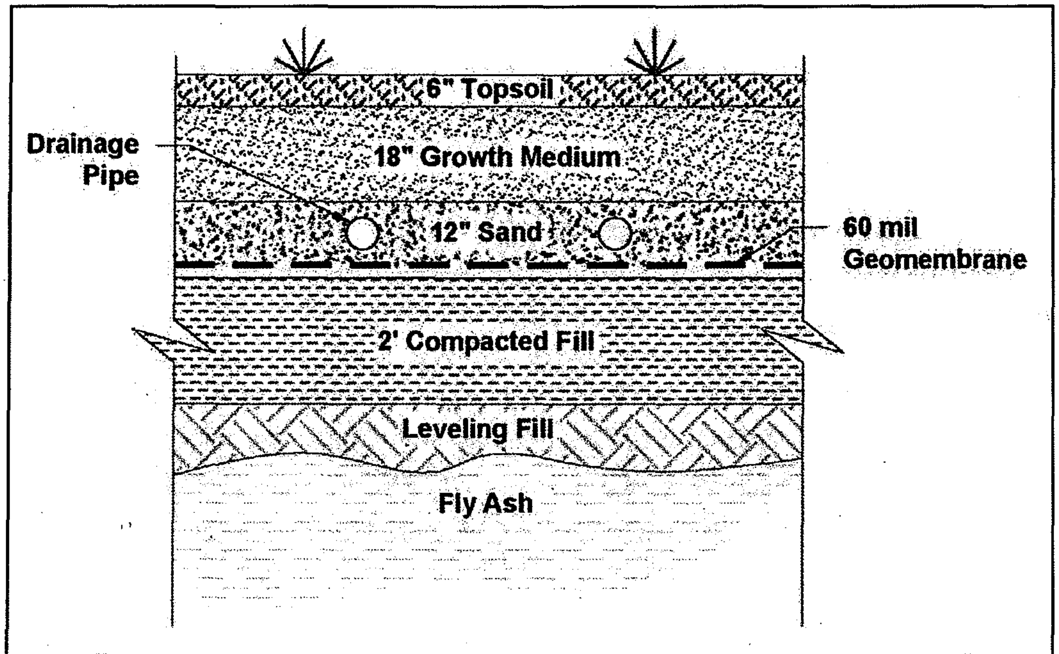

Figure 10: Composite Cover Detail

4.3 Cost Estimate

The cost estimate includes costs for the life of the disposal facility including engineering, design, and permitting; construction; and operations and maintenance, including closure and post-closure care. Golder used actual costs from similar projects at CCS, local contractor rates, RS Means manuals (RS Means 2010), and professional judgment to develop this cost estimate. Sources and assumptions are documented. Some general assumptions for the cost estimate include:

- All costs are estimated in 2011 dollars.
- Capital costs are annualized based on a 20-year life and 5.5% interest rate.
- Existing fly ash processing equipment (silos, unloaders, etc.) is not included. Disposal costs begin once the haul trucks are loaded with fly ash.
- Existing fly ash sales infrastructure (silos, scales, rail facilities) and operations and maintenance are not included.
- Disposal costs only include fly ash disposal and not facility airspace or operations and maintenance for other coal combustion products produced at CCS.

4.3.1 Engineering, Design, and Permitting

This item is estimated as 10% of the total construction costs to develop the facility. Ten percent is based on Golder's experience with coal combustion product facilities within the Midwest. The components included in this cost may include a facility siting evaluation, design of the facility, submittal of a solid waste landfill permit as well as permit renewals, submittal of air permits and NDPES permits, and creation of construction and bid packages for the facility.

Great River Energy's
Legal and Technical Review Of
U.S. EPA's BART Determination for Coal Creek Station

I. INTRODUCTION

On March 2, 2012, EPA issued its *Approval and Promulgation of Implementation Plans; North Dakota; Regional Haze State Implementation Plan; Federal Implementation Plan for Interstate Transport of Pollution Affecting Visibility and Regional Haze*, 76 Fed. Reg. ____(April __, 2012) ("FIP"). EPA largely upheld the North Dakota Department of Health's ("NDDH's") SIP with two exceptions: the NOx Best Available Retrofit Technology ("BART") requirement for Great River Energy's Coal Creek Station ("CCS"), and Reasonable Progress requirements for Basin Electric's Antelope Valley Station. Below, GRE addresses EPA's FIP and its rationale for requiring selective non-catalytic reduction ("SNCR") at CCS. In particular, GRE explains that EPA failed to rationally apply the Clean Air Act's ("CAA's") five-factor BART analysis and GRE responds to key EPA arguments for rejecting NDDH's BART determination.

In rejecting NDDH's BART determination for CCS, EPA made numerous errors, including the following:

- Conducted an improper cost analysis by ignoring the existing controls in use at CCS, including LNC3+ and DryFining™;

- Failed to analyze, or ignored, the incremental cost of SNCR compared to existing and planned controls at CCS, including LNC3+ and DryFining;

- Ignored the demonstrated lack of visibility benefits resulting from its requirement to install SNCR at CCS; and

- Rejected, without validated support, the likelihood of ammonia slip and fly ash contamination.

Beyond these errors, EPA purported to reject NDDH's BART determination for CCS because NDDH relied on cost analyses that contained an error in one component of the costs – the cost of ash contamination and disposal. While objecting to this one component, EPA rejected NDDH's entire BART analysis and NDDH's valuation of the other four, equally important, factors in the BART determination.

The foregoing errors, as well as EPA's failure to give any credence to the values that NDDH's placed on the other BART factors, demonstrate that EPA did not conduct a valid BART analysis for CCS. EPA failed to comply with the CAA requirements and the Agency's own guidelines.

II. EPA's "COST OF CONTROLS" ANALYSIS IS INCONSISTENT WITH THE STATUTE AND EPA'S OWN GUIDANCE

EPA's principal basis for rejecting NDDH's BART determination was NDDH's reliance on purportedly incorrect information regarding the cost associated with ammonia contamination of merchantable fly ash resulting from using SNCR. GRE has addressed the cost issue that EPA raised and has reflected those changes in GRE's Supplemental Best Available Retrofit Technology Refined Analysis for NOx Emissions, April 5, 2012 ("BART Supplement"). EPA asserts, incorrectly, that there should be no ammonia slip or fly ash contamination from using SNCR.[1] However, EPA's own cost analysis is seriously flawed and inconsistent with both the CAA and its own Guidance. EPA made two significant errors in conducting its cost analysis of SNCR. First, it ignored the emission controls already installed and in use that have significantly reduced NOx emissions at CCS. Second, EPA failed to examine the incremental, or marginal, costs of SNCR beyond the existing and planned controls at CCS.

A. <u>EPA Failed to Consider Existing Pollution Controls in Use at CCS and Current Emissions in Performing Its Cost Analysis</u>

Under CAA §169A, the State (or EPA Administrator) must take into consideration five factors in determining BART. One of the five factors is "any existing pollution control technology in use at the source." 42 U.S.C. § 7491(g)(2). EPA completely disregarded this obligation and, instead, relied on 9-year-old emissions data in its cost analysis. The effect of using the inaccurate, inflated emissions data is to distort EPA's cost numbers and make SNCR seem more cost-effective than it is.

EPA relied on emissions data from 2003 and 2004 in its cost analysis. EPA did this notwithstanding its acknowledgement that current emissions are significantly lower. *See* FIP at 20. Since 2004, GRE has made multiple improvements in the combustion and emissions at CCS, including: (1) installing new, adjustable SOFA nozzles in Unit 1 in 2005; (2) installing expanded over-fire air registers in Unit 2 in 2007; (3) installing close coupled over-fire air (CCOFA) on Unit 2 in 2010; and (4) installing DryFining at both units in 2010. All of these measures had beneficial impacts on NOx formation and emissions, reducing emission rates at Unit 2 from 0.22 lbs/mmBtu in 2004 to 0.153 currently. For Unit 1, emissions were reduced from 0.22 in 2004 to 0.20 lbs/mmBtu in 2010.

EPA's failure to acknowledge these installed controls is inconsistent with the plain language of the statute and EPA's own BART guidance. "[B]aseline emissions rate should represent a realistic depiction of anticipated annual emissions for the source." *See* 69 Fed. Reg. 25224. EPA's reliance on 2003 - 2004 emissions from CCS is not a "realistic depiction" of CCS's current or anticipated emissions. By using incorrect emissions data, EPA created and relied on admittedly inaccurate cost effectiveness numbers, the very grounds on which it rejected NDDH's BART determination.

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[1] EPA's assertion is addressed below in Section IV, and by Golder Associates in Exhibit G to the BART Supplement.

EPA's explanation for using inaccurate emission data is both irrational and inapposite to CCS. EPA argues that using emissions resulting from existing emission controls (as required by the statute) would "reward sources that install lesser controls in advance of a BART determination in an effort to avoid more stringent controls." FIP at 95. Whatever EPA's policy considerations, GRE did not install such controls to "game" the BART process. The DryFining technology involved a multi-year, $270 million investment in partnership with the Department of Energy to improve the emissions resulting from coal combustion. The installation of new SOFA nozzles and LNC3+ was done as part of DryFining and in cooperation with the NDDH to achieve better combustion and lower NOx emissions. There is nothing in the record to suggest any of this was done to avoid more stringent BART. It was not.

EPA's statement that these controls were "voluntary" and, thus, EPA need not consider them in evaluating BART is nonsensical. There is nothing in the statute that says voluntarily installed emission controls can or should be ignored. The statute says that EPA must take into consideration "*existing pollution control technology in use at the source*." EPA cannot simply assume emissions that do not exist to bolster its goal of making SNCR appear more cost effective than it is. Further, this is a policy decision beyond EPA's authority. Congress expressly requires EPA to consider existing controls when determining BART. *See* 42 U.S.C. § 7491(g)(2); *St. Mary's Hosp. of Rochester, Minnesota v. Leavitt*, 535 F.3d 802, 806 (8th Cir. 2008) ("The plain meaning of a statute controls, if there is one, regardless of an agency's interpretation."). Although that may result in companies having to do less under BART, that may be precisely what Congress intended. Encouraging sources to install controls voluntarily – as CCS did – results in achieving emission reductions and visibility improvements earlier than might otherwise be required. EPA's policy would discourage companies from ever voluntarily reducing emissions; in other words, EPA is pursuing the "no good deed goes unpunished" theme of regulation.[2]

Finally, EPA acknowledges that it refused to use accurate, current emission rates from CCS because using the lower emission levels would "skew the 5-factor BART analysis by reducing the emissions reductions from combinations of control options and increasing the cost effectiveness values." FIP at 98. This admission lays bare the inaccuracy of the Agency's cost effectiveness assertions and the inappropriateness of EPA's BART determination for CCS.

B. EPA Failed to Properly Calculate and Consider the Incremental Cost of SNCR in Making Its BART Determination

EPA also failed to consider the incremental cost of SNCR in contravention of its own regulations and guidance. EPA guidelines direct the states as follows. "In addition to the average cost effectiveness of a control option, you *should* also calculate incremental cost effectiveness. You *should* consider the incremental cost effectiveness in combination with the total cost effectiveness in order to justify elimination of a control option. *See* 69 Fed. Reg. 25224 (emphases added); 70 Fed. Reg. 39127 ("We *continue* to believe that *both* average and

[2] By EPA's logic, GRE should have done nothing over the past nine years while waiting for a BART determination. This would have postponed any NOx reductions from approximately 2005 until 2018 (five years after BART is determined).

incremental costs provide information useful for making control determinations.") (emphases added).

To justify SNCR, EPA inexplicably ignored half of its own "cost of controls" analysis. Instead, EPA looked only at the total cost of installing both LNC3+ *and* SNCR (as opposed to SNCR alone) and compared that total cost to the emission reductions achieved using both technologies. As discussed above, the emission reductions from LNC3+ (in addition to the DryFining) already have been achieved at Unit 2 and the LNC3+ is planned for Unit 1. The cost of LNC3+ is a small fraction of the costs of SNCR, yet it generates most of the NOx emission reductions. By combining the two costs into one control option, EPA further distorts the cost-effectiveness of SNCR. If EPA had looked at the cost-effectiveness of SNCR alone (i.e., incremental cost), it would have to admit that the emission rate would decline by only 0.023 lbs/mmBtu: from 0.153 lbs/mmBtu to EPA's proposed rate of 0.13 lbs/mmBtu.

The impact of EPA's error is dramatic. Even if we accepted EPA's unfounded assumption that there would be no fly ash contamination resulting from SNCR, the incremental cost of using SNCR would be $8,534 per ton for Unit 1 and $4,688 per ton for Unit 2. EPA's estimate that the cost effectiveness is under $2,500 per ton is misleading because the cost-efficient reductions come from the use of LNC3+, a technology already installed at Unit 2 and planned for Unit 1.[3] *See* BART Supplement, Table 3.1. SNCR cannot be justified on the basis of achieving such a small incremental reduction in NOx emissions at such high costs, particularly in light of the other factors that weigh against SNCR.

III. EPA Failed to Properly Consider the Lack of Visibility Benefits Resulting From the Installation of SNCR

The flaws in EPA's BART analysis were not limited to only cost-related considerations. EPA also failed to give serious consideration to other statutory factors that Congress required to be part of any BART analysis, especially the lack of any demonstrable visibility benefit resulting from SNCR. The modeling on which both NDDH and EPA relied demonstrates that there would be no discernable visibility improvement resulting from installation of SNCR. *See* 76 Fed. Reg. 58,622. The degree of predicted visibility improvement, approximately 0.105 deciviews, is only one tenth of the level that EPA asserts is perceivable by the human eye. Given the many sources of variability of inputs to CALPUFF's visibility analysis versus actual impacts, a difference of 0.1 deciviews between options may reflect no real difference at all. *See* attached Memorandum from Andrew Skoglund, Barr Engineering, to William Bumpers (April 4, 2012).

EPA made no effort in its final rule to dispute that there will be no real improvement in visibility resulting from SNCR. Instead, EPA surprisingly states that "perceptibility of visibility improvement is not a test for the suitability of BART controls." FIP at 112. While EPA later acknowledges that deciview improvements is one of the five factors, it then says that the "Guidelines provide flexibility in determining the weight and significance to be assigned to each factor" and that achieving a perceptible benefit of 0.5 deciview is not a prerequisite for selecting

[3] The significantly higher incremental costs associated with Unit 1 are due to lower utilization and associated emissions at Unit 1 compared to Unit 2.

BART. FIP at 112. While Congress made clear that the state has great discretion in deciding the weight to accord each factor, EPA has effectively eliminated any import associated with the one factor (visibility) that is the central focus of the regional haze rule. EPA is simply imposing controls and costs on CCS notwithstanding that EPA cannot predict with any confidence that there will be any visibility improvement. This is contrary to the entire objective of the statute.

EPA's only attempt to justify ignoring the lack of visibility benefits resulting from its proposed BART was to note that NDDH was satisfied with a similarly small improvement at another source. *See* 76 Fed. Reg. 58,623. But this explanation completely ignores NDDH's source-specific determination for CCS that an estimated 0.1 deciview improvement did not justify the large costs of SNCR. *See* 76 Fed. Reg. 58,624. EPA's attempt to cherry pick the visibility level from a separate BART analysis ignores NDDH's valuation of all of the other four factors, including a much lower cost, that affected the determination.

Even the theoretical improvement of 0.105 deciviews is likely exaggerated. EPA criticizes the modeling that GRE provided because the various control scenarios were modeled together; that is, the NOx control options were modeled along with the SO_2 reductions. But EPA has repeatedly recognized that its modeling requirements overstate real-world visibility improvements by five to seven times. *See, e.g.,* EPA North Dakota Proposed FIP, Technical Support Document, B-41; FIP at 55. EPA's justification is that modeling based on "current degraded visibility conditions would result in a smaller relative benefit than would a comparison relative to natural background visibility." FIP at 55.[4] Importantly, EPA admits that it undertook no independent modeling of the prescribed emission reductions, so EPA cannot state that SNCR will result in *any* visibility improvement, FIP at 99.

IV. EPA's Conclusion that SNCR Will Result In No Fly Ash Contamination Is Unrealistic

The principal basis EPA cites for rejecting NDDH's BART determination is that NDDH had relied on costs provided by GRE for installation of SNCR that included one incorrect value – the cost of disposing of contaminated fly ash.[5] *See* 76 Fed. Reg. 58,603-04. GRE has corrected that value.[6] As discussed above, even if we assumed that there would be zero contamination of the fly ash, the marginal cost of SNCR ($4,688 per ton for Unit 2 and $8,534 per ton for Unit 1) coupled with the lack of any visibility benefit cannot justify SNCR. But EPA's assertion in the FIP that there will be no wastage of fly ash is not supportable. Exhibit G to the BART Supplement is a report from Golder Associates, addressing EPA's assertion that SNCR would not result in any fly ash contamination and reaffirming the expected costs of fly ash disposal. As demonstrated by Golder Associates and below (1) EPA's assertion that CCS could maintain ammonia slip to below 2 ppm is unsupported and almost certainly wrong; and (2) even at 2 ppm

[4] Put differently, EPA does not allow modeling of what is expected to actually happen because that would confirm EPA's approach results in little or no real-world visibility improvements.

[5] GRE had initially included FOB price of ash. The value was not in error, but GRE agreed that the FOB price was not the correct value for the BART cost analysis.

[6] Golder Associates concludes that a cost of $12.30 per ton is the expected cost of lost fly ash sales resulting from ammonia contamination. BART Supplement, Exhibit G at 6.

ammonia slip, a significant amount of CCS's fly ash would become unmerchantable and require disposal.

In EPA's proposed BART determination, EPA recognized that using SNCR could, and likely would, result in some contamination of GRE's merchantable fly ash at CCS. *See* 76 Fed. Reg. 58,620-21. Consequently, EPA assigned costs to SNCR associated with the lost sales and increased disposal costs associated with the contaminated fly ash. *Id.* In the final FIP, EPA asserts that SNCR at CCS would not contaminate any fly ash because "current technology has made it possible to control ammonia slip from SNCR to levels . . . in a range of 2 ppm or less." *See* FIP at 102. In making this remarkable assertion, EPA relies essentially on a single case study – the "Andover Report." *See* FIP at 102 n.32. The Andover Report provides virtually no support for EPA's claims.

The Andover Report's results cannot be relied on to make any operating assumptions about CCS. It states upfront that "[e]xperience with the TDLAS method on coal power plants has had mixed success – and unfortunately, *far more failures than successes*." Andover Report at page 5 (emphasis added). In the course of examining this technology further, the Andover Report analyzes the use of SNCR at the CP Crane station in Baltimore. The CP Crane station consists of two, 200MW cyclone boilers. It is subject to the Maryland Healthy Air Act, a law that imposes a company-wide, NOx tonnage limitation on power plant owners. CP Crane is one of multiple plants owned and operated by Constellation Energy in Maryland. Constellation installed NOx controls on all of its plants in Maryland, installing SCR on its larger, base load plants, and installing SNCR on CP Crane. GRE contacted Constellation about EPA's assertions. Constellation officials informed GRE that the plant conducted four, one-hour performance tests when commissioning the system,[7] on which the Andover Report is based. Since this commissioning test, Constellation has rarely run the SNCR at CP Crane. Constellation's plant is not subject to a short term NOx rate limit, is not subject to an ammonia slip limit and Constellation does not monitor the ammonia slip. The SNCR system has process monitors but they are not certified. The initial NOx rate at these cyclone burners is approximately 0.4 lbs/mmBtu. Because there is no enforceable NOx rate, the level of ammonia injection is completely discretionary. Constellation does not know what its actual ammonia slip rate is, or would be if the SNCR were actually being utilized. Thus, Mr. Staudt's paper, which is based on the initial, short-term, commissioning test, in no way represents a reasoned basis for EPA's assertions that ammonia slip can be held consistently below 2 ppm or that there will be no fly ash loss as a result of installing SNCR at CCS.[8]

In response to EPA's FIP, Golder Associates ("Golder") has re-examined the literature on the impact of ammonia on fly ash, including the studies referenced by Dr. Sahu in the FIP. *See* FIP at 102 n.35. Golder demonstrates that there is no literature that supports EPA's contention that no fly ash wastage is expected. To the contrary, even if ammonia slip could be limited to 2 ppm on a constant basis – something that has never been demonstrated – ammonia

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[7] This short-term commissioning test is hardly an indication of what can be achieved at a much larger facility over a longer term and a wider range of operating levels.

[8] EPA's reference to the Big Brown plant in Texas is similarly unpersuasive. According to EIA data and Luminant, Big Brown landfills approximately one third of its fly ash.

concentration in fly ash could be as high as 100 ppm, which Golder concludes would significantly limit the sale of CCS's fly ash. BART Supplement, Exhibit G at 3-4.

Golder also addresses EPA's criticism of the costs assigned for disposing of contaminated fly ash. BART Supplement, Exhibit G at 5-6. Golder points out that its costs are based on NDDH Solid Waste Management and Land Protection regulations (NDDH, http://www.legis.nd.gov/information/acdata/html/33-20.html). NDDH's rules require controls such as composite liners, leachate collection systems, surface water controls, and ground water monitoring. As a result, Golder estimates the cost of fly ash disposal to be between $11 and $18 per ton. Golder also demonstrates that EPA's estimate of $5 per ton is not supported by any analysis and is inconsistent with EPA's own regulatory impact analysis from 2010, which estimated a range of $2 to $80 per ton, with an average cost of $59 per ton. BART Supplement, Exhibit G at 5. Golder also confirms that the cost of lost fly ash sales for GRE is $12.30 per ton. BART Supplement, Exhibit G at 6.

Perhaps recognizing the fundamental weakness of its assertion, EPA noted that even if SNCR did cause some ammonia contamination, "three possible systems" could be used to cure the problem. *See* FIP at 102 n.35. EPA did not even bother to analyze whether any of these technologies might actually work at CCS. The manufacturer of one of those technologies stated that "[t]he limited current experience in commercial application and lack of research is not adequate for Headwaters to be able to provide any guarantee that the process can be successfully applied to treat lignite ash at the Coal Creek Station." *See* July 15, 2011 Email from Rafic Minkara, PhD., PE (Headwaters) to John Weeda (GRE), forwarded to Gail Fallon and Carl Daly (EPA) on July 15, 2011. Despite the manufacturer's lack of confidence as to whether its own technology would work, EPA asserted its "consultants are aware of no technical reason that ASM technology would not be effective to mitigate ammonia on fly ash from lignite." *See* FIP at 102 n.35. EPA cites nothing to justify its conclusion that the technology in question should work when the technology's own creator refused to support the conclusion. Making bald assertions that are unsupported at best, and flatly contradicted at worst, by evidence in the record is textbook arbitrary and capricious.

III. EPA'S CONSIDERATION OF THE OTHER FACTORS WAS IRRATIONAL

A. Other Cost Errors

1. EPA Arbitrarily Rejected URS's Cost Data

EPA's disregard of construction cost analysis of SNCR at CCS is unfounded. URS is a leading engineering and construction company that has participated in the construction and installation of SNCR projects at more than 30 coal-fired power plants. EPA's criticism that URS is not an SNCR vendor, and thus unable to opine on the costs of installing SNCR at CCS is arbitrary and capricious. *See* FIP at 121-124. As URS states:

> URS is not a technology supplier. The supplier is typically responsible for installation of only their process island and system performance guarantees. The installation of the balance of plant (BOP) equipment, construction management, foundations, utility tie-ins (electrical, water, air, instrumentation and controls

> interface, interconnecting piping, new flue gas emissions monitoring equipment, boiler and air heater modifications, retrofit difficulty due to existing plant access and congestion issues, et al) typically falls outside of the scope of supply for the SNCR vendor. Published cost estimates and vendor proposals in many cases do not consider these BOP cost impacts on the Total Capital Requirement for the installation of emissions control equipment. URS's project experience provides a basis for the assessment of these BOP costs that must be added to the vendor supplied equipment's installed costs to determine the true total capital cost of an installation.

See Letter from URS to Debra Nelson, March 30, 2012, BART Supplement, Exhibit F.

URS also has reconfirmed the basis for the retrofit factor of 1.6 based on the difficulty of installation at CCS. *See* BART Supplement, Exhibit F. URS also further explains the basis for its skepticism regarding SNCR's effectiveness when the initial NOx emission rates are in the lower range, similar to the NOx rate at CCS Unit 2. *See* BART Supplement, Exhibit F. EPA simply had no reasoned basis for disregarding URS's cost and performance analysis. EPA repeatedly refers to information from SNCR-designer Fuel Tech, but EPA's information appears to have been gleaned largely from a promotional website rather than site-specific analysis. *See* FIP at 20 n.2, 97 n.29. EPA's claim that its "consultant" received some sort of input from a SNCR vendor is so vague as to render it useless. *See* FIP at 102 n.34. The record does not show that EPA asked Fuel Tech to evaluate whether its technology would work at CCS. In any event, the follow up analysis provided by URS demonstrates that its cost analysis is well grounded.

2. EPA Provided No Rational Basis for Departing From its Guidelines' Presumptive Values

EPA's FIP ignored the Agency's own Guidelines, which require careful consideration of EPA's presumptive emissions limits. EPA's Guidelines explain that "we believe that States should carefully consider the specific NOx rate limits for different categories of coal-fired utility units, differentiated by boiler design and type of coal burned, set forth below as likely BART limits." *See* 70 Fed. Reg. 39134. EPA went on to note that "States have the ability to consider the specific characteristics of the source at issue and to find that the presumptive limits would not be appropriate for that source." However, EPA's BART analysis does not even acknowledge the existence of its own presumptive emissions limits much less reflect "careful" consideration of them. *See* 76 Fed. Reg. 58620-23. Furthermore, EPA offers no explanation why a departure from them is appropriate in this particular case, particularly where no visibility benefit would result from doing so. EPA cannot ignore its own Guidelines and nonetheless claim to have undertaken a legally-adequate BART analysis. EPA certainly would not allow a state to do so.

B. Energy and Non-Air Quality Environmental Impacts of Compliance

The CAA also requires consideration of the energy and non-air quality environmental impacts resulting from the use of relevant control technologies. This includes the energy requirements of the technology, the local availability of necessary fuels, and the generation of solid or hazardous wastes as a result of applying a control technology. *See* 70 Fed. Reg. 39,169. As already discussed above, EPA assumed contrary to all reasonable evidence that no fly ash

would be contaminated due to SNCR. EPA was therefore able to avoid considering the non-air environmental impacts arising from the creation of hundreds of thousands of tons of solid waste (and perhaps hazardous wastes depending on EPA's consideration of how to regulate fly ash). EPA's unsupported conclusion about fly ash therefore prevented EPA from properly considering two factors – the cost of controls and non-air environmental impacts.

IV. CONCLUSION

EPA rejected NDDH's entire BART analysis principally because of a purported error in a single cost component: the cost of contaminated fly ash. EPA then utilized flawed cost analysis and inaccurate emissions data to justify installation of SNCR. EPA effectively ignored all of the other BART factors, especially the lack of any measurable visibility improvement that might result from investing tens of millions of dollars to install and operate SNCR. GRE has provided NDDH with a revised BART analysis, including a refined cost analysis that examines the average and incremental cost, and cost-effectiveness of various levels of NOx emissions control. In light of the lack of any discernable visibility improvement at any Class I area, NDDH would be justified in supporting its initial BART determination at any cost level, including EPA's artificially low average cost per ton of $2500 per ton. The actual incremental cost of SNCR will be $4,688 per ton and, for Unit 1, will be $8,534 per ton, even if no costs are assigned to the loss of merchantable fly ash. The costs are significantly higher, and other environmental impacts worse, if fly ash contamination were to result from using SNCR. The documentation demonstrates this is very likely.

NDDH's initial BART determination was in compliance with the statutory obligations. With the refined BART analysis, and updated cost information, NDDH can make its own BART determination, assigning its own values to the five BART factors and should not accept EPA's usurpation of NDDH's authority.

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Memorandum

To: William Bumpers, Baker Botts L.L.P.
From: Andrew Skoglund
Subject: CALPUFF Visibility Impact Variations
Date: 4/4/2012
Project: 34280013.01
c: Mary Jo Roth, Debra Nelson - GRE; Joel Trinkle, Laura Brennan - Barr

CALPUFF is the USEPA's preferred model for assessing visibility impacts at Class I Areas resulting from long range (50 – 300 km) plume transport. CALPUFF is a multi-source model which accounts for plume advection and atmospheric chemical reactions to estimate the concentrations of primary chemical species (ammonium nitrate, ammonium sulfate, elemental carbon, organic carbon, fine particulate and soil) known to cause haze (i.e., visibility impairment). Plumes in CALPUFF are transported using sophisticated meteorological data and plume transformations from atmospheric chemical reactions occur due to interactions of plume pollutants, background atmospheric pollutants (ozone and ammonia) and meteorological variables – most importantly water vapor as represented by relative humidity.

Visibility impairment is calculated as a function of the light scattering properties of atmospheric particles and gases. An increase in light scattering particles decreases the visual range as measured in deciviews. The EPA estimates that a sensitive observer may be able to detect a variation of 0.5 deciviews, with 1.0 deciviews being a more accepted threshold for distinguishable difference in visual impairment. Modeled visibility impacts of 0.1 deciviews are therefore indistinguishable to the human eye.

Calpuff modeled visibility impacts are reported in the model output files to thousandths of deciviews. However, this level of sensitivity overstates the potential accuracy of the model when compared to real-world observations. Assessments of the CALPUFF modeling suite versus real-world monitoring data demonstrate the potential for significant differences between modeled and actual concentrations. There are many model inputs which play a role in impact variability, ranging from background chemistry data to emissions data entered into the model.

Visibility calculations are directly affected by the background chemistry input to the model. While ozone is input to the model based on hourly observations from available monitoring locations within the modeling domain, ammonia inputs are calculated monthly average values. The use of monthly ammonia background concentrations in the model, allows for consistency between modeling runs, but is a simplification of the actual conditions and impacts to visibility. Variation in ammonia background can have a measurable effect on the chemical transformations in the model, and in turn on modeled visibility impacts. The background values for visibility impairing pollutants (ammonium nitrate, ammonium sulfate, elemental carbon, organic carbon, fine particulate, and soil.) are based on projected values of pristine or natural conditions. These also are input as monthly average background levels. Variability in actual backgrounds, while demonstrating definite seasonal changes, is not limited to changing by calendar month.

Additionally, the fixed nature of the modeled emissions utilized in BART analyses does not reflect actual operations of a facility. Few facilities will operate at their maximum 24-hour rate 365 days per year. The emission rates and parameters for the potential modeled scenarios use assumed emissions and fixed stack parameters (e.g. exhaust temperature, airflow) for scenarios not already in operation at a facility. Final design may yield variations in these parameters, an additional source of impact variability. There is the possibility for considerable variation in actual emissions versus the modeled maximum rates used for BART analysis. It could be expected that small changes to the source parameter assumptions would result in small changes to the model results. Therefore, if the assumed stack flow rate or temperature for the EPA BART controls were misrepresented by 10 - 20% from potential as-built values, it could be possible that the deciview difference would be on the order of 0.1 deciviews – i.e., within the sensitivity of the model.

Inasmuch as the BART modeling analysis methodology is proscriptive (e.g., model each facility individually, use background monthly ammonia values, etc…), the CALPUFF results from one model run to the next can be useful in a relative sense and not in an absolute sense (i.e., the CALPUFF model results are not expected to reflect observed values). However, the difference in results from any two modeling runs needs to be understood in context of the parameter estimated. For the BART analysis, the parameter of interest is deciviews and the human perceptibility threshold is 0.5 deciviews. On this basis, differences in model run results of less than 0.5 deciviews are not significant.

For the CCS modeling analysis, the model run differences are 1) baseline – current controls compared to 2) baseline – EPA BART controls. In both cases, the relative model results (baseline – controls) show a fairly large difference (up to 2 deciviews), giving some confidence in the modeling results that controls would result in perceptible improvements to visibility. However, the EPA's contention that the 0.1 deciview difference between 1) and 2) is actionable based on modeling, ignores the fact that 0.1 is the difference between two large numbers.

Given the many sources of variability of input to CALPUFF's visibility analysis versus actual impacts, a difference of 0.1 deciviews between options may reflect no real difference at all.

Appendix D

Visibility Impact Tables

Summary of Modeling Inputs

Description		Emission Rate Input									
		Stack Velocity	PM10		PM2.5 (fine)	PM (coarse)	SO_2		NOx		
NOx Control	Units	m/s (ft/s)	% reduction	lb/hr	lb/hr	lb/hr	% reduction	lb/hr	% reduction	lb/hr	30-Day Rolling lb/MMBtu
Pre-BART Protocol	1	25.9 (85)	NA - base	249.2	101.9	147.3	NA - base	5733.5	NA - base	1772.3	NA - base
	1& 2	25.9 (85)	NA - base	465.3	190.3	275.0	NA - base	10702.8	NA - base	3594.7	NA - base
LNC3+	1	16.8(55)	0%	249.2	101.9	147.3	69%	1756.4	31%	1227.6	0.19
	1& 2	16.8(55)	0%	465.3	190.3	275.0	67%	3514.8	32%	2456.5	0.19
LNC3+ with Tuning	1	16.8(55)	0%	249.2	101.9	147.3	69%	1756.4	39%	1083.1	0.17
	1& 2	16.8(55)	0%	465.3	190.3	275.0	67%	3514.8	40%	2167.5	0.17
SNCR	1	16.8(55)	0%	249.2	101.9	147.3	69%	1756.4	49%	902.6	0.14
	1 & 2	16.8(55)	0%	465.3	190.3	275.0	67%	3514.8	50%	1806.3	0.14
SNCR with LNC3+	1	16.8(55)	0%	249.2	101.9	147.3	69%	1756.4	56%	776.2	0.12
	1& 2	16.8(55)	0%	465.3	190.3	275.0	67%	3514.8	57%	1553.4	0.12

Year 2000 Modeling Results

Description			Visibility Impairment											
			TRNP South Unit			TRNP North Unit			TRNP Elkhorn Ranch			Lostwood WA		
NOx Control	Units	Average Improv-ement	Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV	Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV	Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV	Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV
Pre-BART Protocol	1	--	24	0.299	1.229	21	0.318	0.941	18	0.212	0.777	37	0.503	1.183
	1& 2	--	41	0.553	2.176	41	0.586	1.836	35	0.401	1.391	58	0.945	2.157
LNC3+	1	59%	7	0.125	0.494	6	0.124	0.446	2	0.088	0.314	7	0.215	0.499
	1& 2	59%	17	0.217	0.860	16	0.235	0.959	10	0.186	0.596	28	0.376	0.954
LNC3+ with Tuning	1	61%	7	0.119	0.467	6	0.118	0.416	2	0.082	0.300	6	0.207	0.469
	1& 2	56%	18	0.251	0.970	18	0.245	0.909	11	0.175	0.627	29	0.426	0.983
SNCR	1	86%	0	0.041	0.157	0	0.042	0.138	0	0.029	0.103	1	0.069	0.166
	1 & 2	86%	5	0.080	0.310	4	0.083	0.290	2	0.056	0.209	3	0.140	0.326
SNCR with LNC3+	1	65%	6	0.106	0.410	6	0.105	0.352	2	0.072	0.270	4	0.180	0.417
	1& 2	58%	17	0.235	0.918	17	0.236	0.860	10	0.163	0.605	26	0.409	0.924

Year 2001 Modeling Results

Description		Average Improv-ement	Visibility Impairment												
			TRNP South Unit			TRNP North Unit			TRNP Elkhorn Ranch			Lostwood WA		
NOx Control	Units		Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV	Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV	Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV	Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV
Pre-BART Protocol	1	--	21	0.251	1.209	27	0.372	1.154	16	0.192	1.056	40	0.503	1.183
	1& 2	--	34	0.466	2.181	46	0.694	2.094	27	0.365	1.949	56	0.945	2.157
LNC3+	1	58%	8	0.116	0.509	9	0.142	0.547	8	0.076	0.505	21	0.215	0.499
	1& 2	56%	19	0.230	0.986	25	0.282	1.069	14	0.151	0.984	34	0.215	0.499
LNC3+ with Tuning	1	60%	7	0.108	0.482	8	0.136	0.512	6	0.076	0.473	18	0.207	0.469
	1& 2	58%	19	0.214	0.936	24	0.270	1.002	13	0.151	0.923	33	0.207	0.469
SNCR	1	62%	7	0.101	0.453	7	0.133	0.467	4	0.074	0.433	16	0.192	0.486
	1 & 2	60%	19	0.202	0.884	21	0.267	0.917	12	0.147	0.847	33	0.192	0.486
SNCR with LNC3+	1	64%	6	0.096	0.437	6	0.127	0.436	4	0.069	0.405	15	0.180	0.417
	1& 2	62%	18	0.194	0.854	20	0.253	0.858	12	0.137	0.793	31	0.180	0.417

Year 2002 Modeling Results

Description		Average Improv-ement	Visibility Impairment												
			TRNP South Unit			TRNP North Unit			TRNP Elkhorn Ranch			Lostwood WA		
NOx Control	Units		Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV	Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV	Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV	Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV
Pre-BART Protocol	1	--	38	0.540	2.559	30	0.385	2.113	23	0.310	1.703	32	0.385	1.814
	1& 2	--	50	0.971	4.475	45	0.706	3.557	42	0.581	3.039	45	0.707	3.190
LNC3+	1	57%	22	0.219	1.181	15	0.158	0.987	12	0.136	0.789	13	0.178	0.832
	1& 2	54%	32	0.433	2.218	26	0.313	1.880	18	0.269	1.524	26	0.350	1.601
LNC3+ with Tuning	1	59%	20	0.207	1.140	15	0.151	0.918	12	0.129	0.746	13	0.165	0.783
	1& 2	56%	32	0.410	2.145	26	0.298	1.755	18	0.256	1.443	25	0.325	1.510
SNCR	1	63%	20	0.193	1.088	14	0.138	0.850	11	0.123	0.692	12	0.148	0.722
	1 & 2	60%	32	0.382	2.055	24	0.273	1.601	17	0.243	1.342	24	0.292	1.397
SNCR with LNC3+	1	64%	20	0.186	1.052	14	0.131	0.813	11	0.118	0.654	11	0.141	0.680
	1& 2	61%	30	0.371	1.991	24	0.260	1.536	17	0.234	1.271	23	0.279	1.318

Average Incremental Control Comparison for 98th % Δ-dV

Description		Year 2000			Year 2001			Year 2002			Year 2000-2002 Average		
NOx Control	Units	Average Impairment	Improvement from Protocol	Incremental Improvement	Average Impairment	Improvement from Protocol	Incremental Improvement	Average Impairment	Improvement from Protocol	Incremental Improvement	Average Impairment	Improvement from Protocol	Incremental Improvement
Pre-BART Protocol	1	1.033	NA	NA	1.151	NA	NA	2.047	NA	NA	1.410	NA	NA
	1& 2	1.890	NA	NA	2.095	NA	NA	3.565	NA	NA	2.517	NA	NA
LNC3+	1	0.438	0.594	0.594	0.515	0.636	0.636	0.947	1.100	1.100	0.634	0.777	0.777
	1& 2	0.842	1.048	1.048	0.885	1.211	1.211	1.806	1.760	1.760	1.178	1.339	1.339
LNC3+ with Tuning	1	0.413	0.620	0.025	0.484	0.667	0.031	0.897	1.151	0.051	0.598	0.812	0.036
	1& 2	0.872	1.018	-0.030	0.833	1.263	0.052	1.713	1.852	0.093	1.139	1.378	0.038
SNCR	1	0.141	0.892	0.272	0.460	0.691	0.024	0.838	1.209	0.059	0.480	0.931	0.118
	1 & 2	0.284	1.606	0.589	0.784	1.312	0.049	1.599	1.967	0.115	0.889	1.628	0.251
SNCR with LNC3+	1	0.362	0.670	-0.221	0.424	0.727	0.036	0.800	1.248	0.038	0.529	0.882	-0.049
	1& 2	0.827	1.063	-0.543	0.731	1.365	0.053	1.529	2.036	0.070	1.029	1.488	-0.140

Appendix E

Low-Baseline NOx SNCR Demonstration (EPRI Study)

This appendix contains confidential business information and is being submitted under separate seal.
Copyrighted material is not currently available for public release.

Appendix F

URS SNCR Evaluation Supplement

URS

March 30, 2012

Debra Nelson
Great River Energy
12300 Elm Creek Boulevard
Maple Grove, MN 55369

RE: URS Response to EPA FIP Exchange

Dear Debra:

Great River Energy (GRE) contracted URS Energy & Construction (URS) to conduct a review of the costs and performance capability of Selective Non-Catalytic Reduction (SNCR) at their Coal Creek Station (CCS) Units 1 & 2. This review was requested to provide:

- A site-specific rough order of magnitude estimate with a stated accuracy of ±30% for the 2011 capital cost required for installation of SNCR onto the Coal Creek units
- Site-specific operating and maintenance costs for SNCR operation at Coal Creek
- The level of NOx reduction expected when using SNCR on these units.

Cost Estimating Methodology - The basis for the cost estimates was stated to be the EPRI IECCOST model, which URS previously developed for the Electric Power Research Institute. This model provides site-specific cost estimates for all types of emissions control system installations, including individual systems that are designed to remove SO_2, NOx, Hg, and particulate matter. It also evaluates costs for multi-pollutant control systems, producing conceptual cost estimates that are site-specific based on the plant location, current operating characteristics, fuels burned, etc.

EPRI IECCOST Model development has continued for more than ten years; during that period URS has installed all of the commercial systems at utility installations, and become intimately familiar with all emissions control technologies. Consequently URS is very familiar with the relationship between the vendor island costs and the Total Capital Requirement for an emissions control retrofit. This extensive project experience also identified the performance capabilities and emission rate guarantees for the various technologies through review of bid documents and budgetary quote submittals under real world conditions.

The model is updated and escalated continuously as new projects are completed, calibrating the cost estimating results against actual project costs and performance. The economic model used for these calculations is IECCOST Version 3.1 that will be published by EPRI later in 2012.

URS Capabilities and Qualifications - URS is an engineering and construction company that has provided emissions control technology assessments, economic analyses, balance of plant designs, construction, construction management and startup assistance to utility and other industrial clients since the 1970's. During this period, URS participated in more than 30 SNCR projects at multiple sites using systems supplied by multiple vendors.

Total Capital Requirement Cost Estimates - URS is not a technology supplier. The supplier is typically responsible for installation of only their process island and system performance guarantees. The installation of the balance of plant (BOP) equipment, construction management, foundations, utility tie-ins (electrical, water, air, instrumentation and controls interface,

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interconnecting piping, new flue gas emissions monitoring equipment, boiler and air heater modifications, retrofit difficulty due to existing plant access and congestion issues, et al) typically falls outside of the scope of supply for the SNCR vendor. Published cost estimates and vendor proposals in many cases do not consider these BOP cost impacts on the Total Capital Requirement for the installation of emissions control equipment. URS's project experience provides a basis for the assessment of these BOP costs that must be added to the vendor supplied equipment's installed costs to determine the true total capital cost of an installation.

Retrofit Factor - A site visit was made to the Coal Creek plant by one of the URS air quality control engineering staff. Based on his assessment of the site and the location for installation of the SNCR equipment, the retrofit difficulty for this plant was established to be moderately difficult due the constraints provided by existing equipment at the plant. Based on previous industry assessments of the cost impacts of retrofit difficulty, a retrofit factor of 1.6 was established for this moderately difficult SNCR installation. Previous industry surveys by Radian and Kellogg (EPA-450/3-74-015 – "Factors Affecting Ability to Retrofit FGD Systems" & EPA R2-72-100 – "Applicability of SO_2-Control Processes to Power Plants" and the EPA/600/S7-90/008 – "Verification of Simplified Procedure for Site-Specific SO_2 and NOx Control Cost Estimates") attempted to quantify the retrofit cost impacts compared to new equipment installations. These surveys established retrofit factors based on retrofit difficulty that are multiplied times the new plant installed cost estimates to determine the retrofit installed cost. The site assessment by the URS staff resulted in the moderately difficult retrofit assessment, which was translated in the capital cost estimate as a 60% adder to the new equipment installation cost to account for decreasing productivity due to movement of parts and materials around existing equipment and structures, limited access to construction sites due to overhead, underground and side obstructions by existing equipment, crane access, etc.

SNCR Expected Performance – SNCR system performance is directly impacted by the flue gas temperature at the point of urea/ammonia injection, and by the current concentration of NOx in the outlet flue gas. Injection outside the correct temperature window results in significant reductions in reduction efficiency. The lower the current NOx concentration in the outlet flue gas, the lower the reduction efficiency that can be achieved (reduced driving force for the NOx reduction reactions). The performance claims in published articles are typically short term, optimized test results, and are typically inflated compared to the performance guarantees that are actually offered for actual installations. Given the relatively low NOx concentrations in the Coal Creek flue gas, the reduction capabilities of SNCR were set at values in the 20-30% range based on data from other recent projects. The urea feed rate used in the calculation of operating costs

For comparison, recent FuelTech papers (one of the major SNCR vendors) stated that larger utility boilers (such as exist at Coal Creek at 605MW) have reported lower performance mainly due to the size of the units, inaccessible areas for injection, and load following control issues. NOx reductions in the range of 20 – 30% are common for units that start with NOx emission rates of 0.15-0.25 lbs NOx/MMBtu. Urea injection rates to obtain these reduction efficiencies varied from site to site, but fell in the range of 1.1-1.5 normalized stoichiometric ratio while maintaining acceptable ammonia slip rates. All-in costs for these systems were stated to be in the range of $10-20/kW. The injection rates assumed for this URS analysis of SNCR for Coal Creek used NSR injection rates that varied from 1.3-1.5 over the range of control evaluated of 20-30% NOx reduction. All of these performance values and estimated capital costs fall in the ranges stated in the supplier papers.

URS

If you have any additional questions, please contact me.

Sincerely,

Robert J. Keeth
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URS Energy & Construction, Inc.
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303-843-379
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Appendix G

Golder Fly Ash Evaluation Supplement

Golder Associates

April 2, 2012 Project No. 113-82161

Diane Stockdill
Great River Energy
Coal Creek Station
2875 Third Street SW
Underwood, North Dakota 58576

RE: SNCR IMPACT TO FLY ASH MARKETABILITY AND MANAGEMENT COSTS

Dear Diane:

1.0 BACKGROUND

Golder Associates Inc. (Golder) submitted a report to Great River Energy (GRE) on November 15, 2011, providing a third party review of Headwater's ammonia slip mitigation (ASM) technology. Additionally, the review included a detailed engineering estimate of potential disposal costs associated with fly ash impacted by ammonia slip from selective non-catalytic reduction (SNCR) emission controls at GRE's Coal Creek Station (CCS).

This report was included as part of GRE's submittal of November 21, 2011 to the U.S. EPA Region 8 (EPA), with comments responding to the Proposed Rule for the Approval and Promulgation of Implementation Plans: North Dakota Regional Haze State Implementation Plan, Federal Implementation Plan for Interstate Transport of Pollution Affecting Visibility and Regional Haze (Docket ID No. EPA-R08-OAR-2010-0406).

The EPA provided a prepublication version of the "final rule" to GRE on March 2, 2012, which included EPA's response to various comments including those in GRE's November 21, 2011 submittal:

- Section V: Issues Raised by Commenters and EPA's Responses;
- Part E: Comments on BART Determination;
- Subpart 2: CCS Units 1 and 2;
- Item d: CCS Coal Ash had several comments; and
- EPA responses addressing the potential for SNCR to impact fly ash sales and the cost of this impact.

Below are Golder's responses to the EPA's comments on our November 15, 2011 report concerning the potential impact of SNCR controls to fly ash marketability at CCS and the potential cost impact if fly ash requires ASM technology and is less marketable and therefore, placed in greater quantities into disposal facilities.

2.0 SNCR IMPACT TO FLY ASH MARKETABILITY

The potential impact to fly ash marketability is a function of the SNCR ammonia slip adsorption onto the fly ash particles, and the acceptable (allowable) ammonia levels in fly ash by the fly ash end users.

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2.1 Ammonia Adsorption onto Fly Ash

Based on available literature, the adsorption of ammonia onto fly ash from SNCR emission controls is highly variable and dependent upon factors such as SNCR operation, fuel type/fuel mix, boiler configuration, ash content, ash mineralogy, ash alkalinity, ash sulfur content, and temperature. Limited published data are available for ammonia levels in fly ash for coal-fired power plants utilizing SNCR emissions controls, with no published information being found for energy generation facilities burning lignite coal.

In a 2007 EPRI study on the handling, disposal, and sale of ammoniated fly ash (EPRI 2007), responses from eight units utilizing SNCRs were discussed. All the units fired a PRB/eastern bituminous coal blend, were predominantly smaller units, were predominantly wall-fired, and had actual ammonia slip up to 5 parts per million (ppm). Only four units had tested levels of ammonia in the fly ash, with the measured levels ranging from less than 100 ppm to over 200 ppm. Several references attempt to relate the amount of ammonia slip to the ammonia levels in fly ash and suggest that a 2 ppm ammonia slip may result in fly ash ammonia levels from less than 50 ppm to several hundred ppm (Murarka 2003, Bittner 2001, Hinton 2012, Larrimore 2002). In addition, when explaining ash sales impacts at CCS, Sahu (2011) references a figure created by Larrimore (2002) that indicates ammonia slip levels above 2 ppm can lead to "restricted use" of fly ash and ammonia slip levels above 4 ppm may lead to "unmarketable" fly ash for use in ready mix.

2.2 Allowable Ammonia Present In Fly Ash

The amount of "allowable" ammonia present in fly ash destined for beneficial use varies depending on ash marketer preferences and the ultimate end use. Higher concentrations of ammonia present in fly ash are a result of ammonia slip in SCR or SNCR systems (EPRI 2007). Fly ash impacted with elevated levels of ammonia results in ammonia being released into the air when water is added. At low levels, ammonia is a nuisance; however, at higher exposure levels, ammonia can cause irritation of the eyes, throat, and nose as well as difficulty breathing (NIOSH 2011). Strength characteristics do not appear to be affected by the presence of ammonia in fly ash (Rathbone and Robl 2001).

Elevated concentrations of ammonia in fly ash contribute to releases into the environment during placement (with the presence of water), and a reluctance of fly ash marketers and users (i.e. Headwaters Resources, Lafarge, etc.) to buy fly ash for sales to the construction industry. EPRI (2007) explains that the "...industry rule-of-thumb indicates that ammonia contamination on fly ash that is destined for concrete/cement utilization must have less than 100 ppm ammonia to be useable." Headwaters indicated (January 11, 2010) that they "...quit shipping anything over 100 ppm..." in reference to the Eastlake facility, which has had an SNCR system since 2007. Eastlake has attempted to decrease ammonia content in the fly ash to less than 50 ppm using ASM to improve fly ash marketability. Lafarge (January 26, 2010) has found "...when the ammonia levels exceed 40 part per million in the fly ash that the consumer notices the ammonia and finds it to be objectionable." Additional references have generally found that approximately 100 ppm is the maximum "acceptable" ammonia level in fly ash (Bittner et al. 2001, Giampi 2000, Bittner and Gasiorowski 2005). Other sources cite 100 ppm as an acceptable allowable ammonia level in fly ash for enclosed spaces, but allow a higher limit of 200 ppm in well ventilated areas (Brendel et al. 2000, Larrimore 2002).

The amount of ammonia in fly ash can be related to the ammonia off-gassed during placement. Both NIOSH and OSHA have health-based exposure limits for ammonia in the air. NIOSH has a recommended exposure limit (REL) of 25 ppm and OSHA's permissible exposure limit (PEL) is 50 ppm. A "comfortable" threshold of 10 ppm ammonia is referenced by Rathbone and Robl (2001). Rathbone and Robl (2001) evaluated the relationship between ammonia in fly ash and the corresponding amount in air using laboratory and field-scale test methods:

$$NH_{3\,ash} = \frac{(NH_{3\,water})(Water - to - Cement\ ratio)}{(Fly\ Ash\ Content)}$$

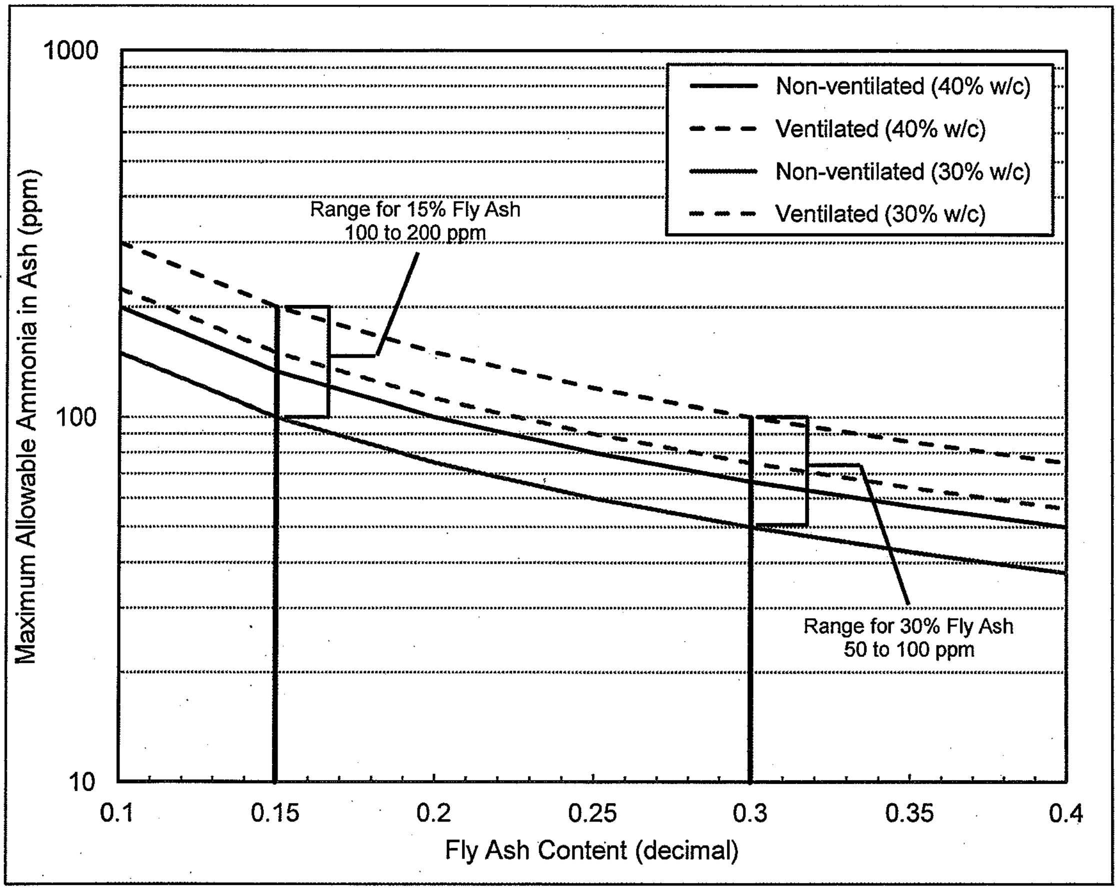
The lab and field scale testing found allowable ammonia levels in the concrete water prior to setting (for 10 ppm in the air), to be approximately 50 mg/l for non-ventilated spaces and 75 mg/l for well ventilated spaces.

Fly ash from CCS is a desirable high quality material and has been used extensively in North Dakota, Minnesota, Colorado, and as far as California. In a review of fly ash uses in North Dakota, the Energy & Environmental Research Center (EERC) stated:

> "NDDOT uses fly ash in almost all concrete projects at a replacement rate of 30%. A replacement rate between 15% and 30% is specified by most state DOTs (if they specify fly ash use at all), making NDDOT's specification on the higher end compared to other states. For mass pours, a replacement rate of 40% is allowed and is more typical." (EERC 2011)

Based on these uses of CCS fly ash, the above relationship was used to evaluate the maximum allowable ammonia content in fly ash for 15% and 30% fly ash mixtures, for water cement ratios between 30% and 40%, and for well-ventilated and non-ventilated areas. Results of the calculations are shown in the following table and the figure below.

Condition	**Ammonia in Air***	**Water/Cement Ratio**	**Allowable Ammonia Content in Fly Ash (15% fly ash mixture)**	**Allowable Ammonia Content in Fly Ash (30% fly ash mixture)**
	ppm	**-**	**ppm**	**ppm**
Ventilated	10	0.4	200	100
Non-Ventilated	10	0.4	133	67
Ventilated	10	0.3	150	75
Non-Ventilated	10	0.3	100	50
*Practical limit based on experience (Rathbone and Robl 2001)				



2.3 Marketability Conclusions

When ammoniated fly ash is used in concrete, the ammonia can be released into the air during placement and may cause irritation to individuals placing the concrete. The amount of ammonia released into the air is a function of fly ash content, the water/cement ratio of the concrete batch, and the ammonia concentration in the ash. Generally, industry experience indicates that fly ash used for concrete should have less than 100 ppm ammonia to prevent handling issues from limiting the marketability of the ash. Based on the use of CCS fly ash as a high percentage cement replacement (30%), a calculated allowable ammonia level in the fly ash may range between 50 ppm and 100 ppm. When discussing ash sales impacts at CCS, Sahu (2011) cites Larrimore (2002) in concluding that 2 ppm ammonia slip can result in 100 ppm ammonia in ash. According to Larrimore (2002), 4 ppm ammonia slip can result in 200 ppm ammonia in ash, a potentially unmarketable level of ammonia for use in ready mix. Because the ash marketer and ready mix user may not know the exact use of fly ash when it is purchased and placed in a silo, the practical limit for CCS fly ash is 50 ppm or less to allow its use in a wide variety of applications. This limit is also supported by the anecdotal comments from both Headwaters and Lafarge.

Definitive information is not available for the levels of ammonia that could be present in the fly ash at CCS due to SNCR ammonia slip. However, review of available literature indicates a reasonably high probability that ammonia concentrations would be in the range that is problematic for marketers and end users of CCS fly ash. Therefore, it is prudent for engineering costs evaluations to assume ammonia levels in CCS fly ash will be higher than the acceptable ammonia levels for CCS fly ash destined for beneficial use, and therefore to assume that CCS fly ash will be disposed or will require treatment with ASM technology to be sold for beneficial use.

3.0 SNCR COST IMPACT TO FLY ASH MANAGEMENT

Golder previously provided a detailed engineering cost estimate for the potential impact to fly ash management as a result of SNCR emissions controls at CCS. Based on the EPA responses, supporting information and clarifications are provided below.

3.1 Fly Ash Disposal Facility Design Basis

The previous evaluation indicated that each cost estimate was prepared assuming that fly ash will be disposed of in a new landfill with a design based on RCRA Subtitle D practices. This may have been taken as a speculative/highly conservative estimate based on impending coal combustion residue (CCR) regulations being developed by the EPA (see EPA response to comment on page 111 of rule prepublication).

In actuality, the assumed design is based on current North Dakota Department of Health (NDDH) regulations (NDDH, http://www.legis.nd.gov/information/acdata/html/33-20.html), which are in-line with RCRA Subtitle D practices. In the early 1990s the NDDH revised its Solid Waste Management and Land Protection rules adopting environmentally sound controls such as composite liners, leachate collection systems, surface water controls, and ground water monitoring.

3.2 Fly Ash Disposal Unit Cost Estimate

Disposal costs of $11 to $18 per ton were estimated based on site-specific designs for the disposal of fly ash at CCS. These disposal costs were based on a detailed engineering cost estimate for CCS including costs from landfill development to post-closure care. In the EPA's responses (page 110), they indicated "we find a disposal cost of $5/ton is reasonable in the improbable event that some ash would need to be disposed."

The cost estimate of $5/ton deemed reasonable by the EPA is not supported by an engineering cost estimate, is not supported by industry information, and is not supported by recent work published by the EPA.

In 2010, the EPA estimated baseline (i.e. current) CCP disposal costs in their Regulatory Impact Analysis for EPA's Proposed RCRA Regulation of Coal Combustion Residues (CCR) Generated by the Electric Utility Industry (EPA 2010). In Chapter 3 of that report, the EPA provided a cost estimate for the management of CCRs and estimated a range of $2/ton to $80/ton with an average of $59/ton. In discussion of these results, the report indicates that $2/ton is reflective of unlined, near-plant impoundments in states with low regulatory requirements, and the high end of $80/ton is reflective of off-site commercial disposal in landfills. Fly ash disposal facilities at CCS are clay- or composite-lined, engineered impoundments and landfills located at varying distances from the plant. North Dakota has comprehensive regulatory requirements in place for ash disposal facilities.

The EPA report further references information from the American Coal Ash Association (ACAA) to validate its cost estimate. The ACAA routinely collects ash disposal and beneficial use information from its members and has developed estimates for the disposal of CCPs. From the ACAA website and referenced in the EPA report:

> "As one can see, a variety of factors enter into determining disposal costs. The lowest cost occurs when a disposal site is located near the power plant and the material being disposed can be easily handled. If the material can be piped, rather than trucked, costs are usually lower. In these types of situations, cost may be as low as $3.00 to $5.00 per ton. In other areas, when distance is far away and the material must be handled several times due to its moisture content or volume, costs could range from $20.00 to $40.00 a ton. In some areas, the costs are even higher. If new sites are required and extensive permitting processes take place, the total cost of the facility may be increased, resulting in higher disposal costs over time." (ACAA, http://acaa.affiniscape.com/displaycommon.cfm?an=1&subarticlenbr=5#Q13)

The disposal of fly ash at CCS does not fall at either cost extreme (unlined impoundment or off-site commercial disposal), and the engineering estimate of $11 to $18 per ton appears well within the EPA's cost estimate and industry practice.

3.3 Lost Fly Ash Sales Revenue

Part of the cost impact to fly ash management is the loss of fly ash sales revenue currently being generated. Based on information from GRE, the 2010 average fly ash sales price per ton was $41.00 with 30% of the sales price going to GRE ($12.30/ton) as revenue and 70% of the sales price going to the fly ash marketer Headwaters ($28.70/ton).

EPA commented that GRE should use $5/ton rather than the updated value of $12.30/ton, and suggested that the lost revenue price included lost revenue to other parties. Based on follow-up discussions with GRE, it was confirmed that the $41/ton is the 2010 average FOB Coal Creek Station sales price and the $12.30/ton portion attributed to GRE does not include lost revenue to other parties. Based on this confirmation, the $12.30/ton rather than the $5/ton is more appropriate for the conditions at Coal Creek Station.

3.4 Cost Impact Conclusions

The fly ash disposal cost estimate is based on an engineering design reflective of the practice in North Dakota, and Golder's engineering estimate of $11 to $18 per ton for fly ash disposal appears to be well within the EPA's cost estimate and consistent with industry practice. Further, the lost fly ash sales revenue of $12.30/ton reported in the cost impact evaluation is reflective of current conditions at CCS.

The disposal and lost revenue cost estimates are valid, and based on the uncertainty with respect to ammonia levels in fly ash, the previous evaluation with respect to fly ash management cost is reasonable.

GOLDER ASSOCIATES INC.

Ron R. Jorgenson
Principal

Todd Stong, P.E.
Senior Engineer

TJS/RRJ/kcs

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Great River Energy's
Legal and Technical Review Of
U.S. EPA's BART Determination for Coal Creek Station

I. INTRODUCTION

On March 2, 2012, EPA issued its *Approval and Promulgation of Implementation Plans; North Dakota; Regional Haze State Implementation Plan; Federal Implementation Plan for Interstate Transport of Pollution Affecting Visibility and Regional Haze*, 76 Fed. Reg. ____(April __, 2012) ("FIP"). EPA largely upheld the North Dakota Department of Health's ("NDDH's") SIP with two exceptions: the NOx Best Available Retrofit Technology ("BART") requirement for Great River Energy's Coal Creek Station ("CCS"), and Reasonable Progress requirements for Basin Electric's Antelope Valley Station. Below, GRE addresses EPA's FIP and its rationale for requiring selective non-catalytic reduction ("SNCR") at CCS. In particular, GRE explains that EPA failed to rationally apply the Clean Air Act's ("CAA's") five-factor BART analysis and GRE responds to key EPA arguments for rejecting NDDH's BART determination.

In rejecting NDDH's BART determination for CCS, EPA made numerous errors, including the following:

- Conducted an improper cost analysis by ignoring the existing controls in use at CCS, including LNC3+ and DryFining™;
- Failed to analyze, or ignored, the incremental cost of SNCR compared to existing and planned controls at CCS, including LNC3+ and DryFining;
- Ignored the demonstrated lack of visibility benefits resulting from its requirement to install SNCR at CCS; and
- Rejected, without validated support, the likelihood of ammonia slip and fly ash contamination.

Beyond these errors, EPA purported to reject NDDH's BART determination for CCS because NDDH relied on cost analyses that contained an error in one component of the costs – the cost of ash contamination and disposal. While objecting to this one component, EPA rejected NDDH's entire BART analysis and NDDH's valuation of the other four, equally important, factors in the BART determination.

The foregoing errors, as well as EPA's failure to give any credence to the values that NDDH's placed on the other BART factors, demonstrate that EPA did not conduct a valid BART analysis for CCS. EPA failed to comply with the CAA requirements and the Agency's own guidelines.

II. EPA's "COST OF CONTROLS" ANALYSIS IS INCONSISTENT WITH THE STATUTE AND EPA'S OWN GUIDANCE

EPA's principal basis for rejecting NDDH's BART determination was NDDH's reliance on purportedly incorrect information regarding the cost associated with ammonia contamination of merchantable fly ash resulting from using SNCR. GRE has addressed the cost issue that EPA raised and has reflected those changes in GRE's Supplemental Best Available Retrofit Technology Refined Analysis for NOx Emissions, April 5, 2012 ("BART Supplement"). EPA asserts, incorrectly, that there should be no ammonia slip or fly ash contamination from using SNCR.[1] However, EPA's own cost analysis is seriously flawed and inconsistent with both the CAA and its own Guidance. EPA made two significant errors in conducting its cost analysis of SNCR. First, it ignored the emission controls already installed and in use that have significantly reduced NOx emissions at CCS. Second, EPA failed to examine the incremental, or marginal, costs of SNCR beyond the existing and planned controls at CCS.

A. <u>EPA Failed to Consider Existing Pollution Controls in Use at CCS and Current Emissions in Performing Its Cost Analysis</u>

Under CAA §169A, the State (or EPA Administrator) must take into consideration five factors in determining BART. One of the five factors is "any existing pollution control technology in use at the source." 42 U.S.C. § 7491(g)(2). EPA completely disregarded this obligation and, instead, relied on 9-year-old emissions data in its cost analysis. The effect of using the inaccurate, inflated emissions data is to distort EPA's cost numbers and make SNCR seem more cost-effective than it is.

EPA relied on emissions data from 2003 and 2004 in its cost analysis. EPA did this notwithstanding its acknowledgement that current emissions are significantly lower. *See* FIP at 20. Since 2004, GRE has made multiple improvements in the combustion and emissions at CCS, including: (1) installing new, adjustable SOFA nozzles in Unit 1 in 2005; (2) installing expanded over-fire air registers in Unit 2 in 2007; (3) installing close coupled over-fire air (CCOFA) on Unit 2 in 2010; and (4) installing DryFining at both units in 2010. All of these measures had beneficial impacts on NOx formation and emissions, reducing emission rates at Unit 2 from 0.22 lbs/mmBtu in 2004 to 0.153 currently. For Unit 1, emissions were reduced from 0.22 in 2004 to 0.20 lbs/mmBtu in 2010.

EPA's failure to acknowledge these installed controls is inconsistent with the plain language of the statute and EPA's own BART guidance. "[B]aseline emissions rate should represent a realistic depiction of anticipated annual emissions for the source." *See* 69 Fed. Reg. 25224. EPA's reliance on 2003 - 2004 emissions from CCS is not a "realistic depiction" of CCS's current or anticipated emissions. By using incorrect emissions data, EPA created and relied on admittedly inaccurate cost effectiveness numbers, the very grounds on which it rejected NDDH's BART determination.

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[1] EPA's assertion is addressed below in Section IV, and by Golder Associates in Exhibit G to the BART Supplement.

EPA's explanation for using inaccurate emission data is both irrational and inapposite to CCS. EPA argues that using emissions resulting from existing emission controls (as required by the statute) would "reward sources that install lesser controls in advance of a BART determination in an effort to avoid more stringent controls." FIP at 95. Whatever EPA's policy considerations, GRE did not install such controls to "game" the BART process. The DryFining technology involved a multi-year, $270 million investment in partnership with the Department of Energy to improve the emissions resulting from coal combustion. The installation of new SOFA nozzles and LNC3+ was done as part of DryFining and in cooperation with the NDDH to achieve better combustion and lower NOx emissions. There is nothing in the record to suggest any of this was done to avoid more stringent BART. It was not.

EPA's statement that these controls were "voluntary" and, thus, EPA need not consider them in evaluating BART is nonsensical. There is nothing in the statute that says voluntarily installed emission controls can or should be ignored. The statute says that EPA must take into consideration "*existing pollution control technology in use at the source.*" EPA cannot simply assume emissions that do not exist to bolster its goal of making SNCR appear more cost effective than it is. Further, this is a policy decision beyond EPA's authority. Congress expressly requires EPA to consider existing controls when determining BART. *See* 42 U.S.C. § 7491(g)(2); *St. Mary's Hosp. of Rochester, Minnesota v. Leavitt*, 535 F.3d 802, 806 (8th Cir. 2008) ("The plain meaning of a statute controls, if there is one, regardless of an agency's interpretation."). Although that may result in companies having to do less under BART, that may be precisely what Congress intended. Encouraging sources to install controls voluntarily – as CCS did – results in achieving emission reductions and visibility improvements earlier than might otherwise be required. EPA's policy would discourage companies from ever voluntarily reducing emissions; in other words, EPA is pursuing the "no good deed goes unpunished" theme of regulation.[2]

Finally, EPA acknowledges that it refused to use accurate, current emission rates from CCS because using the lower emission levels would "skew the 5-factor BART analysis by reducing the emissions reductions from combinations of control options and increasing the cost effectiveness values." FIP at 98. This admission lays bare the inaccuracy of the Agency's cost effectiveness assertions and the inappropriateness of EPA's BART determination for CCS.

B. <u>EPA Failed to Properly Calculate and Consider the Incremental Cost of SNCR in Making Its BART Determination</u>

EPA also failed to consider the incremental cost of SNCR in contravention of its own regulations and guidance. EPA guidelines direct the states as follows. "In addition to the average cost effectiveness of a control option, you *should* also calculate incremental cost effectiveness. You *should* consider the incremental cost effectiveness in combination with the total cost effectiveness in order to justify elimination of a control option. *See* 69 Fed. Reg. 25224 (emphases added); 70 Fed. Reg. 39127 ("We *continue* to believe that *both* average and

[2] By EPA's logic, GRE should have done nothing over the past nine years while waiting for a BART determination. This would have postponed any NOx reductions from approximately 2005 until 2018 (five years after BART is determined).

incremental costs provide information useful for making control determinations.") (emphases added).

To justify SNCR, EPA inexplicably ignored half of its own "cost of controls" analysis. Instead, EPA looked only at the total cost of installing both LNC3+ *and* SNCR (as opposed to SNCR alone) and compared that total cost to the emission reductions achieved using both technologies. As discussed above, the emission reductions from LNC3+ (in addition to the DryFining) already have been achieved at Unit 2 and the LNC3+ is planned for Unit 1. The cost of LNC3+ is a small fraction of the costs of SNCR, yet it generates most of the NOx emission reductions. By combining the two costs into one control option, EPA further distorts the cost-effectiveness of SNCR. If EPA had looked at the cost-effectiveness of SNCR alone (i.e., incremental cost), it would have to admit that the emission rate would decline by only 0.023 lbs/mmBtu: from 0.153 lbs/mmBtu to EPA's proposed rate of 0.13 lbs/mmBtu.

The impact of EPA's error is dramatic. Even if we accepted EPA's unfounded assumption that there would be no fly ash contamination resulting from SNCR, the incremental cost of using SNCR would be $8,534 per ton for Unit 1 and $4,688 per ton for Unit 2. EPA's estimate that the cost effectiveness is under $2,500 per ton is misleading because the cost-efficient reductions come from the use of LNC3+, a technology already installed at Unit 2 and planned for Unit 1.[3] *See* BART Supplement, Table 3.1. SNCR cannot be justified on the basis of achieving such a small incremental reduction in NOx emissions at such high costs, particularly in light of the other factors that weigh against SNCR.

III. EPA Failed to Properly Consider the Lack of Visibility Benefits Resulting From the Installation of SNCR

The flaws in EPA's BART analysis were not limited to only cost-related considerations. EPA also failed to give serious consideration to other statutory factors that Congress required to be part of any BART analysis, especially the lack of any demonstrable visibility benefit resulting from SNCR. The modeling on which both NDDH and EPA relied demonstrates that there would be no discernable visibility improvement resulting from installation of SNCR. *See* 76 Fed. Reg. 58,622. The degree of predicted visibility improvement, approximately 0.105 deciviews, is only one tenth of the level that EPA asserts is perceivable by the human eye. Given the many sources of variability of inputs to CALPUFF's visibility analysis versus actual impacts, a difference of 0.1 deciviews between options may reflect no real difference at all. *See* attached Memorandum from Andrew Skoglund, Barr Engineering, to William Bumpers (April 4, 2012).

EPA made no effort in its final rule to dispute that there will be no real improvement in visibility resulting from SNCR. Instead, EPA surprisingly states that "perceptibility of visibility improvement is not a test for the suitability of BART controls." FIP at 112. While EPA later acknowledges that deciview improvements is one of the five factors, it then says that the "Guidelines provide flexibility in determining the weight and significance to be assigned to each factor" and that achieving a perceptible benefit of 0.5 deciview is not a prerequisite for selecting

[3] The significantly higher incremental costs associated with Unit 1 are due to lower utilization and associated emissions at Unit 1 compared to Unit 2.

BART. FIP at 112. While Congress made clear that the state has great discretion in deciding the weight to accord each factor, EPA has effectively eliminated any import associated with the one factor (visibility) that is the central focus of the regional haze rule. EPA is simply imposing controls and costs on CCS notwithstanding that EPA cannot predict with any confidence that there will be any visibility improvement. This is contrary to the entire objective of the statute.

EPA's only attempt to justify ignoring the lack of visibility benefits resulting from its proposed BART was to note that NDDH was satisfied with a similarly small improvement at another source. *See* 76 Fed. Reg. 58,623. But this explanation completely ignores NDDH's source-specific determination for CCS that an estimated 0.1 deciview improvement did not justify the large costs of SNCR. *See* 76 Fed. Reg. 58,624. EPA's attempt to cherry pick the visibility level from a separate BART analysis ignores NDDH's valuation of all of the other four factors, including a much lower cost, that affected the determination.

Even the theoretical improvement of 0.105 deciviews is likely exaggerated. EPA criticizes the modeling that GRE provided because the various control scenarios were modeled together; that is, the NOx control options were modeled along with the SO_2 reductions. But EPA has repeatedly recognized that its modeling requirements overstate real-world visibility improvements by five to seven times. *See, e.g.,* EPA North Dakota Proposed FIP, Technical Support Document, B-41; FIP at 55. EPA's justification is that modeling based on "current degraded visibility conditions would result in a smaller relative benefit than would a comparison relative to natural background visibility." FIP at 55.[4] Importantly, EPA admits that it undertook no independent modeling of the prescribed emission reductions, so EPA cannot state that SNCR will result in *any* visibility improvement, FIP at 99.

IV. EPA's Conclusion that SNCR Will Result In No Fly Ash Contamination Is Unrealistic

The principal basis EPA cites for rejecting NDDH's BART determination is that NDDH had relied on costs provided by GRE for installation of SNCR that included one incorrect value – the cost of disposing of contaminated fly ash.[5] *See* 76 Fed. Reg. 58,603-04. GRE has corrected that value.[6] As discussed above, even if we assumed that there would be zero contamination of the fly ash, the marginal cost of SNCR ($4,688 per ton for Unit 2 and $8,534 per ton for Unit 1) coupled with the lack of any visibility benefit cannot justify SNCR. But EPA's assertion in the FIP that there will be no wastage of fly ash is not supportable. Exhibit G to the BART Supplement is a report from Golder Associates, addressing EPA's assertion that SNCR would not result in any fly ash contamination and reaffirming the expected costs of fly ash disposal. As demonstrated by Golder Associates and below (1) EPA's assertion that CCS could maintain ammonia slip to below 2 ppm is unsupported and almost certainly wrong; and (2) even at 2 ppm

[4] Put differently, EPA does not allow modeling of what is expected to actually happen because that would confirm EPA's approach results in little or no real-world visibility improvements.
[5] GRE had initially included FOB price of ash. The value was not in error, but GRE agreed that the FOB price was not the correct value for the BART cost analysis.
[6] Golder Associates concludes that a cost of $12.30 per ton is the expected cost of lost fly ash sales resulting from ammonia contamination. BART Supplement, Exhibit G at 6.

ammonia slip, a significant amount of CCS's fly ash would become unmerchantable and require disposal.

In EPA's proposed BART determination, EPA recognized that using SNCR could, and likely would, result in some contamination of GRE's merchantable fly ash at CCS. *See* 76 Fed. Reg. 58,620-21. Consequently, EPA assigned costs to SNCR associated with the lost sales and increased disposal costs associated with the contaminated fly ash. *Id.* In the final FIP, EPA asserts that SNCR at CCS would not contaminate any fly ash because "current technology has made it possible to control ammonia slip from SNCR to levels . . . in a range of 2 ppm or less." *See* FIP at 102. In making this remarkable assertion, EPA relies essentially on a single case study – the "Andover Report." *See* FIP at 102 n.32. The Andover Report provides virtually no support for EPA's claims.

The Andover Report's results cannot be relied on to make any operating assumptions about CCS. It states upfront that "[e]xperience with the TDLAS method on coal power plants has had mixed success – and unfortunately, *far more failures than successes*." Andover Report at page 5 (emphasis added). In the course of examining this technology further, the Andover Report analyzes the use of SNCR at the CP Crane station in Baltimore. The CP Crane station consists of two, 200MW cyclone boilers. It is subject to the Maryland Healthy Air Act, a law that imposes a company-wide, NOx tonnage limitation on power plant owners. CP Crane is one of multiple plants owned and operated by Constellation Energy in Maryland. Constellation installed NOx controls on all of its plants in Maryland, installing SCR on its larger, base load plants, and installing SNCR on CP Crane. GRE contacted Constellation about EPA's assertions. Constellation officials informed GRE that the plant conducted four, one-hour performance tests when commissioning the system,[7] on which the Andover Report is based. Since this commissioning test, Constellation has rarely run the SNCR at CP Crane. Constellation's plant is not subject to a short term NOx rate limit, is not subject to an ammonia slip limit and Constellation does not monitor the ammonia slip. The SNCR system has process monitors but they are not certified. The initial NOx rate at these cyclone burners is approximately 0.4 lbs/mmBtu. Because there is no enforceable NOx rate, the level of ammonia injection is completely discretionary. Constellation does not know what its actual ammonia slip rate is, or would be if the SNCR were actually being utilized. Thus, Mr. Staudt's paper, which is based on the initial, short-term, commissioning test, in no way represents a reasoned basis for EPA's assertions that ammonia slip can be held consistently below 2 ppm or that there will be no fly ash loss as a result of installing SNCR at CCS.[8]

In response to EPA's FIP, Golder Associates ("Golder") has re-examined the literature on the impact of ammonia on fly ash, including the studies referenced by Dr. Sahu in the FIP. *See* FIP at 102 n.35. Golder demonstrates that there is no literature that supports EPA's contention that no fly ash wastage is expected. To the contrary, even if ammonia slip could be limited to 2 ppm on a constant basis – something that has never been demonstrated – ammonia

[7] This short-term commissioning test is hardly an indication of what can be achieved at a much larger facility over a longer term and a wider range of operating levels.

[8] EPA's reference to the Big Brown plant in Texas is similarly unpersuasive. According to EIA data and Luminant, Big Brown landfills approximately one third of its fly ash.

concentration in fly ash could be as high as 100 ppm, which Golder concludes would significantly limit the sale of CCS's fly ash. BART Supplement, Exhibit G at 3-4.

Golder also addresses EPA's criticism of the costs assigned for disposing of contaminated fly ash. BART Supplement, Exhibit G at 5-6. Golder points out that its costs are based on NDDH Solid Waste Management and Land Protection regulations (NDDH, http://www.legis.nd.gov/information/acdata/html/33-20.html). NDDH's rules require controls such as composite liners, leachate collection systems, surface water controls, and ground water monitoring. As a result, Golder estimates the cost of fly ash disposal to be between \$11 and \$18 per ton. Golder also demonstrates that EPA's estimate of \$5 per ton is not supported by any analysis and is inconsistent with EPA's own regulatory impact analysis from 2010, which estimated a range of \$2 to \$80 per ton, with an average cost of \$59 per ton. BART Supplement, Exhibit G at 5. Golder also confirms that the cost of lost fly ash sales for GRE is \$12.30 per ton. BART Supplement, Exhibit G at 6.

Perhaps recognizing the fundamental weakness of its assertion, EPA noted that even if SNCR did cause some ammonia contamination, "three possible systems" could be used to cure the problem. *See* FIP at 102 n.35. EPA did not even bother to analyze whether any of these technologies might actually work at CCS. The manufacturer of one of those technologies stated that "[t]he limited current experience in commercial application and lack of research is not adequate for Headwaters to be able to provide any guarantee that the process can be successfully applied to treat lignite ash at the Coal Creek Station." *See* July 15, 2011 Email from Rafic Minkara, PhD., PE (Headwaters) to John Weeda (GRE), forwarded to Gail Fallon and Carl Daly (EPA) on July 15, 2011. Despite the manufacturer's lack of confidence as to whether its own technology would work, EPA asserted its "consultants are aware of no technical reason that ASM technology would not be effective to mitigate ammonia on fly ash from lignite." *See* FIP at 102 n.35. EPA cites nothing to justify its conclusion that the technology in question should work when the technology's own creator refused to support the conclusion. Making bald assertions that are unsupported at best, and flatly contradicted at worst, by evidence in the record is textbook arbitrary and capricious.

III. EPA'S CONSIDERATION OF THE OTHER FACTORS WAS IRRATIONAL

A. Other Cost Errors

1. EPA Arbitrarily Rejected URS's Cost Data

EPA's disregard of construction cost analysis of SNCR at CCS is unfounded. URS is a leading engineering and construction company that has participated in the construction and installation of SNCR projects at more than 30 coal-fired power plants. EPA's criticism that URS is not an SNCR vendor, and thus unable to opine on the costs of installing SNCR at CCS is arbitrary and capricious. *See* FIP at 121-124. As URS states:

> URS is not a technology supplier. The supplier is typically responsible for installation of only their process island and system performance guarantees. The installation of the balance of plant (BOP) equipment, construction management, foundations, utility tie-ins (electrical, water, air, instrumentation and controls

> interface, interconnecting piping, new flue gas emissions monitoring equipment, boiler and air heater modifications, retrofit difficulty due to existing plant access and congestion issues, et al) typically falls outside of the scope of supply for the SNCR vendor. Published cost estimates and vendor proposals in many cases do not consider these BOP cost impacts on the Total Capital Requirement for the installation of emissions control equipment. URS's project experience provides a basis for the assessment of these BOP costs that must be added to the vendor supplied equipment's installed costs to determine the true total capital cost of an installation.

See Letter from URS to Debra Nelson, March 30, 2012, BART Supplement, Exhibit F.

URS also has reconfirmed the basis for the retrofit factor of 1.6 based on the difficulty of installation at CCS. *See* BART Supplement, Exhibit F. URS also further explains the basis for its skepticism regarding SNCR's effectiveness when the initial NOx emission rates are in the lower range, similar to the NOx rate at CCS Unit 2. *See* BART Supplement, Exhibit F. EPA simply had no reasoned basis for disregarding URS's cost and performance analysis. EPA repeatedly refers to information from SNCR-designer Fuel Tech, but EPA's information appears to have been gleaned largely from a promotional website rather than site-specific analysis. *See* FIP at 20 n.2, 97 n.29. EPA's claim that its "consultant" received some sort of input from a SNCR vendor is so vague as to render it useless. *See* FIP at 102 n.34. The record does not show that EPA asked Fuel Tech to evaluate whether its technology would work at CCS. In any event, the follow up analysis provided by URS demonstrates that its cost analysis is well grounded.

2. EPA Provided No Rational Basis for Departing From its Guidelines' Presumptive Values

EPA's FIP ignored the Agency's own Guidelines, which require careful consideration of EPA's presumptive emissions limits. EPA's Guidelines explain that "we believe that States should carefully consider the specific NOx rate limits for different categories of coal-fired utility units, differentiated by boiler design and type of coal burned, set forth below as likely BART limits." *See* 70 Fed. Reg. 39134. EPA went on to note that "States have the ability to consider the specific characteristics of the source at issue and to find that the presumptive limits would not be appropriate for that source." However, EPA's BART analysis does not even acknowledge the existence of its own presumptive emissions limits much less reflect "careful" consideration of them. *See* 76 Fed. Reg. 58620-23. Furthermore, EPA offers no explanation why a departure from them is appropriate in this particular case, particularly where no visibility benefit would result from doing so. EPA cannot ignore its own Guidelines and nonetheless claim to have undertaken a legally-adequate BART analysis. EPA certainly would not allow a state to do so.

B. Energy and Non-Air Quality Environmental Impacts of Compliance

The CAA also requires consideration of the energy and non-air quality environmental impacts resulting from the use of relevant control technologies. This includes the energy requirements of the technology, the local availability of necessary fuels, and the generation of solid or hazardous wastes as a result of applying a control technology. *See* 70 Fed. Reg. 39,169. As already discussed above, EPA assumed contrary to all reasonable evidence that no fly ash

would be contaminated due to SNCR. EPA was therefore able to avoid considering the non-air environmental impacts arising from the creation of hundreds of thousands of tons of solid waste (and perhaps hazardous wastes depending on EPA's consideration of how to regulate fly ash). EPA's unsupported conclusion about fly ash therefore prevented EPA from properly considering two factors – the cost of controls and non-air environmental impacts.

IV. CONCLUSION

EPA rejected NDDH's entire BART analysis principally because of a purported error in a single cost component: the cost of contaminated fly ash. EPA then utilized flawed cost analysis and inaccurate emissions data to justify installation of SNCR. EPA effectively ignored all of the other BART factors, especially the lack of any measurable visibility improvement that might result from investing tens of millions of dollars to install and operate SNCR. GRE has provided NDDH with a revised BART analysis, including a refined cost analysis that examines the average and incremental cost, and cost-effectiveness of various levels of NOx emissions control. In light of the lack of any discernable visibility improvement at any Class I area, NDDH would be justified in supporting its initial BART determination at any cost level, including EPA's artificially low average cost per ton of $2500 per ton. The actual incremental cost of SNCR will be $4,688 per ton and, for Unit 1, will be $8,534 per ton, even if no costs are assigned to the loss of merchantable fly ash. The costs are significantly higher, and other environmental impacts worse, if fly ash contamination were to result from using SNCR. The documentation demonstrates this is very likely.

NDDH's initial BART determination was in compliance with the statutory obligations. With the refined BART analysis, and updated cost information, NDDH can make its own BART determination, assigning its own values to the five BART factors and should not accept EPA's usurpation of NDDH's authority.

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Memorandum

To: William Bumpers, Baker Botts L.L.P.
From: Andrew Skoglund
Subject: CALPUFF Visibility Impact Variations
Date: 4/4/2012
Project: 34280013.01
c: Mary Jo Roth, Debra Nelson - GRE; Joel Trinkle, Laura Brennan - Barr

CALPUFF is the USEPA's preferred model for assessing visibility impacts at Class I Areas resulting from long range (50 – 300 km) plume transport. CALPUFF is a multi-source model which accounts for plume advection and atmospheric chemical reactions to estimate the concentrations of primary chemical species (ammonium nitrate, ammonium sulfate, elemental carbon, organic carbon, fine particulate and soil) known to cause haze (i.e., visibility impairment). Plumes in CALPUFF are transported using sophisticated meteorological data and plume transformations from atmospheric chemical reactions occur due to interactions of plume pollutants, background atmospheric pollutants (ozone and ammonia) and meteorological variables – most importantly water vapor as represented by relative humidity.

Visibility impairment is calculated as a function of the light scattering properties of atmospheric particles and gases. An increase in light scattering particles decreases the visual range as measured in deciviews. The EPA estimates that a sensitive observer may be able to detect a variation of 0.5 deciviews, with 1.0 deciviews being a more accepted threshold for distinguishable difference in visual impairment. Modeled visibility impacts of 0.1 deciviews are therefore indistinguishable to the human eye.

Calpuff modeled visibility impacts are reported in the model output files to thousandths of deciviews. However, this level of sensitivity overstates the potential accuracy of the model when compared to real-world observations. Assessments of the CALPUFF modeling suite versus real-world monitoring data demonstrate the potential for significant differences between modeled and actual concentrations. There are many model inputs which play a role in impact variability, ranging from background chemistry data to emissions data entered into the model.

Visibility calculations are directly affected by the background chemistry input to the model. While ozone is input to the model based on hourly observations from available monitoring locations within the modeling domain, ammonia inputs are calculated monthly average values. The use of monthly ammonia background concentrations in the model, allows for consistency between modeling runs, but is a simplification of the actual conditions and impacts to visibility. Variation in ammonia background can have a measurable effect on the chemical transformations in the model, and in turn on modeled visibility impacts. The background values for visibility impairing pollutants (ammonium nitrate, ammonium sulfate, elemental carbon, organic carbon, fine particulate, and soil.) are based on projected values of pristine or natural conditions. These also are input as monthly average background levels. Variability in actual backgrounds, while demonstrating definite seasonal changes, is not limited to changing by calendar month.

Additionally, the fixed nature of the modeled emissions utilized in BART analyses does not reflect actual operations of a facility. Few facilities will operate at their maximum 24-hour rate 365 days per year. The emission rates and parameters for the potential modeled scenarios use assumed emissions and fixed stack parameters (e.g. exhaust temperature, airflow) for scenarios not already in operation at a facility. Final design may yield variations in these parameters, an additional source of impact variability. There is the possibility for considerable variation in actual emissions versus the modeled maximum rates used for BART analysis. It could be expected that small changes to the source parameter assumptions would result in small changes to the model results. Therefore, if the assumed stack flow rate or temperature for the EPA BART controls were misrepresented by 10 - 20% from potential as-built values, it could be possible that the deciview difference would be on the order of 0.1 deciviews – i.e., within the sensitivity of the model.

Inasmuch as the BART modeling analysis methodology is proscriptive (e.g., model each facility individually, use background monthly ammonia values, etc…), the CALPUFF results from one model run to the next can be useful in a relative sense and not in an absolute sense (i.e., the CALPUFF model results are not expected to reflect observed values). However, the difference in results from any two modeling runs needs to be understood in context of the parameter estimated. For the BART analysis, the parameter of interest is deciviews and the human perceptibility threshold is 0.5 deciviews. On this basis, differences in model run results of less than 0.5 deciviews are not significant.

For the CCS modeling analysis, the model run differences are 1) baseline – current controls compared to 2) baseline – EPA BART controls. In both cases, the relative model results (baseline – controls) show a fairly large difference (up to 2 deciviews), giving some confidence in the modeling results that controls would result in perceptible improvements to visibility. However, the EPA's contention that the 0.1 deciview difference between 1) and 2) is actionable based on modeling, ignores the fact that 0.1 is the difference between two large numbers.

Given the many sources of variability of input to CALPUFF's visibility analysis versus actual impacts, a difference of 0.1 deciviews between options may reflect no real difference at all.

GREAT RIVER ENERGY®

A Touchstone Energy® Cooperative

Coal Creek Station Units 1 and 2

Best Available Retrofit Technology Refined Analysis for NOx Emissions

November 2011; Updated February 10, 2012

Coal Creek Station BART Supplemental Analysis for NOx Emissions

November 2011

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1.0 Introduction

In December 2007, GRE submitted its final Best Available Retrofit Technology (BART) evaluation for Regional Haze controls to the North Dakota Department of Health (NDDH). The NDDH incorporated the proposed emission limitations for Coal Creek Station (CCS) Units 1 and 2 into their proposed State Implementation Plan (SIP), and issued a draft Permit-to-Construct (PTC) for these BART limits. As part of their review on North Dakota's draft and final SIP, EPA requested supplemental data and documentation on Coal Creek's BART controls. These requests started in February 2010, and continued through June 2011 and July 2011. GRE provided the requested information.

On September 21, 2011, EPA proposed a Federal Implementation Plan (FIP), which would override certain NDDH determinations, particularly with respect to required NOx controls for certain coal-fired utility units. On November 3, 2011, NDDH requested that GRE provide a supplemental BART analysis that is focused on NOx control options at Coal Creek Station. In particular, GRE has performed more refined analyses on selective non-catalytic reduction (SNCR) cost assumptions, achievable control levels and the overall impacts to ash re-use on Coal Creek's Units 1 and 2. This updated refined analysis is being provided to address comments from the NDDH per its letter of January 19, 2012.

Based on these refined analyses, Great River Energy still asserts that use of its state-of-the-art coal drying technology, DryFining™, in conjunction with second generation combustion control low NOx burners with separated overfire air (LNC3+), meets EPA's presumptive BART NOx limit of 0.17 lb/mmBtu, and is consistent with cost effective thresholds as set by North Dakota and ultimately approved by EPA through their partial approval of the North Dakota SIP. When all factors are adequately considered including, most importantly, ammoniated ash impacts, SNCR is not considered cost effective for Coal Creek and would not result in perceptible visibility improvements in the affected Class I areas.

This refined analysis summarizes updated SNCR cost and emission assessments provided by URS Energy and Construction (URS). It also provides an updated ash implication assessment as provided by Golder Associates (Golder). The updated ash implications are then integrated with the updated SNCR cost and emission estimates to more accurately demonstrate that SNCR is not cost effective, by either EPA established thresholds or NDDH established thresholds.

1.1 Initial BART Analysis and EPA Guidance

In preparing the initial BART analysis and subsequent revisions, Great River Energy developed a combination of detailed engineering and screening level analyses which were ultimately used by NDDH to make their BART determinations. Per the BART preamble, EPA sets presumptive levels based on their cost effective assessments and deciview reductions, and essentially rules out post combustion NOx controls for electric generating units greater than 750MW, subject to the state's determination. Great River Energy's screening level analyses on SNCR and ash impacts initially supported EPA's presumptive determination and Great River Energy continues to concur with EPA's establishment of a presumptive NOx emission limit of 0.17 lb/mmBtu.

Specifically, in its final rule publication of 40 CFR Part 51, *Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations*, EPA establishes presumptive NOx levels based on combustion controls, and not SNCR:

> *In today's action, EPA is setting presumptive NOx limits for EGUs larger than 750 MW. EPA's analysis indicates that the large majority of the units can meet these presumptive limits at relatively low costs. Because of differences in individual boilers, however, there may be situations where the use of such controls would not be technically feasible and/or cost-effective. For example, certain boilers may lack adequate space between the burners and before the furnace exit to allow for the installation of over-fire air controls. Our presumption accordingly may not be appropriate for all sources. As noted, the NOx limits set forth here today are presumptions only in making a BART determination, <u>States have the ability to consider the specific characteristics of the source at issue and to find that the presumptive limits would not be appropriate for that source.</u>* (emphasis added)
>
> *For all types of boilers other than cyclone units, the limits in Table 2 are based on the use of current combustion control technology. Current combustion control technology is generally, but not always, more cost-effective than post-combustion controls such as SCRs. For cyclone boilers, SCRs were found to be more cost-effective than current combustion control technology; thus the NOx limits for cyclone units are set based on using SCRs. SNCRs are generally not cost-effective except in very limited applications and therefore were not included in EPA's analysis. The types of current combustion control technology options assumed include low NOx burners, over-fire air, and coal reburning.*

We are establishing presumptive NOx limits in the guidelines that we have determined are cost-effective for most units for the different categories of units below, based on our analysis of the expected costs and performance of controls on BART-eligible units greater than 200 MW. We assumed that coal-fired EGUs would have space available to install separated over-fire air. Based on the large number of units of various boiler designs that have installed separated over-fire air, we believe this assumption to be reasonable. It is possible, however, that some EGUs may not have adequate space available. In such cases, other NOx combustion control technologies could be considered such as Rotating Opposed Fire Air (''ROFA''). The limits provided were chosen at levels that approximately 75 percent of the units could achieve with current combustion control technology. The costs of such controls in most cases range from just over $100 to $1000 per ton. Based on our analysis, however, we concluded that approximately 25 percent of the units could not meet these limits with current combustion control technology. However, our analysis indicates that all but a very few of these units could meet the presumptive limits using advanced combustion controls such as rotating opposed fire air (''ROFA''), which has already been demonstrated on a variety of coal-fired units. Based on the data before us, the costs of such controls in most cases are less than $1500 per ton. (emphasis added)

The advanced combustion control technology we used in our analysis, ROFA, is recently available and has been demonstrated on a variety of unit types. It can achieve significantly lower NOx emission rates than conventional over-fire air and has been installed on a variety of coal-fired units including T-fired and wall-fired units. We expect that not only will sources have gained experience with and improved the performance of the ROFA technology by the time units are required to comply with any BART requirements, but that more refinements in combustion control technologies will likely have been developed by that time. As a result, we believe our analysis and conclusions regarding NOx limits are conservative. For those units that cannot meet the presumptive limits using current combustion control technology, States should carefully consider the use of advanced combustion controls such as ROFA in their BART determination.[1] (emphasis added)

There are several key concepts from EPA's preamble. First, Coal Creek is unique in that it has installed DryFining™, a novel multi-pollutant control technology. This is important because it enhances the effectiveness of the NOx combustion controls. Second, Coal Creek re-uses the vast

[1] Federal Register / Vol. 70, No. 128 / Wednesday, July 6, 2005 / Page 39134-39135.

majority of fly ash rather than disposing of it. Any negative impacts to fly ash, such as adding ammonia, will have both operational risks and cost implications for Great River Energy that must be included in any cost-effectiveness determination. Third, EPA has made its cost-effectiveness determination in setting presumptive BART NOx levels and has given states the ability to determine if more stringent requirements are needed based on their review.

In reviewing EPA's preamble discussion, it was clear to GRE that the EPA did not expect BART control scenarios for tangentially-fired units, such as Coal Creek Station's Units 1 and 2, to include post combustion add-on controls such as selective catalytic reduction (SCR) and SNCR. As such, in the initial BART evaluation, GRE focused on supporting this determination through the use of screening level cost data, and comparing those screening costs to cost effectiveness thresholds.

Based on the direction provided in the BART preamble and guidance, along with an analysis of cost effectiveness thresholds implemented in other EPA regulatory programs,[2] GRE proposed a cost effectiveness range of $1,300 to $1,800 per ton of NOx removed. Guidance provided by NDDH presented higher cost per ton thresholds than EPA's in setting the presumptive level.

GRE's BART NOx determination for CCS Units 1 and 2 was consistent with EPA's preamble and confirmed that advanced combustion controls and an emission limit of 0.17 lb/mmBtu represented BART. SNCR was found to be cost ineffective based on screening level analysis, and presented additional operational and non-environmental impacts that were not exhaustively discussed in the December 2007 BART analysis but are provided herein.

2.0 Refined NOx Control Evaluation at CCS

This section will first establish that Coal Creek is unique, requiring site specific evaluations rather than relying on general screening level assumptions to determine emission reductions and associated costs. It will then summarize the evaluation of site specific SNCR NOx reductions by URS, as well as ash impacts from the ammonia associated with this control.

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[2] http://www.ndhealth.gov/AQ/RegionalHaze/Regional%20Haze%20Link%20Documents/Appendix%20C/Coal%20Creek/Coal%20Creek%20BART%20Analysis.pdf (Appendix B).

2.1 Unique Aspects of Unit 1 and 2 NOx Controls

As discussed in the following sections, Coal Creek Station is neither average nor typical. EPA Guidelines, provided to States in identifying appropriate Regional Haze control requirements and provided in EPA's Pollution Control Cost Manual (2002), are developed in order to assist State authorities in making regulatory determinations. These guidelines are not to be viewed as regulatory requirements. They are best suited for evaluating average or typical installations. Units 1 and 2 are uniquely designed and employ a state-of-the-art lignite fuel enhancement technology, or DryFining™. This means that any accurate analysis of add-on NOx controls must be site specific and not rely upon general guidelines, which might apply to a normal facility.

2.1.1 DryFining™ Technology

GRE has a long track record of being innovative and going beyond minimum environmental requirements. DryFining™ is a $270 million, multi-pollutant technology. It reduces coal moisture and impurities while increasing the heat content of Fort Union lignite, which has the highest moisture of any coal in the US. The operation of DryFining™ has afforded CCS Units 1 and 2 significant reductions across the spectrum of emissions. Sulfur dioxide and mercury emissions have been reduced by more than 40%. Carbon dioxide emissions have been reduced by 4%. NOx emissions – the subject of the EPA FIP and this evaluation – have been reduced by more than 20%.

GRE expected that some additional NOx reductions would result from the implementation of DryFining™. It was estimated that the reduction in coal moisture, and corresponding increase in coal heat content, would result in less coal into the furnace, and more air available elsewhere in the furnace which can be utilized to reduce NOx emissions. However, this NOx reduction benefit was not quantified in the original BART analysis. At the time of the final BART analysis (December 2007), DryFining™ had not yet operated and the exact degree of control was unknown for this innovative strategy. Because DryFining™ has been in place for nearly two years, NOx emissions have been reduced. Consequently, current (baseline) NOx emissions that are used in Section 3.1 have been updated to reflect the URS control cost analysis and are inclusive of DryFining™, with low NOx burner technology as applicable.

2.1.2 NOx Combustion Control Considerations

GRE's proposed BART NOx control strategy includes the use of DryFining™ along with advanced combustion controls. As a result of the installation of the proposed advanced combustion controls on Unit 2, GRE has gained a better understanding of anticipated NOx control levels and costs.

The size and arrangement of the furnace box on CCS Units 1 and 2 is unique. It is literally a one-of-a-kind furnace box, sized specifically for the high moisture Fort Union lignite. Given a larger firebox, relative to other lower-moisture, higher-heat-content coal-fired units, there is a correspondingly higher complexity and higher cost to NOx combustion controls. There is a greater distance across the furnace through which the air must penetrate, thus increasing the size and type of wall nozzles, along with increased nozzle staging complexity throughout the wall sections. When an advanced combustion air system is added to a larger firebox, it requires additional wall openings and redesign to wall water tubes, further increasing costs.

Since the time of the initial BART submittal, GRE has gained direct operational experience on the performance of these advanced combustion controls and DryFining™. Prior to the installation of DryFining™, most of the available primary air was needed to convey, grind, and dry the coal in the pulverizers due to the high moisture in the coal. Consequently, the maximum performance for the LNC3+ control installed on Unit 2 could not be fully realized upon initial installation. The Unit 2 LNC3+ installation includes larger registers to increase available primary air. Since a significant amount of that primary air was used to dry and pulverize the "unrefined" high moisture coal, there was not sufficient air available for the larger registers to act as a form of overfire air. With DryFining™, there is additional air available to be routed to the larger registers which reduces NOx emissions. As a result, Units 1 and 2 currently operate with annual average NOx emissions of 0.200 and 0.153 lb/mmBtu, respectively. Unit 2's lower annual average NOx emission rate is directly attributable to the larger registers, which are tentatively anticipated for Unit 1 in 2014.

2.1.3 Site Specific SNCR Expected Control Levels

Portions of Coal Creek Station's December 2007 submittal of the NOx BART analysis were based on screening level data presented in the EPA Pollution Control Cost Manual (2002). Since EPA has proposed to reject North Dakota's SIP largely on their assessment of SNCR's screening level, cost effectiveness, it is imperative to more accurately portray SNCR costs. With respect to SNCR specifically, EPA acknowledges in its cost manual:

> *SNCR system design is a proprietary technology. Extensive details of the theory and correlations that can be used to estimate design parameters such as the required [normal stoichiometric ratio] NSR are not published in the technical literature. Furthermore, <u>the design is highly site-specific.</u> <u>In light of these complexities, SNCR system design is generally undertaken by providing all of the plant- and boiler-specific data to the SNCR system supplier, who specifies the required</u>*

> *NSR and other design parameters based on prior experience and computational fluid dynamics and chemical kinetic modeling.*[3] (emphasis added)

As discussed above, GRE has established that Coal Creek is unique due to its boiler size, DryFining™, and existing NOx combustion controls. Therefore, only a site specific evaluation, by a competent SNCR supplier (such as URS), should be used to estimate emission reductions and associated costs. URS is a preeminent engineering consultant in SNCR technology, having designed several dozen SNCR pollution control systems throughout the world. This experience qualifies URS to make site-specific recommendations on SNCR design.

URS completed a site inspection, evaluated the unique aspects of Coal Creek, and provided its refined analysis (see Appendix B).

URS has determined that the removal efficiency for Coal Creek Unit 1 with an inlet NOx concentration of 0.22 lb/mmBtu would not be 50% as anticipated from the EPA Pollution Control Cost Manual (2002) and as used in GRE's original BART analysis. Rather, URS estimates a removal rate of approximately 30% for Unit 1. With respect to Unit 2, and an inlet concentration of 0.15 to 0.16 lb/mmBtu, URS estimates the removal efficiency would be approximately 20%.

Given these lower projected emission rates, and the lower "baseline" emission rates from installed controls, the cost evaluation has been revised, accordingly, in Section 3.1.

Rather than relying on the original screening level analyses, GRE finds it imperative to provide this updated information to North Dakota to make their well informed cost effectiveness determinations.

2.2 Revision of Baseline NOx Emissions

The BART Guidelines (40 CFR 51, Appendix Y) state "The baseline emissions rate should represent a realistic depiction of anticipated annual emissions for the source. In general, for the existing sources subject to BART, you will estimate the anticipated annual emissions based upon actual emissions from a baseline period." To accurately depict the anticipated annual emissions for the units at CCS a new baseline must be established taking into consideration the DryFining™ technology and installed combustion controls in Unit 2 (LNC3+). The DryFining™ process is designed to remove

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[3] EPA Pollution Control Cost Manual (2002); Section 4.2 Chapter 1.3.

moisture and segregate dense material from the coal prior to introduction of the coal into the final stage of grinding and conveyance into the boiler. DryFining™, having been funded under a DOE collaborative agreement (DE-FC26-04NT41763), was required to conduct performance tests which demonstrated a heat input reduction of approximately 2 to3 percent. By removing the moisture prior to introduction into the pulverizers, less primary air is required to "dry" and convey the coal through the pulverizers, making air available for staging (over-fire air NOx control) in other areas of the boiler. This drier coal will not require the same amount of heat input into the boiler because wet coal expends some of its heat input to vaporize the moisture in the coal. The heating value of the drier coal has increased per pound so fewer pounds are needed. Thus a drier coal will not require that additional coal which is typically used to vaporize the moisture. DryFining™ is currently obtaining a moisture reduction in the coal of approximately eight percent. Further tuning is continuing so the units will meet a required reduction of 12% by 2016, which is needed to achieve the SO_2 BART limit through full scrubbing. In order to make its cost effectiveness determination, North Dakota must not only have site specific control costs, but also accurate emission reduction estimates. Clearly, with the installation of both LNC3 and LNC3+, and DryFining™, Coal Creek's NOx emissions are greatly reduced with respect to "baseline" values previously provided. In this section, in light of recently refined analysis, GRE has updated baseline emissions to be used in making the cost effectiveness determination.

Based on the timing of the original analysis, the initial BART evaluation used baseline emission rates for approximately the same time period that was used to determine the visibility baseline, which was a 5-year period of emission inventory data from 2000 to 2004. It is necessary to update the baseline emissions for Units 1 and 2 for this technology evaluation in order to reflect current conditions and unit performance. Both units utilize "low NOx coal-and-air nozzles with close-coupled and separated overfire air," which is referred to as LNC3. Since the time of the initial evaluation, NOx controls in the form of larger registers,[4] advancing the LNC3 controls (LNC3+),[5] have been added to Unit 2, which means that the two units have different baselines for the purpose of estimating future emission reductions. For Unit 1, the revised baseline is 0.201 lb/mmBtu, as an annual average. For Unit 2, the

[4] Larger registers allow for a greater ability to tune combustion staging and thus control NOx emissions.

[5] LNC3 is the acronym used by EPA to describe a specific type of restrictive combustion control. To differentiate between the controls installed on Unit 1 and the additional controls installed on Unit 2 (both are versions of LNC3), the acronyms LNC3 and LNC3+ are used for each unit, respectively.

revised baseline is 0.153 lb/mmBtu, as an annual average, as also described in Section 2.1.2. These new “baseline” emission rates are lower than the initial BART baseline of 0.22 lb/mmBtu.

2.2.1 Circumferential Cracking in Boiler Tubes

Following the installation of LNC3+ technology at Unit 2, CCS has determined that an emission rate of 0.15 lb/mmBtu for LNC3+ is not a sustainable 30-day rolling average control level due to circumferential cracking. In other words, the 0.15 lb/mmBtu on a 30-day rolling basis is at the edge of this technology’s capabilities. While GRE may intermittently achieve this rate on a monthly or perhaps more easily as an annual average, it is not the basis for a 30-day rolling limit.

As background, in 2008 GRE lowered NOx emissions from Unit 2 by expanding the OFA registers. This diverted more of the combustion air from the burners of the boiler to an area about 30 feet higher in the boiler. In doing so, the flame temperatures were lowered, which reduced the production of NOx generated by the combination of oxygen and nitrogen gas burned under high temperatures. NOx emissions were lowered, but there was an unexpected side effect. This low NOx emission rate caused circumferential cracks in the boiler tubes between the burner front and the over-fired air registers.

The phenomenon of circumferential cracking has several interrelated contributing factors including high surface temperatures (>900°F bare tubes, >1100°F weld overlays) (which exposes the boiler tubes to high wall temperatures and high temperature fluctuations, which produces numerous thermal fatigue cracks in the boiler walls), frequent and severe thermal spikes (>100°F), and corrosive conditions/deposits. Low NOx burner systems with overfire air ports produce longer flames and increase the chance of flame impingement and local overheating of the boiler walls.

In 2009, Coal Creek Station began to experience unscheduled outages on Unit 2 due to failures from the circumferential cracking described above. To understand and correct this problem, Great River Energy engaged the Electric Power Research Institute (EPRI) to assist in evaluating the causes and potential remedies for this problem. To date, corrective actions have included detailed examinations of the boiler tubes to detect the extent of the cracking, the installations of additional temperature monitors to determine boiler wall temperatures, the replacement of damaged boiler tubes, and continued tuning of the boiler to minimize the circumferential cracking in the zone of concern. While not eliminating the problem, these efforts have greatly reduced the problem of unscheduled outages caused by circumferential cracking. Based on our analysis, it is not clear how to completely and consistently eliminate this problem, while operating at or near 0.15 lb/mmBtu on a 30-day rolling basis. Efforts continue to further reduce this circumferential cracking problem while balancing our desire to operate at lower NOx emission levels.

The only examples of tangentially-fired units with emissions lower than the 0.17 lb/mmBtu NOx presumptive level are facilities with post combustion NOx controls, such as SNCR. Further, a majority of these SNCR controlled sources operate well above the 0.17 lb/mmBtu, as annual averages, as detailed in the Cross State Air Pollution Rule and illustrated in Figure 2.2. Consequently, GRE presumes it cannot safely and consistently operate below 0.17 lb/mmBtu as a 30-day rolling limit, without installing SNCR.

2.2.2 Load Variability

In addition to circumferential cracking, this assessment must also consider load variability and its impacts on NOx emissions. The NOx emission limits proposed in the original BART evaluation for Units 1 and 2 did not consider that Coal Creek's units would experience significant load variability. GRE has historically operated as a baseload unit, without much load swinging. In May 2011, Midwest Independent Transmission System Operator (MISO) began cycling CCS in the real-time market. In September 2011, GRE greatly increased the cycling range of CCS in response to current market prices in the MISO market. This is important because load swinging significantly impacts expected NOx control performance. While base load NOx emissions can be tuned due to relatively stable load, the swinging load cannot be finely tuned but must still be accounted for when assessing compliance with emission limits.

Table 2.1 illustrates the variability experienced during recent load swinging. It is different on Units 1 and 2, due to different NOx controls. Based on changing market conditions, load variability is expected to continue as an operational scenario for Units 1 and 2 for the foreseeable future. As such, any emission limit must account for this additional variability in emissions. It is clear from Table 3 that the BART NOx presumptive emission rate of 0.17 lb/mmBtu is achievable, including load variability, and also reflecting the maximum NOx emission reductions from LNC3+ and DryFining™, as demonstrated through Unit 2.

Table 2.1. Coal Creek Station NOx Emission Rates During Load Variability

Scenario Description		NOx Emissions (lb/mmBtu)			
		Unit 1		Unit 2	
		Min	Max	Min	Max
Overall - Nov. 2010 to Nov. 2011	30-day Rolling	0.179	0.219	0.14	0.169
Load Variability – May – November 2011	30-day Rolling	0.186	0.219	0.146	0.166
	Hourly Average	0.206		0.16	
Load Variability – September – November 2011	30-day Rolling	**0.207**	**0.219**	**0.163**	**0.166**
	Hourly Average	0.218		0.17	

In addition, GRE provides a chart showing Unit 2's 30-day rolling average NOx emission rate, with notes on tuning emphasis and load variability, as further support of the 0.17 lb/mmBtu emission limit.

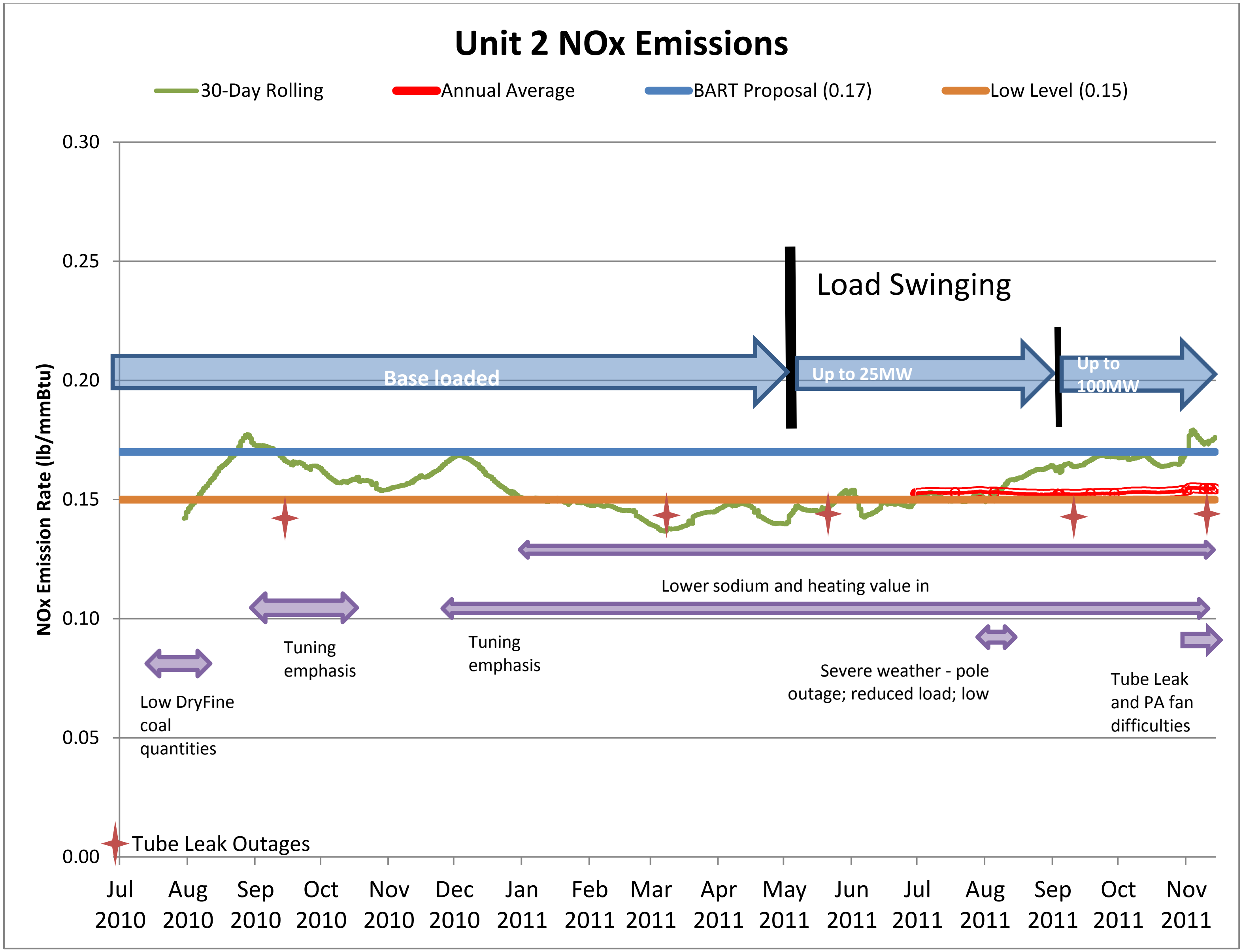

Figure 2.1 Unit 2 30-Day Rolling NO_x Emission Averages

2.2.3 Evaluation of SNCR Effectiveness in CSAPR

Interestingly, the Coal Creek presumptive NOx BART emission rates are consistent with annual average emissions as modeled by EPA in CSAPR. By reviewing existing units of similar design, data from the docket for the proposed Cross State Air Pollution Rule (Docket ID EPA-HQ-OAR-2009-0491) illustrates that there are currently no tangentially-fired utility electricity generating units with LNC3 combustion controls and SNCR post combustion controls that operate at or below the presumptive BART limit of 0.17 lb/mmBtu for NOx (Figure 2.2), as annual averages. If the data set is expanded to include LNC3 ("low NOx coal-and-air nozzles with separated overfire air (LNC2[6])") and "low NOx burners and overfire air (OFA)" as illustrated in Figure 2.3, only four supercritical[7] emission units operate below the presumptive NOx limit of 0.17 lb/mmBtu. None of the facilities included in the CSAPR database operate at or below the proposed FIP limit of 0.12 lb/mmBtu. All of the facilities analyzed use SNCR to effectively achieve the Coal Creek presumptive NOx emission limit of 0.17 lb/mmBtu. To state it differently, Coal Creek effectively achieves presumptive BART with DryFining™ rather than SNCR.

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[6] LNC2 and LNC3 are various types of low NOx burner design.

LNC2 = Low NOx burner with separated OFA

LNC3 = Low NOx burner with close-coupled and separated OFA

[7] For a subcritical boiler (standard operational design consistent with CCS Units 1 and 2), steam to power the turbine is derived by heating liquid water to its saturation point and then isothermally heating of the system causing the phase change from liquid water to steam (boiling). In contrast, a supercritical steam generating unit operates at such a high pressure that liquid water does not boil and is instead converted to a supercritical fluid, an intermediate fluid having properties of both liquid water and steam. Operation of supercritical units is typically more thermally efficient than operation of subcritical units, resulting in less fuel combusted for the same energy output and, consequently, lower emissions.

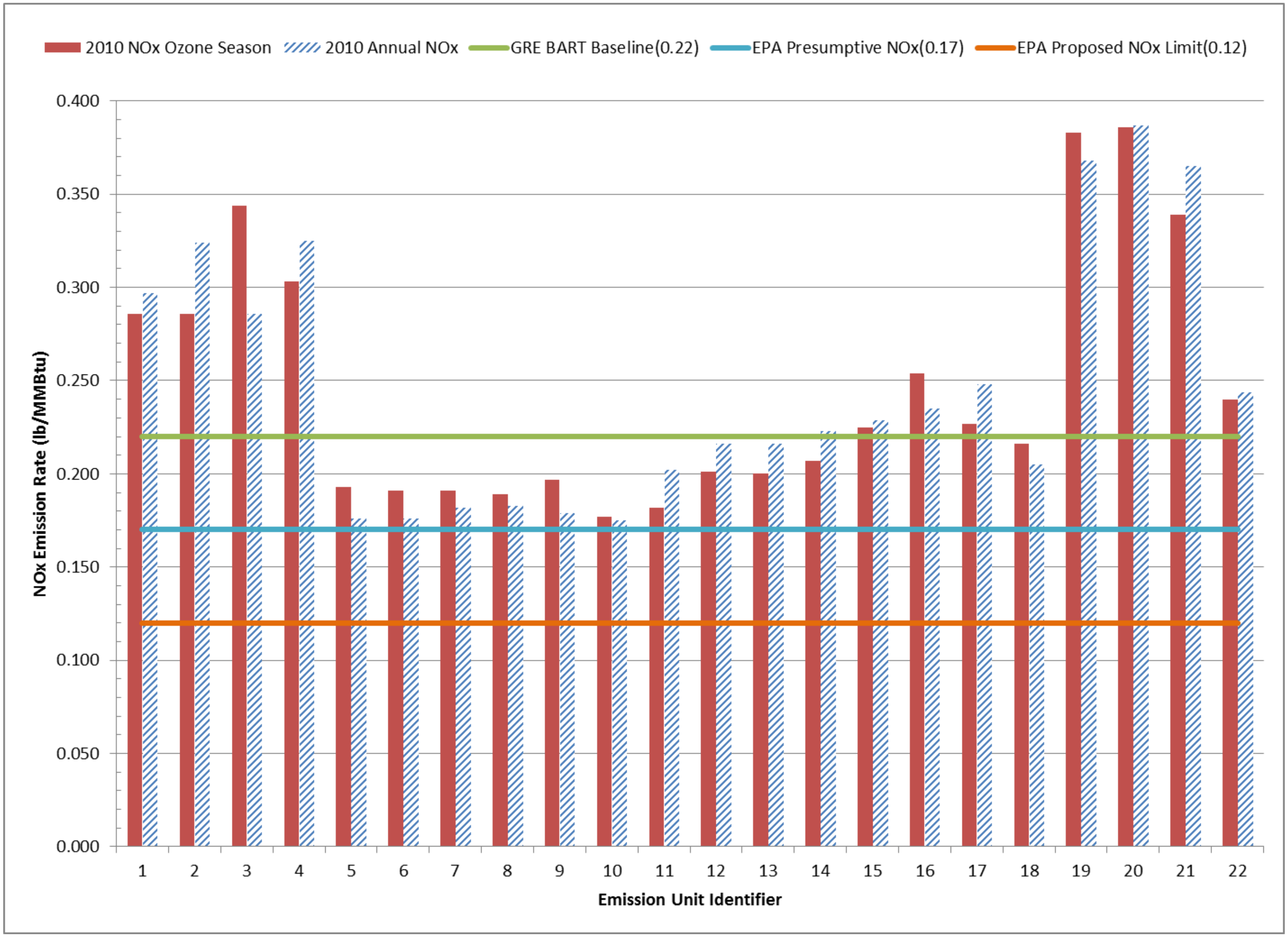

Figure 2.2 2010 NOx Emission Rates from CSAPR Rule Data for Units with SNCR and LNC3/OFA NOx Control

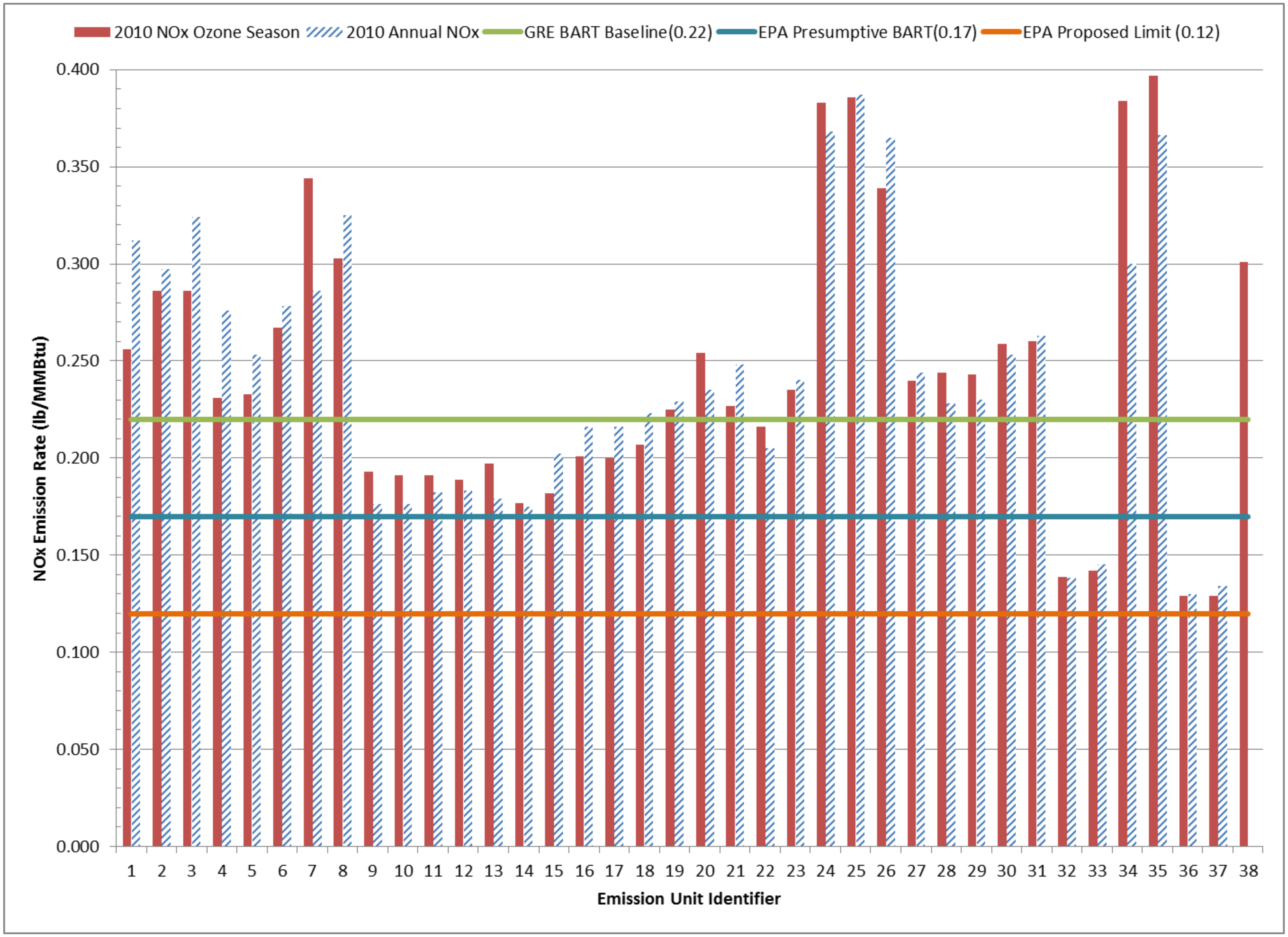

Figure 2.3 2010 NOx Emission Rates from CSAPR Rule Data for Units with SNCR and LNC2/LNC3/OFA NOx Control

2.2.4 Ash Cost Considerations

The EPA indicated in its proposed FIP that GRE fly ash sales and disposal values provided in previous submittals were in error and, when corrected, resulted in SNCR being cost effective. Great River Energy had previously submitted two estimates: $5/ton and $36/ton. Contrary to our Summer 2011 submittal, these values were not necessarily in error, but instead represented different assumptions on economic impacts of lost ash sales and associated disposal costs. Therefore, rather than rely upon these screening level values as previously submitted, GRE contracted with Golder Associates to provide a more refined analysis of ash impacts associated with the installation of SNCR. The following discussion and attached “Fly Ash Storage and Ammonia Slip Mitigation Technology Evaluation” (Appendix C) provides a more comprehensive assessment of ash implications associated with SNCR installation.

To provide some additional background on the previously submitted values, the $36/ton value represented the total freight on board (FOB) Coal Creek Station price that was paid by the end user. The $5/ton dollar per ton figure represented what GRE received as a portion of the FOB price prior to December 1, 2011.

Both of the values ($5/ton and $36/ton) attempted to capture lost revenue from decreased ash sales. In each case, an additional $5/ton cost was added as GRE’s cost to dispose of the unsalable ash. This additional $5/ton disposal value was the result of a screening level analysis and had not taken into account all of the internal costs associated with ash disposal. This disposal value also had not accounted for anticipated cost increases based on changing ash disposal regulations, nor did it take into account various ash disposal levels as could be anticipated due to lost fly ash sales.

GRE and Headwaters Resources, Inc (HRI), GRE’s strategic partner in the sales and distribution of fly ash, have invested heavily into fly ash sales infrastructure including terminals and storage facilities, conveying equipment, scales and train car shuttles. HRI financed GRE’s portion of the infrastructure through a per ton payment on fly ash sales. The current ash sales contract requires payments to GRE that total 30% of the $41 FOB price or $12.30 per ton of ash that is delivered.

Considerable effort has been taken to clarify the impacts that SNCR installation will have on GRE’s ash management methods, overall disposal costs and reduction in ash sales revenues. In short, Great River Energy firmly believes, and EPA acknowledges in its proposed FIP, that SNCR may have a detrimental impact to ash sales. The Golder analysis represents these risk ranging from a worst case 100% lost fly ash sales, to an optimistic 30% lost sales, as shown in their Scenarios B and C, respectively. For the sole purpose of defining a baseline, a hypothetical Scenario A "No Ash Impacts," has also been included as a reference point.

2.2.5 SNCR's Impact on Ash Management Options

Fly ash from CCS is used throughout the Upper Midwest to replace a portion of Portland cement in concrete production, making the concrete more durable and longer lasting. Ash generated at Coal Creek Station has chemical and physical properties that make it an extremely desirable ash in the concrete market. Coal Creek Station currently generates approximately 525,000 tons of fly ash per year. Approximately 415,000 tons of that ash is sold as a Portland cement replacement. Coal Creek fly ash has been used in many large-scale projects such as construction of the new Interstate-35W Bridge after its collapse.

The beneficial use of fly ash also has a strong positive economic benefit to Great River Energy, and the regional economy. We started selling fly ash nearly three decades ago. In that time, we have grown this activity into a sizable annual revenue stream. The addition of SNCR will have a negative impact on the marketability, value and perception of Coal Creek Station's fly ash. The addition of ammonia into the combustion process leaves an ammonia residue on the ash that can cause aesthetic and worker safety issues during the use of the ash. The residual ammonia in the ash eventually off-gases and creates odors which are offensive, are potentially dangerous to human health, and can even pose an explosion risk. EPA's Pollution Control Cost Manual recognizes this fact and states the following:

> *Ammonia sulfates also deposit on the fly ash that is collected by particulate removal equipment. The ammonia sulfates are stable until introduced into an aqueous environment with an elevated pH levels. Under these conditions, ammonia gas can release into the atmosphere. These results in an odor problem or, in extreme instances, a health and safety concern. Plants that burn alkali coal or mix the fly ash with alkali materials can have fly ash with high pH. In general, fly ash is either disposed of as waste or sold as a byproduct for use in processes such as concrete admixture. Ammonia content in the fly ash greater than 5 ppm can result in off-gassing which would impact the salability of the ash as a byproduct and the storage and disposal of the ash by landfill.*[8] (emphasis added)

[8] EPA Pollution Control Cost Manual (2002); Section 4.2, Chapter 1.2.

The range of residual ammonia left with the fly ash can vary with each installation of SNCR. Ammonia slip of only 5 ppm, generally accepted as the minimum that can be achieved with SNCR, can render fly ash unmarketable. (URS, Appendix B) Even in those systems where residual ammonia is generally low, there will be times of increased ammonia slip based on plant operations. As the plant output varies due to market demand or startup/shutdown activity, varying levels of ammonia will be used to control NOx and, consequently, the levels in the ash will change. Variable ammonia levels in the ash create additional complexity to both sales and/or treatment, and will result in increased disposal.

2.2.6 Ammonia Mitigation Technology

Great River Energy is committed to ash re-use due to its economic and environmental benefits. Therefore, we anticipate additional capital and operating costs to treat the ash in order to ideally preserve a percentage of ash sales. With respect to ammoniated ash treatment, Ammonia Slip Mitigation (ASM) technology refers to a variety of technologies that have been designed to improve the marketability of ammoniated ash. These technologies fall into two rough categories, combustion or carbon burn out (CBO) and chemical treatment. CBO is the process of running the ash through an additional combustion unit that would combust and burn out the residual carbon and ammonia that is with the ash. This is a capital intensive technology that also has high operating costs. The second category of ASM technology is generally referred to as chemical treatment. These treatment technologies involve creating a chemical or physical reaction that results in the off-gassing of the residual ammonia. These treatment technologies are generally less costly than CBO. For purposes of this more refined analysis, GRE contracted with Golder Associates to provide a detailed cost estimate of one particular chemical treatment technology as a potentially cost effective option. The detailed cost estimate can be found in Appendix C.

Even with a cost effective ASM technology installed, there will be times when the residual ammonia levels in the ash are too high to treat. Ammonia injection rates will vary during periods of startup and shutdown, in addition to variable load operation, in order to maintain compliance with the BART limits. Variable ammonia injection rates and associated changes in ash concentrations will result in frequent testing and periodic rejection of ash for on-site disposal. Further, variable ammoniated ash levels will put GRE’s generated ash in a very vulnerable position with respect to competitors in the fly ash marketplace, reducing ash sales and increasing on-site disposal.

2.2.7 Ash Disposal Scenario Cost Summaries

Appendix C contains a technical assessment and cost analysis of ammonia slip mitigation technology and ash disposal under RCRA Subtitle D design standards. To address the uncertainty regarding costs associated with ammoniated ash management and disposal, a range of costs is presented. These costs are based on three scenarios described below. Table 1 shows the volumes of ash produced, sold and disposed of in each scenario. For a more detailed description please see Appendix C.

Scenario A (current ash sales levels) – This scenario is the base case with fly ash sales equal to the average sales over the past few years. The scenario assumes that fly ash will be disposed of in a new landfill with a design based on RCRA Subtitle D practices, and has a 20-year disposal capacity. No post processing of the fly ash is required to maintain 100% marketability. (Golder 2011) This hypothetical scenario is not considered to be a possible option for future ash management costs but serves as a point of reference for understanding future impacts.

Scenario B (No ash sales) – This "worst case" scenario assumes that the ammonia slip impact of SNCR makes fly ash at CCS completely unsalable. The scenario also assumes that fly ash will be disposed of in a new landfill with a design based on RCRA Subtitle D practices, and has a 20-year disposal capacity. (Golder 2011)

***Scenario C* (30% sales reduction, ASM costs)** – This "realistic" scenario assumes that Headwater's ASM technology will be viable for ammonia-impacted fly ash at CCS. However, sales will be reduced from current sales levels due to load swing impacts on ammonia slip, market conditions, and other factors previously identified. The scenario also assumes that fly ash will be disposed of in a new landfill with a design based on RCRA Subtitle D practices, and has a 20-year disposal capacity. (Golder 2011)

Table 2.3.1: Fly Ash Sales and Disposal Tons

	Scenario A (Current Sales)	Scenario B (No Sales)	Scenario C (Reduced Sales, ASM)
Fly Ash Produced (ton/yr)	525,000	525,000	525,000
Fly Ash Sold (ton/yr)	415,000	0	290,500
Fly Ash Disposed (ton/yr)	110,000	525,000	234,500

It is clear in EPA's proposed FIP that the installation of SNCR may negatively impact ash sales.[9]

Our knowledge of the ash marketplace, SNCR systems, and treatment technologies confirm that the installation of SNCR will have a detrimental impact on the salability of fly ash. GRE believes that Scenario A, which represents no impact to ash sales, is extremely unlikely. Nevertheless, we present it as a point of reference for better quantifying the ash impacts from SNCR installation.

GRE believes that scenario B (zero ash sales) is a likely outcome, but we hope that through investment in ASM technology we will be able to preserve some of the ash sales. To model partial ash sales, we created Scenario C. Scenario C assumes an investment in ASM technology and a reduction of ash sales by 30%.

It is not possible to determine exactly what percent of ash sales would be lost based on the installation of the SNCR and ammonia mitigation technologies at Coal Creek Station. There are no plants in the country with both of these technologies operating together on a lignite-fired unit. In fact, the vendor responsible for the ammonia mitigation technology will not guarantee the technology's performance at Coal Creek Station.

Across the country there are examples of plants that have SCR or SNCR and sell most of their ash, however, there are also others that sell none of their ash. It is a very site-specific scenario and depends on the type of coal, type of combustion, type of ash collection, plant operation (cycling % load), type of ammonia mitigation technology (if any), and how the SNCR or SCR system has been designed, installed and implemented. Each and every site is very different.

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[9] Federal Register / Vol. 76, No. 183 / Wednesday, September 21, 2011 / Page 58620.

"Regarding this value for fly ash sales, North Dakota concluded that SCR and SNCR use at Coal Creek would likely result in NH_3 in the fly ash due to NH_3 slip which would negatively affect fly ash salability. According to Great River Energy and North Dakota, fly ash that is currently beneficially used in the production of concrete would, instead, be landfilled. While we have opted to agree that fly ash will not be saleable for the SNCR and SCR options for purposes of our cost analyses, we are seeking comment on this issue, particularly related to the levels of NH_3 that fly ash marketers deem problematic, and the availability, applicability, and cost of applying NH_3 mitigation techniques to fly ash derived from lignite coal."

For the sake of modeling the costs related to lost ash sales we determined it was important to model a middle ground between 0% lost ash sales and 100% lost ash sales. There is a strong possibility that all ash sales will be lost and a zero chance that 100% ash sales will be maintained; some middle option needed to be considered. We looked across the industry to determine the best scenario for a moderate outcome. The 30% lost ash sales figure reflects a reasonable and optimistic (i.e., conservative) outcome that can be justified based on our understanding of plant operations and the ash markets in which we compete for sales.

The only plant (Eastlake) in the U.S. operating with the discussed ammonia mitigation technology operates under a very different scenario. This plant mixes the ammoniated ash with a non-ammoniated ash prior to sale. Thus, Eastlake is able to sell up to approximately 85% of its ash.

Coal Creek Station is unlike the Eastlake plant. Increased load variation at CCS, adjusting plant output to match the MISO market in which we operate, can lead to upsets in the SNCR system and higher levels of ammonia in the ash.

The addition of ammonia mitigation technology and additional handling and processing steps will also increase the cost of ash to the end users. As our price point in the market increases, we will face increased competition and will lose some sales to competing ash sources.

Consistency is a prized trait for a fly ash that is marketed to the cement industry. The addition of SNCR will have a detrimental impact on the consistency of the market product. Decreased consistency will lead to lower demand for the ash and will result in some lost sales to competing ash sources.

Predicting exactly what impact all of these factors will have on our ash sales is not possible. Based on our investigation and knowledge, and that of the experts we consulted, we concluded it is very likely that we will lose 50% or more of our ash sales. We chose to model 30% loss in sales as a conservative scenario that likely underestimates the real impact of this technology on ash sales.

Furthermore, in our modeling scenarios, we assumed that the future regulation of coal ash would not be subject to RCRA Subtitle C requirements. Consistent with our comments to EPA's docket during its Coal Combustion Residuals rulemaking, we believe Subtitle C regulation of coal ash is unwarranted and unnecessary. Nevertheless, EPA has proposed it as one option for a final rule. Subtitle C regulation of coal ash would significantly increase our cost to handle and dispose of our ash. Subtitle C regulation has not been included in our scenarios.

We consider a 30% scenario to be a very optimistic view of the future that relies on the successful implementation of a technology that cannot currently be guaranteed by the vendor and has never been installed on lignite-fired units. This scenario also quantifies increased disposal costs, in addition to some GRE-specific economic benefit from preserved ash sales. None of the scenarios attempt to capture economic impacts to GRE's strategic partners or other regional entities, but these impacts are mentioned in Section 3.2 and should also be taken into consideration when making a final BART determination.

2.2.8 Ash Management Costs

There are three major cost categories to be considered in each of these scenarios;

- Fly ash disposal cost estimates,
- Ammonia slip mitigation costs, and
- Lost fly ash sales revenue

Each cost area is summarized below. For a more detailed assessment, see Appendix C.

2.2.9 Fly Ash Disposal Cost Estimates

Given significant uncertainty with pending regulatory requirements such as RCRA Subtitles C and D, with ammonia slip treatment technologies, and with market reactions to ammoniated ash, Great River Energy has developed essentially three scenarios that attempt to capture a range of possibilities associated with SNCR installation. For all three scenarios, a 20-year disposal capacity and a RCRA Subtitle D design is assumed. It is also assumed that the landfill will be built on property not currently owned by GRE, as GRE does not currently have a suitable location for siting a Subtitle D landfill. For this cost estimate, it is assumed that property just west of the plant property would be purchased for the new facility. Landfill size is based on a 20-year fly ash disposal capacity. For the three scenarios, this varies between 2.2 million and 10.5 million tons of capacity. For each scenario, Golder developed a simplified landfill footprint that would provide the 20-year fly ash disposal capacity.

The cost estimate includes costs for the life of the disposal facility including engineering, design, and permitting; construction; and operations and maintenance, including closure and post-closure care. Golder used actual costs from similar projects at CCS, local contractor rates, RS Means manuals (RS Means 2010), and professional judgment to develop this cost estimate. Sources and assumptions are documented. Some general assumptions for the cost estimate include:

- All costs are estimated in 2011 dollars.

- Capital costs are annualized based on a 20-year life and 5.5% interest rate.
- Existing fly ash processing equipment (silos, unloaders, etc.) is not included. Disposal costs begin once the haul trucks are loaded with fly ash.
- Existing fly ash sales infrastructure (silos, scales, rail facilities) and operations and maintenance are not included.
- Disposal costs only include fly ash disposal and not facility airspace or operations and maintenance for other coal combustion products produced at CCS. (Golder 2011)

Table 2.3.2: Disposal Cost Summary

	Scenario A (Current Sales)	Scenario B (No Sales)	Scenario C (Reduced Sales, ASM)
Fly Ash Disposed (ton/yr)	110,000	525,000	234,500
Total Disposal Cost ($/ton)	$18.06	$11.18	$13.91
Annual Disposal Cost ($/yr)	$1,987,000	$5,870,000	$3,262,000
Annual Increase in Disposal Cost Compared to Scenario A ($/yr)	-	$3,883,000	$1,275,000
Incremental Increase in Disposal Cost Compared to Scenario A ($/ton) *	-	$7.40	$5.44

*These values are used in the BART analysis as they represent the only the incremental costs above the baseline costs which would be incurred with or without the installation of SNCR.

2.2.10 Ammonia Slip Mitigation Costs

Post-processing of ammonia slip impacted fly ash by Headwater's ASM technology is proposed as an option to maintain fly ash sales. This post-processing is only being applied to the sold fly ash tonnage in Scenario C. Depending upon the plant power profile and how the fly ash distribution system is setup, it is likely that additional tons of fly ash will be treated and disposed, but these potential cost impacts are not included. The cost impact for ASM post-processing is shown in Table 2.3.3. (Golder 2011)

Table 2.3.3: ASM Post-Processing Costs (Golder 2011)

	Scenario A (Current Sales)	Scenario B (No Sales)	Scenario C (Reduced Sales, ASM)
ASM Unit Rate Capital and O&M ($/ton sold)	$0.00	$0.00	$5.61
ASM Annual Capital and O&M ($/yr)	$0	$0	$1,629,000

2.2.11 Lost Fly Ash Sales Revenue

The current fly ash sales are supported by a large investment in capital infrastructure as well as a large operations and maintenance contingency. Changes to the quantity of fly ash marketed and sold will have a direct impact on fly ash management costs, as the revenue currently used to offset fly ash management will be lost. The lost fly ash sales revenue is based on the 2010 average price per ton FOB of $41.00; with 30% of the sale price going to GRE as revenue. The cost impact of the potential loss in fly ash sales in shown in Table 2.3.4. (Golder 2011)

Table 2.3.4: Lost Fly Ash Sales (Golder 2011)

	Scenario A (Current Sales)	**Scenario B (No Sales)**	**Scenario C (Reduced Sales, ASM)**
Lost Fly Ash Sales Revenue ($/ton lost sales)	$12.30	$12.30	$12.30
Annual Lost Fly Ash Sales Revenue ($/yr)	$0	$5,105,000	$1,531,000

2.2.12 Total Fly Ash Management Costs

The combination of the ASM post-processing, fly ash disposal, and lost fly ash sales revenue is shown in 5. This table represents the total economic impact of SNCR installation on GRE's fly ash management in two likely scenarios; a total loss of ash sales and a 30% reduction in ash sales. (Table 2.3.5)

Table 2.3.5: Total Fly Ash Management Costs (Golder 2011)

	Scenario A (Current Sales)	**Scenario B (No Sales)**	**Scenario C (Reduced Sales, ASM)**
Total (Disposal + Post Processing + Lost Sales)			
Annual Cost ($/yr)	$1,987,000	$10,975,000	$6,422,000
Unit Cost ($/ton produced)	$3.79	$20.91	$12.23
Additional Cost (Scenario B/C - Scenario A)			
Fly Ash Management Cost ($/yr)	-	$8,988,000	$4,435,000
Fly Ash Management Cost ($/ton produced)	-	$17.12	$8.45

2.2.13 BART Analysis Ash Disposal Cost Summary

While the exact impacts to Coal Creek Station's ash are unknown, mandating SNCR will leave GRE in a vulnerable position where we would expect to incur significantly higher costs from lost ash sales and increased landfilling. Based on the detailed technical review discussed above and included as Appendix C, GRE proposes a range of ash disposal costs and lost ash sales revenue figures in the BART analysis.

It is also important to note that none of the scenarios consider the significant cost impact of potential RCRA Subtitle C regulation in the future.

Scenario B represents the highest cost scenario with a total annual additional cost of $8,988,000. The total cost includes lost ash sales revenue of $5,105,000 (Table 2.3.4) and an additional annual ash disposal cost of $3,883,000 or $7.40 per ton disposed (Table 2.3.2).

Scenario C represents an optimistically low cost scenario with a total annual additional cost of $4,435,000. The total cost includes lost ash sales revenue of $1,531,000 (Table 2.3.4) and an additional annual ash disposal cost of $1,275,000 or $5.44 per ton disposed (Table 2.3.2). Scenario C also includes a Ammonia Slip Mitigation cost of $5.61 per ton of ash reused for an additional annual cost of $1,629,000 (Table 2.3.3).

3.0 Integrated NOx Control and Ash Impact Impacts Analyses

This section will integrate the revised baseline emissions, the refined URS SNCR Analysis and the Golder Ash Impact Analysis. It will then provide a summary table with associated cost per ton and incremental cost per ton values.

3.1 SNCR Control Cost Analysis

As discussed in Section 2.1.3, baseline NOx emissions are adjusted to reflect existing controls. Based on the updated baseline, Table 3.1 summarizes the anticipated control costs for additional NOx controls. It includes more refined SNCR costs for CCS Units 1 and 2 (See URS Report Appendix B). It also includes cost scenarios from the Golder Associates Fly Ash Storage and Ammonia Slip Mitigation Technology Evaluation (See Appendix C). It should be noted that the controlled NOx emission concentrations and mass rates have been evaluated on an annual average basis and are not representative of anticipated operation on a shorter scale averaging period (30-day rolling or 24-hour rolling), consistent with BART guidance that costs be normalized to the expected annual emissions reduction. The 30-day rolling limits are intended to be inclusive of unit startup and shutdown as well as variability in load. Consequently, associated BART limits must be higher than stated annual averages used for estimating cost effectiveness. Costs are valued on a present (2011) dollars basis.

Considerable effort has been taken to clarify the impacts that SNCR installation will have on GRE's ash management methods, overall disposal costs and reduction in ash sales revenues. In short, Great River Energy firmly believes, and EPA acknowledges in its proposed FIP, that SNCR may have a detrimental impact to ash sales. The Golder analysis represents these risk ranging from a worst case 100% lost fly ash sales, to an optimistic 30% lost sales, as shown in their Scenarios B and C, respectively. For the sole purpose of defining a baseline, a hypothetical Scenario A "No Ash Impacts," has also been included as a reference point.

Table 3.1 Control Cost Summary

Unit ID	Control Description	NOx Emissions (lb/MMBtu)	Control Eff. From Baseline (%)	Installed Capital Cost ($MM)	Annualized Operating Cost ($MM)	Pollution Control Cost ($/ton)	Incremental Cost $/ton
Unit 1	SNCR,LNC3+,100 % Lost Ash Sales	0.122	33%	$17.87	$8.88	$5,821	$19,125
	SNCR,LNC3+,30% Lost Ash Sales				$6.60	$4,329	$13,762
	SNCR,LNC3+,No Ash Impacts				*$4.38*	*$2,875*	*$8,534*
	SNCR, 100% Lost Ash Sales	0.150	25%	$12.18	$8.79	$7,629	NA – Inferior Control
	SNCR, 30% Lost Ash Sales				$6.52	$5,655	
	SNCR, No Ash Impacts				*$4.30*	*$3,731*	
	LNC3+	0.153	24%	$6.08	$0.76	$693	$693
	Baseline (LNC3)	0.200	NA-Base	NA-Base	NA-Base	NA-Base	NA-Base
Unit 2	SNCR, 100% Lost Ash Sales	0.122	20%	$11.79	$8.11	$10,505	$10,505
	SNCR, 30% Lost Ash Sales				$5.84	$7,559	$7,559
	SNCR, No Ash Impacts				*$3.62*	*$4,688*	*$4,688*
	Baseline – LNC3+	0.153	NA-Base	NA-Base	NA-Base	NA-Base	NA-Base

A "No ash impact" scenario is provided for reference only and does not represent a feasible control option.

Below is provided the least cost envelope illustrated graphically. Only dominant controls falling within the least cost envelope were further analyzed for incremental feasibility. Inferior technologies are deemed not cost effective.

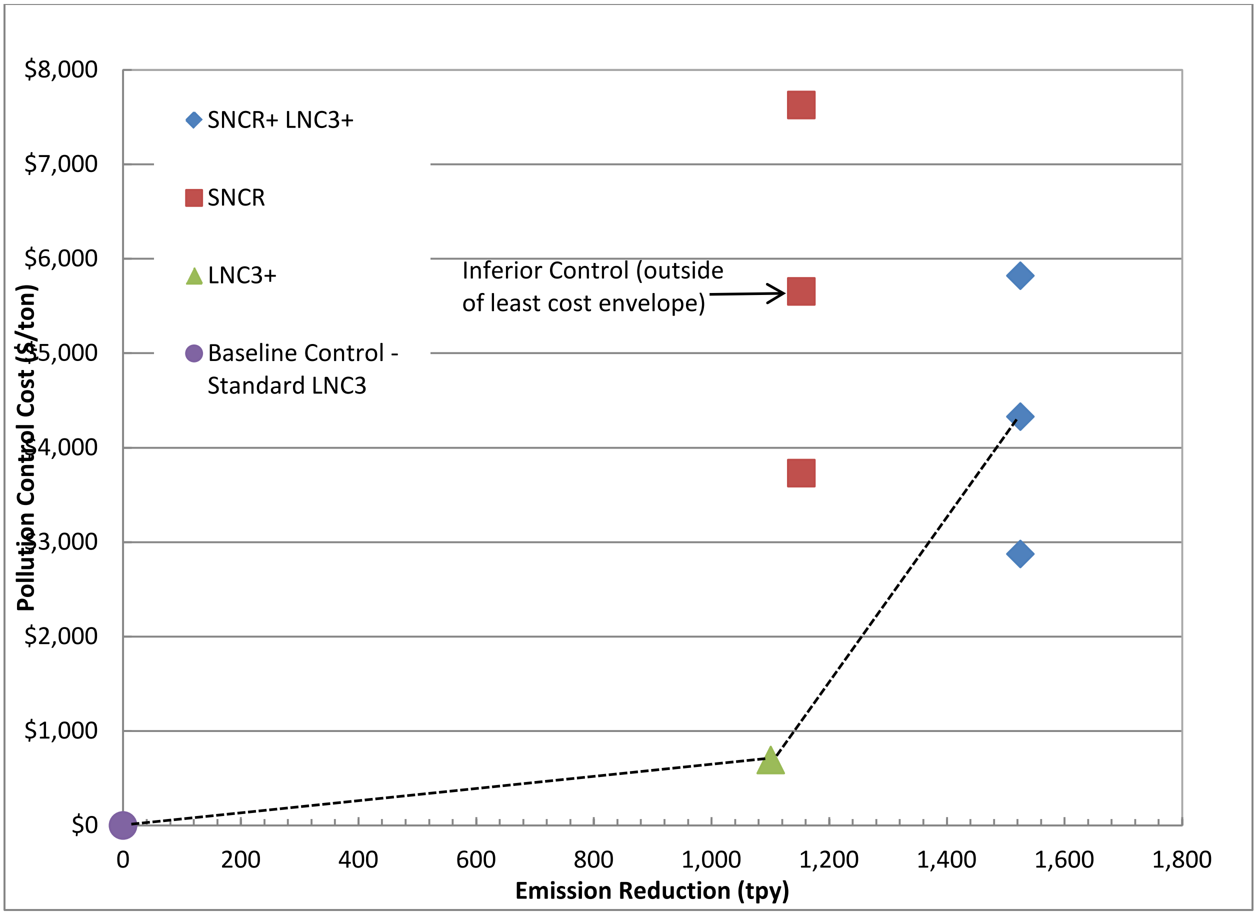

Figure 3-1 Incremental NOx Analysis The remaining feasible technologies are illustrated on the basis of annualized emission reduction in tons per year and total annualized cost in millions of dollars per year.

This refined economic impacts analysis confirms GRE's original conclusion that SNCR is not a cost effective NOx control option. From the table above it would appear as if Unit 1 SNCR – No Ash Impacts would be cost effect on a dollar per ton basis according to the State of ND thresholds, but in understanding that this scenario is considered hypothetical since some level of ash impacts are expected, and the incremental cost per ton is an order of magnitude higher than anything deemed cost effective. The disparity in the incremental costs occurs due to the fact that the DryFining™ with LNC3+ technology could achieve the associated emissions reduction indicated for the SNCR technology. As highlighted, the "most realistic" or optimistic scenario is 30% lost ash sales, with cost exceeding $5,000 per ton of NOx controlled. This value is higher than EPA's determination of economic infeasibility for SCR for CCS at around $4,000/ton of NOx removed stated in the FIP.

Although not directly incorporated into GRE's capital and operating control costs presented above, NDDH must also consider additional impacts, such as indirect and stranded cost components discussed in Section 3.2 and Section 3.3.

3.2 Additional Impacts

GRE provides these additional impact considerations not found in the original BART analysis as important to North Dakota in making its final BART determination.

1. The use of DryFining™ technology that has already been implemented for use at both units at a cost of $270 million. GRE has made a significant investment to achieve multi-pollutant emission reductions and visibility improvements in the region.

2. At the time of this submittal, GRE has already installed LNC3+ combustion controls at Unit 2. In 2011 dollars, this was at a cost of over $6 million and has already resulted in NOx reductions. The same system is currently tentatively scheduled to be installed on Unit 1 during the 2014 outage.

3. Ash infrastructure investments of over $31 million have been made to date for management and sale of Coal Creek Station's ash. Over $7 million of the total investment have been made by GRE, directly.

4. The DryFining™ technology provides a dual emission improvement for the total BART analysis. In order to achieve 100% scrubbing to meet the SO_2 BART limit, GRE must reduce the moisture and related air flow, and therefore the total mass of flue gas traveling through the absorbers in the scrubber. DryFining™ will be implemented to its fullest extent by the BART compliance deadline.

3.2.1 Regional Impact from Ash Sales Revenue

The BART analysis does not take into account additional regional economic impacts resulting from the reduction or elimination of CCS ash sales. In order to estimate these regional impacts, one can use the freight on board (FOB) price of the ash at $41, and subtract GRE's share of that revenue at $12.30. Therefore, SNCR installation would reduce or eliminate ash sales, eliminating an additional $28.70/ton from the local and regional economy. This could result in a loss of as much as $11,910,500 per year from the local and regional economy. In addition to these regional economic impacts, there are other impacts that must also be considered.

3.2.2 Fly Ash is Important to the National Economy

Fly ash is an important part of the regional and national economy. The National Association of Manufacturers reported in 2010 that Coal Combustion Residuals (CCRs) contribute $6-11 billion annually to the U.S. economy through revenues from sales for beneficial use, avoided cost of disposal, and savings from use as a sustainable building material.[10] The beneficial use of fly ash and other CCRs are directly responsible for a large number of jobs throughout the country. A 2011 report by Veritas found that "Approximately 10.6 million tons of coal combustion residuals were used in concrete-related products during 2009. Those products provided employment for 240,100 manufacturing workers, 78,480 foundation, structure, and building exterior workers and many of the 102,350 nonresidential building construction workers during 2010." (Veritas 2011)[11]

3.2.3 Fly Ash is Important to Regional and National Infrastructure

The American Road and Transportation Builders Association completed a report in 2011[12] that highlighted the importance of fly ash as a component of road and bridge construction across the country. Their research found that the elimination of fly ash as a construction material would increase the average annual cost of building roads, runways and bridges in the United States by nearly $5.23 billion. This total includes $2.5 billion in materials price increases, $930 million in additional repair work and $1.8 billion in bridge work. The additional costs would total $104.6 billion over 20 years.

3.2.4 Environmental Benefits of Ash Reuse

The use of fly ash as a replacement for cement has many environmental benefits. As a result of the increased use of fly ash, less land is disturbed for quarrying raw materials, less land is taken out of production for landfills, and less carbon dioxide (CO_2) is emitted into the atmosphere to make cement. Using one ton of fly ash instead of Portland cement reduces up to one ton of greenhouse gas emissions. Inversely, by contaminating the ash with ammonia, and increasing ash disposal, there will be a corresponding 1-to-1 ton increase in CO_2 emissions from using more Portland cement. These CO_2 emissions are not trivial.

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[10] Report available at: http://www.regulations.gov/#!documentDetail;D=EPA-HQ-RCRA-2009-0640-6992.

[11] Available at: http://www.recyclingfirst.org/pdfs/101.pdf.

[12] Available at: http://www.artba.org/mediafiles/study2011flyash.pdf.

3.2.5 Additional Ash Management Cost Considerations

The ash management costs detailed in this report are considered to be conservative figures from reasonable assumptions that most likely underestimate GRE's future expenditures on ash management.

The ash analysis envisions that all future disposal facilities will be designed and constructed to RCRA subtitle D standards. EPA is currently proceeding with an ash disposal rulemaking that will create uniform national disposal standards under RCRA subtitle D, the far more stringent Subtitle C (Hazardous Waste), or some hybrid approach that takes some requirements from each Subtitle D and C. The cost of complying with a Subtitle C rule would vastly exceed the amounts discussed in this report. This analysis reasonably assumes Subtitle D.

The ash disposal costs discussed above are portrayed as three scenario costs: a baseline which represents current ash sales figures; a scenario where all ash must be disposed of; and a scenario where ash sales are reduced by 30% from the baseline. There is significant uncertainty regarding specific impacts to beneficial reuse if SNCR were installed. The zero ash sales scenario (Scenario B) is very possible and is an outcome that we hope to avoid. Scenario C captures a "hybrid" estimate of the future where some ash is beneficially used and some additional ash must be disposed. For the hybrid scenario, we chose a 30% reduction in sales. This 30% estimate is an optimistic figure of preserved ash sales at 70%. It is quite possible that the amount of ash requiring disposal could easily represent a 50%, 70% or larger reduction in fly ash sales. For this reason, Scenario C is likely to produce ash management costs that are lower than will actually be encountered.

As discussed above, there are a variety of different Ammonia Slip Mitigation (ASM) technologies available. Most of these technologies have only been installed at a small number of generating units and, to GRE's knowledge, no lignite-fired unit is currently operating SNCR and ASM technology.[13] Of all ASM technologies that were investigated, the Headwaters technology was the least expensive. If the Headwaters ASM technology fails to function properly on lignite, it is likely that we would incur significantly larger costs to preserve the beneficial reuse of some portion of our fly ash.

The EPA Pollution Control Cost Manual (2002) does not allow GRE to include in our BART analysis the value of previously purchased assets that would be rendered useless by the elimination or

[13] It is important to note that Headwaters ASM technical staff have stated that this technology has not been tested on a lignite unit and they would not guarantee any level of performance if installed at CCS.

reduction of fly ash sales. GRE and its strategic partner, Headwaters Resources, have invested $31M on ash storage, transportation and distribution infrastructure.

3.3 SNCR Visibility Impacts

It is known that NOx contributes to ammonium nitrate formation, which is predominantly a winter "haze" contributor. For purposes of valuing the welfare effects of recreational visibility, it is important to consider that the North Dakota national parks are generally not in high use during the winter season. If required to install SNCR, GRE will pay an extreme price per deciview resulting in imperceptible improvements for a time of year when the parks are generally not used.

To satisfy EPA's proposed Federal Implementation Plan, Coal Creek Station would need to install SNCR technology to reach a NOx emissions level that is 29% lower than EPA's presumptive BART. Yet, the extensive modeling performed as part of the BART analysis concludes that the installation of SNCR, at an emission rate of 0.12 lb/mmBtu, will have an imperceptible improvement in visibility, ranging from 0.05 deciview (dV) to 0.18 dV in the Class I areas near the facility. This is far less than one-half of what EPA has determined to be perceptible to the human eye (0.50 dV).[14] As such, it is not justifiable for GRE to incur the added cost of SNCR without any appreciable improvement in visibility.

It is worth noting that SNCR will result in ammonia emissions to the atmosphere. Ammonia is a listed state toxic in North Dakota, and is viewed as a contributor to regional haze because it can bond with sulfur dioxide and nitrogen oxides to form ammonium sulfate and ammonium nitrate aerosols Consequently, GRE does not believe that SNCR is a cost effective technology for improving visibility.

3.3.1 CCS Modeled Visibility Impacts

Under EPA's modeling guidelines, it is necessary to develop a 24-hour maximum anticipated emission rate for each control technology in order to assess visibility impacts. GRE assumes that on a 30-day rolling basis, combustion and post-combustion NOx controls can experience emissions that are approximately 10% higher than their annual design basis. Similarly, for assessing a 24-hour

[14] Federal Register / Vol. 76, No. 183 / Wednesday, September 21, 2011.
FR discusses State's ability to consider potential impacts for VOC and ammonia although full analyses may not be required.

maximum emission rate, GRE assumes emissions will be up to 20% higher than the annual design rate for a given control.

GRE presented a full evaluation of anticipated cost per unit visibility impairment (Δ-dV) in its final BART analysis (Dec 2007). Pollutant interaction has an impact on modeled visibility impairment and, as such, GRE believes that modeling changes to NOx emission rates alone will not provide visibility modeling results that are representative of actual emission controls. This may overstate visibility improvement as compared to modeling NOx, SO_2 and fine PM together. However, for the purpose of illustrating the relative visibility impacts of SNCR and LNC3+, an analysis of the difference in modeled impacts is presented in Table 3.

Table 3.3.1. Difference in Impairment for LNC3+ with Tuning and SNCR with LNC3+

Year	2000	2001	2002	Average
Unit 1	0.05	0.06	0.10	0.07
Unit 1 & 2	0.05	0.10	0.18	0.11

The visibility analysis demonstrates that SNCR will not result in perceptible improvements to visibility in North Dakota's affected Class I areas. Utilities in North Dakota only contribute ~6% to total NOx emissions in the State. Consequently, any additional utility NOx reductions will not have an appreciable effect on visibility improvement. Additional details regarding modeling inputs and visibility impairment is presented in Appendix D

4.0 Conclusions

Great River Energy provided BART Determinations utilizing the 5 step process in 2007. Until now, Great River Energy has provided screening level analyses and assumptions with respect to SNCR installation. Due to EPA's proposed FIP, and its assertion that SNCR is cost effective for Coal Creek Station, Great River Energy responds with more refined analyses in three primary areas. This refined analysis reevaluates the last two steps of the BART Determination process for LNC3+ and SNCR technologies at Coal Creek Station.

First, URS provides a site specific evaluation of SNCR effectiveness at Coal Creek Station, which results in lower projected emissions reductions from this control. These emission estimates clearly change the basis for any cost effective determination. Consideration for startup and shutdown emissions, circumferential cracking and load variations should also factor into this determination as discussed in Section 2.2.

Second, URS reviewed and updated both capital and operating costs for SNCR, based on their expertise and site specific investigation. These values were relatively consistent with values presented to EPA in June and July 2011, but are somewhat higher than the screening values presented in the original BART analysis.

Third, Golder Associates conducted a detail ash impact analysis associated with a range of costs from contaminating the fly ash with ammonia from SNCR. While the exact impacts to Coal Creek Station's ash management and sales are unknown, mandating SNCR will leave GRE in a vulnerable position where we would expect to incur significantly higher costs from lost ash sales and increased landfilling. Based on a detailed technical review, GRE would expect to incur additional ash annual costs somewhere between $4,435,000 and $8,988,000.

The final two steps of the BART Determination include Step 4 - "Evaluate Impacts and Document Results" and Step 5 – "Evaluate Visibility Impacts." In evaluating the impacts of Unit 1's technologies it was concluded that installation of SNCR alone (without LNC3+) is an economically inferior technology and therefore is not further evaluated incrementally. When the SNCR and LNC3+ technologies were evaluated together for Unit 1 and Unit 2 they were deemed not cost effective on an incremental basis and therefore not an appropriate BART technology option. GRE included the visibility tables for the associated LNC3+ and SNCR cases presented in Table 3.1. The final conclusion for the visibility impacts is that, based on our refined analysis, the North Dakota Class I areas would not receive any perceptible improvement in visibility by requiring a level of NOx control above LNC3+ for CCS.

When the three refined analyses of the final two steps of the BART Determination process are combined and evaluated, it clearly demonstrates that the presumptive NOx limit of 0.17 lb/mmBtu is both cost effective and results in significant visibility improvements in North Dakota’s Class I areas.

On strictly a cost effective basis, SNCR can be ruled out as not cost effective, especially when the GRE specific risks and costs associated with this technology are included. As noted, there are additional economic and visibility impacts associated with SNCR that further preclude it from consideration.

Appendix A

Pollution Control Cost Evaluations

Great River Energy Coal Creek Station
BART Supplement - NOx Emission Control Cost Analysis

Table A-1: Cost Summary

NO_x Control Cost Summary - Unit 1

Case	Control Technology [1]	Annual Designed Emissions lb/MMBtu	Control Eff % from Baseline	Controlled Emissions T/yr	Emission Reduction T/yr	Installed Capital Cost MM$	Annualized Control Cost MM$/yr	Pollution Control Cost $/ton	Annual Incremental Cost $/ton [3]	See Table XX for additional information
	SNCR + LNC3+ - 100% Lost Ash Sales						$8.88	$5,821	$19,125	A-4, A-10
3 [2]	SNCR + LNC3+ - 30% Lost Ash Sales	0.122	33%	3,086.2	1,525.2	$17.87	$6.60	$4,329	$13,762	A-4, A-9
	SNCR + LNC3+ - No Ash Impacts						*$4.38*	*$2,875*	*$8,534*	*A-4, A-8*
	SNCR - 100% Lost Ash Sales						$8.79	$7,629	NA - Inferior Control	A-7
2	SNCR - 30% Lost Ash Sales	0.150	25%	3,458.5	1,152.8	$12.18	$6.52	$5,655	NA - Inferior Control	A-6
	SNCR - No Ash Impacts						*$4.30*	*$3,731*	*NA - Inferior Control*	*A-5*
1	LNC3+	0.153	24%	3,510.5	1,100.9	$6.08	$0.76	$693	$693	A-4
0	Baseline Control - Standard LNC3	0.200	NA-Base	4,611.4	NA-Base	NA-Base	NA-Base	NA-Base	NA-Base	A-3

NO_x Control Cost Summary - Unit 2

Case	Control Technology [1]	Annual Designed Emissions lb/MMBtu	Control Eff % from Baseline	Controlled Emissions T/yr	Emission Reduction T/yr	Installed Capital Cost MM$	Annualized Control Cost MM$/yr	Pollution Control Cost $/ton	Annual Incremental Cost $/ton [3]	See Table XX for additional information
	SNCR - 100% Lost Ash Sales					$11.79	$8.11	$10,505	$10,505	A-10
1	SNCR - 30% Lost Ash Sales	0.122	20%	3,089.8	772.5	$11.79	$5.84	$7,559	$7,559	A-9
	SNCR - No Ash Impacts					*$11.79*	*$3.62*	*$4,688*	*$4,688*	*A-8*
0	Baseline Control - LNC3+	0.153	NA-Base	3,862.3	NA-Base	NA-Base	NA-Base	NA-Base	NA-Base	A-3

[1] Ash impact scenarios align with November 2011 Golder report.
No Ash Impacts - Golder Scenario A; *Scenario provided for reference only and does not represent a feasible outcome*
30% Lost Ash Sales - Golder Scenario C
100% Lost Ash Sales - Golder Scenario B

[2] Capital costs for combined control scenario on Unit 1 are calculated using LNC3+ costs for Unit 1 (scenario 1) and SNCR costs for Unit 2, as unit 2 presently has LNC3+ installed.

[3] Incremental costs calculated as the difference in annualized operating cost divided by the difference in emission reduction for the next lowest level of dominant control.

Great River Energy Coal Creek Station

BART Supplement - NOx Emission Control Cost Analysis

Table A-2: Emission Inventory Data / Baseline Emission Rate for BART Control Cost Analysis

Equipment Information: GRE Coal Creek Unit I			6015	MMBtu/hr	
Year (12-Month Avg. Period)	Jul 2010 - Jun 2011	Aug 2010 - Jul 2011	Sep 2010 - Aug 2011	Oct 2010 - Sep 2011	Nov 2010 -Oct 2011
Hours of Operation	7,700	7,700	7,635	7,599	7,629
Fuels Used:					
Quanity of Lignite - Tons	3,356,248	3,352,605	3,296,938	3,268,966	3,282,270
Percent Sulfur in Coal (Average)	0.64%	0.65%	0.65%	0.66%	0.61%
BTU per Unit of Coal (Average)	6,415	6,448	6,482	6,517	6,003
Heat Input	4.410E+07	4.422E+07	4.356E+07	4.320E+07	4.346E+07
MMBtu/hr	5,727	5,743	5,705	5,685	5,697
% of Capacity	95.2%	95.5%	94.8%	94.5%	94.7%
NOx lb/MMBtu	0.200	0.200	0.199	0.200	0.203
Total Stack Emissions:					
NOx Emitted Tons Per Year:	4,416.3	4,412.0	4,333.1	4,330.2	4,402.3
NOx Emitted Lb Per Hour:	1,204.8	1,200.3	1,196.7	1,205.8	1,218.5
Stack Emissions --- Lignite:					
NOX CEM Annual Average lb/MMBtu	0.201	0.200	0.200	0.201	0.203

Baseline Emis	
Unit 1	**Unit 2**
7,653	8,410
3,311,405	3,688,805
0.64%	0.64%
6,373	6,373
43,708,554	47,761,077
5,712	5,679
95.0%	94.3%
0.200	0.153
4,378.8	3,642.5
1205.2	918.5
0.201	0.153

Equipment Information: GRE Coal Creek Unit II			6022	MMBtu/hr	
Year	Jul 2010 - Jun 2011	Aug 2010 - Jul 2011	Sep 2010 - Aug 2011	Oct 2010 - Sep 2011	Nov 2010 -Oct 2011
Hours of Operation	8,430	8,430	8,397	8,401	8,390
Fuels Used:					
Quanity of Lignite - Tons	3,730,674	3,718,253	3,676,481	3,672,436	3,646,178
Percent Sulfur in Coal (Average)	0.64%	0.65%	0.65%	0.66%	0.61%
BTU per Unit of Coal (Average)	6,415	6,448	6,482	6,517	6,003
Heat Input	4.810E+07	4.799E+07	4.757E+07	4.764E+07	4.751E+07
MMBtu/hr	5,706	5,692	5,665	5,671	5,662
% of Capacity	94.9%	94.6%	94.2%	94.3%	94.1%
NOx lb/MMBtu	0.152	0.153	0.152	0.152	0.153
Total Stack Emissions:					
NOx Emitted Tons Per Year:	3,662.4	3,666.8	3,610.4	3,626.8	3,646.1
Stack Emissions --- Lignite:					
NOX CEM Annual Average lb/MMBtu	0.152	0.153	0.152	0.153	0.154

Great River Energy Coal Creek Station
BART Supplement - NOx Emission Control Cost Analysis
Table A-3: Summary of Utility, Chemical and Supply Costs

Operating Unit: Unit 1 or 2 **Study Year** 2011

From Golder Report

Item	Unit Cost	Units	Reference Cost	Year	Data Source	Notes
Operating Labor	37	$/hr	25.86	2002	Stone & Webster 2002 Cost Estimate; confirmed by GRE	
Maintenance Labor	37	$/hr	26.25	2002	Stone & Webster 2002 Cost Estimate; confirmed by GRE	
Electricity	0.060	$/kwh	0.049	2004	DOE Average Retail Price of Industrial Electricity, 2004	http://www.eia.doe.gov/emeu/aer/txt/ptb0810.html
Water	0.31	$/kgal	0.79	2002	Stone & Webster 2002 Cost Estimate; confirmed by GRE	
Cooling Water	0.32	$kgal	0.23	1999	EPA Air Pollution Control Cost Manual, 6th ed. Section 3.1 Ch 1	Ch 1 Carbon Adsorbers, 1999 $0.15 - $0.30 Avg of 22.5 and 7 yrs and 3% inflation
Compressed Air	0.37	$/kscf	0.25	1998	EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1	Example problem; Dried & Filtered, Ch 1.6 '98 cost adjusted for 3% inflation
Wastewater Disposal Neutralization	1.96	$/kgal	1.50	2002	EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 2 Chapter 2.5.5.5	Section 2 lists $1- $2/1000 gal. Cost adjusted for 3% inflation Sec 6 Ch 3 lists $1.30 - $2.15/1,000 gal
Wastewater Disposal Bio-Treat	4.96	$/kgal	3.80	2002	EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 5.2 Chapter 1	Ch 1 lists $1.00 - $6.00 for municipal treatment, $3.80 is average. Cost adjusted for 3% inflation
Solid Waste Disposal - No Impact	0.00	$/ton	0.00	2011	Assume no chang in GRE landfill cost for ash	Fly ash disposal of 0 net tons
Solid Waste Disposal - 30% Lost	5.44	$/ton	5.44	2011	Golder Fly Ash Management Evaluation - Nov. 2011	Cost per ton of $13.91/ ton for 234,500 tons less existing cost of $18.06/tons for 110,000 tons
Solid Waste Disposal - 100% Lost	7.40	$/ton	7.40	2011	Golder Fly Ash Management Evaluation - Nov. 2011	Cost per ton of $11.18/ ton for 525,000 tons less existing cost of $18.06/tons for 110,000 tons
Hazardous Waste Disposal	326.19	$/ton	250.00	2002	EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 2 Chapter 2.5.5.5	Section 2 lists $200 - $300/ton Used $250/ton. Cost adjusted for 3% inflation
Waste Transport	0.65	$/ton-mi	0.50	2002	EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 3	Example problem. Cost adjusted for 3% inflation
Ash Sales	12.30	$/ton	12.30	2011	Golder Fly Ash Management Evaluation - Nov. 2011	$/ton received for sale of ash; this amount is lost if ash cannot be sold
Ammonia Mitigation	5.61	$/ton	5.61	2011	Golder Fly Ash Management Evaluation - Nov. 2011	
Chemicals & Supplies						
Lime	90.00	$/ton	72.19	2005	GRE per Diane Stockdill 12/6/05 email	Cost adjusted for 3% inflation
Caustic	364	$/ton	305.21	2005	GRE per Diane Stockdill 12/6/05 email	Cost adjusted for 3% inflation
Urea	500	$/ton	500	2011	URS SNCR Report - November 2011	
Oxygen	17.91	kscf	15.00	2005	Get cost from Air Prod Website	Cost adjusted for 3% inflation
EPA Urea	179.1	$/ton				
Ammonia	1	$/lb	0.92	2005	GRE per Diane Stockdill	Cost adjusted for 3% inflation
Other						
Sales Tax	0	%			GRE per Diane Stockdill 12/6/05 email	
Interest Rate	5.50%	%			GRE per Diane Stockdill 12/6/05 email	Estimated prime rate plus 3%
Please note, for units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal						
Operating Information	**Unit 1**	**Unit 2**				
Annual Op. Hrs	7,653	8,410	Hours		July 2010 to October 2011 Coal Creek Emission Data	
Utilization Rate	100.0%	100.0%			GRE per Diane Stockdill 12/6/05 email	
Equipment Life	20	20	yrs			Engineering Estimate
Coal Ash	11.70	11.70	wt % ash		2010 Coal Creek Emission Inventory	
Coal Sulfur	0.64	0.64	% Coal Sulfur Content		July 2010 to October 2011 Coal Creek Emission Data	
Coal Heating Value	6,373	6,373	Btu/lb of coal		July 2010 to October 2011 Coal Creek Emission Data	
Design Capacity	6,015	6,022	MMBtu/hr			
ID Fan Flow Rates	Assumes coal drying with DryFining™					
Standardized Flow Rate	866,294	866,294	scfm @ 32º F			
Temperature	330	330	Deg F		GRE per G. Riveland 4/5/06 email	
Moisture Content	13.3%	13.3%			GRE per G. Riveland 4/5/06 email	
Actual Flow Rate	2,234,300	2,234,300	acfm		GRE per G. Riveland 4/5/06 email	
Standardized Flow Rate	1,391,000	1,391,000	scfm @ 330º F		GRE per G. Riveland 4/5/06 email	
Dry Std Flow Rate	1,205,997	1,205,997	dscfm @ 330º F			
NOx Pollutant Data						
Max Emis (lb/hr)	1,205	919			July 2010 to October 2011 Coal Creek Emission Data	
Max Emis (tpy)	4,611	3,862				
Baseline Emiss (lb/MMBtu)	0.200	0.153				

Great River Energy Coal Creek Station

BART Supplement - NOx Emission Control Cost Analysis

Table A-4: Unit 1 NOx Control - Foster Wheeler LNC3+

Operating Unit: **Unit 1**

Emission Unit Number	EU-1		Stack/Vent Number	SV-1		CEPCI	
Desgin Capacity	6,015	MMBtu/hr	Standardized Flow Rate	866,294	scfm @ 32º F	2005	468.2
Expected Utiliztion Rate	100%		Temperature	330	Deg F	2011	588.9
Expected Annual Hours of Operation	7,653	Hours	Moisture Content	13.3%		Inflation Factor	1.26
Annual Interest Rate	5.5%		Actual Flow Rate	2,234,300	acfm		
Expected Equipment Life	20	yrs	Standardized Flow Rate	1,391,000	scfm @ 330º F		
Baseline NOx	0.200	lb/MMBtu	Dry Std Flow Rate	1,205,997	dscfm @ 330º F		

CONTROL EQUIPMENT COSTS

Capital Costs								
Direct Capital Costs								
Purchased Equipment (A)								1,257,796
Purchased Equipment Total (B)								**1,958,057**
Installation - Standard Costs								1,958,057
Installation - Site Specific Costs								NA
Installation Total								3,729,632
Total Direct Capital Cost, DC								5,687,689
Total Indirect Capital Costs, IC								391,611
Total Capital Investment (TCI) = DC + IC								**6,079,300**
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.						7,079
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost						756,131
Total Annual Cost (Annualized Capital Cost + Operating Cost)								**763,210**

Emission Control Cost Calculation

Pollutant	**Max Emis Lb/Hr**	**Annual T/Yr**	**Cont Eff %**	**Exit Conc**	**Conc Units**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
Nitrous Oxides (NOx)	1,205.2	4,611.4	24%			3510.5	1,100.9	693

Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 2 (Used PM Scrubber which has lowest installed cost multiplier)

Notes & Assumptions

1 Sept 2005 Cost Estimate from Foster Wheeler, Option 2, inflated to 2011 dollars. Ratio based on actual cost for Unit 2 instalaltion.

2 Total capital investment reflects actual installed costs for Unit 2 installation, infllated to 2011 dollars.

3 Assumed 0.1 hr/shift operatior and maintenance labor for LNB

4 Process, emissions and cost data listed above is for one unit.

5 For units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal

Great River Energy Coal Creek Station
BART Supplement - NOx Emission Control Cost Analysis
Table A-4: Unit 1 NOx Control - Foster Wheeler LNC3+

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) (1)			**1,257,796**
Instrumentation			
Sales Taxes			
Freight			
Purchased Equipment Total (B)			**1,958,057**
Installation			
Foundations & supports			
Handling & erection			
Electrical			
Piping			
Insulation			
Painting			
Installation Subtotal Standard Expenses (1)			**1,958,057**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Site Specific - Other		Site Specific	NA
Total Site Specific Costs			NA
Installation Total			**3,729,632**
Total Direct Capital Cost, DC			**5,687,689**
Indirect Capital Costs			
Engineering, supervision	5%	of purchased equip cost (B)	97,903
Construction & field expenses	10%	of purchased equip cost (B)	195,806
Contractor fees	0%	of purchased equip cost (B)	0
Start-up	1%	of purchased equip cost (B)	19,581
Performance test	1%	of purchased equip cost (B)	19,581
Model Studies	NA	of purchased equip cost (B)	NA
Contingencies	3%	of purchased equip cost (B)	58,742
Total Indirect Capital Costs, IC	20%	of purchased equip cost (B)	**391,611**
Ozone Generator, Installed Cost			**0**
Total Capital Investment (TCI) = DC + IC (2)			**6,079,300**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**6,079,300**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	NA		-
Supervisor	NA		-
Maintenance			
Maintenance Labor	37.00	$/Hr, 0.1 hr/8 hr shift, 7652.6 hr/yr	3,539
Maintenance Materials	100%	of maintenance labor costs	3,539
Utilities, Supplies, Replacements & Waste Management			
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
Total Annual Direct Operating Costs			**7,079**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	4,247
Administration (2% total capital costs)	2%	of total capital costs (TCI)	121,586
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	60,793
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	60,793
Capital Recovery	0.0837	for a 20- year equipment life and a 5.5% interest rate	508,712
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**756,131**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**763,210**

Great River Energy Coal Creek Station

BART Supplement - NOx Emission Control Cost Analysis

Table A-4: Unit 1 NOx Control - Foster Wheeler LNC3+

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Parts & Equipment:		
Equipment Life	5	years
CRF	0.0000	
Rep part cost per unit	0	$/ft^3
Amount Required	0	ft^3
Packing Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:			
Equipment Life	3		
CRF	0.3707		
Rep part cost per unit	0	$ each	
Amount Required	0	Number	
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax	
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr	OAQPS list replacement times from 5 - 20 min per bag.
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	
Annualized Cost	**0**		

Electrical Use							
	Flow acfm		D P in H2O	Efficiency	Hp	kW	
Blower, Scrubber	2,234,300		0	0.7	-	0.0	EPA Cost Cont Manual 6th ed Section 5.2 Chapter 1 Eq 1.48
	Flow	Liquid SPGR	D P ft H2O	Efficiency	Hp	kW	
Circ Pump	000 gpm	1	0	0.7	-	0.0	EPA Cost Cont Manual 6th ed Section 5.2 Chapter 1 Eq 1.49
H2O WW Disch	0 gpm	1	0	0.7	-	0.0	EPA Cost Cont Manual 6th ed Section 5.2 Chapter 1 Eq 1.49
			lb/hr O_3				
LTO Electric Use	4.5 kW/lb O_3					0	
Other							
Total						0.0	

Reagent Use & Other Operating Costs					
Ozone Needed	1.8	lb O3/lb NOx	- lb/hr O3		
Oxygen Needed	10%	wt O2 to O3 conversion		0 lb/hr O2	0 scfh O2
LTO Cooling Water	150	gal/lb O3	0 gpm		
Liquid/Gas ratio	0.0	* L/G = Gal/1,000 acf			
Circulating Water Rate	0 gpm				
Water Makeup Rate/WW Disch =		20% of circulating water rate =		0 gpm	
Scrubber Cost	10	$/scfm Gas	$0	Incremental cost per BOC. Need to increase vessel size over standard absorber.	
Ozone Generator	$350	lb O3/day	$0 Installed	Installed cost factor per BOC.	

Operating Cost Calculations — **Annual hours of operation:** **7,653**; **Utilization Rate:** **100%**

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Operating Labor							
Op Labor	0	$/Hr	0.1	hr/8 hr shift	96	0	$/Hr, 0.1 hr/8 hr shift, 7652.6 hr/yr
Supervisor	15%	of Op.			NA	-	15% of Operator Costs
Maintenance							
Maint Labor	37.00	$/Hr	0.1	hr/8 hr shift	96	3,539	$/Hr, 0.1 hr/8 hr shift, 7652.6 hr/yr
Maint Mtls	100	% of Maintenance Labor			NA	3,539	100% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.060	$/kwh	0.0	kW-hr	0	0	$/kwh, 0 kW-hr, 7652.6 hr/yr, 100% utilization
Water	0.31	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 7652.6 hr/yr, 100% utilization
Cooling Water	0.32	$kgal	0.0	gpm	0	0	$kgal, 0 gpm, 7652.6 hr/yr, 100% utilization
Comp Air	0.37	$/kscf	0	kscfm	0	0	$/kscf, 0 kscfm, 7652.6 hr/yr, 100% utilization
WW Treat Neutralization	1.96	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 7652.6 hr/yr, 100% utilization
WW Treat Biotreatement	4.96	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 7652.6 hr/yr, 100% utilization
SW Disposal	0.00	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 7652.6 hr/yr, 100% utilization
Haz W Disp	326	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 7652.6 hr/yr, 100% utilization
Ammonia Mitigation	5.61	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 7652.6 hr/yr, 100% utilization
Lost Ash Sales	12.30	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 7652.6 hr/yr, 100% utilization
Lime	90.0	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 7652.6 hr/yr, 100% utilization
Caustic	364.4	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 7652.6 hr/yr, 100% utilization
Oxygen	17.9	kscf	0.0	kscf/hr	0	0	kscf, 0 kscf/hr, 7652.6 hr/yr, 100% utilization

*annual use rate is in same units of measurement as the unit cost factor

See summary on first page of this table for notes and assumptions

Great River Energy Coal Creek Station

BART Supplement - NOx Emission Control Cost Analysis

Table A-5: Unit 1 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (Maintain Ash Sales)

Operating Unit: **Unit 1**

Emission Unit Number	EU-1		Stack/Vent Number	SV-1	
Desgin Capacity	6,015	MMBtu/hr	Standardized Flow Rate	866,294	scfm @ 32º F
Expected Utiliztion Rate	100%		Temperature	330	Deg F
Expected Annual Hours of Operation	7,653	Hours	Moisture Content	13.3%	
Annual Interest Rate	5.5%		Actual Flow Rate	2,234,300	acfm
Expected Equipment Life	20	yrs	Standardized Flow Rate	1,391,000	scfm @ 330º F
Baseline NOx	0.200	lb/MMBtu	Dry Std Flow Rate	1,205,997	dscfm @ 330º F

CONTROL EQUIPMENT COSTS

Capital Costs		
Direct Capital Costs		
Purchased Equipment (A)		3,700,000
Purchased Equipment Total (B)		**8,465,600**
Installation - Standard Costs		1,270,000
Installation - Site Specific Costs		1,036,000
Installation Total		1,758,000
Total Capital Investment (TCI) = DC + IC		**12,176,084**
Operating Costs		
Total Annual Direct Operating Costs	Labor, supervision, materials, replacement parts, utilities, etc.	3,282,068
Total Annual Indirect Operating Costs	Sum indirect oper costs + capital recovery cost	1,018,887
Total Annual Cost (Annualized Capital Cost + Operating Cost)		**4,300,954**

Emission Control Cost Calculation

Pollutant	**Max Emis Lb/Hr**	**Annual T/Yr**	**Cont Eff %**	**Exit Conc**	**Conc Units**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
Nitrous Oxides (NOx)	1,205.2	4,611.4	25.0%			3458.5	1,152.8	3,731

Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1

Notes & Assumptions

1. November 2011 SNCR Evaluation from URS
2. SNCR Maintenance Costs EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.21
3. Process, emissions and cost data listed above is for one unit.
4. For units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal
5. Retrofit factor of 60% used by URS based on site visit to Coal Creek Station.
6. SW disposal and fly ash sales data from Nov. 2011 Golder Fly Ash Evaluation, Appendix B2

Great River Energy Coal Creek Station
BART Supplement - NOx Emission Control Cost Analysis
Table A-5: Unit 1 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (Maintain Ash Sales)

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment			**3,700,000**
Purchased Equipment Costs			
Instrumentation	10%	of purchased equipment cost	370,000
Site Specific and Prime Contractor Markup	28%	of purchased equipment cost	1,036,000
Freight	5%	of purchased equipment cost	185,000
Purchased Equipment Total	43%		5,291,000
Purchased Equipment Total+ Retrofit Factor (A)			**8,465,600**
Indirect Installation			
General Facilities	5%	of purchased equip cost (A)	420,000
Engineering & Home Office	10%	of purchased equip cost (A)	850,000
Process Contingency	6%	of purchased equip cost (A)	488,000
Total Indirect Installation Costs (B)	21%	of purchased equip cost (A)	**1,758,000**
Project Contingeny (C)	15%	of (A + B)	**1,540,000**
Total Plant Cost (D)		A + B + C	**11,763,600**
Allowance for Funds During Construction (E)		0 for SNCR	**0**
Royalty Allowance (F)		0 for SNCR	**0**
Pre Production Costs (G)	2%	of (D+E)	**236,000**
Inventory Capital (H)		Reagent Vol * $/gal	**134,484**
Intial Catalyst and Chemicals (I)		0 for SNCR	**0**
Prepaid Royalties (J)			**42,000**
Total Capital Investment (TCI) = DC + IC		D + E + F + G +H + I + J	**12,176,084**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**12,176,084**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	NA		-
Supervisor	NA		-
Maintenance			
Maintenance Total	1.50	% of Total Capital Investment	182,641
Maintenance Materials	NA	% of Maintenance Labor	-
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.06	$/kwh, 61 kW-hr, 7652.6 hr/yr, 100% utilization	28,218
Water	0.31	$/kgal, 3,480 gph, 7652.6 hr/yr, 100% utilization	8,256
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
Urea	500.00	$/ton, 1 ton/hr, 7652.6 hr/yr, 100% utilization	3,062,953
NA	NA		-
Total Annual Direct Operating Costs			**3,282,068**
Indirect Operating Costs			
Overhead	NA	of total labor and material costs	NA
Administration (2% total capital costs)	NA	of total capital costs (TCI)	NA
Property tax (1% total capital costs)	NA	of total capital costs (TCI)	NA
Insurance (1% total capital costs)	NA	of total capital costs (TCI)	NA
Capital Recovery	0.0837	for a 20- year equipment life and a 5.5% interest rate	1,018,887
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**1,018,887**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**4,300,954**

Great River Energy Coal Creek Station
BART Supplement - NOx Emission Control Cost Analysis
Table A-5: Unit 1 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (Maintain Ash Sales)

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Catayst		<- Enter Equipment Name to Get Cost
Equipment Life	5	years
CRF	0.2342	
Rep part cost per unit	0	$/ft^3
Amount Required	12	ft^3
Packing Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:		<- Enter Equipment Name to Get Cost	
Equipment Life	2	years	
CRF	0.0000		
Rep part cost per unit	0	$/ft^3	
Amount Required	0	Cages	
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax	See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs
Installation Labor	0	10 min per bag, Labor + Overhead (68% = $29.65/hr)	
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	EPA CCM list replacement times from 5 - 20 min per bag.
Annualized Cost	**0**		

Electrical Use			
NOx in	0.20	lb/MMBtu	kW
NSR	0.60		
Power			61.0
Total			61.0

Reagent Use & Other Operating Costs					
NOx in	0.20	lb/MMBtu	Urea Use	1601	lb/hr
Efficiency	25%		Volume 14 day inventory	269	ton
Duty	6,015	MMBtu/hr	Inventory Cost	$134,484	
Water Use	3480	gal/hr			

Operating Cost Calculations — **Annual hours of operation: 7,653** — **Utilization Rate: 100%**

Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
Operating Labor							
Op Labor	37	$/Hr	0.0	hr/8 hr shift	0	0	$/Hr, 0.0 hr/8 hr shift, 7652.6 hr/yr
Supervisor	15%	of Op.			NA	-	15% of Operator Costs
Maintenance							
Maintenance Total	1.5	% of Total Capital Investment				182,641	% of Total Capital Investment
Maint Mtls	0	% of Maintenance Labor			NA	0	0% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.060	$/kwh	61.0	kW-hr	466,809	28,218	$/kwh, 61 kW-hr, 7652.6 hr/yr, 100% utilization
Water	0.31	$/kgal	3,480.0	gph	26,631	8,256	$/kgal, 3,480 gph, 7652.6 hr/yr, 100% utilization
Cooling Water	0.32	$kgal	0.0	gpm	0	0	$kgal, 0 gpm, 7652.6 hr/yr, 100% utilization
Comp Air	0.37	$/kscf	0.0	scfm/kacfm**	0	0	$/kscf, 0 scfm/kacfm**, 7652.6 hr/yr, 100% utilization
WW Treat Neutralization	1.96	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 7652.6 hr/yr, 100% utilization
WW Treat Biotreatement	4.96	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 7652.6 hr/yr, 100% utilization
SW Disposal	0.00	$/ton	7.2	ton/hr	55,000	0	$/ton, 7 ton/hr, 7652.6 hr/yr, 100% utilization
Haz W Disp	326	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 7652.6 hr/yr, 100% utilization
Ammonia Mitigation	5.61	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 7652.6 hr/yr, 100% utilization
Lost Ash Sales	12.30	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 7652.6 hr/yr, 100% utilization
Lime	90.00	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 7652.6 hr/yr, 100% utilization
Urea	500.00	$/ton	0.8005	ton/hr	6,126	3,062,953	$/ton, 1 ton/hr, 7652.6 hr/yr, 100% utilization
Oxygen	17.91	kscf	0.0	kscf/hr	0	0	kscf, 0 kscf/hr, 7652.6 hr/yr, 100% utilization

** Std Air use is 2 scfm/kacfm *annual use rate is in same units of measurement as the unit cost factor

See summary on first page of this table for notes and assumptions

Great River Energy Coal Creek Station

BART Supplement - NOx Emission Control Cost Analysis

Table A-6: Unit 1 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (30% Lost Ash Sales)

Operating Unit: **Unit 1**

Emission Unit Number	EU-1		Stack/Vent Number	SV-1	
Desgin Capacity	6,015	MMBtu/hr	Standardized Flow Rate	866,294	scfm @ 32º F
Expected Utiliztion Rate	100%		Temperature	330	Deg F
Expected Annual Hours of Operation	7,653	Hours	Moisture Content	13.3%	
Annual Interest Rate	5.5%		Actual Flow Rate	2,234,300	acfm
Expected Equipment Life	20	yrs	Standardized Flow Rate	1,391,000	scfm @ 330º F
Baseline NOx	0.200	lb/MMBtu	Dry Std Flow Rate	1,205,997	dscfm @ 330º F

CONTROL EQUIPMENT COSTS

Capital Costs								
Direct Capital Costs								
Purchased Equipment (A)								3,700,000
Purchased Equipment Total (B)								**8,465,600**
Installation - Standard Costs								1,270,000
Installation - Site Specific Costs								1,036,000
Installation Total								1,758,000
Total Capital Investment (TCI) = DC + IC								**12,176,084**
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.						5,500,243
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost						1,018,887
Total Annual Cost (Annualized Capital Cost + Operating Cost)								**6,519,129**

Emission Control Cost Calculation

Pollutant	**Max Emis Lb/Hr**	**Annual T/Yr**	**Cont Eff %**	**Exit Conc**	**Conc Units**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
Nitrous Oxides (NOx)	1,205.2	4,611.4	25.0%			3458.5	1,152.8	5,655

Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1

Notes & Assumptions

1 November 2011 SNCR Evaluation from URS

2 SNCR Maintenance Costs EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.21

3 Process, emissions and cost data listed above is for one unit.

4 For units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal

5 Retrofit factor of 60% used by URS based on site visit to Coal Creek Station.

6 SW disposal and fly ash sales data from Nov. 2011 Golder Fly Ash Evaluation, Appendix B2

Great River Energy Coal Creek Station
BART Supplement - NOx Emission Control Cost Analysis
Table A-6: Unit 1 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (30% Lost Ash Sales)

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment			**3,700,000**
Purchased Equipment Costs			
Instrumentation	10%	of purchased equipment cost	370,000
Site Specific and Prime Contractor Markup	28%	of purchased equipment cost	1,036,000
Freight	5%	of purchased equipment cost	185,000
Purchased Equipment Total	43%		5,291,000
Purchased Equipment Total+ Retrofit Factor (A)			**8,465,600**
Indirect Installation			
General Facilities	5%	of purchased equip cost (A)	420,000
Engineering & Home Office	10%	of purchased equip cost (A)	850,000
Process Contingency	6%	of purchased equip cost (A)	488,000
Total Indirect Installation Costs (B)	21%	of purchased equip cost (A)	**1,758,000**
Project Contingeny (C)	15%	of (A + B)	**1,540,000**
Total Plant Cost (D)		A + B + C	**11,763,600**
Allowance for Funds During Construction (E)		0 for SNCR	**0**
Royalty Allowance (F)		0 for SNCR	**0**
Pre Production Costs (G)	2%	of (D+E)	**236,000**
Inventory Capital (H)		Reagent Vol * $/gal	**134,484**
Intial Catalyst and Chemicals (I)		0 for SNCR	**0**
Prepaid Royalties (J)			**42,000**
Total Capital Investment (TCI) = DC + IC		D + E + F + G +H + I + J	**12,176,084**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**12,176,084**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	NA		-
Supervisor	NA		-
Maintenance			
Maintenance Total	1.50	% of Total Capital Investment	182,641
Maintenance Materials	NA	% of Maintenance Labor	-
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.06	$/kwh, 61 kW-hr, 7652.6 hr/yr, 100% utilization	28,218
Water	0.31	$/kgal, 3,480 gph, 7652.6 hr/yr, 100% utilization	8,256
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
SW Disposal	5.44	$/ton, 15 ton/hr, 7652.6 hr/yr, 100% utilization	637,648
NA	NA		-
Ammonia Mitigation	5.61	$/ton, 19 ton/hr, 7652.6 hr/yr, 100% utilization	814,853
Lost Ash Sales	12.30	$/ton, 8 ton/hr, 7652.6 hr/yr, 100% utilization	765,675
NA	NA		-
Urea	500.00	$/ton, 1 ton/hr, 7652.6 hr/yr, 100% utilization	3,062,953
NA	NA		-
Total Annual Direct Operating Costs			**5,500,243**
Indirect Operating Costs			
Overhead	NA	of total labor and material costs	NA
Administration (2% total capital costs)	NA	of total capital costs (TCI)	NA
Property tax (1% total capital costs)	NA	of total capital costs (TCI)	NA
Insurance (1% total capital costs)	NA	of total capital costs (TCI)	NA
Capital Recovery	0.0837	for a 20- year equipment life and a 5.5% interest rate	1,018,887
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**1,018,887**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**6,519,129**

Great River Energy Coal Creek Station

BART Supplement - NOx Emission Control Cost Analysis

Table A-6: Unit 1 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (30% Lost Ash Sales)

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Catayst		<- Enter Equipment Name to Get Cost
Equipment Life	5	years
CRF	0.2342	
Rep part cost per unit	0	$/ft^3
Amount Required	12	ft^3
Packing Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:		<- Enter Equipment Name to Get Cost	
Equipment Life	2	years	
CRF	0.0000		
Rep part cost per unit	0	$/ft^3	
Amount Required	0	Cages	
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax	See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs
Installation Labor	0	10 min per bag, Labor + Overhead (68% = $29.65/hr)	
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	EPA CCM list replacement times from 5 - 20 min per bag.
Annualized Cost	**0**		

Electrical Use			
NOx in	0.20	lb/MMBtu	kW
NSR	0.60		
Power			61.0
Total			61.0

Reagent Use & Other Operating Costs					
NOx in	0.20	lb/MMBtu	Urea Use	1601	lb/hr
Efficiency	25%		Volume 14 day inventory	269	ton
Duty	6,015	MMBtu/hr	Inventory Cost	$134,484	
Water Use	3480	gal/hr			

Operating Cost Calculations | **Annual hours of operation:** **7,653** | **Utilization Rate:** **100%**

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Operating Labor							
Op Labor	37	$/Hr	0.0	hr/8 hr shift	0	0	$/Hr, 0.0 hr/8 hr shift, 7652.6 hr/yr
Supervisor	15%	of Op.			NA	-	15% of Operator Costs
Maintenance							
Maintenance Total	1.5	% of Total Capital Investment				182,641	% of Total Capital Investment
Maint Mtls	0	% of Maintenance Labor			NA	0	0% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.060	$/kwh	61.0	kW-hr	466,809	28,218	$/kwh, 61 kW-hr, 7652.6 hr/yr, 100% utilization
Water	0.31	$/kgal	3,480.0	gph	26,631	8,256	$/kgal, 3,480 gph, 7652.6 hr/yr, 100% utilization
Cooling Water	0.32	$kgal	0.0	gpm	0	0	$kgal, 0 gpm, 7652.6 hr/yr, 100% utilization
Comp Air	0.37	$/kscf	0.0	scfm/kacfm**	0	0	$/kscf, 0 scfm/kacfm**, 7652.6 hr/yr, 100% utilization
WW Treat Neutralization	1.96	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 7652.6 hr/yr, 100% utilization
WW Treat Biotreatement	4.96	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 7652.6 hr/yr, 100% utilization
SW Disposal	5.44	$/ton	15.3	ton/hr	117,250	637,648	$/ton, 15 ton/hr, 7652.6 hr/yr, 100% utilization
Haz W Disp	326	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 7652.6 hr/yr, 100% utilization
Ammonia Mitigation	5.61	$/ton	19.0	ton/hr	145,250	814,853	$/ton, 19 ton/hr, 7652.6 hr/yr, 100% utilization
Lost Ash Sales	12.30	$/ton	8.1	ton/hr	62,250	765,675	$/ton, 8 ton/hr, 7652.6 hr/yr, 100% utilization
Lime	90.00	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 7652.6 hr/yr, 100% utilization
Urea	500.00	$/ton	0.8005	ton/hr	6,126	3,062,953	$/ton, 1 ton/hr, 7652.6 hr/yr, 100% utilization
Oxygen	17.91	kscf	0.0	kscf/hr	0	0	kscf, 0 kscf/hr, 7652.6 hr/yr, 100% utilization
					1,786,575		

** Std Air use is 2 scfm/kacfm

*annual use rate is in same units of measurement as the unit cost factor

See summary on first page of this table for notes and assumptions

Great River Energy Coal Creek Station

BART Supplement - NOx Emission Control Cost Analysis

Table A-7: Unit 1 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (100% Lost Ash Sales)

Operating Unit: **Unit 1**

Emission Unit Number	EU-1		Stack/Vent Number	SV-1	
Desgin Capacity	6,015	MMBtu/hr	Standardized Flow Rate	866,294	scfm @ 32º F
Expected Utiliztion Rate	100%		Temperature	330	Deg F
Expected Annual Hours of Operation	7,653	Hours	Moisture Content	13.3%	
Annual Interest Rate	5.5%		Actual Flow Rate	2,234,300	acfm
Expected Equipment Life	20	yrs	Standardized Flow Rate	1,391,000	scfm @ 330º F
Baseline NOx	0.200	lb/MMBtu	Dry Std Flow Rate	1,205,997	dscfm @ 330º F

CONTROL EQUIPMENT COSTS

Capital Costs								
Direct Capital Costs								
Purchased Equipment (A)								3,700,000
Purchased Equipment Total (B)								**8,465,600**
Installation - Standard Costs								1,270,000
Installation - Site Specific Costs								1,036,000
Installation Total								1,758,000
Total Capital Investment (TCI) = DC + IC								**12,176,084**
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.						7,775,768
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost						1,018,887
Total Annual Cost (Annualized Capital Cost + Operating Cost)								**8,794,654**

Emission Control Cost Calculation

Pollutant	**Max Emis Lb/Hr**	**Annual T/Yr**	**Cont Eff %**	**Exit Conc**	**Conc Units**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
Nitrous Oxides (NOx)	1,205.2	4,611.4	25.0%			3458.5	1,152.8	7,629

Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1

Notes & Assumptions

1. November 2011 SNCR Evaluation from URS
2. SNCR Maintenance Costs EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.21
3. Process, emissions and cost data listed above is for one unit.
4. For units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal
5. Retrofit factor of 60% used by URS based on site visit to Coal Creek Station.
6. SW disposal and fly ash sales data from Nov. 2011 Golder Fly Ash Evaluation, Appendix B2

Great River Energy Coal Creek Station
BART Supplement - NOx Emission Control Cost Analysis
Table A-7: Unit 1 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (100% Lost Ash Sales)

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment			**3,700,000**
Purchased Equipment Costs			
Instrumentation	10%	of purchased equipment cost	370,000
Site Specific and Prime Contractor Markup	28%	of purchased equipment cost	1,036,000
Freight	5%	of purchased equipment cost	185,000
Purchased Equipment Total	43%		5,291,000
Purchased Equipment Total+ Retrofit Factor (A)			**8,465,600**
Indirect Installation			
General Facilities	5%	of purchased equip cost (A)	420,000
Engineering & Home Office	10%	of purchased equip cost (A)	850,000
Process Contingency	6%	of purchased equip cost (A)	488,000
Total Indirect Installation Costs (B)	21%	of purchased equip cost (A)	**1,758,000**
Project Contingeny (C)	15%	of (A + B)	**1,540,000**
Total Plant Cost (D)		A + B + C	**11,763,600**
Allowance for Funds During Construction (E)		0 for SNCR	**0**
Royalty Allowance (F)		0 for SNCR	**0**
Pre Production Costs (G)	2%	of (D+E)	**236,000**
Inventory Capital (H)		Reagent Vol * $/gal	**134,484**
Intial Catalyst and Chemicals (I)		0 for SNCR	**0**
Prepaid Royalties (J)			**42,000**
Total Capital Investment (TCI) = DC + IC		D + E + F + G +H + I + J	**12,176,084**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**12,176,084**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	NA		-
Supervisor	NA		-
Maintenance			
Maintenance Total	1.50	% of Total Capital Investment	182,641
Maintenance Materials	NA	% of Maintenance Labor	-
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.06	$/kwh, 61 kW-hr, 7652.6 hr/yr, 100% utilization	28,218
Water	0.31	$/kgal, 3,480 gph, 7652.6 hr/yr, 100% utilization	8,256
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
SW Disposal	7.40	$/ton, 34 ton/hr, 7652.6 hr/yr, 100% utilization	1,941,450
NA	NA		-
NA	NA		-
Lost Ash Sales	12.30	$/ton, 27 ton/hr, 7652.6 hr/yr, 100% utilization	2,552,250
NA	NA		-
Urea	500.00	$/ton, 1 ton/hr, 7652.6 hr/yr, 100% utilization	3,062,953
NA	NA		-
Total Annual Direct Operating Costs			**7,775,768**
Indirect Operating Costs			
Overhead	NA	of total labor and material costs	NA
Administration (2% total capital costs)	NA	of total capital costs (TCI)	NA
Property tax (1% total capital costs)	NA	of total capital costs (TCI)	NA
Insurance (1% total capital costs)	NA	of total capital costs (TCI)	NA
Capital Recovery	0.0837	for a 20- year equipment life and a 5.5% interest rate	1,018,887
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**1,018,887**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**8,794,654**

Great River Energy Coal Creek Station
BART Supplement - NOx Emission Control Cost Analysis
Table A-7: Unit 1 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (100% Lost Ash Sales)

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Catayst			<- Enter Equipment Name to Get Cost	
Equipment Life	5	years		
CRF	0.2342			
Rep part cost per unit	0	$/ft^3		
Amount Required	12	ft^3		
Packing Cost	0	Cost adjusted for freight & sales tax		
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)		
Total Installed Cost	**0**	**Zero out if no replacement parts needed**		
Annualized Cost	**0**			

Replacement Parts & Equipment:			<- Enter Equipment Name to Get Cost	
Equipment Life	2	years		
CRF	0.0000			
Rep part cost per unit	0	$/ft^3		
Amount Required	0	Cages		
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax		See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs
Installation Labor	0	10 min per bag, Labor + Overhead (68% = $29.65/hr)		
Total Installed Cost	**0**	**Zero out if no replacement parts needed**		EPA CCM list replacement times from 5 - 20 min per bag.
Annualized Cost	**0**			

Electrical Use			
NOx in	0.20	lb/MMBtu	kW
NSR	0.60		
Power			61.0
Total			61.0

Reagent Use & Other Operating Costs					
NOx in	0.20	lb/MMBtu	Urea Use	1601	lb/hr
Efficiency	25%		Volume 14 day inventory	269	ton
Duty	6,015	MMBtu/hr	Inventory Cost	$134,484	
Water Use	3480	gal/hr			

Operating Cost Calculations — **Annual hours of operation:** **7,653**; **Utilization Rate:** **100%**

Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
Operating Labor							
Op Labor	37	$/Hr	0.0	hr/8 hr shift	0	0	$/Hr, 0.0 hr/8 hr shift, 7652.6 hr/yr
Supervisor	15%	of Op.			NA	-	15% of Operator Costs
Maintenance							
Maintenance Total	1.5	% of Total Capital Investment				182,641	% of Total Capital Investment
Maint Mtls	0	% of Maintenance Labor			NA	0	0% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.060	$/kwh	61.0	kW-hr	466,809	28,218	$/kwh, 61 kW-hr, 7652.6 hr/yr, 100% utilization
Water	0.31	$/kgal	3,480.0	gph	26,631	8,256	$/kgal, 3,480 gph, 7652.6 hr/yr, 100% utilization
Cooling Water	0.32	$kgal	0.0	gpm	0	0	$kgal, 0 gpm, 7652.6 hr/yr, 100% utilization
Comp Air	0.37	$/kscf	0.0	scfm/kacfm**	0	0	$/kscf, 0 scfm/kacfm**, 7652.6 hr/yr, 100% utilization
WW Treat Neutralization	1.96	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 7652.6 hr/yr, 100% utilization
WW Treat Biotreatement	4.96	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 7652.6 hr/yr, 100% utilization
SW Disposal	7.40	$/ton	34.3	ton/hr	262,500	1,941,450	$/ton, 34 ton/hr, 7652.6 hr/yr, 100% utilization
Haz W Disp	326	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 7652.6 hr/yr, 100% utilization
Ammonia Mitigation	5.61	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 7652.6 hr/yr, 100% utilization
Lost Ash Sales	12.30	$/ton	27.1	ton/hr	207,500	2,552,250	$/ton, 27 ton/hr, 7652.6 hr/yr, 100% utilization
Lime	90.00	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 7652.6 hr/yr, 100% utilization
Urea	500.00	$/ton	0.8005	ton/hr	6,126	3,062,953	$/ton, 1 ton/hr, 7652.6 hr/yr, 100% utilization
Oxygen	17.91	kscf	0.0	kscf/hr	0	0	kscf, 0 kscf/hr, 7652.6 hr/yr, 100% utilization
					5,955,250		

** Std Air use is 2 scfm/kacfm — *annual use rate is in same units of measurement as the unit cost factor

See summary on first page of this table for notes and assumptions

Great River Energy Coal Creek Station

BART Supplement - NOx Emission Control Cost Analysis

Table A-8: Unit 2 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (Maintain Ash Sales)

Operating Unit: **Unit 2**

Emission Unit Number	EU-2		Stack/Vent Number	SV-2	
Desgin Capacity	6,022	MMBtu/hr	Standardized Flow Rate	866,294	scfm @ 32º F
Expected Utiliztion Rate	100%		Temperature	330	Deg F
Expected Annual Hours of Operation	8,410	Hours	Moisture Content	13.3%	
Annual Interest Rate	5.5%		Actual Flow Rate	2,234,300	acfm
Expected Equipment Life	20	yrs	Standardized Flow Rate	1,391,000	scfm @ 330º F
Baseline NOx	0.153	lb/MMBtu	Dry Std Flow Rate	1,205,997	dscfm @ 330º F

CONTROL EQUIPMENT COSTS

Capital Costs		
Direct Capital Costs		
Purchased Equipment (A)		3,600,000
Purchased Equipment Total (B)		**8,236,800**
Installation - Standard Costs		1,230,000
Installation - Site Specific Costs		1,008,000
Installation Total		1,702,000
Total Capital Investment (TCI) = DC + IC		**11,793,820**
Operating Costs		
Total Annual Direct Operating Costs	Labor, supervision, materials, replacement parts, utilities, etc.	2,634,116
Total Annual Indirect Operating Costs	Sum indirect oper costs + capital recovery cost	986,899
Total Annual Cost (Annualized Capital Cost + Operating Cost)		**3,621,015**

Emission Control Cost Calculation

Pollutant	**Max Emis Lb/Hr**	**Annual T/Yr**	**Cont Eff %**	**Exit Conc**	**Conc Units**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
Nitrous Oxides (NOx)	918.5	3,862.3	20.0%			3089.8	772.5	4,688

Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1

Notes & Assumptions

1. November 2011 SNCR Evaluation from URS
2. SNCR Maintenance Costs EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.21
3. Process, emissions and cost data listed above is for one unit.
4. For units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal
5. Retrofit factor of 60% used by URS based on site visit to Coal Creek Station.
6. SW disposal and fly ash sales data from Nov. 2011 Golder Fly Ash Evaluation, Appendix B2

Great River Energy Coal Creek Station

BART Supplement - NOx Emission Control Cost Analysis

Table A-8: Unit 2 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (Maintain Ash Sales)

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment			**3,600,000**
Purchased Equipment Costs			
Instrumentation	10%	of purchased equipment cost	360,000
Site Specific and Prime Contractor Markup	28%	of purchased equipment cost	1,008,000
Freight	5%	of purchased equipment cost	180,000
Purchased Equipment Total	43%		5,148,000
Purchased Equipment Total+ Retrofit Factor (A)			**8,236,800**
Indirect Installation			
General Facilities	5%	of purchased equip cost (A)	410,000
Engineering & Home Office	10%	of purchased equip cost (A)	820,000
Process Contingency	6%	of purchased equip cost (A)	472,000
Total Indirect Installation Costs (B)	21%	of purchased equip cost (A)	**1,702,000**
Project Contingeny (C)	15%	of (A + B)	**1,490,000**
Total Plant Cost (D)		A + B + C	**11,428,800**
Allowance for Funds During Construction (E)		0 for SNCR	**0**
Royalty Allowance (F)		0 for SNCR	**0**
Pre Production Costs (G)	2%	of (D+E)	**227,000**
Inventory Capital (H)		Reagent Vol * $/gal	**97,020**
Intial Catalyst and Chemicals (I)		0 for SNCR	**0**
Prepaid Royalties (J)			**41,000**
Total Capital Investment (TCI) = DC + IC		D + E + F + G +H + I + J	**11,793,820**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**11,793,820**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	NA		-
Supervisor	NA		-
Maintenance			
Maintenance Total	1.50	% of Total Capital Investment	176,907
Maintenance Materials	NA	% of Maintenance Labor	-
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.06	$/kwh, 44 kW-hr, 8409.6 hr/yr, 100% utilization	22,367
Water	0.31	$/kgal, 2,520 gph, 8409.6 hr/yr, 100% utilization	6,570
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
Urea	500.00	$/ton, 1 ton/hr, 8409.6 hr/yr, 100% utilization	2,428,272
NA	NA		-
Total Annual Direct Operating Costs			**2,634,116**
Indirect Operating Costs			
Overhead	NA	of total labor and material costs	NA
Administration (2% total capital costs)	NA	of total capital costs (TCI)	NA
Property tax (1% total capital costs)	NA	of total capital costs (TCI)	NA
Insurance (1% total capital costs)	NA	of total capital costs (TCI)	NA
Capital Recovery	0.0837	for a 20- year equipment life and a 5.5% interest rate	986,899
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**986,899**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**3,621,015**

Great River Energy Coal Creek Station

BART Supplement - NOx Emission Control Cost Analysis

Table A-8: Unit 2 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (Maintain Ash Sales)

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Catayst		<- Enter Equipment Name to Get Cost
Equipment Life	5	years
CRF	0.2342	
Rep part cost per unit	0	$/ft^3
Amount Required	12	ft^3
Packing Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:		<- Enter Equipment Name to Get Cost	
Equipment Life	2	years	
CRF	0.0000		
Rep part cost per unit	0	$/ft^3	
Amount Required	0	Cages	
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax	See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs
Installation Labor	0	10 min per bag, Labor + Overhead (68% = $29.65/hr)	
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	EPA CCM list replacement times from 5 - 20 min per bag.
Annualized Cost	**0**		

Electrical Use			
NOx in	0.15	lb/MMBtu	kW
NSR	0.44		
Power			44.0
Total			44.0

Reagent Use & Other Operating Costs					
NOx in	0.15	lb/MMBtu	Urea Use	1155	lb/hr
Efficiency	20%		Volume 14 day inventory	194	ton
Duty	6,022	MMBtu/hr	Inventory Cost	$97,020	
Water Use	2520	gal/hr			

Operating Cost Calculations — **Annual hours of operation:** **8,410** — **Utilization Rate:** **100%**

Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
Operating Labor							
Op Labor	37	$/Hr	0.0	hr/8 hr shift	0	0	$/Hr, 0.0 hr/8 hr shift, 8409.6 hr/yr
Supervisor	15%	of Op.			NA	-	15% of Operator Costs
Maintenance							
Maintenance Total	1.5	% of Total Capital Investment				176,907	% of Total Capital Investment
Maint Mtls	0	% of Maintenance Labor			NA	0	0% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.060	$/kwh	44.0	kW-hr	370,022	22,367	$/kwh, 44 kW-hr, 8409.6 hr/yr, 100% utilization
Water	0.31	$/kgal	2,520.0	gph	21,192	6,570	$/kgal, 2,520 gph, 8409.6 hr/yr, 100% utilization
Cooling Water	0.32	$kgal	0.0	gpm	0	0	$kgal, 0 gpm, 8409.6 hr/yr, 100% utilization
Comp Air	0.37	$/kscf	0.0	scfm/kacfm**	0	0	$/kscf, 0 scfm/kacfm**, 8409.6 hr/yr, 100% utilization
WW Treat Neutralization	1.96	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 8409.6 hr/yr, 100% utilization
WW Treat Biotreatement	4.96	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 8409.6 hr/yr, 100% utilization
SW Disposal	0.00	$/ton	6.5	ton/hr	55,000	0	$/ton, 7 ton/hr, 8409.6 hr/yr, 100% utilization
Haz W Disp	326	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8409.6 hr/yr, 100% utilization
Ammonia Mitigation	5.61	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8409.6 hr/yr, 100% utilization
Lost Ash Sales	12.30	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8409.6 hr/yr, 100% utilization
Lime	90.00	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 8409.6 hr/yr, 100% utilization
Urea	500.00	$/ton	0.5775	ton/hr	4,857	2,428,272	$/ton, 1 ton/hr, 8409.6 hr/yr, 100% utilization
Oxygen	17.91	kscf	0.0	kscf/hr	0	0	kscf, 0 kscf/hr, 8409.6 hr/yr, 100% utilization

** Std Air use is 2 scfm/kacfm

*annual use rate is in same units of measurement as the unit cost factor

See summary on first page of this table for notes and assumptions

Great River Energy Coal Creek Station

BART Supplement - NOx Emission Control Cost Analysis

Table A-9: Unit 2 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (30% Lost Ash Sales)

Operating Unit: **Unit 2**

Emission Unit Number	EU-2		Stack/Vent Number	SV-2	
Desgin Capacity	6,022	MMBtu/hr	Standardized Flow Rate	866,294	scfm @ 32º F
Expected Utiliztion Rate	100%		Temperature	330	Deg F
Expected Annual Hours of Operation	8,410	Hours	Moisture Content	13.3%	
Annual Interest Rate	5.5%		Actual Flow Rate	2,234,300	acfm
Expected Equipment Life	20	yrs	Standardized Flow Rate	1,391,000	scfm @ 330º F
Baseline NOx	0.153	lb/MMBtu	Dry Std Flow Rate	1,205,997	dscfm @ 330º F

CONTROL EQUIPMENT COSTS

Capital Costs		
Direct Capital Costs		
Purchased Equipment (A)		3,600,000
Purchased Equipment Total (B)		**8,236,800**
Installation - Standard Costs		1,230,000
Installation - Site Specific Costs		1,008,000
Installation Total		1,702,000
Total Capital Investment (TCI) = DC + IC		**11,793,820**
Operating Costs		
Total Annual Direct Operating Costs	Labor, supervision, materials, replacement parts, utilities, etc.	4,852,291
Total Annual Indirect Operating Costs	Sum indirect oper costs + capital recovery cost	986,899
Total Annual Cost (Annualized Capital Cost + Operating Cost)		**5,839,190**

Emission Control Cost Calculation

Pollutant	**Max Emis Lb/Hr**	**Annual T/Yr**	**Cont Eff %**	**Exit Conc**	**Conc Units**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
Nitrous Oxides (NOx)	918.5	3,862.3	20.0%			3089.8	772.5	7,559

Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1

Notes & Assumptions

1. November 2011 SNCR Evaluation from URS
2. SNCR Maintenance Costs EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.21
3. Process, emissions and cost data listed above is for one unit.
4. For units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal
5. Retrofit factor of 60% used by URS based on site visit to Coal Creek Station.
6. SW disposal and fly ash sales data from Nov. 2011 Golder Fly Ash Evaluation, Appendix B2

Great River Energy Coal Creek Station
BART Supplement - NOx Emission Control Cost Analysis
Table A-9: Unit 2 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (30% Lost Ash Sales)

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment			**3,600,000**
Purchased Equipment Costs			
Instrumentation	10%	of purchased equipment cost	360,000
Site Specific and Prime Contractor Markup	28%	of purchased equipment cost	1,008,000
Freight	5%	of purchased equipment cost	180,000
Purchased Equipment Total	43%		5,148,000
Purchased Equipment Total+ Retrofit Factor (A)			**8,236,800**
Indirect Installation			
General Facilities	5%	of purchased equip cost (A)	410,000
Engineering & Home Office	10%	of purchased equip cost (A)	820,000
Process Contingency	6%	of purchased equip cost (A)	472,000
Total Indirect Installation Costs (B)	21%	of purchased equip cost (A)	**1,702,000**
Project Contingeny (C)	15%	of (A + B)	**1,490,000**
Total Plant Cost (D)		A + B + C	**11,428,800**
Allowance for Funds During Construction (E)		0 for SNCR	**0**
Royalty Allowance (F)		0 for SNCR	**0**
Pre Production Costs (G)	2%	of (D+E)	**227,000**
Inventory Capital (H)		Reagent Vol * $/gal	**97,020**
Intial Catalyst and Chemicals (I)		0 for SNCR	**0**
Prepaid Royalties (J)			**41,000**
Total Capital Investment (TCI) = DC + IC		D + E + F + G +H + I + J	**11,793,820**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**11,793,820**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	NA		-
Supervisor	NA		-
Maintenance			
Maintenance Total	1.50	% of Total Capital Investment	176,907
Maintenance Materials	NA	% of Maintenance Labor	-
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.06	$/kwh, 44 kW-hr, 8409.6 hr/yr, 100% utilization	22,367
Water	0.31	$/kgal, 2,520 gph, 8409.6 hr/yr, 100% utilization	6,570
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
SW Disposal	5.44	$/ton, 14 ton/hr, 8409.6 hr/yr, 100% utilization	637,648
NA	NA		-
Ammonia Mitigation	5.61	$/ton, 17 ton/hr, 8409.6 hr/yr, 100% utilization	814,853
Lost Ash Sales	12.30	$/ton, 7 ton/hr, 8409.6 hr/yr, 100% utilization	765,675
NA	NA		-
Urea	500.00	$/ton, 1 ton/hr, 8409.6 hr/yr, 100% utilization	2,428,272
NA	NA		-
Total Annual Direct Operating Costs			**4,852,291**
Indirect Operating Costs			
Overhead	NA	of total labor and material costs	NA
Administration (2% total capital costs)	NA	of total capital costs (TCI)	NA
Property tax (1% total capital costs)	NA	of total capital costs (TCI)	NA
Insurance (1% total capital costs)	NA	of total capital costs (TCI)	NA
Capital Recovery	0.0837	for a 20- year equipment life and a 5.5% interest rate	986,899
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**986,899**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**5,839,190**

Great River Energy Coal Creek Station

BART Supplement - NOx Emission Control Cost Analysis

Table A-9: Unit 2 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (30% Lost Ash Sales)

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Catayst		<- Enter Equipment Name to Get Cost
Equipment Life	5	years
CRF	0.2342	
Rep part cost per unit	0	$/ft³
Amount Required	12	ft³
Packing Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:		<- Enter Equipment Name to Get Cost	
Equipment Life	2	years	
CRF	0.0000		
Rep part cost per unit	0	$/ft³	
Amount Required	0	Cages	
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax	See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs
Installation Labor	0	10 min per bag, Labor + Overhead (68% = $29.65/hr)	
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	EPA CCM list replacement times from 5 - 20 min per bag.
Annualized Cost	**0**		

Electrical Use			
NOx in	0.15	lb/MMBtu	kW
NSR	0.44		
Power			44.0
Total			44.0

Reagent Use & Other Operating Costs					
NOx in	0.15	lb/MMBtu	Urea Use	1155	lb/hr
Efficiency	20%		Volume 14 day inventory	194	ton
Duty	6,022	MMBtu/hr	Inventory Cost	$97,020	
Water Use	2520	gal/hr			

Operating Cost Calculations — **Annual hours of operation:** **8,410** — **Utilization Rate:** **100%**

Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
Operating Labor							
Op Labor	37	$/Hr	0.0	hr/8 hr shift	0	0	$/Hr, 0.0 hr/8 hr shift, 8409.6 hr/yr
Supervisor	15%	of Op.			NA	-	15% of Operator Costs
Maintenance							
Maintenance Total	1.5	% of Total Capital Investment				176,907	% of Total Capital Investment
Maint Mtls	0	% of Maintenance Labor			NA	0	0% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.060	$/kwh	44.0	kW-hr	370,022	22,367	$/kwh, 44 kW-hr, 8409.6 hr/yr, 100% utilization
Water	0.31	$/kgal	2,520.0	gph	21,192	6,570	$/kgal, 2,520 gph, 8409.6 hr/yr, 100% utilization
Cooling Water	0.32	$kgal	0.0	gpm	0	0	$kgal, 0 gpm, 8409.6 hr/yr, 100% utilization
Comp Air	0.37	$/kscf	0.0	scfm/kacfm**	0	0	$/kscf, 0 scfm/kacfm**, 8409.6 hr/yr, 100% utilization
WW Treat Neutralization	1.96	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 8409.6 hr/yr, 100% utilization
WW Treat Biotreatement	4.96	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 8409.6 hr/yr, 100% utilization
SW Disposal	5.44	$/ton	13.9	ton/hr	117,250	637,648	$/ton, 14 ton/hr, 8409.6 hr/yr, 100% utilization
Haz W Disp	326	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8409.6 hr/yr, 100% utilization
Ammonia Mitigation	5.61	$/ton	17.3	ton/hr	145,250	814,853	$/ton, 17 ton/hr, 8409.6 hr/yr, 100% utilization
Lost Ash Sales	12.30	$/ton	7.4	ton/hr	62,250	765,675	$/ton, 7 ton/hr, 8409.6 hr/yr, 100% utilization
Lime	90.00	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 8409.6 hr/yr, 100% utilization
Urea	500.00	$/ton	0.5775	ton/hr	4,857	2,428,272	$/ton, 1 ton/hr, 8409.6 hr/yr, 100% utilization
Oxygen	17.91	kscf	0.0	kscf/hr	0	0	kscf, 0 kscf/hr, 8409.6 hr/yr, 100% utilization

** Std Air use is 2 scfm/kacfm

*annual use rate is in same units of measurement as the unit cost factor

See summary on first page of this table for notes and assumptions

Great River Energy Coal Creek Station

BART Supplement - NOx Emission Control Cost Analysis

Table A-10: Unit 2 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (100% Lost Ash Sales)

Operating Unit: **Unit 2**

Emission Unit Number	EU-2		Stack/Vent Number	SV-2	
Desgin Capacity	6,022	MMBtu/hr	Standardized Flow Rate	866,294	scfm @ 32º F
Expected Utiliztion Rate	100%		Temperature	330	Deg F
Expected Annual Hours of Operation	8,410	Hours	Moisture Content	13.3%	
Annual Interest Rate	5.5%		Actual Flow Rate	2,234,300	acfm
Expected Equipment Life	20	yrs	Standardized Flow Rate	1,391,000	scfm @ 330º F
Baseline NOx	0.153	lb/MMBtu	Dry Std Flow Rate	1,205,997	dscfm @ 330º F

CONTROL EQUIPMENT COSTS

Capital Costs	
Direct Capital Costs	
Purchased Equipment (A)	3,600,000
Purchased Equipment Total (B)	**8,236,800**
Installation - Standard Costs	1,230,000
Installation - Site Specific Costs	1,008,000
Installation Total	1,702,000
Total Capital Investment (TCI) = DC + IC	**11,793,820**
Operating Costs	
Total Annual Direct Operating Costs — Labor, supervision, materials, replacement parts, utilities, etc.	7,127,816
Total Annual Indirect Operating Costs — Sum indirect oper costs + capital recovery cost	986,899
Total Annual Cost (Annualized Capital Cost + Operating Cost)	**8,114,715**

Emission Control Cost Calculation

Pollutant	**Max Emis Lb/Hr**	**Annual T/Yr**	**Cont Eff %**	**Exit Conc**	**Conc Units**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
Nitrous Oxides (NOx)	918.5	3,862.3	20.0%			3089.8	772.5	10,505

Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1

Notes & Assumptions

1 November 2011 SNCR Evaluation from URS
2 SNCR Maintenance Costs EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.21
3 Process, emissions and cost data listed above is for one unit.
4 For units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal
5 Retrofit factor of 60% used by URS based on site visit to Coal Creek Station.
6 SW disposal and fly ash sales data from Nov. 2011 Golder Fly Ash Evaluation, Appendix B2

Great River Energy Coal Creek Station
BART Supplement - NOx Emission Control Cost Analysis
Table A-10: Unit 2 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (100% Lost Ash Sales)

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment			**3,600,000**
Purchased Equipment Costs			
Instrumentation	10%	of purchased equipment cost	360,000
Site Specific and Prime Contractor Markup	28%	of purchased equipment cost	1,008,000
Freight	5%	of purchased equipment cost	180,000
Purchased Equipment Total	43%		5,148,000
Purchased Equipment Total+ Retrofit Factor (A)			**8,236,800**
Indirect Installation			
General Facilities	5%	of purchased equip cost (A)	410,000
Engineering & Home Office	10%	of purchased equip cost (A)	820,000
Process Contingency	6%	of purchased equip cost (A)	472,000
Total Indirect Installation Costs (B)	21%	of purchased equip cost (A)	**1,702,000**
Project Contingeny (C)	41%	of (A + B)	**1,490,000**
Total Plant Cost (D)		A + B + C	**11,428,800**
Allowance for Funds During Construction (E)		0 for SNCR	**0**
Royalty Allowance (F)		0 for SNCR	**0**
Pre Production Costs (G)	2%	of (D+E)	**227,000**
Inventory Capital (H)		Reagent Vol * $/gal	**97,020**
Intial Catalyst and Chemicals (I)		0 for SNCR	**0**
Prepaid Royalties (J)			**41,000**
Total Capital Investment (TCI) = DC + IC		D + E + F + G +H + I + J	**11,793,820**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**11,793,820**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	NA		-
Supervisor	NA		-
Maintenance			
Maintenance Total	1.50	% of Total Capital Investment	176,907
Maintenance Materials	NA	% of Maintenance Labor	-
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.06	$/kwh, 44 kW-hr, 8409.6 hr/yr, 100% utilization	22,367
Water	0.31	$/kgal, 2,520 gph, 8409.6 hr/yr, 100% utilization	6,570
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
SW Disposal	7.40	$/ton, 31 ton/hr, 8409.6 hr/yr, 100% utilization	1,941,450
NA	NA		-
NA	NA		-
Lost Ash Sales	12.30	$/ton, 25 ton/hr, 8409.6 hr/yr, 100% utilization	2,552,250
NA	NA		-
Urea	500.00	$/ton, 1 ton/hr, 8409.6 hr/yr, 100% utilization	2,428,272
NA	NA		-
Total Annual Direct Operating Costs			**7,127,816**
Indirect Operating Costs			
Overhead	NA	of total labor and material costs	NA
Administration (2% total capital costs)	NA	of total capital costs (TCI)	NA
Property tax (1% total capital costs)	NA	of total capital costs (TCI)	NA
Insurance (1% total capital costs)	NA	of total capital costs (TCI)	NA
Capital Recovery	0.0837	for a 20- year equipment life and a 5.5% interest rate	986,899
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**986,899**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**8,114,715**

Great River Energy Coal Creek Station

BART Supplement - NOx Emission Control Cost Analysis

Table A-10: Unit 2 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (100% Lost Ash Sales)

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Catayst		<- Enter Equipment Name to Get Cost	
Equipment Life	5	years	
CRF	0.2342		
Rep part cost per unit	0	$/ft^3	
Amount Required	12	ft^3	
Packing Cost	0	Cost adjusted for freight & sales tax	
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)	
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	
Annualized Cost	**0**		

Replacement Parts & Equipment:		<- Enter Equipment Name to Get Cost	
Equipment Life	2	years	
CRF	0.0000		
Rep part cost per unit	0	$/ft^3	
Amount Required	0	Cages	
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax	See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs
Installation Labor	0	10 min per bag, Labor + Overhead (68% = $29.65/hr)	
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	EPA CCM list replacement times from 5 - 20 min per bag.
Annualized Cost	**0**		

Electrical Use			
NOx in	0.15	lb/MMBtu	kW
NSR	0.44		
Power			44.0
Total			44.0

Reagent Use & Other Operating Costs					
NOx in	0.15	lb/MMBtu	Urea Use	1155	lb/hr
Efficiency	20%		Volume 14 day inventory	194	ton
Duty	6,022	MMBtu/hr	Inventory Cost	$97,020	
Water Use	2520	gal/hr			

Operating Cost Calculations — **Annual hours of operation:** **8,410**; **Utilization Rate:** **100%**

Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
Operating Labor							
Op Labor	37	$/Hr	0.0	hr/8 hr shift	0	0	$/Hr, 0.0 hr/8 hr shift, 8409.6 hr/yr
Supervisor	15%	of Op.			NA	-	15% of Operator Costs
Maintenance							
Maintenance Total	1.5	% of Total Capital Investment				176,907	% of Total Capital Investment
Maint Mtls	0	% of Maintenance Labor			NA	0	0% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.060	$/kwh	44.0	kW-hr	370,022	22,367	$/kwh, 44 kW-hr, 8409.6 hr/yr, 100% utilization
Water	0.31	$/kgal	2,520.0	gph	21,192	6,570	$/kgal, 2,520 gph, 8409.6 hr/yr, 100% utilization
Cooling Water	0.32	$kgal	0.0	gpm	0	0	$kgal, 0 gpm, 8409.6 hr/yr, 100% utilization
Comp Air	0.37	$/kscf	0.0	scfm/kacfm**	0	0	$/kscf, 0 scfm/kacfm**, 8409.6 hr/yr, 100% utilization
WW Treat Neutralization	1.96	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 8409.6 hr/yr, 100% utilization
WW Treat Biotreatement	4.96	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 8409.6 hr/yr, 100% utilization
SW Disposal	7.40	$/ton	31.2	ton/hr	262,500	1,941,450	$/ton, 31 ton/hr, 8409.6 hr/yr, 100% utilization
Haz W Disp	326	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8409.6 hr/yr, 100% utilization
Ammonia Mitigation	5.61	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8409.6 hr/yr, 100% utilization
Lost Ash Sales	12.30	$/ton	24.7	ton/hr	207,500	2,552,250	$/ton, 25 ton/hr, 8409.6 hr/yr, 100% utilization
Lime	90.00	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 8409.6 hr/yr, 100% utilization
Urea	500.00	$/ton	0.5775	ton/hr	4,857	2,428,272	$/ton, 1 ton/hr, 8409.6 hr/yr, 100% utilization
Oxygen	17.91	kscf	0.0	kscf/hr	0	0	kscf, 0 kscf/hr, 8409.6 hr/yr, 100% utilization

** Std Air use is 2 scfm/kacfm

*annual use rate is in same units of measurement as the unit cost factor

See summary on first page of this table for notes and assumptions

Appendix B

SNCR Evaluation for Coal Creek Station

COAL CREEK STATION
SELECTIVE NON-CATALYTIC REDUCTION (SNCR)
COST AND PERFORMANCE REVIEW

UNDERWOOD, MCLEAN COUNTY, NORTH DAKOTA

PROJECT NUMBER 28966-007

GREAT RIVER ENERGY

A Touchstone Energy Cooperative

URS ENERGY & CONSTRUCTION
7800 E. UNION AVE., SUITE 100
DENVER, CO 80237

Revision: 0 Status: Final

Introduction

Great River Energy (GRE) contracted URS Energy & Construction (URS) to conduct a review of the costs and performance capability of Selective Non-Catalytic Reduction (SNCR) at their Coal Creek Station (CCS) Units 1 & 2. This review was requested to provide; an estimate of the current capital cost for the installation of SNCR, operating and maintenance costs for SNCR, and the level of NOx reductions that can be achieved by SNCR.

The CCS units are identical 605 MW (gross - nominal) CE tangentially-fired furnaces burning North Dakota lignite. Each unit is equipped with Low NOx Burners (LNB) and Over-Fire Air (OFA). Unit 2's LNBs are 2nd generation technology while Unit 1's are the 1st generation installation. Unit 1 currently has a NOx emission rate of 0.20 lbs/MMBtu while Unit 2's NOx emission rate is 0.16 lbs/MMBtu.

The Final Best Achievable Retrofit Technology (BART) analysis submitted in 2007 was based on an inlet NOx concentration of 0.22 lbs/MMBtu and an SNCR removal efficiency of 50%. The current review uses the existing CCS NOx values presented in the previous paragraph and updated removal efficiencies. The following sections present data on SNCR capabilities and cost.

SNCR Capabilities

SNCR was originally developed in Japan in the 1970s for use on oil- and gas-fired units. Coal plant applications began in the late 1980s in Western Europe. Commercial U.S. installations on coal-fired utility boilers started in the early 1990s. More than 2 GW of capacity have been installed on coal-fired plants worldwide. SNCR requires injection of ammonia or urea into the proper temperature window within the back-pass of the furnace. The ammonia or urea reacts with NOx species to form nitrogen and water. Emission reduction capabilities range from 25% at 5-ppm ammonia slip to 30% at 10-ppm ammonia slip in most commercial installations.

An SNCR system will require the installation of reagent storage and transfer equipment, a multilevel injection grid and the necessary control instrumentation. Due to the elimination of the catalyst used in the SCR process, the SNCR consumption rates for ammonia or urea are typically 3-4 times the rates required for an SCR system on a per mole of NOx basis.

SNCR performance is dependent upon factors that are specific to each source. These factors are; flue gas temperature, flue gas residence time at temperatures within the reaction temperature range, reagent distribution, uncontrolled NOx levels, mixing between the injected reagent and the flue gas, and the CO and O2 concentrations in the flue gas stream. NOx reductions ranging from 25-75% have been reported with SNCR but the higher levels of reduction are only possible with high inlet NOx levels and

optimum temperatures and residence time. Typical SNCR performance for utility boilers is in the range of 20-35% NOx reductions.

The gas temperature at the point of injection is critical to the NOx reduction performance of an SNCR system. This window falls in a range of 1600-2000°F with an optimum temperature of approximately 1800°F. Above this temperature, ammonia begins to thermally decompose and below this temperature, the reaction rate for NOx reduction decreases, resulting in increased ammonia slip. The temperature profile in any given boiler changes with fluctuations in boiler load. Therefore, the optimum injection point will move during cycling operation and multiple injection points will be required. It should also be noted that the longer the ammonia or urea stays within the optimum temperature window, the higher the NOx reduction that is achieved. Residence times in excess of one second are desirable to achieve the maximum reduction efficiency. The minimum residence time is approximately 0.3 seconds for moderate performance. However, most large utility boilers have heat transfer surfaces (pendants and platens) positioned in this flue gas temperature zone. This reduces the effective use of the SNCR system, even when multiple injection levels are installed. In some cases, these internal obstructions will make the application of SNCR impractical.

Figure 1 shows SNCR NOx removal efficiency as a function of Inlet NOx concentration for 55 existing SNCR installations. The data shows the majority of the installations achieving 20-35% reductions in NOx and only a few installations achieving 50% or greater reductions. There is only one installation achieving 50% reduction at an inlet NOx concentration less than 0.4 lb/MMBtu. This single installation is a cyclone boiler burning a PRB/Illinois coal blend and is the only unit in the data set showing greater than 35% reduction for inlet NOx concentrations less than 0.4 lb/MMBtu.

This figure shows that there are no installations operating with Coal Creek's NOx levels that are achieving greater than 20-25% NOx reductions. The figure also shows that the majority of installations are achieving NOx reductions in the range of 20-30%. Based on the available data, from existing installations operating at the CCS inlet NOx levels used in the BART, the highest level of NOx reduction that could be expected is 30%. At the present CCS NOx levels, it is expected that the highest level of NOx reduction that could be expected is 20%.

Another factor to be considered in the application of SNCR is its effect upon fly ash sales. An ammonia slip of only 5 ppm, which is generally accepted as the minimum that can be achieved in an SNCR application, can render the fly ash produced by the unit unmarketable. CCS currently sells 400,000 tons/yr of fly ash. With SNCR, this fly ash will have to be disposed of in a landfill.

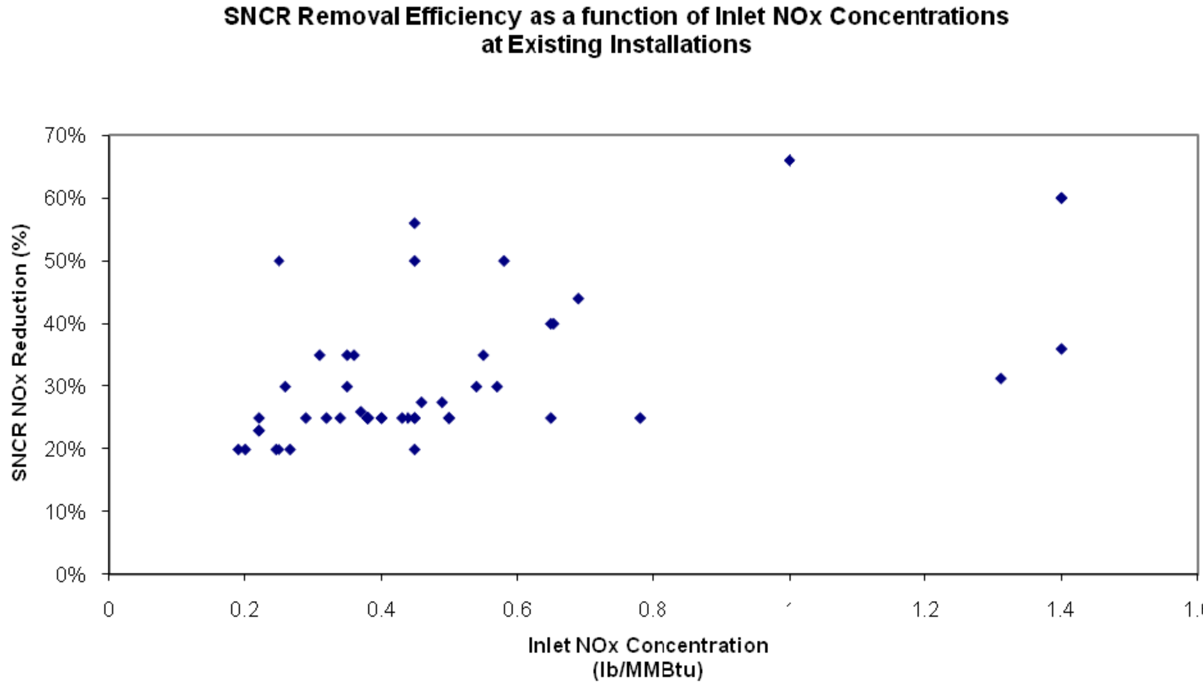

Figure 1 – SNCR Removal Efficiency

SNCR Costs

SNCR capital and operating costs were developed for five (5) different cases utilizing the Electric Power Research Institute's (EPRI) IECCOST model (Rev 3, Nov. 2010) with CCS site specific factors and cost components. The Integrated Emissions Control Cost Model (IECCOST) economic analysis workbook was first published by the Electric Power Research Institute in December 2004. IECCOST produces rough-order-of-magnitude (ROM) cost estimates (stated accuracy of ± 30%) of the installed capital and levelized annual operating costs for Integrated Emission Control (IEC) systems installed on coal-fired power plants. The IECCOST model allows comparison of cost information for conventional and developing SO_2, NOx, particulate, mercury, and integrated emissions control technologies. Costs for utility emission control systems are site-specific, and vary with technology, labor rates, construction conditions and material costs. The site-specific characteristics, operating conditions, process performance requirements and economic criteria serve as input to IECCOST.

IECCOST is able to calculate both new and retrofit plant costs. IECCOST calculates a retrofit factor for each cost area based on site congestion, existence of underground obstructions, soil conditions, seismic zone and state productivity. A series of combustion calculations are carried out based on the ultimate coal analysis provided by the utility and

the operating conditions specified for the boiler(s). The resulting flue gas composition serves as the basis for the calculation of a material balance for the control equipment. The material balance provides data for equipment sizing and calculation of the variable operating costs. The process-specific design criteria, including flue gas flow rate, pollutant removal rate, chemical consumption rate and waste production rate all are incorporated into the production of each process- and site-specific material balance.

The five (5) cases estimated for CCS are:

1. 0.22 lb/MMBtu inlet NOx with 30% reduction
2. 0.20 lb/MMBtu inlet NOx with 25% reduction
3. 0.16 lb/MMBtu inlet NOx with 20% reduction
4. 0.15 lb/MMBtu inlet NOx with 20% reduction
5. 0.22 lb/MMBtu inlet NOx with 50% reduction

These represent the initial BART assessment NOx rate of 0.22 lb/MMBtu with a commercially achievable reduction of 30% for case 1. Cases 2-4 are representative of CCS's existing NOx emission rates and commercially achievable reductions. The final case is the BART assessment case using 2011 dollars. The costs are for a urea-based SNCR system with 14 days of reagent storage. Urea pricing from a source local to CCS was obtained and the current cost of urea is $500/ton delivered to the site. The general plant input data and IECCOST outputs for SNCR capital and operation and maintenance costs are presented in the following section.

IECCOST DATA

Table 1 – Coal Creek Station Data

General Plant Technical Inputs

Total Gross Rating	MW	605
Gross Plant Heat Rate (GPHR)	Btu/KWhr	9,760
Total Net Rating (Less Auxiliary Power)	MW	572.0
Net Plant Heat Rate (NPHR, Without FGD)	Btu/KWhr	10,500
Plant Capacity Factor	%	90%
TECHNICAL INPUTS FOR BOILER:		
Boiler Heat Input	MMBtu/Hr	5,900
Boiler Heat Output	MMBtu/Hr	4,780
Total Air Downstream of Economizer	%	117.0%
Air Heater Leakage (% of econ. flue gas)	%	7.0%
Air Heater Outlet Gas Temp.	°F	300
Inlet Air Temp.	°F	80
Ambient Absolute Pressure	in. Hg	27.9
Pressure After Air Heater	in. H2O	-11
Moisture in Air	lb/lb dry air	0.013
Carbon Loss	%	0.5%
ASH SPLIT		
Fly Ash or Ash Overhead	%	76%
Bottom Ash	%	24%

Table 2 – SNCR Equipment Sizing

SNCR Equipment Sizing and Capacity Calcs			0.22 Inlet & 30% Reduction	0.20 Inlet & 25% Reduction	0.16 Inlet & 20% Reduction	0.15 Inlet & 20% Reduction	0.22 & 50% Reduction
Chosen Reagent			Urea	Urea	Urea	Urea	Urea
Required Reagent Injection	lb/hr		1991	1601	1188	1155	3318
Total Reagent Injection Flowrate	lb/hr		3982	3202	2375	2310	6636
NOx Removed	lb/hr		384	291	186	170	640
NOx Removed	tons/yr		1513	1147	734	670	2522
NOx Emissions	lb/hr		896	873	745	679	640
NOx Emissions	tons/yr		3531	3440	2935	2678	2522
Power Consumption	kW		75	61	45	44	126

Table 3 – Material Costs

SNCR Material Costs			0.22 Inlet & 30% Reduction	0.20 Inlet & 25% Reduction	0.16 Inlet & 20% Reduction	0.15 Inlet & 20% Reduction	0.22 & 50% Reduction
Cost Basis Year			2011	2011	2011	2011	2011
SNCR Equipment Cost	$		$3,800,000	$3,700,000	$3,600,000	$3,600,000	$4,200,000
Installation Factor			1.30	1.30	1.30	1.30	1.30
Installed Equipment Cost	$		$4,970,000	$4,800,000	$4,700,000	$4,700,000	$5,500,000
Prime Contractor's Markup	$		$497,000	$480,000	$470,000	$470,000	$550,000
Total Installed Cost	$		$5,500,000	$5,300,000	$5,100,000	$5,100,000	$6,000,000
Retrofit Factor			1.6	1.6	1.6	1.6	1.6
Total Equipment Cost	$		$8,750,000	$8,500,000	$8,200,000	$8,200,000	$9,600,000
General Facilities	$		$440,000	$420,000	$410,000	$410,000	$480,000
Engineering Fees	$		$875,000	$850,000	$820,000	$820,000	$960,000
Process Contingencies	$		$503,000	$488,000	$472,000	$472,000	$553,000
Project Contingencies	$		$1,580,000	$1,540,000	$1,490,000	$1,490,000	$1,740,000
Total Plant Cost (TPC)	$		$12,145,000	$11,790,000	$11,420,000	$11,400,000	$13,350,000
Total Cash Expended (TCE)	$		$12,145,000	$11,790,000	$11,420,000	$11,400,000	$13,350,000
Allowance for Funds During Constru	$		0	0	0	0	0
Total Plant Investment (TPI)	$		$12,145,000	$11,790,000	$11,420,000	$11,400,000	$13,350,000
Preproduction Costs	$		$243,000	$236,000	$228,000	$227,000	$267,000
Inventory Capital	$		$167,000	$134,000	$100,000	$98,000	$280,000
Initial Catalyst and Chemicals	$		$0	$0	$0	$0	$0
Prepaid Royalties	$		$44,000	$42,000	$41,000	$41,000	$48,000
Total Capital Requirement (TCR)	$		$12,600,000	$12,200,000	$11,800,000	$11,800,000	$13,900,000
Market Demand Escalation	$		$0	$0	$0	$0	$0
Power Outage Penalty	$		$0	$0	$0	$0	$0
Land Cost	$		$0	$0	$0	$0	$0
TCR w/ Market Dem., Power Outage	$		$12,600,000	$12,200,000	$11,800,000	$11,800,000	$13,900,000
	$/kW		21.80	21.10	20.40	20.40	24.00
	Mills/KWh		0.40	0.38	0.37	0.37	0.44

Table 4 – Operation & Maintenance Costs

SNCR O&M Costs			0.22 Inlet & 30% Reduction	0.20 Inlet & 25% Reduction	0.16 Inlet & 20% Reduction	0.15 Inlet & 20% Reduction	0.22 & 50% Reduction
Cost Basis Year			2011	2011	2011	2011	2011
Reagent Type			Urea	Urea	Urea	Urea	Urea
Reagent Consumption	lb/hr		1991	1601	1188	1155	3318
	tons/yr		7848	6310	4681	4553	13080
Water	gpm		72	58	43	42	119
Electricity	kW		75	61	45	44	126
NOx allowances generated	tons/yr		n/a	n/a	n/a	n/a	n/a
Reagent Cost	$/yr		$3,924,000	$3,155,000	$2,340,000	$2,280,000	$6,540,000
Water Cost	$/yr		$410,000	$330,000	$250,000	$240,000	$688,000
Additional Power Costs	$/yr		$24,000	$19,000	$142,000	$13,800	$40,000
NOx Credit	$/yr		$0	$0	$0	$0	$0
Total First Year Variable O&M Cost	$/yr		$4,360,000	$3,500,000	$2,600,000	$2,530,000	$7,270,000
Maintenance	$/yr		$189,000	$183,000	$177,000	$176,000	$210,000
Total First Year Fixed O&M Costs	$/yr		$189,000	$183,000	$177,000	$176,000	$210,000

Attachments

URS SNCR Experience
ICAC White Paper – SNCR for Controlling NOx Emissions – 2000
ICAC White Paper – SNCR for Controlling NOx Emissions – 2008 Update

ATTACHMENTS

The following table presents a listing a URS's SNCR experience. Additionally, a partial listing of the Integrated Emission Control (IEC) Technologies that URS has evaluated for the Electric Power Research Institute (EPRI) follows the SNCR experience list.

NO_X CONTROL EXPERIENCE – SNCR

Client	Project	Unit #	Location	Size (MW)	Fuel	PRB	Equipment Supplier	New (N) vs. Retrofit I	Completion Date	Scope
NRG Energy	5 Stations	14 Units	Various	2350	Coal		NA	R	Dec 02	FS, CE
Dayton Power & Light	Total System (6 plants)	15	Various	60-800	Coal		NA	R	1998	FS
Niagara Mohawk	Four Stations	1, 2, 3, 4	NY		Oil, Gas, Coal		NA	R	Dec 94	FS, CE
New York State Electric and Gas	System-wide	10 units	NY	Various	Coal			R	Dec 94	FS, CE
Duquesne Light and Power	System-wide		PA	Various	Coal		NA	R	Dec 93	FS, CE
Atlantic Electric	B. L. England Station			290	Coal		NA	R	Dec 93	FS, CE
Pennsylvania Power & Light	Brunner Island Station	3	PA	790	Coal		NA	R	Dec 93	FS, CE
PEPCO	Various	1, 2, 3, 4, 5, 6	Various	N/A	Coal, Oil, Gas		NA	R	Dec 93	FS, CE
Niagara Mohawk	Huntley Station	6, 7	Syracuse, NY	2 x 420	Coal		NA	R	Apr 93	FS, CE

NO_X CONTROL EXPERIENCE – SNCR

Client	Project	Unit #	Location	Size (MW)	Fuel	PRB	Equipment Supplier	New (N) vs. Retrofit I	Completion Date	Scope
Inland Steel and Nippon Steel (I/N Tek)	Furnaces and Aux. Boiler Continuous Galvanizing Line (9,000,000 tons/yr capacity)	N/A	IN	N/A	Gas		NA	N	Dec 92	FS, CE
Centerior Energy				72 thru 680	Coal			R	1992	FS, CE
Allegheny Energy Supply	Harrison Station	1, 2, 3	Shinnston, WV	3 x 685	Coal		NA	R	1992	E
San Diego Gas & Electric	System-Wide NO_X Compliance	13 Units	CA	Various	Various		NA	R	1991	PE
Entergy Services, Inc.	System-Wide NO_X Reduction Assessment	54 Units	Various	Various	Various		NA	R		FS
Chevron	El Segundo Refinery		CA		Refinery off-gas		NA	R		FS, CE
AES	Warrior Run	1	Cumberland, MD	180	Coal		NA	N	1998	E, P, C
PEPCO	Various	1, 2, 3, 4, 5, 6	Various	N/A	T-fired oil and coal Wall-fired oil and gas		NA	R	Dec 93	E
Tennessee Valley Authority	Johnsonville	6 units	Johnsonville, TN	6 x 100	Coal		NA	R	Dec 92	E
Los Angeles Dept. of Water & Power	Haynes	1, 2	Long Beach, CA	2 x 230	Gas/Oil		Ammonia injection	R	1992	E, C

NO_X CONTROL EXPERIENCE – SNCR

Client	Project	Unit #	Location	Size (MW)	Fuel	PRB	Equipment Supplier	New (N) vs. Retrofit I	Completion Date	Scope
Air Products	Stockton Cogeneration	1	Stockton, CA	50	Coal		NA	N	1988	D, E, CS
Chevron	El Segundo Refinery				Refinery off-gas		NA	R		FS
Texaco	Los Angeles Refinery		Los Angeles, CA	22	Refinery off-gas		NA	R		FS
Air Products	Cambria County	1	Pennsylvania		Waste Coal		NA	N		E, P

Legend:

BE	Bid Evaluation	D	Design	S	Startup
C	Construction	E	Engineering	STG	Steam Turbine Generator
CA	Construction Advisory	FS	Feasibility Study	T	Testing
CE	Cost Estimate	OE	Owner's Engineer	PRB	Powder River Basin Coal
CM	Construction Management	P	Procurement		

Integrated Emission Control Technologies evaluated for EPRI.

Gas Phase Oxidation Systems

Chem-Mod
ECO™
ECO2™
ISCA

Lextran SO2/NOx/Hg
LoTOx

Low-Temperature Multi-Pollutant Control System (MPCS)
THERMALONOx
Plasma/Electron Beam Systems
EBFGT
e-SCRUB™
Pioneer Industrial Technologies (PIT)
Pulsatech
WOWClean

Combustion Modification/Fuel Processing
Ashworth Combustor
Clean Combustion System (CCS)
Coal Tech
Emulsified Fuel Technology
Green Coal
High-Sodium Lignite-Derived Chars
K-Fuel
K-Lean
Lignite Cleaning System
The Mobotec System
N-Viro Fuel
Oxycombustion
Soot Free Catalyst
WRI Coal Processing

Wet Scrubbing Systems
Airborne

Aqueous Foam Air (AFA) Filter
CEFCO
Dry-Wet Hybrid Electrostatic Precipitator (ESP)
DynaWave
Eco Technologies
Envirolution/PureStream Gas-Liquid Contactor
FLU-ACE
Integrated Flue Gas Treatment
Integrated Advanced Tower
Ispra by SRT Group
LABSORB
Membrane Wet ESP
MercOx
PEA
Rapid Absorption Process (RAP)/Dry Absorption Process (DAP)
SkyMine

Dry Technologies
Argonne Spray Dryer
NOxOUT CASCADE / Turbosorp Technology (formerly CDS/SCR)
ClearGas Dry Scrubber
Copper Oxide
EMx (previously SCONOx/SCOSOx)
Indigo MAPS
Kuttner Luehr Filter Technology
Low Temperature Mercury Control (LTMC)
Novacon
PahlmanTM Process
ReACT Technology
SNOX

SOx-NOx-Rox Box (SNRB)
Trona Injection

Other Technologies
Argonne Hg/NOx Process
CANSOLV SO2/CO2 Process
GreenFuel
Integrated Pollutant Removal (IPR)
Low Temperature Sulfur Trioxide Removal System (LT-STRS) / Mitsubishi Mercury Treatment System (Mi-MeTS) (Previously MHI High Efficiency System / HCl Injection)
TIPS
Combined Plasma Scrubbing Technology (CPS)
Consummator
ECOBIK
Aqua Ammonia Process
BioDeNOx
Fungal Bioreactor
Plasma Enhanced ESP
ElectroCore

Appendix C

Fly Ash Storage and ASM Technology Evaluation

REPORT

FLY ASH STORAGE AND AMMONIA SLIP MITIGATION TECHNOLOGY EVALUATION

Great River Energy

Coal Creek Station

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November 15, 2011 **113-82161**

A world of capabilities delivered locally

Golder Associates

EXECUTIVE SUMMARY

Great River Energy (GRE) has requested that Golder Associates Inc. prepare a third-party review of potential ammonia slip mitigation (ASM) technology and cost comparisons for associated RCRA Subtitle D ash storage facility design for their Coal Creek Station (CCS) located in Underwood, North Dakota.

These evaluations are prepared in response to the United States Environmental Protection Agency's (EPA's) proposed Federal Implementation Plan (FIP) for the state of North Dakota. As part of the FIP process, the North Dakota Department of Health (NDDH) has requested that GRE prepare a Best Available Retrofit Technology (BART) analysis for nitrogen oxides (NOx) emissions, specifically evaluating the application of selective non-catalytic reduction (SNCR) emission control technology. Due to the potential for unreacted ammonia in the flue gas downstream of the SNCR (ammonia slip) reacting with sulfur compounds to form ammonia sulfates that deposit in the fly ash, there is concern over the significant impact on current fly ash sales. Therefore, GRE is evaluating an ASM technology at CCS as an option for treating ammonia slip impacted fly ash to allow continued beneficial use and sale of fly ash. This ASM technology is not proven for lignite derived fly ash and is presented as a potential option to reduce the impact of an SNCR on fly ash management. This evaluation includes an ASM technology cost estimation, fly ash disposal cost comparisons, and evaluation of the total cost impact of an SNCR on fly ash management at CCS.

Golder recently visited the Eastlake Station where Headwaters Energy Services' patented ASM technology is currently applied to manage ammonia levels in the fly ash. Based on this operation and Golder's knowledge of CCS and lignite coal-fired power plants, a cost estimate to apply ASM at CCS was prepared. The cost estimate includes costs for the ASM infrastructure including engineering and design, construction, and operations and maintenance. Costs are based on 2011 dollars and capital costs are annualized for a 20-year life and 5.5% interest rate. Existing fly ash sales infrastructure and operations and maintenance are not included in the cost estimate. ASM post-processing costs are estimated to be $5.61 per ton of fly ash treated.

Fly ash that cannot be marketed for beneficial use is disposed of in engineered and permitted facilities at CCS. Golder prepared a cost estimate for three potential operating scenarios: Scenario A – fly ash sales equal to the average sales over the past few years, Scenario B – ammonia slip impact of an SNCR makes fly ash at CCS unsalable, and Scenario C – ASM technology will be viable for ammonia impacted fly ash at CCS allowing a reduced amount of fly ash sales. A summary of the total estimated fly ash disposal costs is shown in the following table.

	Scenario A (Current Sales)	Scenario B (No Sales)	Scenario C (Reduced Sales, ASM)
Fly Ash Disposed (ton/yr)	110,000	525,000	234,500
Disposal Cost ($/ton)	$18.06	$11.18	$13.91
Annual Disposal Cost ($/yr)	$1,987,000	$5,870,000	$3,262,000
Annual Increase in Disposal Cost Compared to Scenario A ($/yr)	-	$3,883,000	$1,275,000

The landfill design included the specific size, location, infrastructure, liner, and cover relevant to each scenario. Costs for each scenario included the specific landfill design, engineering, and permitting costs, land acquisition, infrastructure development, liner construction, post-closure care, construction management and construction quality assurance (CQA), GRE internal costs, project contingencies, and operational costs. Based on the annual disposal cost estimate shown in the table above, the potential impact of an SNCR on the fly ash disposal costs at CCS may be an additional $3.9 million per year if fly ash is no longer marketable or an additional $1.3 million per year if the ASM technology proves successful.

The total cost impact of an SNCR on fly ash management at CCS includes ASM post-processing costs, fly ash disposal costs, and the loss in revenue generated from the sale of fly ash. Golder evaluated this total cost impact for each scenario, and is summarized in the table that follows. Based on this evaluation, the total additional cost impact to fly ash management as a result of an SNCR is between $4.4 and $9.0 million per year.

	Scenario A (Current Sales)	Scenario B (No Sales)	Scenario C (Reduced Sales, ASM)
Total (Disposal + Post Processing + Lost Sales)			
Annual Cost ($/yr)	$1,987,000	$10,975,000	$6,422,000
Unit Cost ($/ton produced)	$3.79	$20.91	$12.23
Additional Cost (Scenario B/C - Scenario A)			
Fly Ash Management Cost ($/yr)	-	$8,988,000	$4,435,000
Fly Ash Management Cost ($/ton produced)	-	$17.12	$8.45

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1.0 INTRODUCTION

Great River Energy (GRE) has requested that Golder prepare a third party review of ammonia slip mitigation technology, and cost comparisons for associated RCRA Subtitle D ash storage facility design for Coal Creek Station (CCS) located in Underwood, North Dakota. These evaluations are prepared in response to the United States Environmental Protection Agency's (EPA's) proposed Federal Implementation Plan (FIP) for the state of North Dakota. Based on the proposed FIP, GRE is evaluating selective non-catalytic reduction (SNCR) control technology to reduce nitrogen oxide (NO_x) emissions from CCS. If SNCR is installed at CCS, there is potential for unreacted ammonia in the flue gas downstream of the SNCR, called ammonia slip, and higher ammonia in fly ash. Due to the significant impact on current ash sales, GRE is evaluating a potential ammonia slip mitigation (ASM) technology patented by Headwaters Energy Services. In addition, GRE is evaluating three potential management scenarios for fly ash based on the potential impact of ammonia concentrations to the sale of fly ash.

Golder performed a third party review and estimated costs associated with implementation of Headwaters' ASM technology as applied to CCS. The review includes an estimate of the capital and operating and maintenance (O&M) costs for implementation of the ASM technology at CCS, with a focus on potential impacts to ash marketing and future sales to assist GRE in determining the feasibility of the ASM technology for operations at CCS. This evaluation is limited in scope given that "Headwaters has not conducted any field scale assessment on application of this technology to lignite derived fly ash. The limited current experience in commercial application and lack of field trials is not adequate for Headwaters to be able to provide any guarantee that the process can be successfully applied to treat lignite ash at the Coal Creek Station," per an email from Rafic Minkara (Headwaters) to John Weeda (GRE) on July 15, 2011.

Golder also prepared a cost comparison for three fly ash storage facility scenarios:

- Scenario 1: CCS's current fly ash sales rate (most fly ash sold);
- Scenario 2: No fly ash sales;
- Scenario 3: Application of ASM technology (allowing for some fly ash sales).

The cost evaluation includes a comparison of capital and O&M costs for each scenario assuming a new facility that meets EPA RCRA Subtitle D type regulations.

1.1 Qualifications

Golder Associates Corporation is an international employee-owned consulting engineering company specializing in the application of earth sciences and engineering to environmental, natural resources, and civil engineering projects. Operating since 1960, our company maintains a network of approximately

160 offices. Current worldwide employment exceeds 7,000 people. The United States operating company, Golder Associates Inc., employs approximately 1,200 people in 51 offices.

This project was conducted by a team based in our Denver, Colorado and Fort Collins, Colorado, offices. The project team was well-suited to perform the proposed services at CCS because of the experience of our technical staff on comparable projects, and our familiarity with the geotechnical and engineering properties of Subtitle D landfill designs. In addition, our team has a firm understanding of the engineering practice and regulatory environment surrounding coal-fired power plants, both in North Dakota and nationally, including ongoing rulemaking efforts by the EPA.

2.0 BACKGROUND

2.1 Regulatory Basis

In order to attain and maintain the National Ambient Air Quality Standards (NAAQS) within a state, state air quality agencies prepare State Implementation Plans (SIP) for EPA approval. If EPA disapproves of the SIP, either partially or fully, EPA will develop a Federal Implementation Plan (FIP) to address the deficiencies in the SIP.

On September 21, 2011, EPA proposed to partially disapprove the North Dakota SIP, specifically addressing regional haze and proposed a FIP to address the deficiency "concerning non-interference with programs to protect visibility in other states"[1]. As part of this process North Dakota Department of Health (NDDH) has requested a Best Available Retrofit Technology (BART) analysis for nitrogen oxides (NOx) emissions. This analysis was submitted by GRE in 2007 and additional evaluations and response to questions were submitted in 2010 and on July 15, 2011 to NDDH. NDDH is requesting additional analyses of selective non-catalytic reduction technology. This report does not include an SNCR evaluation, but provides a cost evaluation to address the potential impact the installation of SNCR would have on the existing GRE fly ash storage and sales.

2.2 SNCR and Ammonia Slip

Selective non-catalytic reduction (SNCR) technology is a post-combustion technology based on the chemical reduction of NOx into molecular nitrogen (N_2) and water vapor (H_2O). A nitrogen based reagent, such as urea, is injected into the post-combustion flue gas. The injection causes mixing of the reagent and flue gas while the heat in the flue gas provides energy for the reaction. The primary byproduct of the reaction is nitrous oxide (N_2O), which is a potent greenhouse gas (GHG).

Unreacted reagent in the flue gas downstream of the SNCR is called slip. This unreacted reagent will appear as ammonia, and reacts with sulfur compounds (from sulfur containing fuels) to form ammonia sulfates which deposit on the fly ash that is collected by the particulate emissions control equipment. The ammonia sulfates are stable in a dry state, but ammonia gas can release if the fly ash becomes wet. Ammonia content in the fly ash greater than 5 parts per million (ppm) (based on Headwaters' experience this level is 35 ppm) can result in release of ammonia gases which impact either the sale or storage and disposal of fly ash.

[1] Federal Register, EPA, 9/21/2011, www.federalregister.gov/articles/2011/9/21/2011-23372

3.0 AMMONIA SLIP MITIGATION

3.1 Background

Headwaters has developed an ammonia slip mitigation (ASM) technology to manage ammonia levels in the fly ash, so that a portion of the fly ash produced can be sold as a concrete additive. The Headwaters' ASM technology was initially developed in 2001 with the first US patent issued in 2004. The first commercial installation of ASM technology was installed at RG&E Russell Station in Rochester, New York in 2004. Russell Station used an SNCR and burned eastern bituminous coal.

The second commercial installation was installed at Eastlake Station in Ohio. Eastlake Station has a 600 megawatt (MW) unit that is fired with a 50/50 blend of Power River Basin (PRB) and eastern bituminous coal while generating approximately 100,000 TPY of fly ash. Headwaters is able to blend, treat, and market approximately 85% of the fly ash produced at Eastlake station. Fly ash is not treated during periods of highly variable ammonia concentrations, typically occurring during SNCR upset or plant load swings.

Currently, there are no commercial applications of ASM technology at a lignite-fired power plant, and Headwaters has not conducted any research on the application of the technology to lignite derived fly ash. Due to the lack of commercial experience with lignite derived fly ash, Headwaters will not provide a guarantee that the ASM technology can be successfully applied to lignite derived fly ash.

3.2 Process Description

The ASM technology mixes approximately 0.5-pound (lb) calcium hypochlorite (Cal-Hypo) with approximately 3,000-lb of fly ash in a hopper. The dose of cal-hypo, which is fed into the hopper using a rotary screw, is based on the ammonia concentration in the fly ash. Typical ammonia range for treatment is 50 to 150 ppm with a dosage of 0.2 to 1.3 lb of Cal-Hypo, resulting in ammonia concentrations after treatment of about 35 to 80 ppm.

Golder visited a current commercial application of ASM technology at the Eastlake Station (Figure 1). Fly ash from the electrostatic precipitator (ESP) is sent to one of two fly ash silos where the fly ash is tested daily to determine ammonia concentrations (Figure 2). If the ammonia concentrations are above 150 ppm, the fly ash is diverted for disposal. Fly ash with ammonia concentrations less than 150 ppm are sent to the third silo, after which it is "dosed" with Cal-Hypo and sent to the fourth silo (Figure 3 through Figure 5). The SNCR at Eastlake cannot keep the ammonia slip consistent, and often over-treats a portion of the fly ash stream. To increase the amount of treatable and marketable fly ash, fly ash with no ammonia from other sources is regularly blended into the Eastlake fly ash to keep the initial ammonia content below 150 ppm. Through the operation of the SNCR and by blending non-ammonia impacted fly ash with Eastlake's ammonia impacted fly ash, Eastlake is able to market approximately 85% of what

they produce because this fly ash is considered "treatable" (i.e., ammonia concentration levels are < 150 ppm). Diagrams of the East Lake Station system provided by Headwaters are shown in Appendix A. Subsequent to these diagrams, Headwaters has added a weigh hopper under the silo as shown in Figure 5.

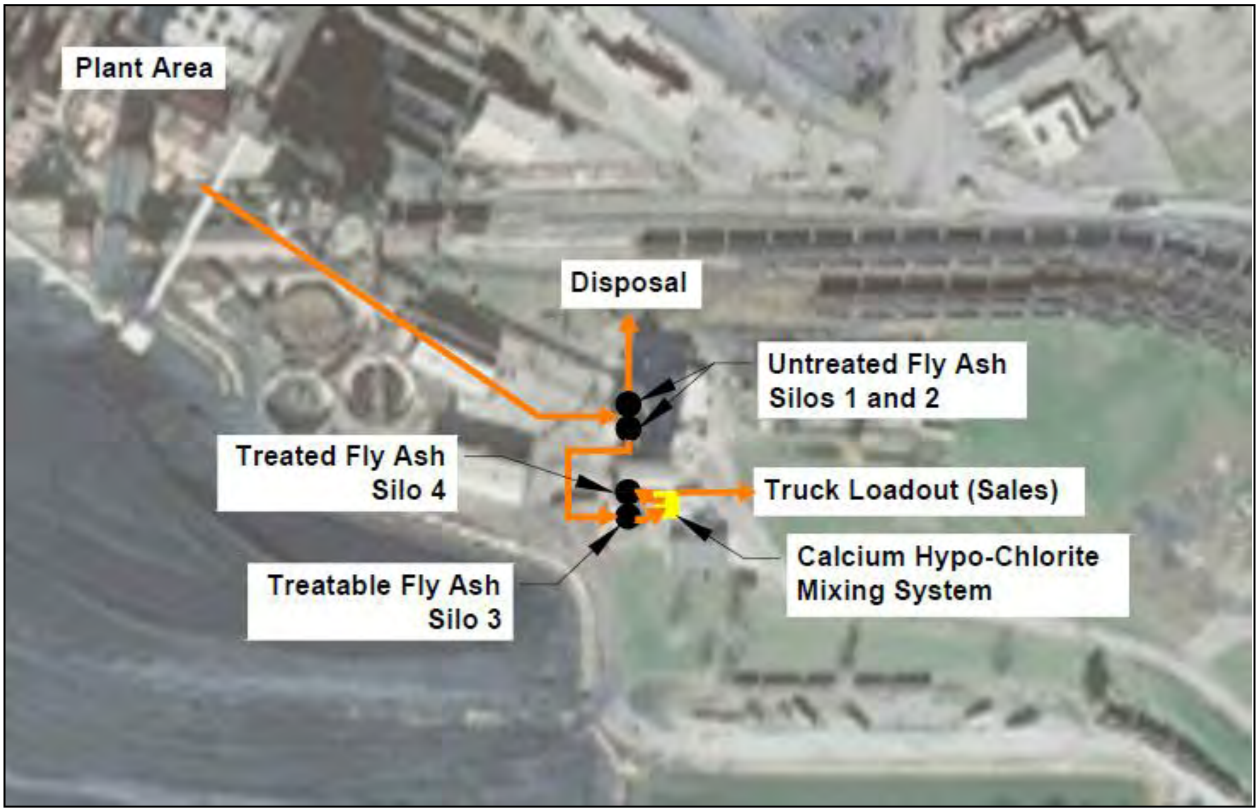


Figure 1: Eastlake Station ASM Schematic


Figure 2: Eastlake Station ASM Lab

Figure 3: Eastlake Station Silo 3, Silo 4, and ASM Setup

Figure 4: Eastlake Station ASM Control Panel

Figure 5: Eastlake Station ASM Mixing Hopper

3.3 Design and Limitations

Based on the Eastlake Station application, ASM is applied to fly ash with ammonia concentration levels less than 150 ppm. Ammonia levels can fluctuate based on plant load variations and SNCR operation. Ammonia concentrations are more consistent at base load conditions and dosing levels are typically based on this condition. Therefore, during load “swings,” it can be difficult to properly adjust the amount of ammonia injected into the flue gas resulting in varying concentrations of ammonia in the fly ash. If there is a plant upset condition, it may be several days until the ammonia concentrations in the fly ash being produced are at “treatable” levels again. The concern is two-fold. If the fly ash is not treated with enough Cal-Hypo, objectionable levels of ammonia will be released when the fly ash is mixed with water. Ammonia gas at low levels is an irritant but can be dangerous to life and health at high concentrations. If too much Cal-Hypo is added, chlorine gas will be released when the fly ash is mixed with water. Chlorine gas even at low concentrations is dangerous to life and health.

3.4 ASM Application at CCS

The application of ASM technology at CCS is being evaluated as an option for treating ammonia slip impacted fly ash to allow continued beneficial use and sale of fly ash.

3.4.1 Potential Design at CCS

For cost estimating, a potential layout for the application of ASM at CCS is shown in Figure 6. This potential layout utilizes the existing fly ash infrastructure including the truck load-out silos (91 and 92), the rail load-out silo (93), and the fly ash storage dome (94). To utilize ASM, the layout adds a new truck load-out silo south of Silos 91 and 92, and adds ASM Cal-Hypo feed systems at both the new truck load-out silo and the existing rail load-out silo (93). The general flow of material is treatable fly ash being routed to either the new truck load-out silo, the fly ash dome (94) or the rail load-out silo. From these silos, the fly ash is tested, and then mixed with Cal-Hypo as it is loaded into the trucks or rail cars. Additional testing of the resultant product would also be performed. Fly ash that is expected not to be treatable or saleable is routed to the exiting truck load-out silos (91 and 92) where it will be loaded into haul trucks and disposed at on-site disposal facilities.

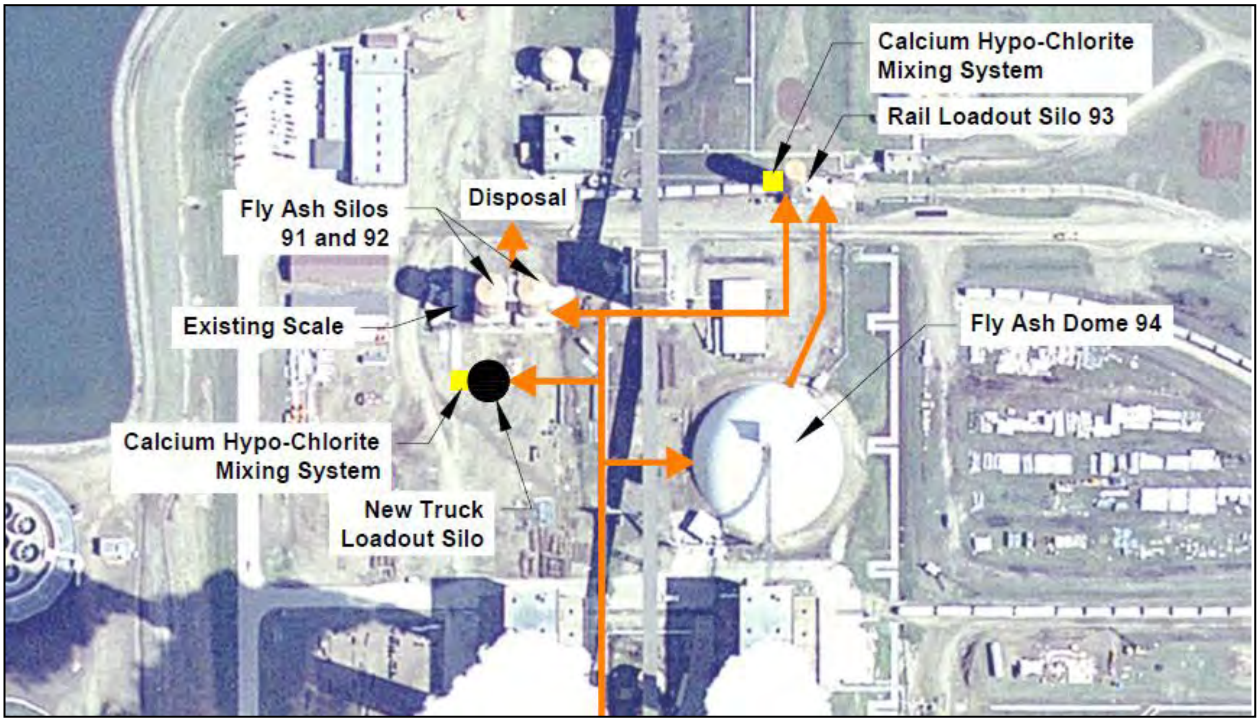


Figure 6: Coal Creek Station ASM Schematic

As discussed earlier, not all of the fly ash coming from the precipitators is expected to be within treatable levels of ammonia. In general, when the power generation units are operating at steady load and the SNCR ammonia injection system is operating properly, the fly ash produced should be treatable using the ASM system and will be collected in the rail load silo (93), the fly ash dome (94), or the new truck loadout silo (95). Conditions under which the ammonia content of the produced fly ash will be questionable include:

- Unit load swings causing variations in ash ammonia concentration (load swings may be due to regional wind penetration or variable load consistent with MISO);
- SNCR ammonia injection feed system problems; and
- Unit startup and shutdown which results in oily ash.

Golder expects that when any of these conditions occur, the fly ash produced will automatically be directed to the disposal silos (91 & 92). Fly ash will not be redirected to the sales silos (93, 94 or 95) until the upset is over and the fly ash collected in the first two rows of the electrostatic precipitator (ESP) has been tested and proven to have less than 150 ppm of ammonia in it.

Based on a review of the recent load profile at CCS, historic information on marketable fly ash at CCS, and an estimate of the reliability of the SNCR and ASM systems, approximately 30% of the fly ash now sent to the sales silos is assumed to have ammonia concentrations which will make it untreatable if an SNCR system is installed.

3.5 Cost Estimate

The cost estimate includes costs for the ASM infrastructure including engineering and design; construction; and operations and maintenance. Golder used actual costs from similar projects, and professional judgment to develop this cost estimate. Sources and assumptions are documented where appropriate. Some general assumptions for the cost estimate include:

- All costs are estimated in 2011 dollars.
- Capital costs are annualized based on a 20-year life and 5.5% interest rate.
- Existing fly ash sales infrastructure (silos, scales, rail facilities) and operations and maintenance are not included.

3.5.1 System Engineering and Design

This item is estimated as 10% of the total construction costs to develop the new facilities. Ten percent is based on Golder's professional judgment.

3.5.2 New Truck Load-Out Silo

The costs for the new truck load-out silo include site preparation, permit application, the silo and handling equipment, dust collection equipment, and feed piping. The costs for this construction are based on the construction of a similar fly ash sales terminal constructed for GRE in 2003. This silo had a 5,000-ton capacity and was used to transfer fly ash from rail cars to trucks (Figure 7). The total estimated cost for this item is $1.6 million and includes the following:

- Silo and truck scale similar to the Irondale, CO unit:
  - Silo slab on grade;
  - Starvrac reclaimer;
  - Truck scale beside the silo on grade;
  - Screw conveyor from discharge of the Starvrac reclaimer;
  - Bucket elevator to overhead;
  - Air slide ;
  - Building with the scale and ASM controls
- Additional items needed at CCS:
  - Feed piping and valves from each of the four fly ash conveying lines;
  - Higher capacity dust collectors to handle the high air flow from ESP.

Details for this cost estimate are included in Appendix B.

Figure 7: Typical Silo used in Cost Estimate

3.5.3 Cal-Hypo Feed System

The costs for the Cal-Hypo feed systems are estimated at $574,500 and include:

- Rail loadout silo (93):
  - Cal-Hypo storage and conveying building;
  - Day storage hopper for Cal-Hypo on the silo weigh bin floor;
  - Conveying system from the storage building to the day storage hopper;
  - Variable speed screw conveyor to feed Cal-Hypo into existing weigh hopper;
  - ASM system controls
- New truck loadout silo (95):
  - Weigh hopper above truck loadout spout;
  - Cal-Hypo storage and conveying building;
  - Day storage hopper for Cal-Hypo on the silo weigh bin floor;
  - Conveying system from the storage building to the day storage hopper;
  - Variable speed screw conveyor to feed Cal-Hypo into existing weigh hopper;
  - ASM system controls.

3.5.4 GRE Internal Costs

Internal costs for GRE to manage consultants, contractors, and in-house staff is estimated as 10% of the total costs (construction, engineering, permitting, CQA). Ten percent is based on GRE's experience with projects at CCS.

3.5.5 Project Contingency

Due to the order-of-magnitude scope of this cost estimate a contingency of 15% on the construction costs was added.

3.5.6 Operational and Maintenance Costs

ASM post-processing operations and maintenance costs are estimated as an annual cost. Operations costs include the cost of Cal-Hypo, fly ash sampling and testing costs, and labor to operate the system. Maintenance costs include labor and materials to maintain and repair the added equipment at the rail load-out silo (93) and the new truck load-out silo (95).

The estimated cost for this item, based on annual sale/processing of 290,500 tons, is approximately $1.4 million per year. Details for this cost estimate are included in Appendix B.

3.6 ASM Post-Processing Cost Summary

Using the quantities and the unit pricing described above, ASM post-processing costs are estimated as $5.61 per ton of fly ash treated.

4.0 FLY ASH DISPOSAL

Fly ash that cannot be marketed for beneficial use is disposed of in engineered and permitted facilities at CCS. Golder has prepared this order-of-magnitude cost estimate to compare costs between three scenarios defined to assess the potential impact of an SNCR on fly ash sales and disposal at CCS. Summary costs and key inputs are included in Table 1 through Table 3, and Figure 8 through Figure 10, with cost estimate details provided in Appendix B.

4.1 Fly Ash Disposal Scenarios

Three scenarios were evaluated to estimate the annual cost and the cost per ton to dispose of fly ash at CCS. These scenarios include:

- ***Scenario A*** – This scenario is the base case with fly ash sales equal to the average sales over the past few years. The scenario assumes that fly ash will be disposed of in a new landfill with a design based on RCRA Subtitle D practices, and has a 20-year disposal capacity. No post processing of the fly ash is required to make it marketable.
- ***Scenario B*** – This scenario assumes that the ammonia slip impact of an SNCR makes fly ash at CCS unsalable. The scenario also assumes that fly ash will be disposed of in a new landfill with a design based on RCRA Subtitle D practices, and has a 20-year disposal capacity.
- ***Scenario C*** – This scenario assumes that Headwater's ASM technology will be viable for ammonia impacted fly ash at CCS. However, sales will be reduced from current sales due to load swing impacts on ammonia slip, market conditions, and other factors previously identified. The scenario also assumes that fly ash will be disposed of in a new landfill with a design based on RCRA Subtitle D practices, and has a 20-year disposal capacity.

A summary of the fly ash production, sales, and disposal annual tonnages for these scenarios is provided in Table 1.

Table 1: Fly Ash Sales and Disposal Tons

	Scenario A (Current Sales)	Scenario B (No Sales)	Scenario C (Reduced Sales, ASM)
Fly Ash Produced (ton/yr)	525,000	525,000	525,000
Fly Ash Sold (ton/yr)	415,000	0	290,500
Fly Ash Disposed (ton/yr)	110,000	525,000	234,500

The total tonnage of fly ash produced is variable based on items such as plant load, plant efficiency, coal quality, and coal processing. Tonnage used in this analysis is meant to represent a typical or average amount of fly ash produced, sold, and disposed at CCS.

4.2 Landfill Design

For all three scenarios a 20-year disposal capacity and a RCRA Subtitle D design is assumed. It is also assumed that the landfill will be built on property not currently owned by GRE. For this cost estimate, it is assumed that property just west of the plant property would be purchased for the new facility. Figure 8 shows a potential location for these new facilities just west of the plant property and represents the approximate footprint required for Scenario A.

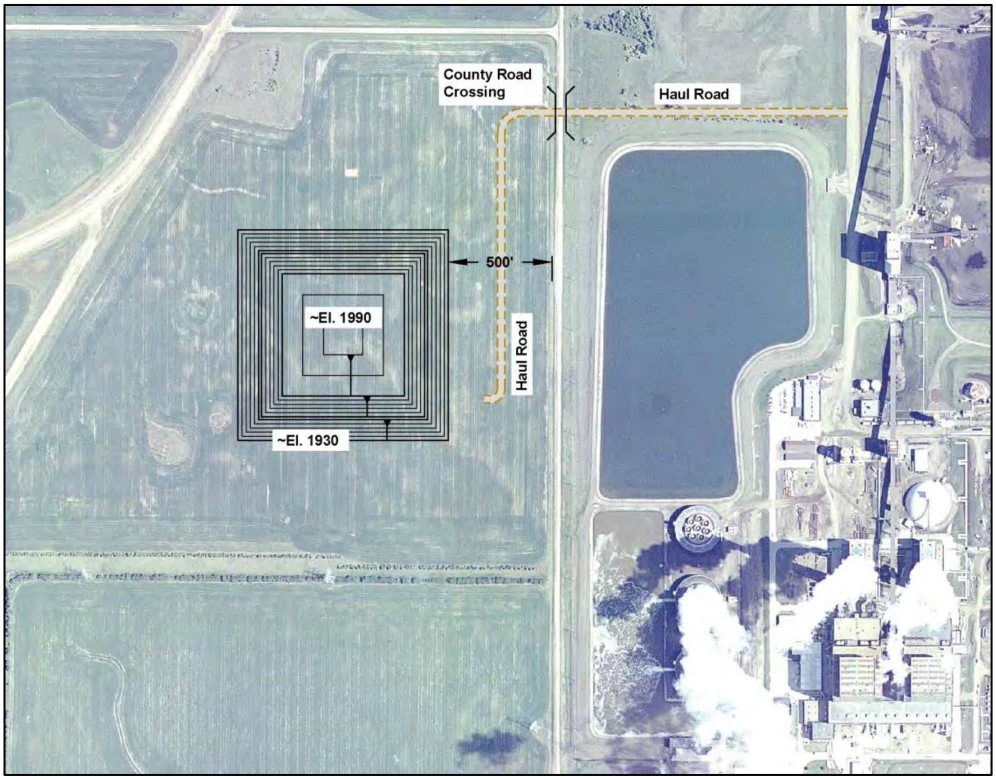


Figure 8: Potential Landfill Location (Scenario A)

4.2.1 Landfill Size

Landfill size is based on a 20-year fly ash disposal capacity. For the three scenarios this varies between 2.2 million and 10.5 million tons of capacity. For each Scenario, Golder developed a simplified landfill footprint that would provide the 20-year fly ash disposal capacity. The simplified landfill design assumes 10 feet of cut, 12-foot high soil berm, 3H:1V soil berm slopes, and 4H:1V fly ash slopes with a 5% crown. Based on preliminary engineering, the landfill capacity ranges between 75,000 and 118,000 cubic yards (cy) per lined acre due to the increased height capacity of a larger footprint facility. Figures showing the size of each Scenario are included in Appendix B.

The amount of cover area in relationship to the liner area has also been estimated based on preliminary engineering as 1.1 acres of cover for every 1 acre of liner.

The amount of land required is assumed to encompass at least a 500-foot buffer beyond this lined footprint to allow for access roads, fencing, support structures, and groundwater monitoring. For the land acquisition purchase estimate, the nearest whole or partial section of land to the required footprint was assumed.

Table 2 provides a summary of the estimated facility liner area, cover area, and site area for the three scenarios.

Table 2: Scenario Landfill Size

	Scenario A (Current Sales)	Scenario B (No Sales)	Scenario C (Reduced Sales, ASM)
Liner Acres (acres)	24.0	73.5	41.0
Cover Area (acres)	26.5	81.0	45.0
Site Area (acres)	160.0	240.0	160.0

4.2.2 Infrastructure Development

With the landfill constructed on a new property, considerable site development is required, which may include a haul truck access road, fencing and gates around the property, power to the new site, monitoring wells up- and down-gradient of the new facility, and a water return pipeline to allow the pumping of excess contact water from the site to the ash water tanks within the plant.

In addition, haul trucks will be required to cross a county road to deliver fly ash from the plant to the new facility. For safety and operational flexibility, a new country road bridge should be constructed to allow haul truck traffic under the county road. This bridge would include the bridge structure as well as the grading and embankment costs associated with the approach on the county road.

4.2.3 Liner

A liner design based on RCRA Subtitle D standards and historic practice at CCS was utilized. The assumed liner system is shown in Figure 9 and consists of (from bottom to top) a compacted clay layer ($1x10^{-7}$ cm/sec maximum permeability), a geomembrane liner, a leachate collection layer consisting of drainage material, piping and sumps, and a protective cover layer.

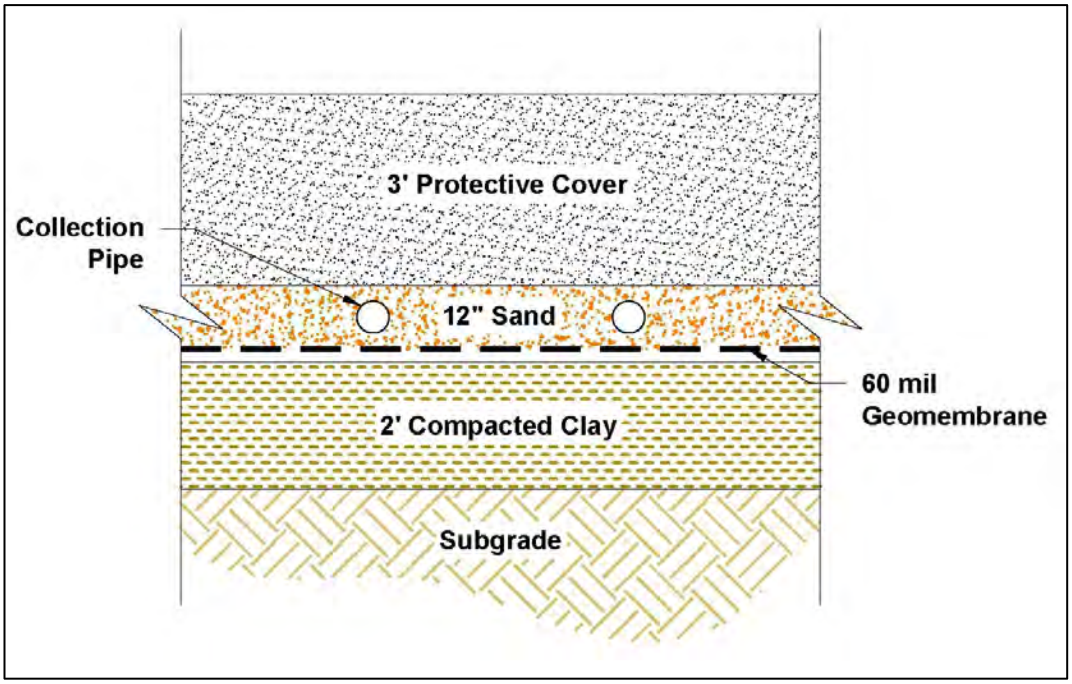


Figure 9: Composite Liner Detail

4.2.4 Cover

The final cover is also design based on RCRA Subtitle D standards and historic practice at CCS. The assumed cover system is shown in Figure 10 and consists of (from bottom to top) a compacted soil layer ($1x10^{-5}$ cm/sec maximum permeability), a textured geomembrane, a drainage layer consisting of drainage material and piping, and a vegetation layer. The drainage layer over the geomembrane is required to control the head on the liner and the resulting stability of growth medium. In addition, the cover will utilize terrace channels and armored down-chute channels to manage surface water runoff and reduce erosion.

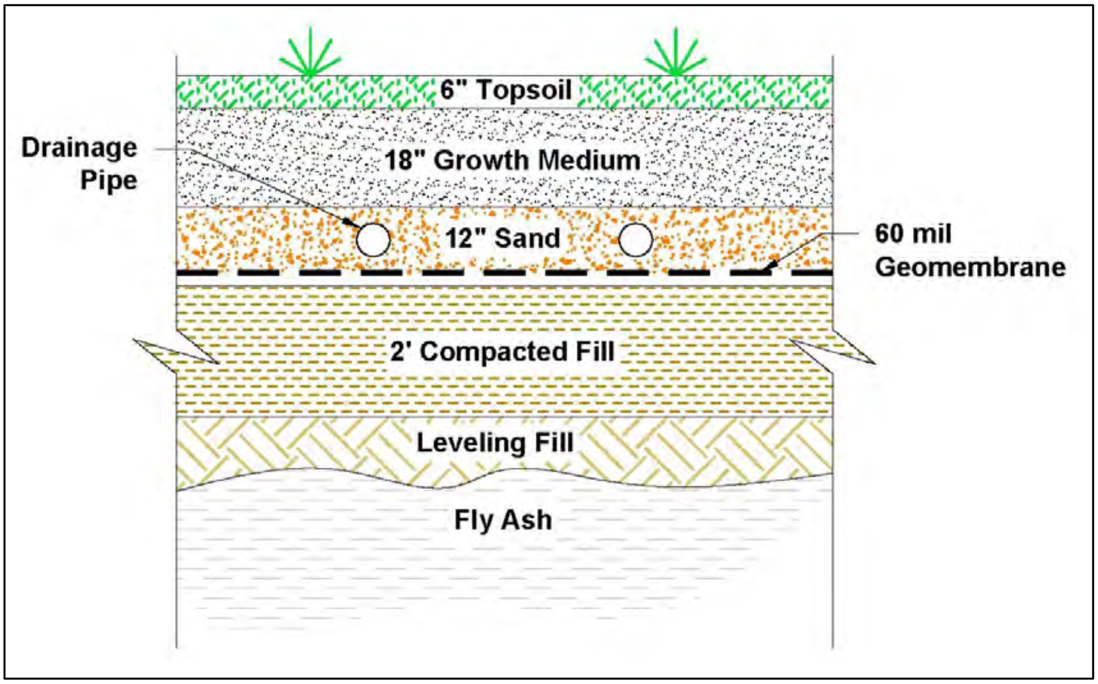


Figure 10: Composite Cover Detail

4.3 Cost Estimate

The cost estimate includes costs for the life of the disposal facility including engineering, design, and permitting; construction; and operations and maintenance, including closure and post-closure care. Golder used actual costs from similar projects at CCS, local contractor rates, RS Means manuals (RS Means 2010), and professional judgment to develop this cost estimate. Sources and assumptions are documented. Some general assumptions for the cost estimate include:

- All costs are estimated in 2011 dollars.
- Capital costs are annualized based on a 20-year life and 5.5% interest rate.
- Existing fly ash processing equipment (silos, unloaders, etc.) is not included. Disposal costs begin once the haul trucks are loaded with fly ash.
- Existing fly ash sales infrastructure (silos, scales, rail facilities) and operations and maintenance are not included.
- Disposal costs only include fly ash disposal and not facility airspace or operations and maintenance for other coal combustion products produced at CCS.

4.3.1 Engineering, Design, and Permitting

This item is estimated as 10% of the total construction costs to develop the facility. Ten percent is based on Golder's experience with coal combustion product facilities within the Midwest. The components included in this cost may include a facility siting evaluation, design of the facility, submittal of a solid waste landfill permit as well as permit renewals, submittal of air permits and NDPES permits, and creation of construction and bid packages for the facility.

The siting evaluation may include a hydrogeological characterization of the site, which includes drilling, soil testing, establishing groundwater baseline data, and preparing a hydrogeologic characterization report. Additional siting efforts may include a wetlands delineation, a site topographic survey, as well as other required evaluations.

Facility design includes both landfill design and infrastructure design. This includes grading plans, deposition plans, contact and surface water management plans, design of haul roads, and the design of the country bridge crossing.

Permitting may include the solid waste landfill permit, air permits, and an NPDES permit. This includes the development of operations plans for the facility, closure plans, post-closure care plans, groundwater sampling and analysis plans, a Stormwater Pollution Prevention (SWPP) plan, and other required submittals associated with the construction and operation of a new fly ash disposal facility.

4.3.2 Land Acquisition

Land acquisition of the property for the new facility includes site due diligence, and property purchase. Site due diligence may include survey, geotechnical characterization, environmental audit, and a landfill siting suitability evaluation. The property purchase may include legal fees as well as the purchase price. At this time, good crop land in the vicinity of CCS is selling for as much as $1,500 per acre. A unit cost of $2,000 per acre is used in the analysis to account for both the cost of the land and the site due diligence.

4.3.3 Infrastructure Development

The costs for the infrastructure development include fencing, monitoring well installation, power from the plant to landfill, facility access haul road, a return water pipeline, and a county road bridge crossing. The costs for this construction are estimated to be between $649,500 and $924,000 for the different scenarios. Details for the quantities and unit rates applied to this work are included in Appendix B.

4.3.4 Liner Construction

Liner construction includes several elements as described above including a compacted clay layer, a geomembrane liner, a leachate collection system, and protective cover. In addition, this construction effort will include clearing and grubbing, topsoil stripping and stockpiling, construction of temporary roads, soil excavation and stockpiling to be used for perimeter berms, compacted liner, and cover, and application of site controls such as erosion controls. The costs for this construction are estimated to be between $174,500 and $178,300 per acre for the different scenarios. Details for the quantities and unit rates applied to this work are included in Appendix B.

4.3.5 Final Cover Construction

Final cover construction includes leveling fill, compacted soil layer, a geomembrane liner, a drainage collection system, growth medium, topsoil, armored down-chute channels, and vegetation of the site. The costs for this construction are estimated to be between $132,400 and $143,000 per acre for the different scenarios. Details for the quantities and unit rates applied to this work are included in Appendix B.

4.3.6 Post-Closure Care

Post-closure care includes groundwater monitoring and reporting, annual site inspections, repair and maintenance of the final cover (soil, seeding, mowing, surface water structures), maintenance of the facility access roads and fencing, as well as permit required record keeping. Post closure care will occur for 30 years following the closure of the facility and is included in the capital/direct costs for this cost analysis. The costs for post closure care are estimated to be between $50,000 and $108,500 per year for the different scenarios. Details for the quantities and unit rates applied to this work are included in Appendix B.

4.3.7 Construction Management and Construction Quality Assurance

Throughout the construction effort, a construction manager will be on-site to communicate between the contractors and the design engineer. In addition to the construction manager, one or several construction quality assurance (CQA) monitors will be on-site during the construction. This item is estimated as 10% of the total construction costs to develop the facility. Ten percent is based on Golder's experience with coal combustion product facilities within the Midwest.

4.3.8 GRE Internal Costs

Internal costs for GRE to manage consultants, contractors, and in-house staff is estimated as 10% of the total costs (construction, engineering, permitting, CQA). Ten percent is based on GRE's experience with projects at CCS.

4.3.9 Project Contingency

Due to the order-of-magnitude scope of this cost estimate and the associated engineering and unit rate development, a contingency of 15% on the construction and land acquisition costs was added.

4.3.10 Operational Costs

Landfill operations and maintenance costs are estimated as an annual cost and include both engineering support and site operations. Engineering support includes design support; permit support, an annual inspection, groundwater monitoring, and an annual survey. Site operations include the ownership and operation of site haul and placement equipment, full-time site staff, and material expenses.

Estimated costs for this work are broken into haul costs, placement costs, and site management and maintenance costs.

Haul costs were estimated at $2.14 per ton based on haul distance, equipment capacity, operator costs, and equipment costs. Placement costs were estimated at $1.71 per ton based on dozer spreading with minimal compaction. Details on the haul and placement costs are included in Appendix B.

Site management and maintenance costs were estimated between $154,500 and $396,000 per year for the different scenarios. Details on the annual site management and maintenance costs are included in Appendix B.

4.4 Disposal Cost Summary

Using the quantities and the unit pricing described above, disposal costs were estimated for the three scenarios and are summarized in Table 3.

Table 3: Disposal Cost Summary

	Scenario A (Current Sales)	**Scenario B (No Sales)**	**Scenario C (Reduced Sales, ASM)**
Fly Ash Disposed (ton/yr)	110,000	525,000	234,500
Disposal Cost ($/ton)	$18.06	$11.18	$13.91
Annual Disposal Cost ($/yr)	$1,987,000	$5,870,000	$3,262,000
Annual Increase in Disposal Cost Compared to Scenario A ($/yr)	-	$3,883,000	$1,275,000

The disposal cost per ton is reduced with increased disposal quantity due to the efficiency of the landfill footprint (larger landfill can be built higher and has larger capacity), and the distribution of fixed costs (roads, bridge, fence) across a larger amount of disposed fly ash.

Based on the annual disposal cost estimate, the potential impact of an SNCR to the fly ash disposal costs at CCS may be an additional $3.9 million per year if fly ash is no longer marketable or an additional $1.3 million per year if the ASM technology proves successful.

5.0 COST IMPACT

The total cost impact of an SNCR on fly ash management at CCS requires the aggregation of the post-processing costs (ASM), the disposal costs, and the loss in revenue generated from the sale of fly ash. This total cost impact was evaluated for the three Scenarios discussed previously. As a basis for the cost comparison, Table 4 provides a summary of the annual tons of fly ash produced, sold, disposed, and the loss in fly ash sales in comparison to Scenario A (current sales).

Table 4: Fly Ash Sales and Disposal Tons

	Scenario A (Current Sales)	Scenario B (No Sales)	Scenario C (Reduced Sales, ASM)
Fly Ash Produced (ton/yr)	525,000	525,000	525,000
Fly Ash Sold (ton/yr)	415,000	0	290,500
Fly Ash Disposed (ton/yr)	110,000	525,000	234,500
Lost Fly Ash Sales (ton/yr)	0	415,000	124,500

5.1 Ammonia Slip Mitigation

Post-processing of ammonia slip impacted fly ash by Headwater's ASM technology is proposed as an option to maintain fly ash sales. This post-processing is only being applied to the sold fly ash tonnage in Scenario C. Depending upon the plant power profile and how the fly ash distribution system is setup, it is likely that additional tons of fly ash will be treated and disposed, but these potential costs impacts are not included. The cost impact for ASM post-processing is shown in Table 5.

Table 5: ASM Post-Processing Costs

	Scenario A (Current Sales)	Scenario B (No Sales)	Scenario C (Reduced Sales, ASM)
ASM Unit Rate Capital and O&M ($/ton sold)	$0.00	$0.00	$5.61
ASM Annual Capital and O&M ($/yr)	$0	$0	$1,629,000

5.2 Fly Ash Disposal

Disposal costs vary between the Scenarios with the per ton cost being reduced by disposal volume. The cost impact for fly ash disposal is shown in Table 6.

Table 6: Disposal Costs

	Scenario A (Current Sales)	Scenario B (No Sales)	Scenario C (Reduced Sales, ASM)
Unit Rate Capital and O&M ($/ton disposed)	$18.06	$11.18	$13.91
Annual Capital and O&M ($/yr)	$1,987,000	$5,870,000	$3,262,000

5.3 Lost Sales

The current fly ash sales are supported by a large investment in capital infrastructure as well as a large operations and maintenance contingency. Changes to the quantity of fly ash marketed and sold will have a direct impact on fly ash management costs, as the revenue currently used to offset fly ash management will be lost. The lost fly ash sales revenue is based on the 2010 average price per ton FOB of $41.00; with 30% of the sale price going to GRE as revenue. The cost impact of the potential loss in fly ash sales in shown in Table 7.

Table 7: Lost Fly Ash Sales

	Scenario A (Current Sales)	Scenario B (No Sales)	Scenario C (Reduced Sales, ASM)
Lost Fly Ash Sales Revenue ($/ton lost sales)	$12.30	$12.30	$12.30
Annual Lost Fly Ash Sales Revenue ($/yr)	$0	$5,105,000	$1,531,000

5.4 Combined Impact to Fly Ash Management

The combination of the ASM post-processing, fly ash disposal, and lost fly ash sales revenue is shown in Table 8. This table also shows the additional cost impact of Scenario B and Scenario C in comparison with the current sales (Scenario A).

Table 8: Total Fly Ash Management Costs

	Scenario A (Current Sales)	Scenario B (No Sales)	Scenario C (Reduced Sales, ASM)
Total (Disposal + Post Processing + Lost Sales)			
Annual Cost ($/yr)	$1,987,000	$10,975,000	$6,422,000
Unit Cost ($/ton produced)	$3.79	$20.91	$12.23
Additional Cost (Scenario B/C - Scenario A)			
Fly Ash Management Cost ($/yr)	-	$8,988,000	$4,435,000
Fly Ash Management Cost ($/ton produced)	-	$17.12	$8.45

The total additional cost impact to fly ash management as a result of an SNCR is between $4.4 and $9.0 million per year.

We appreciate the opportunity to provide this third-party review of Headwater's ASM technology, and an estimate of the potential impact of SNCR on fly ash management costs including disposal and sales. Please contact us if you have any questions about the information provided.

GOLDER ASSOCIATES INC.

Fawn W. Bergen, PE
Senior Project Engineer

Ron Jorgenson
Principal

FWB/TS/dls

6.0 REFERENCES

1. *EPA Air Pollution Control Cost Manual*, Sixth Edition, EPA/452/B-02-001, January 2002.

2. Email from Rafic Minkara, PhD, PE, Vice President – Technology, Headwaters Energy Services, July 15, 2011.

3. RSMeans, 2010. *Heavy Construction Cost Data, 24th Annual Edition*. Construction Publishers & Consultants; Kingston, MA.

APPENDIX A

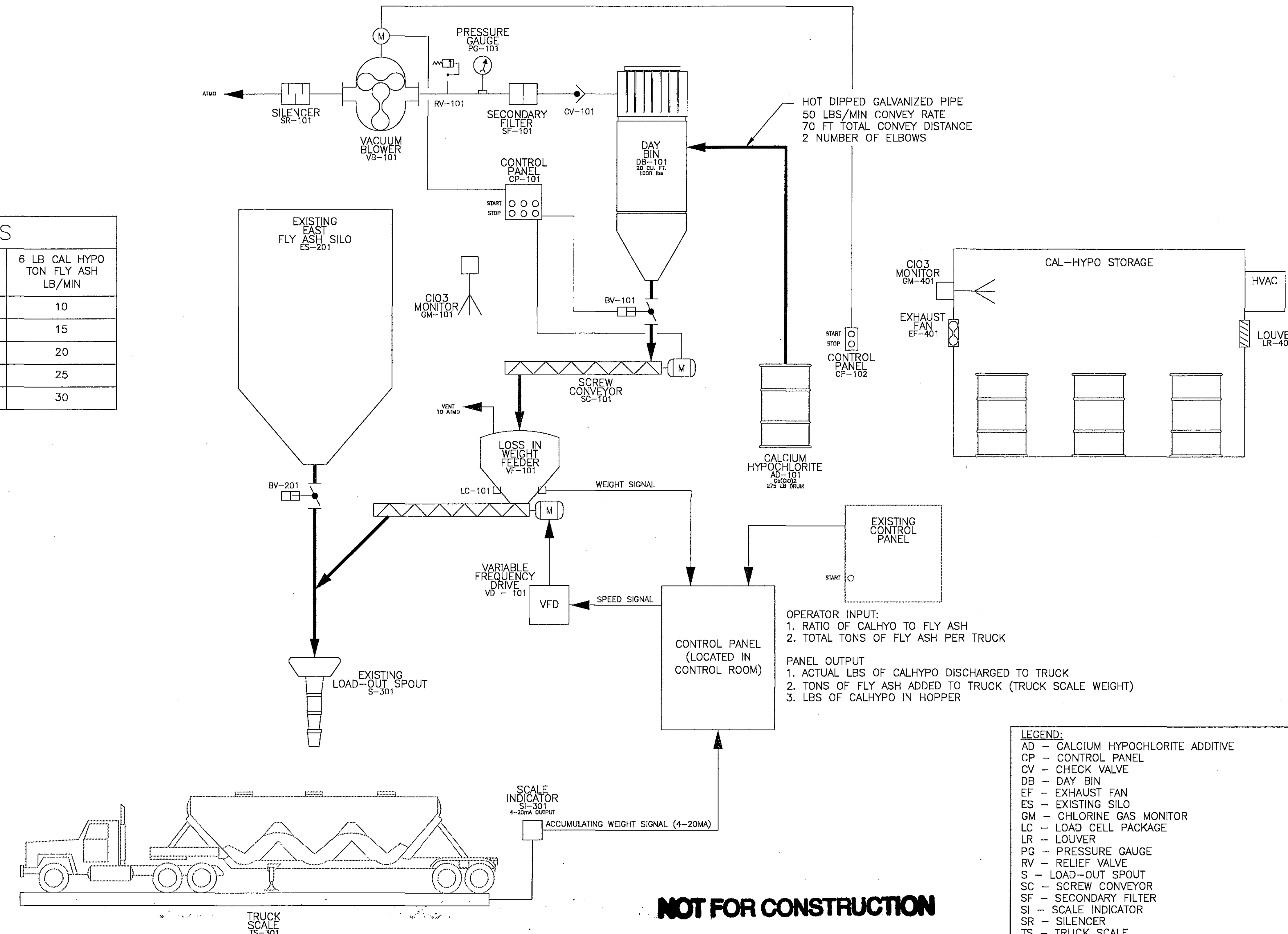
EASTLAKE ASM DESIGN DRAWINGS (HEADWATERS RESOURCES)

NOTES:

1. APPROXIMATELY 1½ TO 6 LBS CALCIUM HYPOCHLORITE/TON FLY ASH OR 38 LBS (1½*25) TO 150 LBS (6*25)/TRUCK
2. 30 TRUCKS MAX PER DAY. 1140 LBS (38*30) TO 4500 LBS (150*30) PER DAY
3. FLY ASH FEED RATE 300 TONS/HR TO 150 TONS/HR
4. CALCIUM HYPOCHLORITE FEED RATE 2.5 LBS/MIN TO 30 LBS/MIN
5. TRUCK LOAD TIME BETWEEN 5 AND 10 MINUTES
6. FLY ASH PH BETWEEN 11.5 TO 12
7. FLY ASH DENSITY 70 LBS LOOSE 100 LBS VIBRATED
8. CALHYPO APPROX. 50 LBS/FT^3
9. CALHYPO DRUM 275 LBS

LOSS IN WEIGHT FEEDER RATES

FLY ASH LOAD-OUT TON/HR	1.5 LB CAL HYPO TON FLY ASH LB/MIN	2 LB CAL HYPO TON FLY ASH LB/MIN	4 LB CAL HYPO TON FLY ASH LB/MIN	6 LB CAL HYPO TON FLY ASH LB/MIN
100	2.5	3.3	6.7	10
150	3.75	5.0	10.0	15
200	5	6.7	13.3	20
250	6.25	8.3	16.7	25
300	7.5	10.0	20.0	30



NOT FOR CONSTRUCTION

LEGEND:

AD – CALCIUM HYPOCHLORITE ADDITIVE
CP – CONTROL PANEL
CV – CHECK VALVE
DB – DAY BIN
EF – EXHAUST FAN
ES – EXISTING SILO
GM – CHLORINE GAS MONITOR
LC – LOAD CELL PACKAGE
LR – LOUVER
PG – PRESSURE GAUGE
RV – RELIEF VALVE
S – LOAD-OUT SPOUT
SC – SCREW CONVEYOR
SF – SECONDARY FILTER
SI – SCALE INDICATOR
SR – SILENCER
TS – TRUCK SCALE
VB – VACUUM BLOWER
VD – VARIABLE SPEED DRIVE
VF – VIBRATORY FEEDER

HEADWATERS RESOURCES

HEADWATERS RESOURCES, INC.
10653 S. RIVER FRONT PARKWAY
SUITE 300
SOUTH JORDAN, UT 84095
(801) 984-9400
FAX (801) 984-9419
www.headwaters.com

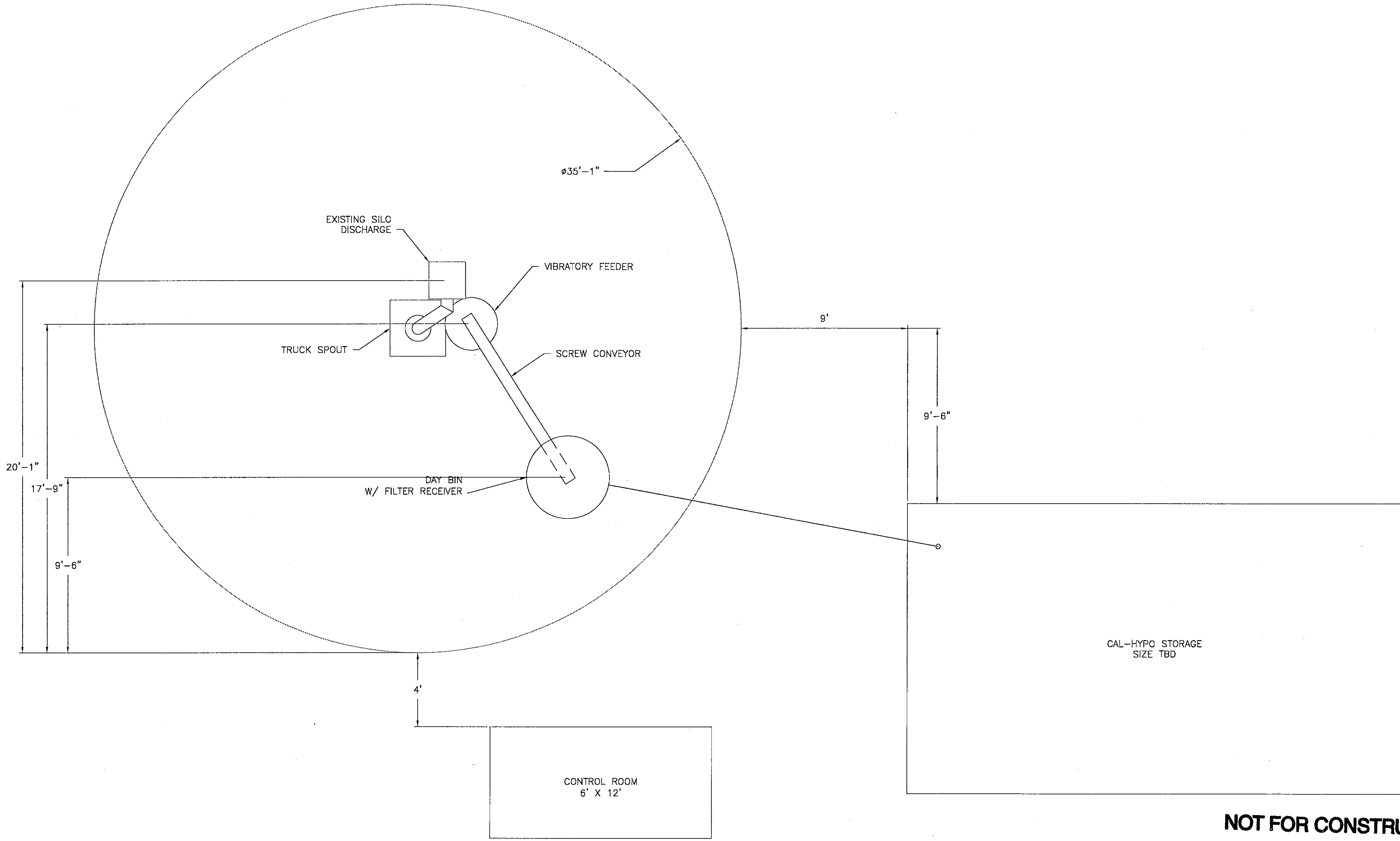
DATE	NO.	REVISION DESCRIPTION	BY
8/13/07	G	ADDED EXHAUST FAN & LOUVER	DCB
8/2/07	F	ADDED CONTROL PANELS	DCB
7/16/07	E	ADDED GAS MONITORS AND STORAGE BUILDING	DCB
5/21/07	B	GENERAL REV.	DCB

EAST LAKE AMMONIA SLIP MITIGATION PROCESS FLOW DIAGRAM

EAST LAKE, OH

SCALE: NO SCALE
DATE: 05-18-07
DESIGN BY: LS
DRAWN BY: DCB
CHECKED BY:
APPROVED BY:

SHEET NO. PF100
REVISION NO. G
PROJECT NO. R070H0



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RESOURCES

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10653 S. RIVER FRONT PARKWAY
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SOUTH JORDAN, UT 84095
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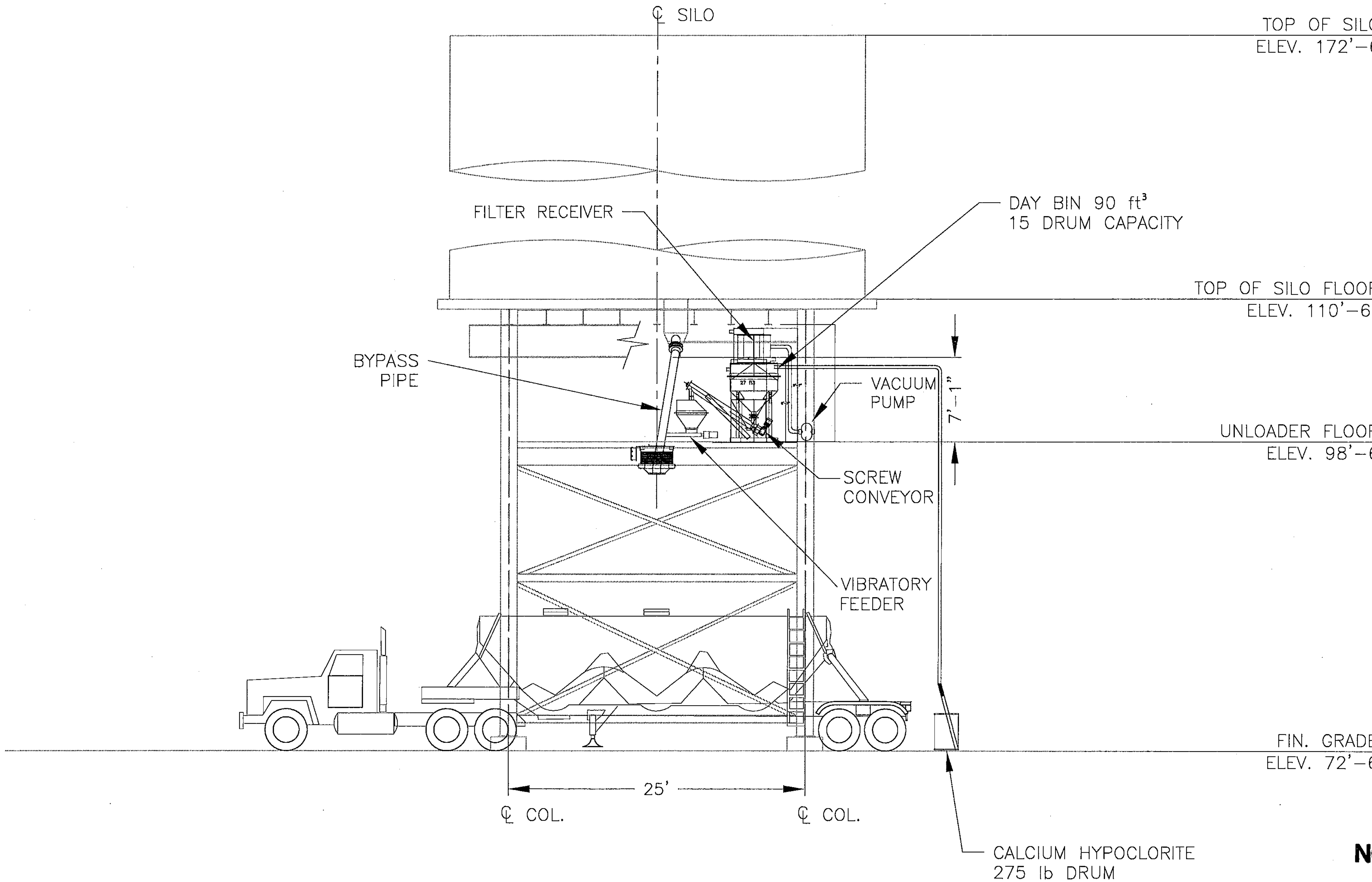
www.headwaters.com

DATE	NO.	REVISION DESCRIPTION	BY
7/18/07	A	DRAWING CREATED	DCB

EAST LAKE
AMMONIA SLIP MITIGATION
PLAN VIEW
EAST LAKE, OH

SCALE: 3/16" = 1'	
DATE: 07-18-07	
DESIGN BY:	LAS
DRAWN BY:	DCB
CHECKED BY:	
APPROVED BY:	

SHEET NO.
M100
REVISION NO.
A
PROJECT NO.
R07OH0



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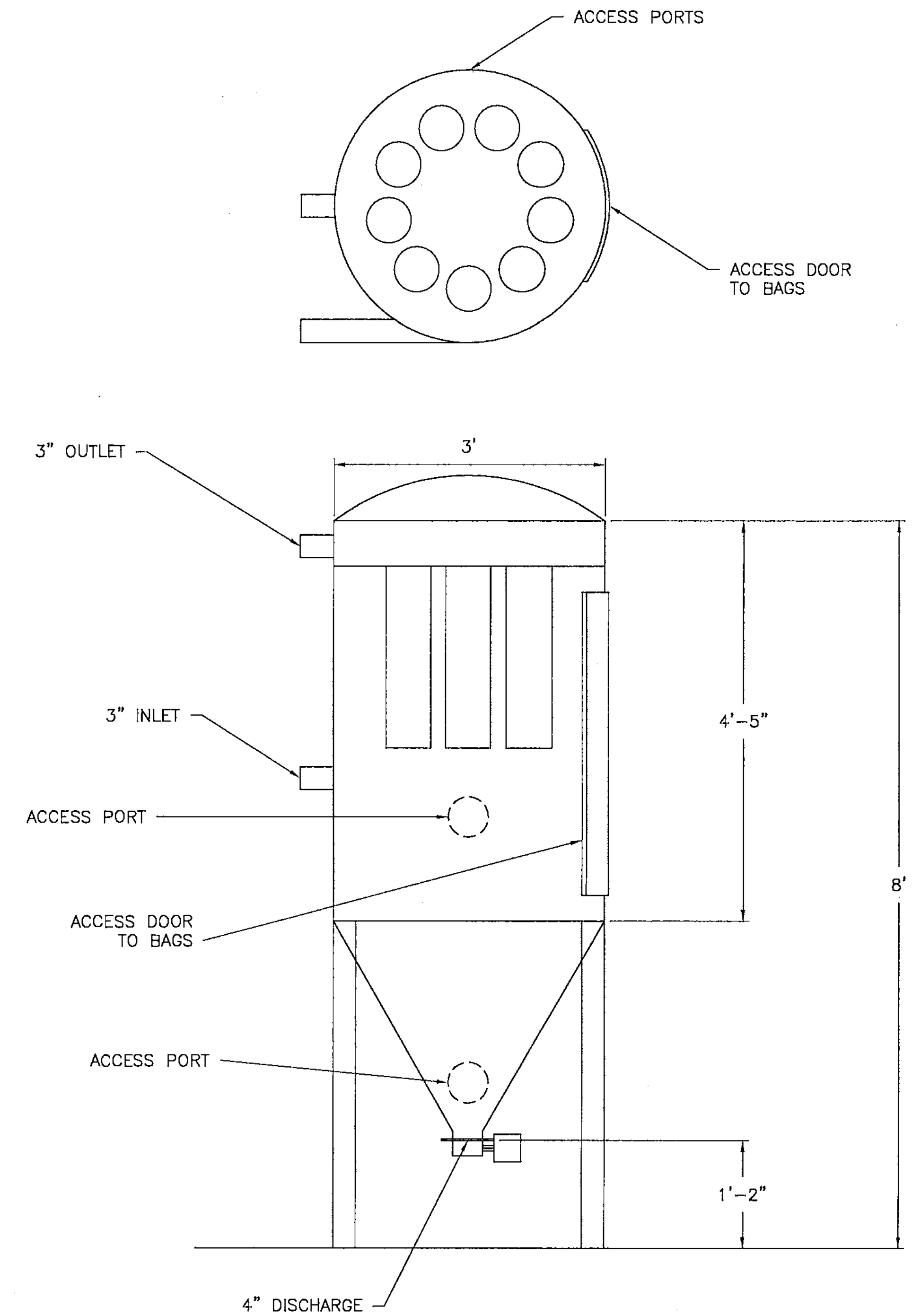
DATE	NO.	REVISION DESCRIPTION	BY
7/18/07	A	DRAWING CREATED	DCB

EAST LAKE
AMMONIA SLIP MITIGATION
ELEVATION
EAST LAKE, OH

SCALE: 1"=10'	
DATE: 07-18-07	
DESIGN BY:	LAS
DRAWN BY:	DCB
CHECKED BY:	
APPROVED BY:	

SHEET NO. M101
REVISION NO. A
PROJECT NO. R070H0



NOTE:
1. EPOXY PAINT INSIDE AND OUT
2. TOTAL CAPACITY – 17 FT^3
3. USE 2' TEFLON-COATED BAGS

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FAX (801) 984-9419
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DATE	NO.	REVISION DESCRIPTION	BY
8/6/07	B	RELOCATED ACCESS PORTS	DCB
8/3/07	A	DRAWING CREATED	DCB

EAST LAKE
AMMONIA SLIP MITIGATION
FILTER RECEIVER
EAST LAKE, OH

SCALE:	1/2" = 1'
DATE:	08-03-07
DESIGN BY:	LAS
DRAWN BY:	DCB
CHECKED BY:	
APPROVED BY:	
SHEET NO.	M200
REVISION NO.	B
PROJECT NO.	R07OH0

APPENDIX B
COST ESTIMATE DETAILS

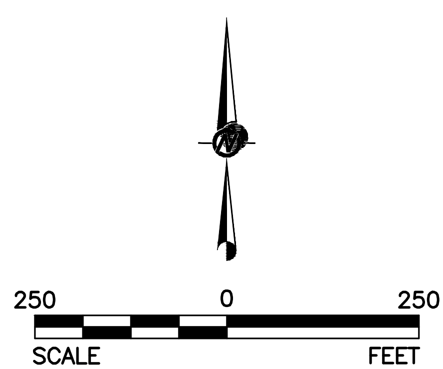
Legend

Fly Ash Stream

Calcium Hypo–Chlorite Mixing System

Notes

1. Eastlake Generating Plant has a truck loadout for both untreatable fly ash destined for disposal (silos 1 and 2) and treated fly ash (silo 4).



FOR DISCUSSION PURPOSES ONLY

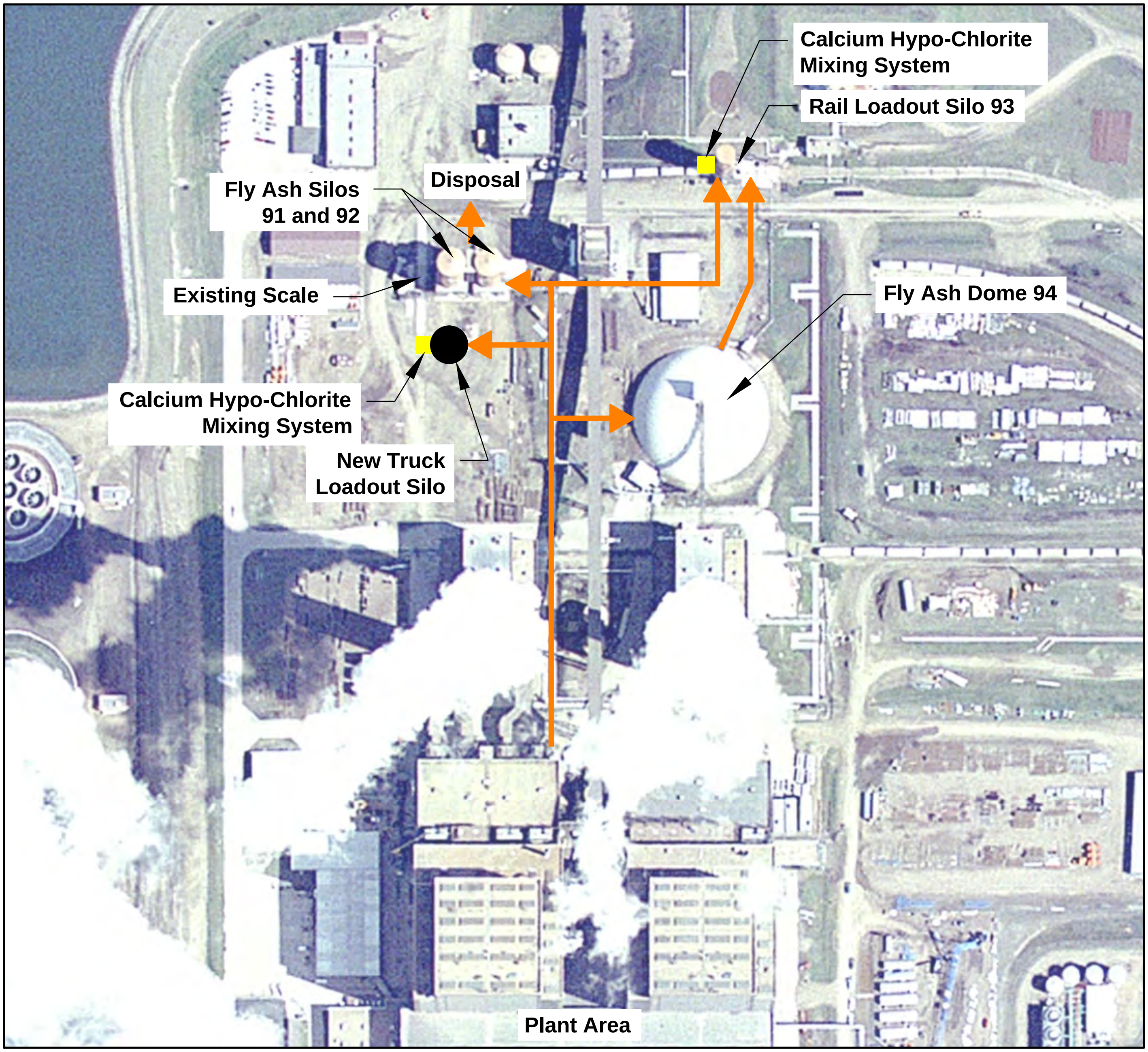
Golder Associates

Fly Ash Loadout Schematic
Eastlake Generating Plant

FIGURE 1

PROJECT No. 113–82161 CADD CCS DATE 11/1/11 FILE No. 11382161_Figures.dwg

Drawing File: J:\11JOBS\113-82161 GRE SNCR\Figures\ 11382161_Figures.dwg | Layout: Fly Ash Loadout-Eastlake | Modified: Nov 02, 2011 16:04 CSchuettpelz | Plotted: 11/02/11 4:05pm CSchuettpelz



Legend

Fly Ash Stream

Calcium Hypo–Chlorite Mixing System

Notes

1. New truck loadout silo and scale are required to store treatable fly ash for sale.
2. Two Calcium Hypo–Chlorite Mixing Systems would be required near the new truck loadout silo and the rail loadout silo (93) for treating fly ash available for sale.
3. The existing fly ash silos (91 and 92) are available to store untreatable fly ash for disposal.
4. The existing Fly Ash Dome (94) is available to store treatable fly ash for rail sale.

250 0 250
SCALE FEET

Golder Associates

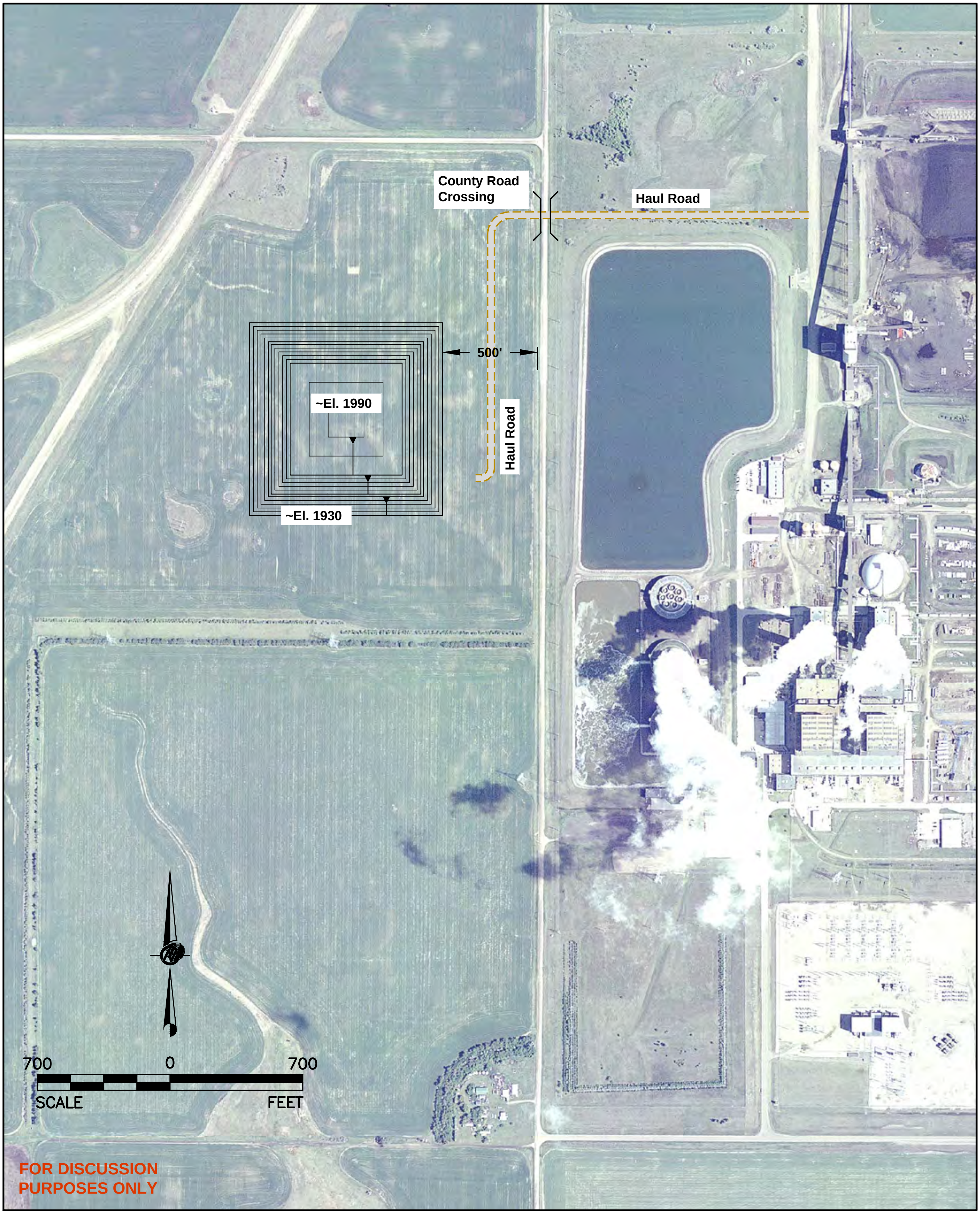
FOR DISCUSSION PURPOSES ONLY

Fly Ash Loadout Schematic Coal Creek Station

FIGURE 2

PROJECT No. 113–82161 CADD CCS DATE 11/1/11 FILE No. 11382161_Figures.dwg

Drawing File: J:\1JOBS\113-82161 GRE SNCR\Figures\ 11382161_Figures.dwg | Layout: Fly Ash Loadout-CCS | Modified: Nov 02, 2011 16:04 CSchuettpelz | Plotted: 11/02/11 4:05pm CSchuettpelz



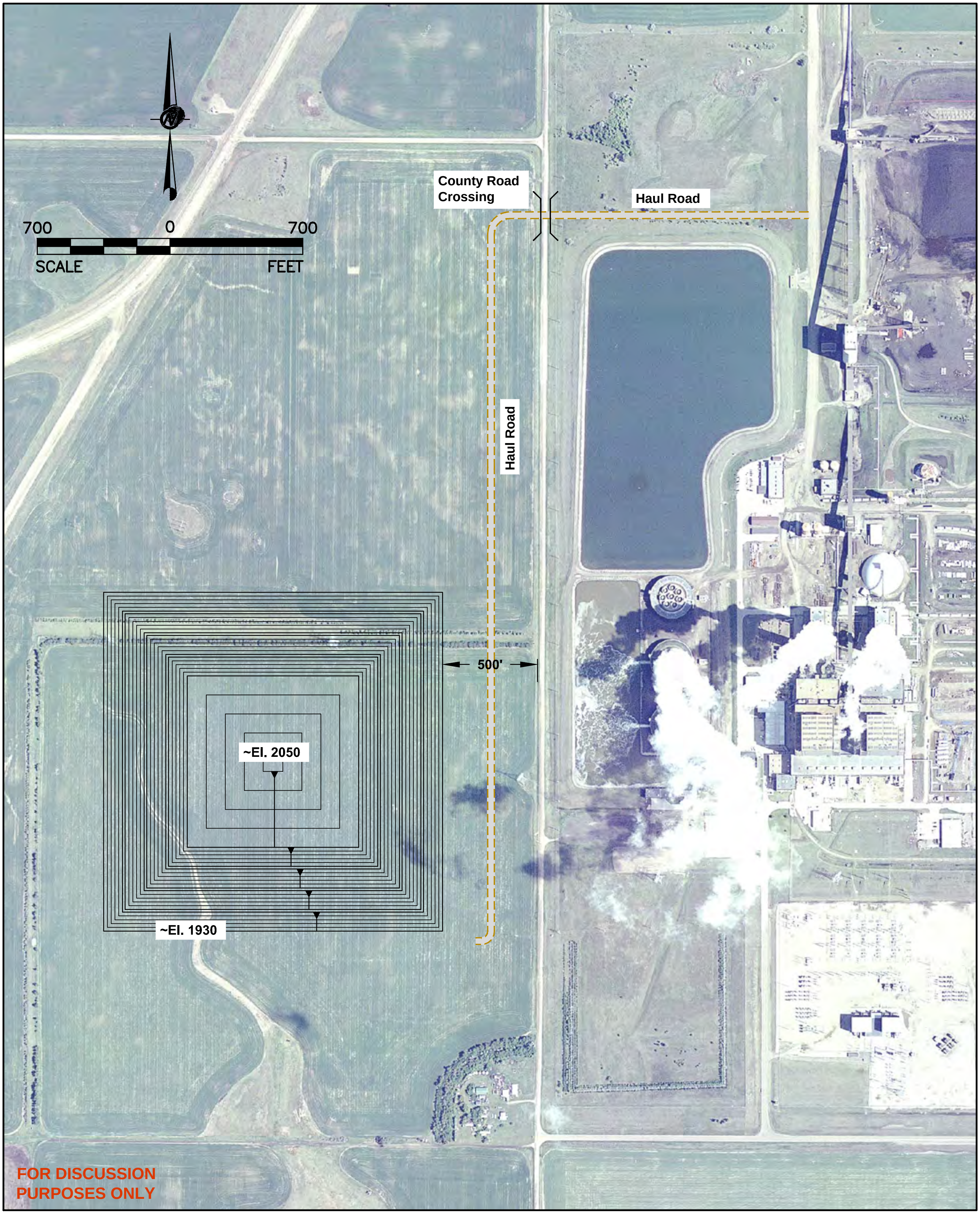
Scenario A
Fly Ash Containment Facility

Golder Associates

FIGURE 3

PROJECT No. 113-82161 CADD CCS DATE 11/1/11 FILE No. 11382161_Figures.dwg

Drawing File: J:\11JOBS\113-82161 GRE SNCR\Figures\ 11382161_Figures.dwg | Layout: Small Facility | Modified: Nov 02, 2011 16:04 CSchuettpelz | Plotted: 11/02/11 4:05pm CSchuettpelz



Scenario B
Fly Ash Containment Facility

Golder Associates

FIGURE 4

PROJECT No. 113-82161 CADD CCS DATE 11/1/11 FILE No. 11382161_Figures.dwg

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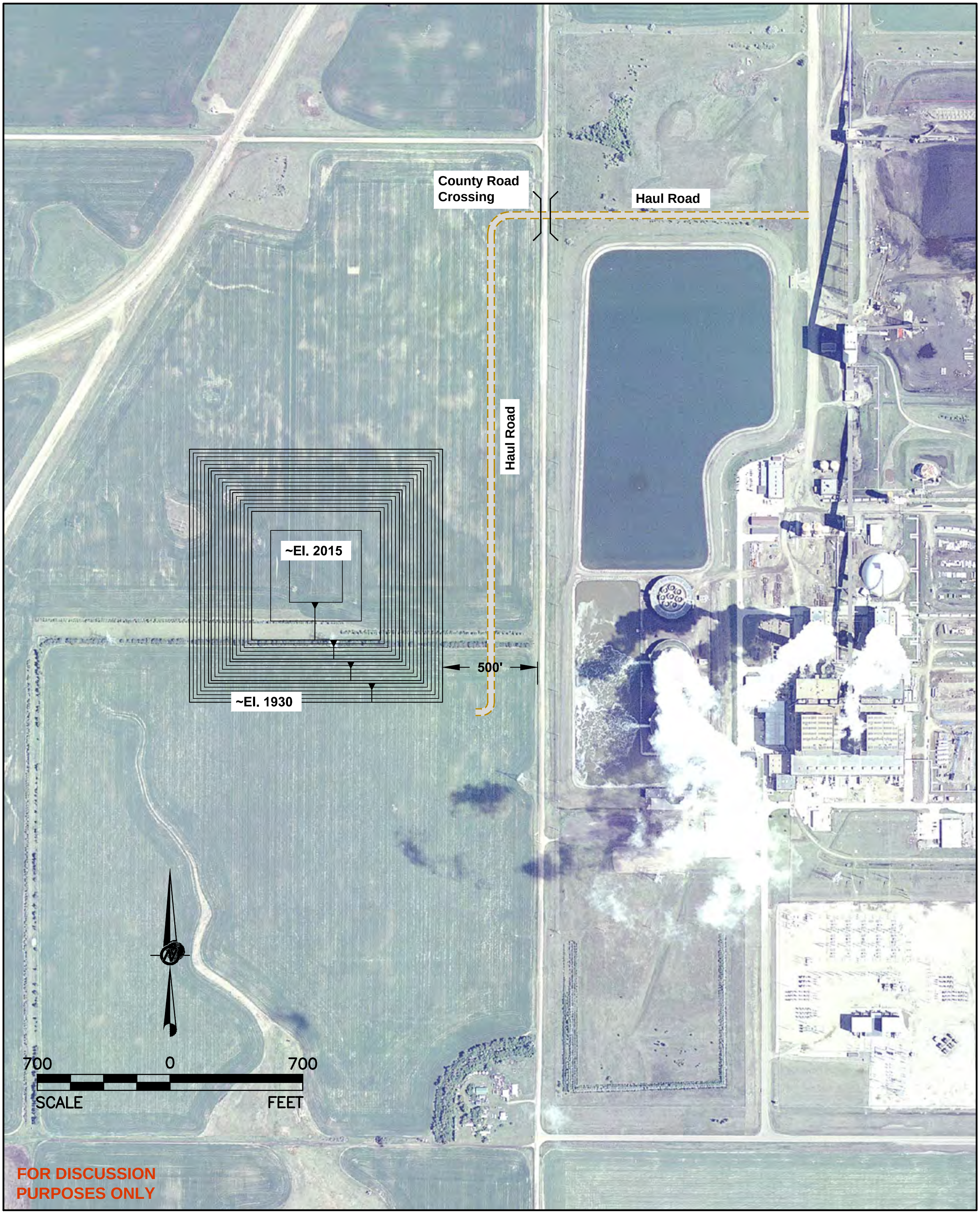


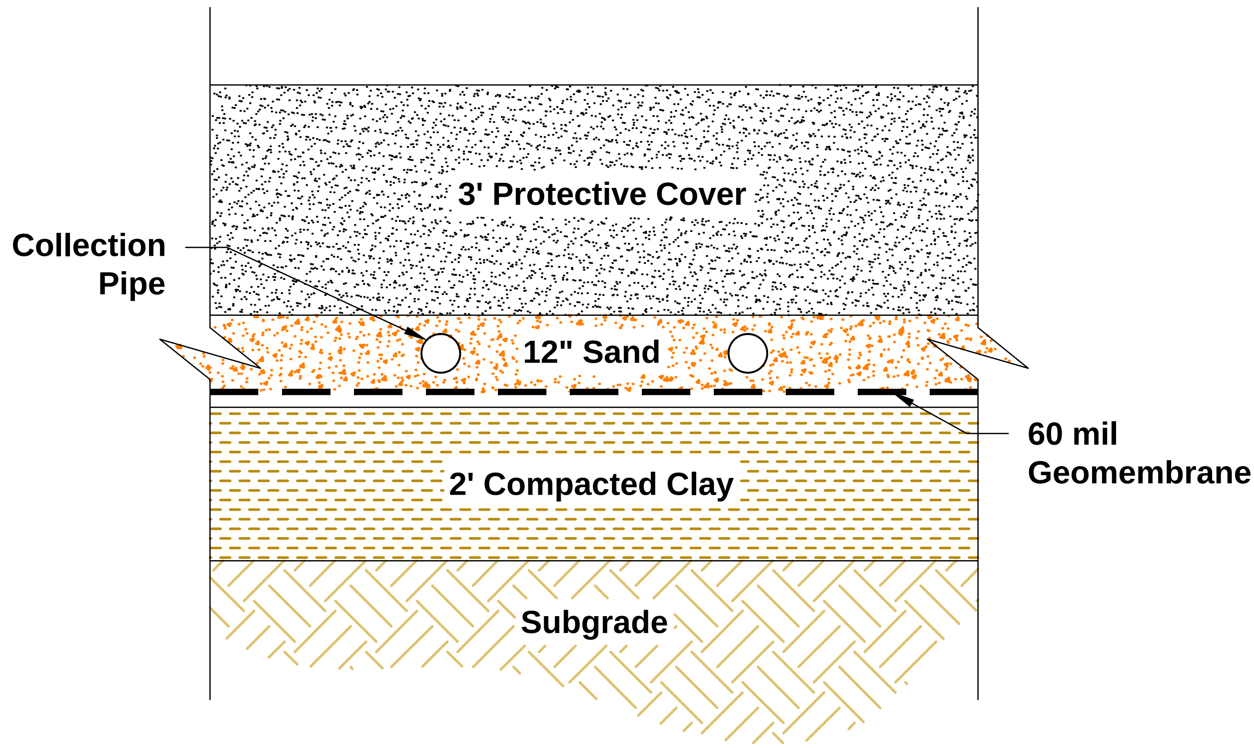
Scenario C
Fly Ash Containment Facility

Golder Associates

FIGURE 5

PROJECT No. 113-82161 CADD CCS DATE 11/1/11 FILE No. 11382161_Figures.dwg

Drawing File: J:\11JOBS\113-82161 GRE SNCR\Figures\ 11382161_Figures.dwg | Layout: Medium Facility | Modified: Nov 02, 2011 16:04 CSchuettpelz | Plotted: 11/02/11 4:05pm CSchuettpelz



FOR DISCUSSION
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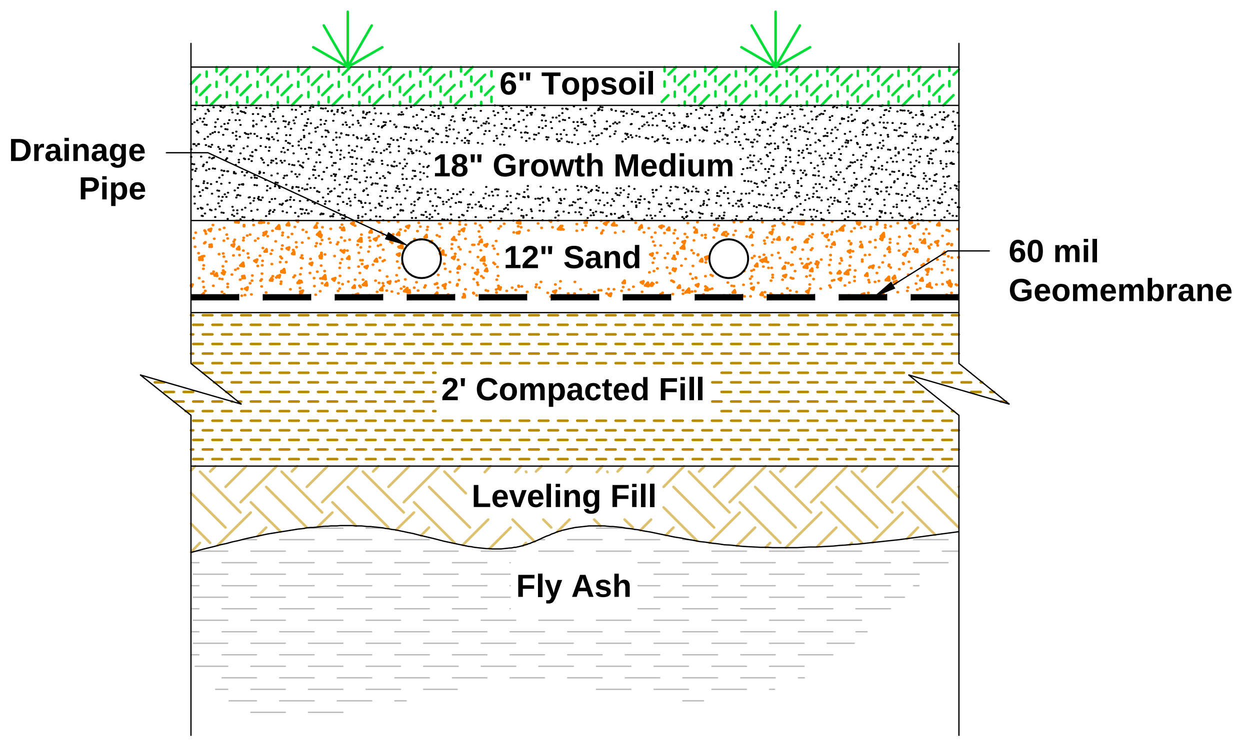
Golder Associates

Composite Liner

FIGURE 6

PROJECT No. 113-82161 CADD CCS DATE 11/1/11 FILE No. 11382161_Figures.dwg

Drawing File: J:\11JOBS\113-82161 GRE SNCR\Figures\ 11382161_Figures.dwg | Layout: Liner | Modified: Nov 02, 2011 16:04 CSchuettpelz | Plotted: 11/02/11 4:05pm CSchuettpelz



FOR DISCUSSION
PURPOSES ONLY

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Cover

FIGURE 7

PROJECT No. 113-82161 CADD CCS DATE 11/1/11 FILE No. 11382161_Figures.dwg

Drawing File: J:\11JOBS\113-82161 GRE SNCR\Figures\ 11382161_Figures.dwg | Layout: Cover | Modified: Nov 02, 2011 16:04 CSchuettpelz | Plotted: 11/02/11 4:06pm CSchuettpelz

Fly Ash Management Impact Evaluation Summary (November 15, 2011)

	Option A	Option B	Option C
	Current fly ash sales with new RCRA Subtitle D landfill	No fly ash sales with new RCRA Subtitle D landfill	ASM technology to allow reduced fly ash sales with new RCRA Subtitle D landfill
Fly Ash Quantities			
Fly Ash production (ton/yr)	525,000	525,000	525,000
Fly Ash Sales (ton/yr)	415,000	0	290,500
Fly Ash Disposal (ton/yr)	110,000	525,000	234,500
Lost Fly Ash Sales (ton/yr)	0	415,000	124,500
ASM Fly Ash Post Processing			
ASM Unit Rate Capital and O&M ($/ton sold)	$ -	$ -	$ 5.61
ASM Annual Capital and O&M ($/yr)	$ -	$ -	$ 1,629,000
Fly Ash Disposal			
Lined Footprint (acres)	24.0	73.5	41.0
Unit Rate Capital and O&M ($/ton disposed)	$ 18.06	$ 11.18	$ 13.91
Annual Capital and O&M ($/yr)	$ 1,987,000	$ 5,870,000	$ 3,262,000
Lost Fly Ash Sales			
Lost Fly Ash Sales Revenue ($/ton lost sales)	$ 12.30	$ 12.30	$ 12.30
Annual Lost Fly Ash Sales Revenue ($/yr)	$ -	$ 5,105,000	$ 1,531,000
Total (Disposal + Post Processing + Lost Sales)			
Annual Cost ($/yr)	$ 1,987,000	$ 10,975,000	$ 6,422,000
Unit Cost ($/ton produced)	$ 3.79	$ 20.91	$ 12.23
Additional Cost (Scenario B/C - Scenario A)			
Fly Ash Management Cost ($/yr)	-	$ 8,988,000	$ 4,435,000
Fly Ash Management Cost ($/ton produced)	-	$ 17.12	$ 8.45

Notes:

Capital costs annualized based on 20-year life and 5.5% interest rate.

Disposal costs based on new facility built across county road from Coal Creek Station with 20-year life.

RCRA Subtitle D type facility (composite liner, leachate collection system, and composite cover).

Disposal costs only include fly ash disposal and not facility airspace or O&M for other CCPs.

Ammonia slip mitigation costs based on existing facility site visit and historic costs for fly ash infrastructure.

All costs are in 2011 dollars.

Lost fly ash sales revenue based on expected 2011 average price per ton FOB of $43 and 30% of sale price to GRE.

Existing fly ash sales infrastructure and O&M costs are not included.

Scenario A - Current Sales

Project	113-82161
Date	11/15/2011
By	TJS
Checked	JJS

Sizing Information

Annual Fly Ash Disposal	110,000	tn	
20yr Fly Ash Disposal	2,200,000	tn	
Fly Ash Dry Density (in-situ)	90	pcf	
20yr Fly Ash Quantity	1,811,000	cy	
Lined Footprint	24.0	ac	75,000 cy/ac
Disturbance Footprint	34.5	ac	100' offset on liner footprint
Berm Length	4,240	ft	20' offset on liner footprint
Total Footprint	160		500' offset on liner footprint, nearest 1/8 section
Total Cover Area	26.5	ac	1.1 ration of cover area to liner area

Direct/Capital Costs

Item	Rate		#		Total Cost	
Land Acquisition	$ 2,000	/ac	160.0	ac	$ 320,000	
Infrastructure Development	$ 649,500	ea	1.0	LS	$ 649,500	
County Road Crossing	$ 1,730,500	ea	1.0	LS	$ 1,730,500	
Liner Construction	$ 178,300	/ac	24.0	ac	$ 4,279,200	
Final Cover Construction	$ 143,000	/ac	26.5	ac	$ 3,789,500	
Post-Closure Care	$ 50,000	/yr	30.0	yr	$ 1,500,000	
Facility Design & Permitting (on construction)	10.0%	-	$ 10,448,700	LS	$ 1,044,870	
Construction Quality Assurance (on construction)	5.0%	-	$ 10,448,700	LS	$ 522,435	
GRE Internal Costs (on construction, design, CQA, & land purchase)	10.0%	-	$ 13,836,005	-	$ 1,384,000	
Project Contingency (on construction & land)	15.0%	-	$ 10,768,700	-	$ 1,615,000	
			Total Direct/Capital Costs		$ 16,835,005	
			Annualized Capital Cost*		$ 1,409,000	/yr
			Capital Costs		$ 12.81	/tn

Operational Costs

Hauling Costs	$ 2.14	/tn	110,000	tn/yr	$ 235,469	/yr
Placement Costs	$ 1.71	/tn	110,000	tn/yr	$ 188,000	/yr
Maintenance Costs	$ 154,500	/yr	1	yr	$ 154,500	/yr
			Annual Operational Costs		$ 578,000	/yr
			Operational Costs		$ 5.26	/tn

TOTAL DISPOSAL COSTS

Annual Costs	$ 1,987,000	/yr
20-Year Total Costs	$ 39,740,000	
Per Ton Cost	$ 18.06	/tn

Notes:
*Annualized capital cost based on 20-year life and 5.5% interest rate.
All costs are in 2011 dollars.

Scenario B - No Fly Ash Sales

Project	113-82161
Date	11/15/2011
By	TJS
Checked	JJS

Sizing Information

Annual Fly Ash Disposal	525,000	tn	
20yr Fly Ash Disposal	10,500,000	tn	
Fly Ash Dry Density (in-situ)	90	pcf	
20yr Fly Ash Quantity	8,642,000	cy	
Lined Footprint	73.5	ac	118,000 cy/ac
Disturbance Footprint	91.0	ac	100' offset on liner footprint
Berm Length	7,320	ft	20' offset on liner footprint
Total Footprint	240		500' offset on liner footprint, nearest 1/8 section
Total Cover Area	81.0	ac	1.1 ration of cover area to liner area

Direct/Capital Costs

Item	Rate		#		Total Cost	
Land Acquisition	$ 2,000	/ac	240.0	ac	$ 480,000	
Infrastructure Development	$ 924,000	ea	1.0	LS	$ 924,000	
County Road Crossing	$ 1,730,500	ea	1.0	LS	$ 1,730,500	
Liner Construction	$ 174,500	/ac	73.5	ac	$ 12,825,750	
Final Cover Construction	$ 132,400	/ac	81.0	ac	$ 10,724,400	
Post-Closure Care	$ 108,500	/yr	30.0	yr	$ 3,255,000	
Facility Design & Permitting (on construction)	10.0%	-	$ 26,204,650	LS	$ 2,620,465	
Construction Quality Assurance (on construction)	5.0%	-	$ 26,204,650	LS	$ 1,310,233	
GRE Internal Costs (on construction, design, CQA, & land purchase)	10.0%	-	$ 33,870,348	-	$ 3,387,000	
Project Contingency (on construction & land)	15.0%	-	$ 26,684,650	-	$ 4,003,000	
			Total Direct/Capital Costs		$ 41,260,348	
			Annualized Capital Cost*		$ 3,453,000	/yr
			Capital Costs		$ 6.58	/tn

Operational Costs

Hauling Costs	$ 2.14	/tn	525,000	tn/yr	$ 1,123,830	/yr
Placement Costs	$ 1.71	/tn	525,000	tn/yr	$ 897,273	/yr
Maintenance Costs	$ 396,000	/yr	1	yr	$ 396,000	/yr
			An. Operational Costs		$ 2,417,000	/yr
			Operational Costs		$ 4.60	/tn

TOTAL DISPOSAL COSTS

Annual Costs	$ 5,870,000	/yr
20-Year Total Costs	$ 117,400,000	
Per Ton Cost	$ 11.18	/tn

Notes:
*Annualized capital cost based on 20-year life and 5.5% interest rate.
All costs are in 2011 dollars.

Scenario C - Partial Fly Ash Sales with ASM

Project	113-82161
Date	11/15/2011
By	TJS
Checked	JJS

Sizing Information

Annual Fly Ash Disposal	234,500	tn	
20yr Fly Ash Disposal	4,690,000	tn	
Fly Ash Dry Density (in-situ)	90	pcf	
20yr Fly Ash Quantity	3,860,000	cy	
Lined Footprint	41.0	ac	94,000 cy/ac
Disturbance Footprint	54.0	ac	100' offset on liner footprint
Berm Length	5,500	ft	20' offset on liner footprint
Total Footprint	160		500' offset on liner footprint, nearest 1/8 section
Total Cover Area	45.0	ac	1.1 ration of cover area to liner area

Direct/Capital Costs

Item	Rate		#		Total Cost	
Land Acquisition	$ 2,000	/ac	160.0	ac	$ 320,000	
Infrastructure Development	$ 779,500	ea	1.0	LS	$ 779,500	
County Road Crossing	$ 1,730,500	ea	1.0	LS	$ 1,730,500	
Liner Construction	$ 175,600	/ac	41.0	ac	$ 7,199,600	
Final Cover Construction	$ 138,500	/ac	45.0	ac	$ 6,232,500	
Post-Closure Care	$ 72,500	/yr	30.0	yr	$ 2,175,000	
Facility Design & Permitting (on construction)	10.0%	-	$ 15,942,100	LS	$ 1,594,210	
Construction Quality Assurance (on construction)	5.0%	-	$ 15,942,100	LS	$ 797,105	
GRE Internal Costs (on construction, design, CQA, & land purchase)	10.0%	-	$ 20,828,415	-	$ 2,083,000	
Project Contingency (on construction & land)	15.0%	-	$ 16,262,100	-	$ 2,439,000	
			Total Direct/Capital Costs		$ 25,350,415	
			Annualized Capital Cost*		$ 2,121,000	/yr
			Capital Costs		$ 9.05	/tn

Operational Costs

Hauling Costs	$ 2.14	/tn	234,500	tn/yr	$ 501,977	/yr
Placement Costs	$ 1.71	/tn	234,500	tn/yr	$ 400,782	/yr
Maintenance Costs	$ 238,500	/yr	1	yr	$ 238,500	/yr
			An. Operational Costs		$ 1,141,000	/yr
			Operational Costs		$ 4.87	/tn

TOTAL DISPOSAL COSTS

Annual Costs	$ 3,262,000	/yr
20-Year Total Costs	$ 65,240,000	
Per Ton Cost	$ 13.91	/tn

Notes:
*Annualized capital cost based on 20-year life and 5.5% interest rate.
All costs are in 2011 dollars.

ASM Post-Processing

Project	113-82161
Date	11/15/2011
By	REN
Checked	TJS

Sizing Information

Annual Fly Ash Sales 290,500 tn

Direct/Capital Costs

Item	Rate		#		Total Cost	
New Truck Load-out Silo	$ 1,568,500	ea	1.0	LS	$ 1,568,500	
Cal-Hypo Feed Systems (Rail silo)	$ 246,000	ea	1.0	LS	$ 246,000	
Cal-Hypo Feed Systems (New silo)	$ 328,500	ea	1.0	LS	$ 328,500	
System Design & Engineering (on construction)	10.0%	-	$ 2,143,000	-	$ 214,000	
GRE Internal Costs (on all)	10.0%	-	$ 2,357,000	-	$ 236,000	
Project Contingency (on construction)	15.0%	-	$ 2,143,000	-	$ 321,000	
			Total Direct/Capital Costs		$ 2,914,000	
			Annualized Capital Cost*		$ 244,000	/yr
			Capital Costs		$ 0.84	/tn

Operational Costs

Maintenance	$ 75.00	$/hr	4,600	hr	$ 345,000	/yr
Maintenance Materials	50%	-	$ 345,000	-	$ 172,500	/yr
Operations Materials	$ 75.00	$/hr	5,750	hr	$ 431,250	/yr
Operations Materials (Cal-Hypo)	$ 0.50	/tn	290,500	tn/yr	$ 145,250	/yr
Technology Royalty	$ 1.00	/tn	290,500	tn/yr	$ 290,500	/yr
			An. Operational Costs		$ 1,385,000	/yr
			Operational Costs		$ 4.77	/tn

TOTAL ASM COSTS

Annual Costs	$ 1,629,000	/yr
20-Year Total Costs	$ 32,580,000	
Per Ton Cost	$ 5.61	/tn

Notes:

*Annualized capital cost based on 20-year life and 5.5% interest rate.
Capital costs based on previous silo construction and discussions with Headwaters.
Assumed calcium hypo-chlorite cost of $1.00/lb.
Calcium hypo-chlorite mix rate is estimated between 0.3 and 1.3 lbs per 3,000 lbs of fly ash.

Scenario A (Current Sales) Unit Rate Details

PROJECT COMPONENT		QTY	UNIT	UNIT PRICE	TOTAL	Source	NOTES
Infrastructure Development				Total	$ 649,325	$ 649,500	
General							
	Mobilize/Demobilize	5%	%	$ -	$ 29,515		
	Miscellaneous Site Work & Materials	5%	%	$ -	$ 29,515		Erosion controls, offices, toilets, temporary roads, survey control, etc.
Civil							
	Road Topsoil Stripping and Stockpiling	7,778	CY	$ 2.21	$ 17,181	Ames 2005 construction bid	18" topsoil
	Access Road Construction	140,000	SF	$ 1.55	$ 217,101	RSMeans 2010 (01 55 23.50-0100)	8" Gravel temporary road ($13.55/SY = $1.51/sf), 4,000' x 35'
	Return Water Pipeline	2,640	LF	$ 41.52	$ 109,622	RSMeans 2008 (33 11 13.25-4160)	6" PVC, 3' deep
	Fence	8,090	LF	$ 23.66	$ 191,391	GRE Estimate	7' Chain link fence, GRE paid $22.30/ft in 2009
	Overhead Power (Plant to Landfill)	1	EA	$ 25,000	$ 25,000	Golder Estimate	$25,000 for 1/2 mile distribution w/ transformer
	Monitoring Well Installation	5	EA	$ 6,000	$ 30,000	Golder Estimate	
County Road Crossing				Total	$ 1,730,693	$ 1,730,500	
General							
	Mobilize/Demobilize	5%	%	$ -	$ 78,668		
	Misc. (erosion controls, toilets, etc)	5%	%	$ -	$ 78,668		Erosion controls, offices, toilets, temporary roads, survey control, etc.
Civil							
	Topsoil Stripping and Stockpiling	4,577	CY	$ 2.21	$ 10,111	Ames 2005 construction bid	18" topsoil
	Embankment Fill	35,591	CY	$ 3.59	$ 127,906	Northern 2006 construction bid	
	County Road Sub-Base Course	2,385	CY	$ 3.59	$ 8,572	Northern 2006 construction bid	2' Sub-base preparation
	County Road Base Course	32,200	SF	$ 1.55	$ 49,933	RSMeans 2010 (01 55 23.50-0100)	8" Gravel temporary road ($13.55/SY = $1.51/sf) 920' x35'
	Bridge Deck Construction	5,250	SF	$ 262	$ 1,376,836	2008 California DOT Average	150 ft bridge deck, 35 ft wide
Liner Construction				Total	$ 4,278,853	Cost Per Acre of Liner	$ 178,300
General							
	Mobilize/Demobilize	5%	%	$ -	$ 194,493		
	Miscellaneous Site Work & Materials	5%	%	$ -	$ 194,493		Erosion controls, offices, toilets, temporary roads, survey control, etc.
Civil							
	Clearing and Grubbing	35	AC	$ 6,077.00	$ 209,657	RSMeans 2010 (31 11 10.10-0200)	Clear & grub brush including stumps
	Topsoil Stripping & Stockpiling (18")	-	CY	$ 2.21		Ames 2005 construction bid	
		35	AC	$ 5,346	$ 184,429		
	Subgrade Cut to Stockpile	291,093	CY	$ 3.00	$ 873,280	Golder Estimate	10' across liner area: for liner, berms and cover
	Subgrade Cut/Embankment Fill	96,107	CY	$ 3.59	$ 345,383	Northern 2006 construction bid	612 ft2 cross section area
	Low Permeability Soil Liner (24")	-	CY	$ 4.32		Northern 2008 construction bid	
		24	AC	$ 13,927	$ 334,252		
	60-mil HDPE Liner	-	SF	$ 0.76		Northern 2008 construction bid	materials, waste, conformance testing, installation
		24	AC	$ 33,319	$ 799,666		
	Leachate Collection Layer, Sand (12")		CY	$ 25.00		Golder Estimate	
		24	AC	$ 40,333	$ 968,000		
	Protective Cover (3')	-	CY	$ 4.04		Northern 2008 construction bid	fly ash as protective cover
		6	AC	$ 19,569	$ 117,411		contractor place 25% (side slopes, haul routes)
Piping							
	LCS 4" Piping	4,475	LF	$ 5.25	$ 23,472	Northern 2008 construction bid	4" ADS N-12
	LCS 8" Piping	900	LF	$ 12.02	$ 10,818	Northern 2008 construction bid	8" ADS N-12
	LCS Sump/Riser	1	EA	$ 17,314	$ 17,314	Northern 2005 construction bid	
Equipment and Electrical							
	Power Posts at Pumps/Sumps	1	EA	$ 1,185	$ 1,185	RSMeans 2010 (26 24 16.30-0150)	Panelboard/utility box with outlets
	Collection pump	1	EA	$ 5,000	$ 5,000	Golder Estimate	

Scenario A (Current Sales) Unit Rate Details

PROJECT COMPONENT	QTY	UNIT	UNIT PRICE	TOTAL	Source	NOTES
Final Cover			Total	$ 3,790,408	Cost Per Acre of Cover	$ 143,000
General						
Mobilize/Demobilize	5%	%	$ -	$ 172,291		
Miscellaneous Site Work & Materials	5%	%	$ -	$ 172,291		Erosion controls, offices, toilets, temporary roads, survey control, etc.
Civil						
Leveling Fill (6") & Compacted Fill (24")	-	CY	$ 3.59		Northern 2006 construction bid	
	27	AC	$ 14,495	$ 384,112		
60-mil HDPE Liner	-	SF	$ 0.76		Northern 2008 construction bid	materials, waste, conformance testing, installation
	27	AC	$ 33,319	$ 882,965		
Leachate Collection Layer, Sand (12")		CY	$ 25.00		Golder Estimate	
	27	AC	$ 40,333	$ 1,068,833		
Growth Medium (18")		CY	$ 4.92		Northern 2010 construction bid	
	27	AC	$ 11,915	$ 315,738		
Topsoil (6")		CY	$ 4.92		Same as Growth Medium	
	27	AC	$ 3,972	$ 105,246		
Downchute Channels	57,600	SF	$ 10.82	$ 622,944	Northern 2010 construction bid	36' wide, 4 downchutes
Seed and Mulch	27	AC	$ 2,490.11	$ 65,988	RSMeans 2010 (32 92 19.14-4600)	Slope mix, with mulch & fertilizer
Post Closure Care			Total	$ 50,020	$ 50,000	
Groundwater Monitoring & Reporting	1	EA	$ 15,000	$ 15,000	Golder Estimate	$1,000 per well + $10,000 for the report
Annual Site Inspection	1	EA	$ 1,060	$ 1,060	Golder Estimate	$1,000 per 25 acres
Final Cover Repair	1	EA	$ 4,210	$ 4,210	Golder Estimate	2% of cover area, 12" growth medium/topsoil fill
Seeding Repair	1	EA	$ 6,600	$ 6,600	Golder Estimate	10% of cover area
Mowing and/or rodent, weed, & tree control	1	EA	$ 2,120	$ 2,120	Golder Estimate	$2,000 per 25 acres
Surface Water Controls Maintenance	1	EA	$ 12,230	$ 12,230	Golder Estimate	1% of armored channel replaced + other repairs
Gate and/or fence Maintenance	1	EA	$ 1,910	$ 1,910	Golder Estimate	1% of fence
Recordkeeping	1	EA	$ 1,590	$ 1,590	Golder Estimate	$1,500 per 25 acres
Direct Expenses	1	EA	$ 5,300	$ 5,300	Golder Estimate	$5,000 per 25 acres
Annual Operations & Maintenance Costs (not haul and place)			Total	$ 154,710	$ 154,500	
Groundwater Monitoring & Reporting	1	EA	$ 15,000	$ 15,000	Golder Estimate	$1,000 per well + $10,000 for the report
Annual Site Inspection	1	EA	$ 12,000	$ 12,000	Golder Estimate	$1,000 per 25 acres of liner per month
Engineering Support	1	EA	$ 48,000	$ 48,000	Golder Estimate	$50,000 per 25 acres of liner
Survey Control	1	EA	$ 25,000	$ 25,000	Golder Estimate	GPS unit(s), $25,000 per year
Gate and/or fence Maintenance	1	EA	$ 1,910	$ 1,910	Golder Estimate	1% of fence
Recordkeeping	1	EA	$ 4,800	$ 4,800	Golder Estimate	$5,000 per 25 acres
Misc Work (contact water, dust, erosion, grading, etc)	1	EA	$ 48,000	$ 48,000	Golder Estimate	$50,000 per 25 acres
Haul & Place Costs						
Haul Cost	1	CY	$ 2.14	$ 2.14	RSMeans 2010 (32 23 23.20-8180)	60cy Off-road, 20 min wait, 15 mph, 2 mile cycle
Haul Cost	1	TON	$ 2.14	$ 2.14	Golder Estimate	75pcf haul density (1 ton/cy)
Place Cost	1	CY	$ 1.42	$ 1.42	RSMeans 2010 (31 23 23.17-0020)	Dozer, no compaction
Place Cost	1	TON	$ 1.71	$ 1.71	Golder Estimate	90pcf placed density (1.2 ton/cy)

Scenario B (No Sales) Unit Rate Details

PROJECT COMPONENT	QTY	UNIT	UNIT PRICE	TOTAL	Source	NOTES
Infrastructure Development			Total	$ 924,006	$ 924,000	
General						
Mobilize/Demobilize	5%	%	$ -	$ 42,000		
Miscellaneous Site Work & Materials	5%	%	$ -	$ 42,000		Erosion controls, offices, toilets, temporary roads, survey control, etc.
Civil						
Road Topsoil Stripping and Stockpiling	11,667	CY	$ 2.21	$ 25,772	Ames 2005 construction bid	18" topsoil
Access Road Construction	210,000	SF	$ 1.55	$ 325,652	RSMeans 2010 (01 55 23.50-0100)	8" Gravel temporary road ($13.55/SY = $1.51/sf), 6,000' x 35'
Return Water Pipeline	2,640	LF	$ 41.52	$ 109,622	RSMeans 2008 (33 11 13.25-4160)	6" PVC, 3' deep
Fence	11,157	LF	$ 23.66	$ 263,960	GRE Estimate	7' Chain link fence, GRE paid $22.30/ft in 2009
Overhead Power (Plant to Landfill)	1	EA	$ 25,000	$ 25,000	Golder Estimate	$25,000 for 1/2 mile distribution w/ transformer
Monitoring Well Installation	15	EA	$ 6,000	$ 90,000	Golder Estimate	
County Road Crossing			Total	$ 1,730,693	$ 1,730,500	
General						
Mobilize/Demobilize	5%	%	$ -	$ 78,668		
Misc. (erosion controls, toilets, etc)	5%	%	$ -	$ 78,668		Erosion controls, offices, toilets, temporary roads, survey control, etc.
Civil						
Topsoil Stripping and Stockpiling	4,577	CY	$ 2.21	$ 10,111	Ames 2005 construction bid	18" topsoil
Embankment Fill	35,591	CY	$ 3.59	$ 127,906	Northern 2006 construction bid	
County Road Sub-Base Course	2,385	CY	$ 3.59	$ 8,572	Northern 2006 construction bid	2' Sub-base preparation
County Road Base Course	32,200	SF	$ 1.55	$ 49,933	RSMeans 2010 (01 55 23.50-0100)	8" Gravel temporary road ($13.55/SY = $1.51/sf) 920' x35'
Bridge Deck Construction	5,250	SF	$ 262	$ 1,376,836	2008 California DOT Average	150 ft bridge deck, 35 ft wide
Liner Construction			Total	$ 12,827,387	Cost Per Acre of Liner	$ 174,500
General						
Mobilize/Demobilize	5%	%	$ -	$ 583,063		
Miscellaneous Site Work & Materials	5%	%	$ -	$ 583,063		Erosion controls, offices, toilets, temporary roads, survey control, etc.
Civil						
Clearing and Grubbing	91	AC	$ 6,077.00	$ 553,007	RSMeans 2010 (31 11 10.10-0200)	Clear & grub brush including stumps
Topsoil Stripping & Stockpiling (18")	-	CY	$ 2.21		Ames 2005 construction bid	
	91	AC	$ 5,346	$ 486,465		
Subgrade Cut to Stockpile	1,019,880	CY	$ 3.00	$ 3,059,640	Golder Estimate	10' across liner area: for liner, berms and cover
Subgrade Cut/Embankment Fill	165,920	CY	$ 3.59	$ 596,275	Northern 2006 construction bid	612 ft2 cross section area
Low Permeability Soil Liner (24")	-	CY	$ 4.32		Northern 2008 construction bid	
	74	AC	$ 13,927	$ 1,023,647		
60-mil HDPE Liner	-	SF	$ 0.76		Northern 2008 construction bid	materials, waste, conformance testing, installation
	74	AC	$ 33,319	$ 2,448,978		
Leachate Collection Layer, Sand (12")		CY	$ 25.00		Golder Estimate	
	74	AC	$ 40,333	$ 2,964,500		
Protective Cover (3')	-	CY	$ 4.04		Northern 2008 construction bid	fly ash as protective cover
	18	AC	$ 19,569	$ 359,572		contractor place 25% (side slopes, haul routes)
Piping						
LCS 4" Piping	15,640	LF	$ 5.25	$ 82,033	Northern 2008 construction bid	4" ADS N-12
LCS 8" Piping	3,340	LF	$ 12.02	$ 40,147	Northern 2008 construction bid	8" ADS N-12
LCS Sump/Riser	2	EA	$ 17,314	$ 34,628	Northern 2005 construction bid	
Equipment and Electrical						
Power Posts at Pumps/Sumps	2	EA	$ 1,185	$ 2,369	RSMeans 2010 (26 24 16.30-0150)	Panelboard/utility box with outlets
Collection pump	2	EA	$ 5,000	$ 10,000	Golder Estimate	

Scenario B (No Sales) Unit Rate Details

PROJECT COMPONENT		QTY	UNIT	UNIT PRICE	TOTAL	Source	NOTES
Final Cover				Total	$ 10,724,703	Cost Per Acre of Cover	$ 132,400
General							
	Mobilize/Demobilize	5%	%	$ -	$ 487,486		
	Miscellaneous Site Work & Materials	5%	%	$ -	$ 487,486		Erosion controls, offices, toilets, temporary roads, survey control, etc.
Civil							
	Leveling Fill (6") & Compacted Fill (24")	-	CY	$ 3.59		Northern 2006 construction bid	
		81	AC	$ 14,495	$ 1,174,078		
	60-mil HDPE Liner	-	SF	$ 0.76		Northern 2008 construction bid	materials, waste, conformance testing, installation
		81	AC	$ 33,319	$ 2,698,874		
	Leachate Collection Layer, Sand (12")		CY	$ 25.00		Golder Estimate	
		81	AC	$ 40,333	$ 3,267,000		
	Growth Medium (18")		CY	$ 4.92		Northern 2010 construction bid	
		81	AC	$ 11,915	$ 965,085		
	Topsoil (6")		CY	$ 4.92		Same as Growth Medium	
		81	AC	$ 3,972	$ 321,695		
	Downchute Channels	103,680	SF	$ 10.82	$ 1,121,299	Northern 2010 construction bid	36' wide, 4 downchutes
	Seed and Mulch	81	AC	$ 2,490.11	$ 201,699	RSMeans 2010 (32 92 19.14-4600)	Slope mix, with mulch & fertilizer
Post Closure Care				Total	$ 108,670	$ 108,500	
	Groundwater Monitoring & Reporting	1	EA	$ 25,000	$ 25,000	Golder Estimate	$1,000 per well + $10,000 for the report
	Annual Site Inspection	1	EA	$ 3,240	$ 3,240	Golder Estimate	$1,000 per 25 acres
	Final Cover Repair	1	EA	$ 12,870	$ 12,870	Golder Estimate	2% of cover area, 12" growth medium/topsoil fill
	Seeding Repair	1	EA	$ 20,170	$ 20,170	Golder Estimate	10% of cover area
	Mowing and/or rodent, weed, & tree control	1	EA	$ 6,480	$ 6,480	Golder Estimate	$2,000 per 25 acres
	Surface Water Controls Maintenance	1	EA	$ 17,210	$ 17,210	Golder Estimate	1% of armored channel replaced + other repairs
	Gate and/or fence Maintenance	1	EA	$ 2,640	$ 2,640	Golder Estimate	1% of fence
	Recordkeeping	1	EA	$ 4,860	$ 4,860	Golder Estimate	$1,500 per 25 acres
	Direct Expenses	1	EA	$ 16,200	$ 16,200	Golder Estimate	$5,000 per 25 acres
Annual Operations & Maintenance Costs (not haul and place)				Total	$ 396,140	$ 396,000	
	Groundwater Monitoring & Reporting	1	EA	$ 25,000	$ 25,000	Golder Estimate	$1,000 per well + $10,000 for the report
	Annual Site Inspection	1	EA	$ 34,800	$ 34,800	Golder Estimate	$1,000 per 25 acres of liner per month
	Engineering Support	1	EA	$ 147,000	$ 147,000	Golder Estimate	$50,000 per 25 acres of liner
	Survey Control	1	EA	$ 25,000	$ 25,000	Golder Estimate	GPS unit(s), $25,000 per year
	Gate and/or fence Maintenance	1	EA	$ 2,640	$ 2,640	Golder Estimate	1% of fence
	Recordkeeping	1	EA	$ 14,700	$ 14,700	Golder Estimate	$5,000 per 25 acres
	Misc Work (contact water, dust, erosion, grading, etc)	1	EA	$ 147,000	$ 147,000	Golder Estimate	$50,000 per 25 acres
Haul & Place Costs							
	Haul Cost	1	CY	$ 2.14	$ 2.14	RSMeans 2010 (32 23 23.20-8180)	60cy Off-road, 20 min wait, 15 mph, 2 mile cycle
	Haul Cost	1	TON	$ 2.14	$ 2.14	Golder Estimate	75pcf haul density (1 ton/cy)
	Place Cost	1	CY	$ 1.42	$ 1.42	RSMeans 2010 (31 23 23.17-0020)	Dozer, no compaction
	Place Cost	1	TON	$ 1.71	$ 1.71	Golder Estimate	90pcf placed density (1.2 ton/cy)

Scenario C (Reduced Sales with ASM) Unit Rate Details

PROJECT COMPONENT		QTY	UNIT	UNIT PRICE	TOTAL	Source	NOTES
Infrastructure Development				Total	$ 779,431	$ 779,500	
General							
	Mobilize/Demobilize	5%	%	$ -	$ 35,429		
	Miscellaneous Site Work & Materials	5%	%	$ -	$ 35,429		Erosion controls, offices, toilets, temporary roads, survey control, etc.
Civil							
	Road Topsoil Stripping and Stockpiling	9,722	CY	$ 2.21	$ 21,476	Ames 2005 construction bid	18" topsoil
	Access Road Construction	175,000	SF	$ 1.55	$ 271,376	RSMeans 2010 (01 55 23.50-0100)	8" Gravel temporary road ($13.55/SY = $1.51/sf), 5,000' x 35'
	Return Water Pipeline	2,640	LF	$ 41.52	$ 109,622	RSMeans 2008 (33 11 13.25-4160)	6" PVC, 3' deep
	Fence	9,346	LF	$ 23.66	$ 221,099	GRE Estimate	7' Chain link fence, GRE paid $22.30/ft in 2009
	Overhead Power (Plant to Landfill)	1	EA	$ 25,000	$ 25,000	Golder Estimate	$25,000 for 1/2 mile distribution w/ transformer
	Monitoring Well Installation	10	EA	$ 6,000	$ 60,000	Golder Estimate	
County Road Crossing				Total	$ 1,730,693	$ 1,730,500	
General							
	Mobilize/Demobilize	5%	%	$ -	$ 78,668		
	Misc. (erosion controls, toilets, etc)	5%	%	$ -	$ 78,668		Erosion controls, offices, toilets, temporary roads, survey control, etc.
Civil							
	Topsoil Stripping and Stockpiling	4,577	CY	$ 2.21	$ 10,111	Ames 2005 construction bid	18" topsoil
	Embankment Fill	35,591	CY	$ 3.59	$ 127,906	Northern 2006 construction bid	
	County Road Sub-Base Course	2,385	CY	$ 3.59	$ 8,572	Northern 2006 construction bid	2' Sub-base preparation
	County Road Base Course	32,200	SF	$ 1.55	$ 49,933	RSMeans 2010 (01 55 23.50-0100)	8" Gravel temporary road ($13.55/SY = $1.51/sf) 920' x35'
	Bridge Deck Construction	5,250	SF	$ 262	$ 1,376,836	2008 California DOT Average	150 ft bridge deck, 35 ft wide
Liner Construction				Total	$ 7,200,075	Cost Per Acre of Liner	$ 175,600
General							
	Mobilize/Demobilize	5%	%	$ -	$ 327,276		
	Miscellaneous Site Work & Materials	5%	%	$ -	$ 327,276		Erosion controls, offices, toilets, temporary roads, survey control, etc.
Civil							
	Clearing and Grubbing	54	AC	$ 6,077.00	$ 328,158	RSMeans 2010 (31 11 10.10-0200)	Clear & grub brush including stumps
	Topsoil Stripping & Stockpiling (18")	-	CY	$ 2.21		Ames 2005 construction bid	
		54	AC	$ 5,346	$ 288,672		
	Subgrade Cut to Stockpile	536,800	CY	$ 3.00	$ 1,610,400	Golder Estimate	10' across liner area: for liner, berms and cover
	Subgrade Cut/Embankment Fill	124,667	CY	$ 3.59	$ 448,021	Northern 2006 construction bid	612 ft2 cross section area
	Low Permeability Soil Liner (24")	-	CY	$ 4.32		Northern 2008 construction bid	
		41	AC	$ 13,927	$ 571,014		
	60-mil HDPE Liner	-	SF	$ 0.76		Northern 2008 construction bid	materials, waste, conformance testing, installation
		41	AC	$ 33,319	$ 1,366,097		
	Leachate Collection Layer, Sand (12")		CY	$ 25.00		Golder Estimate	
		41	AC	$ 40,333	$ 1,653,667		
	Protective Cover (3')	-	CY	$ 4.04		Northern 2008 construction bid	fly ash as protective cover
		10	AC	$ 19,569	$ 200,578		contractor place 25% (side slopes, haul routes)
Piping							
	LCS 4" Piping	7,770	LF	$ 5.25	$ 40,754	Northern 2008 construction bid	4" ADS N-12
	LCS 8" Piping	1,220	LF	$ 12.02	$ 14,664	Northern 2008 construction bid	8" ADS N-12
	LCS Sump/Riser	1	EA	$ 17,314	$ 17,314	Northern 2005 construction bid	
Equipment and Electrical							
	Power Posts at Pumps/Sumps	1	EA	$ 1,185	$ 1,185	RSMeans 2010 (26 24 16.30-0150)	Panelboard/utility box with outlets
	Collection pump	1	EA	$ 5,000	$ 5,000	Golder Estimate	

Scenario C (Reduced Sales with ASM) Unit Rate Details

PROJECT COMPONENT	QTY	UNIT	UNIT PRICE	TOTAL	Source	NOTES
Final Cover			Total	$ 6,232,264	Cost Per Acre of Cover	$ 138,500
General						
Mobilize/Demobilize	5%	%	$ -	$ 283,285		
Miscellaneous Site Work & Materials	5%	%	$ -	$ 283,285		Erosion controls, offices, toilets, temporary roads, survey control, etc.
Civil						
Leveling Fill (6") & Compacted Fill (24")	-	CY	$ 3.59		Northern 2006 construction bid	
	45	AC	$ 14,495	$ 652,266		
60-mil HDPE Liner	-	SF	$ 0.76		Northern 2008 construction bid	materials, waste, conformance testing, installation
	45	AC	$ 33,319	$ 1,499,374		
Leachate Collection Layer, Sand (12")		CY	$ 25.00		Golder Estimate	
	45	AC	$ 40,333	$ 1,815,000		
Growth Medium (18")		CY	$ 4.92		Northern 2010 construction bid	
	45	AC	$ 11,915	$ 536,158		
Topsoil (6")		CY	$ 4.92		Same as Growth Medium	
	45	AC	$ 3,972	$ 178,719		
Downchute Channels	80,640	SF	$ 10.82	$ 872,122	Northern 2010 construction bid	36' wide, 4 downchutes
Seed and Mulch	45	AC	$ 2,490.11	$ 112,055	RSMeans 2010 (32 92 19.14-4600)	Slope mix, with mulch & fertilizer
Post Closure Care			Total	$ 72,390	$ 72,500	
Groundwater Monitoring & Reporting	1	EA	$ 20,000	$ 20,000	Golder Estimate	$1,000 per well + $10,000 for the report
Annual Site Inspection	1	EA	$ 1,800	$ 1,800	Golder Estimate	$1,000 per 25 acres
Final Cover Repair	1	EA	$ 7,150	$ 7,150	Golder Estimate	2% of cover area, 12" growth medium/topsoil fill
Seeding Repair	1	EA	$ 11,210	$ 11,210	Golder Estimate	10% of cover area
Mowing and/or rodent, weed, & tree control	1	EA	$ 3,600	$ 3,600	Golder Estimate	$2,000 per 25 acres
Surface Water Controls Maintenance	1	EA	$ 14,720	$ 14,720	Golder Estimate	1% of armored channel replaced + other repairs
Gate and/or fence Maintenance	1	EA	$ 2,210	$ 2,210	Golder Estimate	1% of fence
Recordkeeping	1	EA	$ 2,700	$ 2,700	Golder Estimate	$1,500 per 25 acres
Direct Expenses	1	EA	$ 9,000	$ 9,000	Golder Estimate	$5,000 per 25 acres
Annual Operations & Maintenance Costs (not haul and place)			Total	$ 238,610	$ 238,500	
Groundwater Monitoring & Reporting	1	EA	$ 20,000	$ 20,000	Golder Estimate	$1,000 per well + $10,000 for the report
Annual Site Inspection	1	EA	$ 19,200	$ 19,200	Golder Estimate	$1,000 per 25 acres of liner per month
Engineering Support	1	EA	$ 82,000	$ 82,000	Golder Estimate	$50,000 per 25 acres of liner
Survey Control	1	EA	$ 25,000	$ 25,000	Golder Estimate	GPS unit(s), $25,000 per year
Gate and/or fence Maintenance	1	EA	$ 2,210	$ 2,210	Golder Estimate	1% of fence
Recordkeeping	1	EA	$ 8,200	$ 8,200	Golder Estimate	$5,000 per 25 acres
Misc Work (contact water, dust, erosion, grading, etc)	1	EA	$ 82,000	$ 82,000	Golder Estimate	$50,000 per 25 acres
Haul & Place Costs						
Haul Cost	1	CY	$ 2.14	$ 2.14	RSMeans 2010 (32 23 23.20-8180)	60cy Off-road, 20 min wait, 15 mph, 2 mile cycle
Haul Cost	1	TON	$ 2.14	$ 2.14	Golder Estimate	75pcf haul density (1 ton/cy)
Place Cost	1	CY	$ 1.42	$ 1.42	RSMeans 2010 (31 23 23.17-0020)	Dozer, no compaction
Place Cost	1	TON	$ 1.71	$ 1.71	Golder Estimate	90pcf placed density (1.2 ton/cy)

ASM Unit Rate Details

PROJECT COMPONENT	QTY	UNIT OF MEASURE	UNIT PRICE	TOTAL	Source	NOTES
New Silo			Total	$ 1,568,494	$ 1,568,500	
Miscellaneous Site Work & Materials	10%	%	$ -	$ 142,590		Erosion controls, offices, toilets, temporary roads, survey control, etc.
Silo slab on grade	1	EA	$ 536,796	$ 536,796	2003 Irondale CO Unit less RR & land	Site prep, silo & handling equipment, permit
Starvac reclaimer	1	EA	$ 83,455	$ 83,455		
Truck scale	1	EA	$ 81,474	$ 81,474		Beside the silo on grade
Screw conveyor	1	EA	$ 24,626	$ 24,626		From Starvac reclaimer to bucket elevator
Bucket Elevator	1	EA	$ 88,927	$ 88,927		From screw conveyor to overhead airslide
Air Slide	1	EA	$ 26,906	$ 26,906		From bucket elevator to new weigh hopper
Truck load-out spout	1	EA	$ 45,604	$ 45,604		From new weigh hopper to truck
Building	1	EA	$ 11,401	$ 11,401		With scales and ASM controls
Feed piping & valves	1	EA	$ 329,202	$ 329,202	Golder Estimate	From each of the four fly ash conveying lines
Dust collectors	1	EA	$ 197,512	$ 197,512	Golder Estimate	Higher capacity to handle high air flow from ESP
Cal-Hypo Feed System (Rail Load-out Silo)			Total	$ 245,960	$ 246,000	
Miscellaneous Site Work & Materials	10%	%	$ -	$ 22,360		
Storage & Conveying Building	1,000	SF	$ 50.00	$ 50,000	GRE 2009 Construction Project	$35/sf for large insulated bldg, use $50/sf
Building Foundation	62	CY	$ 300.00	$ 18,600	Worley Parsons Jul09	12' x 40' x 1' thick plus 1' x 5' perimeter
Day Storage Hopper	1	EA	$ 15,000	$ 15,000	Golder Estimate	On the silo weigh bin floor
Conveying System	1	EA	$ 20,000	$ 20,000	Golder Estimate	From stroage building to the day storage hopper
Variable speed conveyor	1	EA	$ 20,000	$ 20,000	Golder Estimate	To feed cal-hypo into the existing weigh hopper
ASM System Controls	1	EA	$ 100,000	$ 100,000	Golder Estimate	
Cal-Hypo Feed System (New Truck Load-out Silo)			Total	$ 328,460	$ 328,500	
Miscellaneous Site Work & Materials	10%	%	$ -	$ 29,860		
Weigh Hopper	1	EA	$ 75,000	$ 75,000	Golder Estimate	Above truck load-out spout
Storage & Conveying Building	1,000	SF	$ 50.00	$ 50,000	GRE 2009 Construction Project	$35/sf for large insulated bldg, use $50/sf for 25'x40
Building Foundation	62	CY	$ 300.00	$ 18,600	Worley Parsons Jul09	25' x 40' x 1' thick plus 1' x 5' perimeter
Day Storage Hopper	1	EA	$ 15,000	$ 15,000	Golder Estimate	On the silo weigh bin floor
Conveying System	1	EA	$ 20,000	$ 20,000	Golder Estimate	From stroage building to the day storage hopper
Variable speed conveyor	1	EA	$ 20,000	$ 20,000	Golder Estimate	To feed cal-hypo into the existing weigh hopper
ASM System Controls	1	EA	$ 100,000	$ 100,000	Golder Estimate	

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Appendix D

Visibility Impact Tables

Summary of Modeling Inputs

Description		Emission Rate Input									
		Stack Velocity	PM10		PM2.5 (fine)	PM (coarse)	SO_2		NOx		
NOx Control	Units	m/s (ft/s)	% reduction	lb/hr	lb/hr	lb/hr	% reduction	lb/hr	% reduction	lb/hr	30-Day Rolling lb/MMBtu
Pre-BART Protocol	1	25.9 (85)	NA - base	249.2	101.9	147.3	NA - base	5733.5	NA - base	1772.3	NA - base
	1& 2	25.9 (85)	NA - base	465.3	190.3	275.0	NA - base	10702.8	NA - base	3594.7	NA - base
LNC3+	1	16.8(55)	0%	249.2	101.9	147.3	69%	1756.4	31%	1227.6	0.19
	1& 2	16.8(55)	0%	465.3	190.3	275.0	67%	3514.8	32%	2456.5	0.19
LNC3+ with Tuning	1	16.8(55)	0%	249.2	101.9	147.3	69%	1756.4	39%	1083.1	0.17
	1& 2	16.8(55)	0%	465.3	190.3	275.0	67%	3514.8	40%	2167.5	0.17
SNCR	1	16.8(55)	0%	249.2	101.9	147.3	69%	1756.4	49%	902.6	0.14
	1 & 2	16.8(55)	0%	465.3	190.3	275.0	67%	3514.8	50%	1806.3	0.14
SNCR with LNC3+	1	16.8(55)	0%	249.2	101.9	147.3	69%	1756.4	56%	776.2	0.12
	1& 2	16.8(55)	0%	465.3	190.3	275.0	67%	3514.8	57%	1553.4	0.12

Year 2000 Modeling Results

Description			Visibility Impairment											
			TRNP South Unit			TRNP North Unit			TRNP Elkhorn Ranch			Lostwood WA		
NOx Control	Units	Average Improv-ement	Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV	Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV	Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV	Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV
Pre-BART Protocol	1	--	24	0.299	1.229	21	0.318	0.941	18	0.212	0.777	37	0.503	1.183
	1& 2	--	41	0.553	2.176	41	0.586	1.836	35	0.401	1.391	58	0.945	2.157
LNC3+	1	59%	7	0.125	0.494	6	0.124	0.446	2	0.088	0.314	7	0.215	0.499
	1& 2	59%	17	0.217	0.860	16	0.235	0.959	10	0.186	0.596	28	0.376	0.954
LNC3+ with Tuning	1	61%	7	0.119	0.467	6	0.118	0.416	2	0.082	0.300	6	0.207	0.469
	1& 2	56%	18	0.251	0.970	18	0.245	0.909	11	0.175	0.627	29	0.426	0.983
SNCR	1	86%	0	0.041	0.157	0	0.042	0.138	0	0.029	0.103	1	0.069	0.166
	1 & 2	86%	5	0.080	0.310	4	0.083	0.290	2	0.056	0.209	3	0.140	0.326
SNCR with LNC3+	1	65%	6	0.106	0.410	6	0.105	0.352	2	0.072	0.270	4	0.180	0.417
	1& 2	58%	17	0.235	0.918	17	0.236	0.860	10	0.163	0.605	26	0.409	0.924

Year 2001 Modeling Results

Description		Average Improv-ement	Visibility Impairment											
			TRNP South Unit			TRNP North Unit			TRNP Elkhorn Ranch			Lostwood WA		
NOx Control	Units		Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV	Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV	Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV	Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV
Pre-BART Protocol	1	--	21	0.251	1.209	27	0.372	1.154	16	0.192	1.056	40	0.503	1.183
	1& 2	--	34	0.466	2.181	46	0.694	2.094	27	0.365	1.949	56	0.945	2.157
LNC3+	1	58%	8	0.116	0.509	9	0.142	0.547	8	0.076	0.505	21	0.215	0.499
	1& 2	56%	19	0.230	0.986	25	0.282	1.069	14	0.151	0.984	34	0.215	0.499
LNC3+ with Tuning	1	60%	7	0.108	0.482	8	0.136	0.512	6	0.076	0.473	18	0.207	0.469
	1& 2	58%	19	0.214	0.936	24	0.270	1.002	13	0.151	0.923	33	0.207	0.469
SNCR	1	62%	7	0.101	0.453	7	0.133	0.467	4	0.074	0.433	16	0.192	0.486
	1 & 2	60%	19	0.202	0.884	21	0.267	0.917	12	0.147	0.847	33	0.192	0.486
SNCR with LNC3+	1	64%	6	0.096	0.437	6	0.127	0.436	4	0.069	0.405	15	0.180	0.417
	1& 2	62%	18	0.194	0.854	20	0.253	0.858	12	0.137	0.793	31	0.180	0.417

Year 2002 Modeling Results

Description		Average Improv-ement	Visibility Impairment											
			TRNP South Unit			TRNP North Unit			TRNP Elkhorn Ranch			Lostwood WA		
NOx Control	Units		Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV	Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV	Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV	Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV
Pre-BART Protocol	1	--	38	0.540	2.559	30	0.385	2.113	23	0.310	1.703	32	0.385	1.814
	1& 2	--	50	0.971	4.475	45	0.706	3.557	42	0.581	3.039	45	0.707	3.190
LNC3+	1	57%	22	0.219	1.181	15	0.158	0.987	12	0.136	0.789	13	0.178	0.832
	1& 2	54%	32	0.433	2.218	26	0.313	1.880	18	0.269	1.524	26	0.350	1.601
LNC3+ with Tuning	1	59%	20	0.207	1.140	15	0.151	0.918	12	0.129	0.746	13	0.165	0.783
	1& 2	56%	32	0.410	2.145	26	0.298	1.755	18	0.256	1.443	25	0.325	1.510
SNCR	1	63%	20	0.193	1.088	14	0.138	0.850	11	0.123	0.692	12	0.148	0.722
	1 & 2	60%	32	0.382	2.055	24	0.273	1.601	17	0.243	1.342	24	0.292	1.397
SNCR with LNC3+	1	64%	20	0.186	1.052	14	0.131	0.813	11	0.118	0.654	11	0.141	0.680
	1& 2	61%	30	0.371	1.991	24	0.260	1.536	17	0.234	1.271	23	0.279	1.318

Average Incremental Control Comparison for 98th % Δ-dV

Description		Year 2000			Year 2001			Year 2002			Year 2000-2002 Average		
NOx Control	Units	Average Impairment	Improvement from Protocol	Incremental Improvement	Average Impairment	Improvement from Protocol	Incremental Improvement	Average Impairment	Improvement from Protocol	Incremental Improvement	Average Impairment	Improvement from Protocol	Incremental Improvement
Pre-BART Protocol	1	1.033	NA	NA	1.151	NA	NA	2.047	NA	NA	1.410	NA	NA
	1& 2	1.890	NA	NA	2.095	NA	NA	3.565	NA	NA	2.517	NA	NA
LNC3+	1	0.438	0.594	0.594	0.515	0.636	0.636	0.947	1.100	1.100	0.634	0.777	0.777
	1& 2	0.842	1.048	1.048	0.885	1.211	1.211	1.806	1.760	1.760	1.178	1.339	1.339
LNC3+ with Tuning	1	0.413	0.620	0.025	0.484	0.667	0.031	0.897	1.151	0.051	0.598	0.812	0.036
	1& 2	0.872	1.018	-0.030	0.833	1.263	0.052	1.713	1.852	0.093	1.139	1.378	0.038
SNCR	1	0.141	0.892	0.272	0.460	0.691	0.024	0.838	1.209	0.059	0.480	0.931	0.118
	1 & 2	0.284	1.606	0.589	0.784	1.312	0.049	1.599	1.967	0.115	0.889	1.628	0.251
SNCR with LNC3+	1	0.362	0.670	-0.221	0.424	0.727	0.036	0.800	1.248	0.038	0.529	0.882	-0.049
	1& 2	0.827	1.063	-0.543	0.731	1.365	0.053	1.529	2.036	0.070	1.029	1.488	-0.140

GREAT RIVER ENERGY®

A Touchstone Energy® Cooperative

Coal Creek Station Units 1 and 2

Best Available Retrofit Technology Refined Analysis for NOx Emissions

November 2011

Coal Creek Station BART Supplemental Analysis for NOx Emissions

November 2011

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1.0 Introduction

In December 2007, GRE submitted its final Best Available Retrofit Technology (BART) evaluation for Regional Haze controls to the North Dakota Department of Health (NDDH). The NDDH incorporated the proposed emission limitations for Coal Creek Station (CCS) Units 1 and 2 into their proposed State Implementation Plan (SIP), and issued a draft Permit-to-Construct (PTC) for these BART limits. As part of their review on North Dakota's draft and final SIP, EPA requested supplemental data and documentation on Coal Creek's BART controls. These requests started in February 2010, and continued through June 2011 and July 2011. GRE provided the requested information.

On September 21, 2011, EPA proposed a Federal Implementation Plan (FIP), which would override certain NDDH determinations, particularly with respect to required NOx controls for certain coal-fired utility units. On November 3, 2011, NDDH requested that GRE provide a supplemental BART analysis that is focused on NOx control options at Coal Creek Station. In particular, GRE has performed more refined analyses on selective non-catalytic reduction (SNCR) cost assumptions, achievable control levels and the overall impacts to ash re-use on Coal Creek's Units 1 and 2.

Based on these refined analyses, Great River Energy still asserts that use of its state-of-the-art coal drying technology, DryFining™, in conjunction with second generation combustion control low NOx burners with separated overfire air (LNC3+), meets EPA's presumptive BART NOx limit of 0.17 lb/mmBtu, and is consistent with cost effective thresholds, as set by North Dakota and ultimately approved by EPA through their partial approval of the North Dakota SIP. When all factors are adequately considered including, most importantly, ammoniated ash impacts, SNCR is not considered cost effective for Coal Creek and would not result in perceptible visibility improvements in the affected Class I areas.

This refined analysis summarized updated SNCR cost and emission assessment provided by URS Energy and Construction (URS). It also provides an updated ash implication assessment as provided by Golder Associates (Golder). The updated ash implications are then integrated with the updated SNCR cost and emission estimates to more accurately demonstrate that SNCR is not cost effective, by either EPA established thresholds or NDDH established thresholds.

1.1 Initial BART Analysis and EPA Guidance

In preparing the initial BART analysis and subsequent revisions, Great River Energy developed a combination of detailed engineering and screening level analyses, which were ultimately used by NDDH to make their BART determinations. From the BART preamble, EPA sets presumptive levels based on their cost effective assessments and deciview reductions, and essentially rule out post combustion NOx controls for electric generating units greater than 750MW, subject to the state's determination. Great River Energy's screening level analyses on SNCR and ash impacts initially supported EPA's presumptive determination. Great River Energy continues to concur with EPA's establishment of a presumptive NOx emission limit at 0.17 lb/mmBtu.

Specifically, in its final rule publication of 40 CFR Part 51, Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations, EPA establishes presumptive NOx levels based on combustion controls, and not SNCR:

> *In today's action, EPA is setting presumptive NOx limits for EGUs larger than 750 MW. EPA's analysis indicates that the large majority of the units can meet these presumptive limits at relatively low costs. Because of differences in individual boilers, however, there may be situations where the use of such controls would not be technically feasible and/or cost-effective. For example, certain boilers may lack adequate space between the burners and before the furnace exit to allow for the installation of over-fire air controls. Our presumption accordingly may not be appropriate for all sources. As noted, the NOx limits set forth here today are presumptions only in making a BART determination, <u>States have the ability to consider the specific characteristics of the source at issue and to find that the presumptive limits would not be appropriate for that source.</u>* (emphasis added)
>
> *For all types of boilers other than cyclone units, the limits in Table 2 are based on the use of current combustion control technology. Current combustion control technology is generally, but not always, more cost-effective than post-combustion controls such as SCRs. For cyclone boilers, SCRs were found to be more cost-effective than current combustion control technology; thus the NOx limits for cyclone units are set based on using SCRs. SNCRs are generally not cost-effective except in very limited applications and therefore were not included in EPA's analysis. The types of current combustion control technology options assumed include low NOx burners, over-fire air, and coal reburning.*

> *We are establishing presumptive NOx limits in the guidelines that we have determined are cost-effective for most units for the different categories of units below, based on our analysis of the expected costs and performance of controls on BART-eligible units greater than 200 MW. We assumed that coal-fired EGUs would have space available to install separated over-fire air. Based on the large number of units of various boiler designs that have installed separated over-fire air, we believe this assumption to be reasonable. It is possible, however, that some EGUs may not have adequate space available. In such cases, other NOx combustion control technologies could be considered such as Rotating Opposed Fire Air (''ROFA''). The limits provided were chosen at levels that approximately 75 percent of the units could achieve with current combustion control technology. The costs of such controls in most cases range from just over $100 to $1000 per ton. Based on our analysis, however, we concluded that approximately 25 percent of the units could not meet these limits with current combustion control technology. However, our analysis indicates that all but a very few of these units could meet the presumptive limits using advanced combustion controls such as rotating opposed fire air (''ROFA''), which has already been demonstrated on a variety of coal-fired units. Based on the data before us, the costs of such controls in most cases are less than $1500 per ton.* (emphasis added)
>
> *The advanced combustion control technology we used in our analysis, ROFA, is recently available and has been demonstrated on a variety of unit types. It can achieve significantly lower NOx emission rates than conventional over-fire air and has been installed on a variety of coal-fired units including T-fired and wall-fired units. We expect that not only will sources have gained experience with and improved the performance of the ROFA technology by the time units are required to comply with any BART requirements, but that more refinements in combustion control technologies will likely have been developed by that time. As a result, we believe our analysis and conclusions regarding NOx limits are conservative. For those units that cannot meet the presumptive limits using current combustion control technology, States should carefully consider the use of advanced combustion controls such as ROFA in their BART determination* (emphasis added).[1]

There are several key concepts from EPA's preamble. First, Coal Creek is unique in that it has installed DryFining™, as a novel multi-pollutant control technology. This is important because it enhances the effectiveness of the NOx combustion controls. Second, Coal Creek re-uses the vast

[1] Federal Register / Vol. 70, No. 128 / Wednesday, July 6, 2005 / Page 39134-39135.

majority of fly ash rather than disposing of it. Any negative impacts to fly ash such as adding ammonia, will have both operational risks, and cost implications for Great River Energy that must be included in any cost-effectiveness determination. Third, EPA has made its cost-effectiveness determination in setting presumptive BART NOx levels and has given states the ability to determine if more stringent requirements are needed based on their review.

In reviewing EPA's preamble discussion, it was clear to GRE that the EPA did not expect BART control scenarios for tangentially-fired units, such as Coal Creek Station's Units 1 and 2, to include post combustion add-on controls such as selective catalytic reduction (SCR) and SNCR. As such, in the initial BART evaluation, GRE focused on supporting this determination through the use of screening level cost data, and comparing those screening costs to cost effectiveness thresholds.

Based on the direction provided in the BART preamble and guidance, along with an analysis of cost effectiveness thresholds implemented in other EPA regulatory programs[2], GRE proposed a cost effectiveness range of $1,300 to $1,800 per ton of NOx removed. Guidance provided by NDDH presented higher cost per ton thresholds than EPA's in setting the presumptive level.

GRE's BART NOx determination for CCS Units 1 and 2 was consistent with EPA's preamble and confirmed that advanced combustion controls and an emission limit of 0.17 lb/mmBtu represented BART. SNCR was found to be cost ineffective based on screening level analysis, and presented additional operational and non-environmental impacts that were not exhaustively discussed in the December 2007 BART analysis but are provided herein.

2.0 Refined NOx Control Evaluation at CCS

This section will first establish that Coal Creek is unique, requiring site specific evaluations rather than relying on general screening level assumptions to determine emission reductions and associated costs. It will then summarize the evaluation of site specific SNCR NOx reductions by URS, as well as ash impacts from the ammonia associated with this control..

[2] http://www.ndhealth.gov/AQ/RegionalHaze/Regional%20Haze%20Link%20Documents/Appendix%20C/Coal%20Creek/Coal%20Creek%20BART%20Analysis.pdf (Appendix B).

2.1 Unique Aspects of Unit 1 and 2 NOx Controls

As discussed in the following sections, Coal Creek Station is neither average nor typical. EPA Guidelines, provided to States in identifying appropriate Regional Haze control requirements and provided in EPA's Pollution Control Cost Manual (2002), are developed in order to assist State authorities in making regulatory determinations. These guidelines are not to be viewed as regulatory requirements. They are best suited for evaluating average or typical installations. Units 1 and 2 are uniquely designed and employ a state-of-the-art lignite fuel enhancement technology, or DryFining™. This means that any accurate analysis of add-on NOx controls must be site specific and not rely upon general guidelines, which might apply to a normal facility.

2.1.1 DryFining™ Technology

GRE has a long track record of being innovative and going beyond minimum environmental requirements. DryFining™ is a $270 million, multi-pollutant technology. It reduces coal moisture and impurities while increasing the heat content of Fort Union lignite, which has the highest moisture of any coal in the US. The operation of DryFining™ has afforded CCS Units 1 and 2 significant reductions across the spectrum of emissions. Sulfur dioxide and mercury emissions have been reduced by more than 40%. Carbon dioxide emissions have been reduced by 4%. NOx emissions – the subject of the EPA FIP and this evaluation – have been reduced by more than 20%.

GRE expected that some additional NOx reductions would result from the implementation of DryFining™. It was estimated that the reduction in coal moisture, and corresponding increase in coal heat content, would result in less coal into the furnace, and more air available elsewhere in the furnace, which can be utilized to reduce NOx emissions. However, this NOx reduction benefit was not quantified in the original BART analysis. At the time of the final BART analysis (December 2007), DryFining™ had not yet operated, and, the exact degree of control was unknown for this innovative strategy. Because DryFining™ has been in place for nearly two years, NOx emissions are reduced. Consequently, current (baseline) NOx emissions that are used in Section 3.1 have been updated to reflect the URS control cost analysis and are inclusive of DryFining™, with low NOx burner technology as applicable.

2.1.2 NOx Combustion Control Considerations

GRE's proposed BART NOx control strategy includes the use of DryFining™ along with advanced combustion controls. As a result of the installation of the proposed advanced combustion controls on Unit 2, GRE has gained a better understanding of anticipated NOx control levels and costs.

The size and arrangement of the furnace box on CCS Units 1 and 2 is unique. It is literally a one-of-a-kind furnace box, sized specifically for the high moisture Fort Union lignite. Given a larger firebox, relative to other lower-moisture, higher-heat-content coal-fired units, there is a correspondingly higher complexity and higher cost to NOx combustion controls. There is a greater distance across the furnace through which the air must penetrate, thus increasing the size and type of wall nozzles, along with increased nozzle staging complexity throughout the wall sections. When an advanced combustion air system is added to a larger firebox, it requires additional wall openings, and redesign to wall water tubes, further increasing costs.

Since the time of the initial BART submittal, GRE has gained direct operational experience on the performance of these advanced combustion controls and DryFining™. Prior to the installation of DryFining™, most of the available primary air was needed to convey, grind, and dry the coal in the pulverizers due to the high moisture in the coal. Consequently, the maximum performance for the LNC3+ control installed on Unit 2 could not be fully realized upon initial installation. The Unit 2 LNC3+ installation includes larger registers to increase available primary air. Since a significant amount of that primary air was used to dry and pulverize the “unrefined” high moisture coal, there was not sufficient air available for the larger registers to act as a form of overfire air. With DryFining™, there is additional air available to be routed to the larger registers, which reduces NOx emissions. As a result, Units 1 and 2 currently operate with annual average NOx emissions of 0.200 and 0.153 lb/mmBtu, respectively. Unit 2’s lower annual average NOx emission rate is directly attributable to the larger registers, which are tentatively anticipated for Unit 1 in 2014.

2.1.3 Site Specific SNCR Expected Control Levels

Portions of Coal Creek Station’s December 2007 submittal of the NOx BART analysis were based on screening level data presented in the EPA Pollution Control Cost Manual (2002). Since EPA has proposed to reject North Dakota’s SIP largely on their assessment of SNCR’s screening level, cost effectiveness, it is imperative to more accurately portray SNCR costs. With respect to SNCR specifically, EPA acknowledges in its cost manual:

> *SNCR system design is a proprietary technology. Extensive details of the theory and correlations that can be used to estimate design parameters such as the required [normal stoichiometric ratio] NSR are not published in the technical literature. Furthermore, <u>the design is highly site-specific.</u> <u>In light of these complexities, SNCR system design is generally undertaken by providing all of the plant- and boiler-specific data to the SNCR system supplier, who specifies the required</u>*

<u>NSR and other design parameters based on prior experience</u> and computational fluid dynamics and chemical kinetic modeling.[3](emphasis added)

As discussed above, GRE has established that Coal Creek is unique due to its boiler size, DryFining™, and existing NOx combustion controls. Therefore, only a site specific evaluation, by a competent SNCR supplier (URS), should be used to estimate emission reductions and associated costs. URS is a preeminent engineering consultant in SNCR technology, having designed several dozen SNCR pollution control systems throughout the world. This experience qualifies URS to make site-specific recommendations on SNCR design.

URS completed a site inspection, evaluated the unique aspects of Coal Creek, and provided their refined analysis (see Appendix B).

URS has determined that the removal efficiency for Coal Creek Unit 1 with an inlet NOx concentration of 0.22 lb/mmBtu would not be 50% as anticipated from the EPA Pollution Control Cost Manual (2002), and as used in GRE's original BART analysis. Rather, URS estimates a removal rate of approximately 30% removal for Unit 1. With respect to Unit 2, and an inlet concentration of 0.15 to 0.16 lb/mmBtu, URS estimates the removal efficiency would be approximately 20%.

Given these lower projected emission rates, and the lower "baseline" emission rates from installed controls, the cost evaluation will be revised, accordingly, in Section 3.1.

Rather than relying on the original screening level analyses, GRE finds it imperative to provide this updated information to North Dakota to make their well informed cost effectiveness determinations.

2.2 Revision of Baseline NOx Emissions

In order to make its cost effectiveness determination, North Dakota must not only have site specific control cost, but also accurate emission reduction estimates. Clearly, with the installation of both LNC3, LNC3+, and DryFining™, Coal Creek's NOx emissions are greatly reduced with respect to "baseline" values previously provided. In this section, in light of recently refined analysis, GRE will update baseline emissions to be used in making the cost effectiveness determination.

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[3] EPA Pollution Control Cost Manual (2002); Section 4.2 Chapter 1.3.

Based on the timing of the original analysis, the initial BART evaluation used baseline emission rates for approximately the same time period that was used to determine the visibility baseline, which was a 5-year period of emission inventory data from 2000 to 2004. It is necessary to update the baseline emissions for Units 1 and 2 for this technology evaluation in order to reflect current conditions and unit performance. Both units utilize “low NOx coal-and-air nozzles with close-coupled and separated overfire air,” which is referred to as LNC3. Since the time of the initial evaluation, NOx controls in the form of larger registers,[4] advancing the LNC3 controls (LNC3+),[5] have been added to Unit 2, which means that the two units have different baselines for the purpose of estimating future emission reductions. For Unit 1, the revised baseline is 0.201 lb/mmBtu, as an annual average. For Unit 2, the revised baseline is 0.153 lb/mmBtu, as an annual average, as also described in Section 2.1.2. These new “baseline” emission rates are lower than the initial BART baseline of 0.22 lb/mmBtu.

2.2.1 Circumferential Cracking in Boiler Tubes

Following the installation of LNC3+ technology at Unit 2, CCS has determined that an emission rate of 0.15 lb/mmBtu for LNC3+ is not a sustainable 30-day rolling average control level due to circumferential cracking. In other words, the 0.15 lb/mmBtu on a 30-day rolling basis is at the edge of this technology’s capabilities. While GRE may intermittently achieve this rate on a monthly or perhaps more easily as an annual average, it is not the basis for a 30-day rolling limit.

As background, in 2008 GRE lowered NOx emissions from Unit 2 by expanding the OFA registers. This diverted more of the combustion air from the burners of the boiler to an area about 30 feet higher in the boiler. In doing so, the flame temperatures were lowered, which reduced the production of NOx generated by the combination of oxygen and nitrogen gas burned under high temperatures. NOx emissions were lowered, but there was an unexpected side effect. This low NOx emission rate caused circumferential cracks in the boiler tubes between the burner front and the over-fired air registers.

The phenomenon of circumferential cracking has several interrelated contributing factors including high surface temperatures (>900°F bare tubes, >1100°F weld overlays) (which exposes the boiler

[4] Larger registers allow for a greater ability to tune combustion staging and thus control NOx emissions.

[5] LNC3 is the acronym used by EPA to describe a specific type of restrictive combustion control. To differentiate between the controls installed on Unit 1 and the additional controls installed on Unit 2 (both are versions of LNC3), the acronyms LNC3 and LNC3+ are used for each unit, respectively.

tubes to high wall temperatures and high temperature fluctuations, which produces numerous thermal fatigue cracks in the boiler walls), frequent and severe thermal spikes (>100°F), and corrosive conditions/deposits. Low NOx burner systems with overfire air ports produce longer flames and increase the chance of flame impingement and local overheating of the boiler walls.

In 2009, Coal Creek Station began to experience unscheduled outages on Unit 2 due to failures from the circumferential cracking described above. To understand and correct this problem, Great River Energy engaged the Electric Power Research Institute (EPRI) to assist in evaluating the causes and potential remedies for this problem. To date, corrective actions have included detailed examinations of the boiler tubes to detect the extent of the cracking, the installations of additional temperature monitors to determine boiler wall temperatures, the replacement of damaged boiler tubes, and continued tuning of the boiler to minimize the circumferential cracking in the zone of concern. While not eliminating the problem, these efforts have greatly reduced the problem of unscheduled outages caused by circumferential cracking. Based on our analysis, it is not clear how to completely and consistently eliminate this problem, while operating at or near 0.15 lb/mmBtu on a 30-day rolling basis. Efforts continue to further reduce this circumferential cracking problem while balancing our desire to operate at lower NOx emission levels.

The only examples of tangentially-fired units with emissions lower than the 0.17 lb/mmBtu NOx presumptive level are facilities with post combustion NOx controls, such as SNCR. Further, a majority of these SNCR controlled sources operate well above the 0.17 lb/mmBtu, as annual averages, as detailed in the Cross State Air Pollution Rule and illustrated in Figure 2.2. Consequently, GRE presumes it cannot safely and consistently operate below 0.17 lb/mmBtu as a 30-day rolling limit, without installing SNCR.

2.2.2 Load Variability

In addition to circumferential cracking, this assessment must also consider load variability and its impacts on NOx emissions. The NOx emission limits proposed in the original BART evaluation for Units 1 and 2 did not consider that Coal Creek's units would experience significant load variability. GRE has historically operated as a baseload unit, without much load swinging. In May 2011, Midwest Independent Transmission System Operator (MISO) began cycling CCS in the real-time market. In September 2011, GRE greatly increased the cycling range of CCS in response to current market prices in the MISO market. This is important because load swinging significantly impacts expected NOx control performance. While base load NOx emissions can be tuned due to relatively stable load, the swinging load cannot be finely tuned but must still be accounted for when assessing compliance with emission limits.

Table 2.1 illustrates the variability experienced during recent load swinging. It is different on Units 1 and 2, due to different NOx controls. Based on changing market conditions, load variability is expected to continue as an operational scenario for Units 1 and 2 for the foreseeable future. As such, any emission limit must account for this additional variability in emissions. It is clear from Table 3 that the BART NOx presumptive emission rate of 0.17 lb/mmBtu is achievable, including load variability, and also reflecting the maximum NOx emission reductions from LNC3+ and DryFining™, as demonstrated through Unit 2.

Table 2.1. Coal Creek Station NOx Emission Rates During Load Variability

Scenario Description		NOx Emissions (lb/mmBtu)			
		Unit 1		Unit 2	
		Min	Max	Min	Max
Overall - Nov. 2010 to Nov. 2011	30-day Rolling	0.179	0.219	0.14	0.169
Load Variability – May – November 2011	30-day Rolling	0.186	0.219	0.146	0.166
	Hourly Average	0.206		0.16	
Load Variability – September – November 2011	30-day Rolling	**0.207**	**0.219**	**0.163**	**0.166**
	Hourly Average	0.218		0.17	

In addition, GRE provides a chart showing Unit 2's 30-day rolling average NOx emission rate, with notes on tuning emphasis and load variability, as further support of the 0.17 lb/mmBtu emission limit.

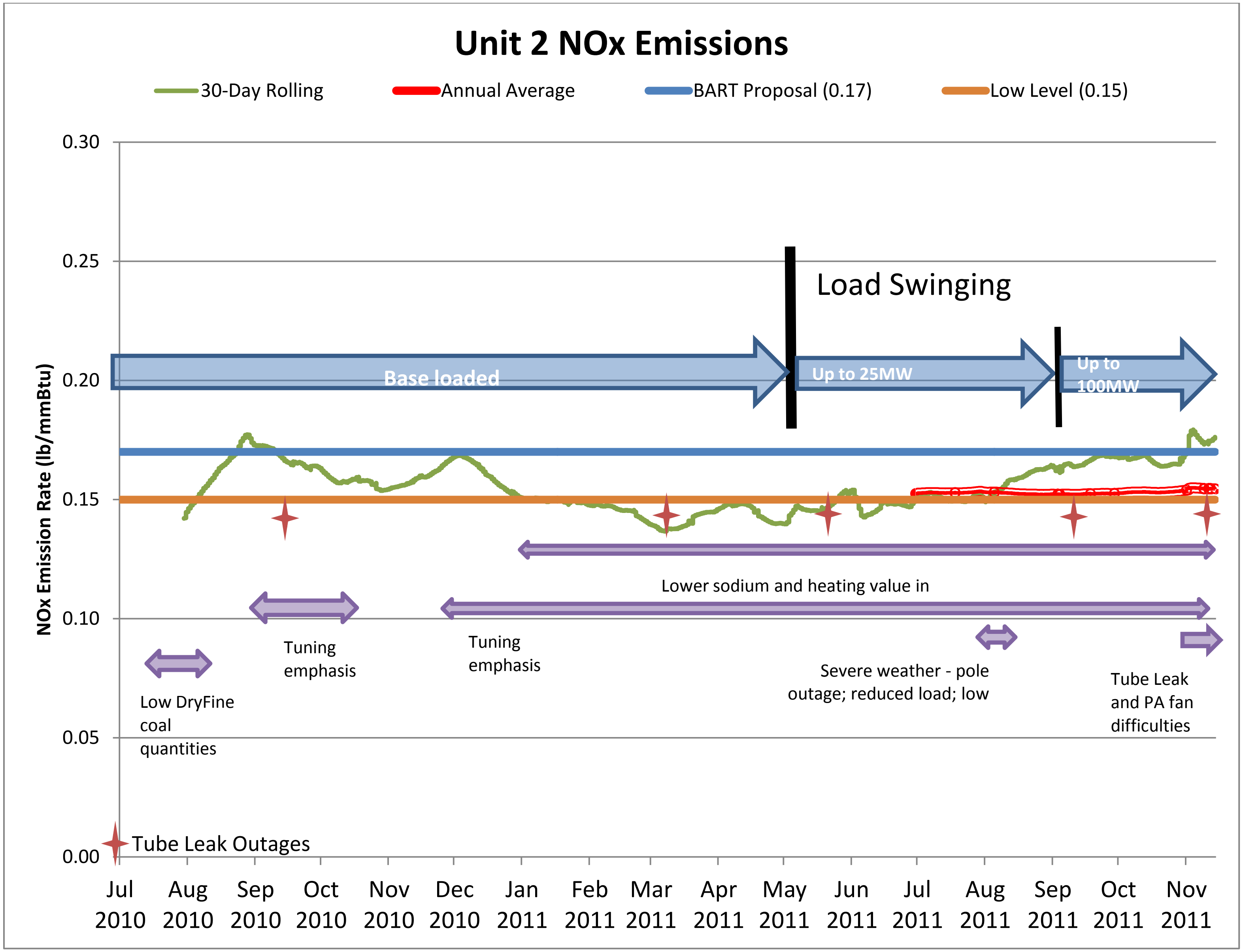

Figure 2.1 Unit 2 30-Day Rolling NO_x Emission Averages

2.2.3 Evaluation of SNCR Effectiveness in CSAPR

Interestingly, the Coal Creek presumptive NOx BART emission rates are consistent with annual average emissions as modeled by EPA in CSAPR. By reviewing existing units of similar design, data from the docket for the proposed Cross State Air Pollution Rule (Docket ID EPA-HQ-OAR-2009-0491) illustrates that there are currently no tangentially-fired utility electricity generating units with LNC3 combustion controls and SNCR post combustion controls that operate at or below the presumptive BART limit of 0.17 lb/mmBtu for NOx (Figure 2.2), as annual averages. If the data set is expanded to include LNC3 ("low NOx coal-and-air nozzles with separated overfire air (LNC2[6])") and "low NOx burners and overfire air (OFA)" as illustrated in Figure 2.3, only four supercritical[7] emission units operate below the presumptive NOx limit of 0.17 lb/mmBtu. None of the facilities included in the CSAPR database operate at or below the proposed FIP limit of 0.12 lb/mmBtu. All of the facilities analyzed use SNCR to effectively achieve the Coal Creek presumptive NOx emission limit of 0.17 lb/mmBtu. To state it differently, Coal Creek effectively achieves presumptive BART with DryFining™ rather than SNCR.

[6] LNC2 and LNC3 are various types of low NOx burner design.

LNC2 = Low NOx burner with separated OFA

LNC3 = Low NOx burner with close-coupled and separated OFA

[7] For a subcritical boiler (standard operational design consistent with CCS Units 1 and 2), steam to power the turbine is derived by heating liquid water to its saturation point and then isothermally heating of the system causing the phase change from liquid water to steam (boiling). In contrast, a supercritical steam generating unit operates at such a high pressure that liquid water does not boil and is instead converted to a supercritical fluid, an intermediate fluid having properties of both liquid water and steam. Operation of supercritical units is typically more thermally efficient than operation of subcritical units, resulting in less fuel combusted for the same energy output and, consequently, lower emissions.

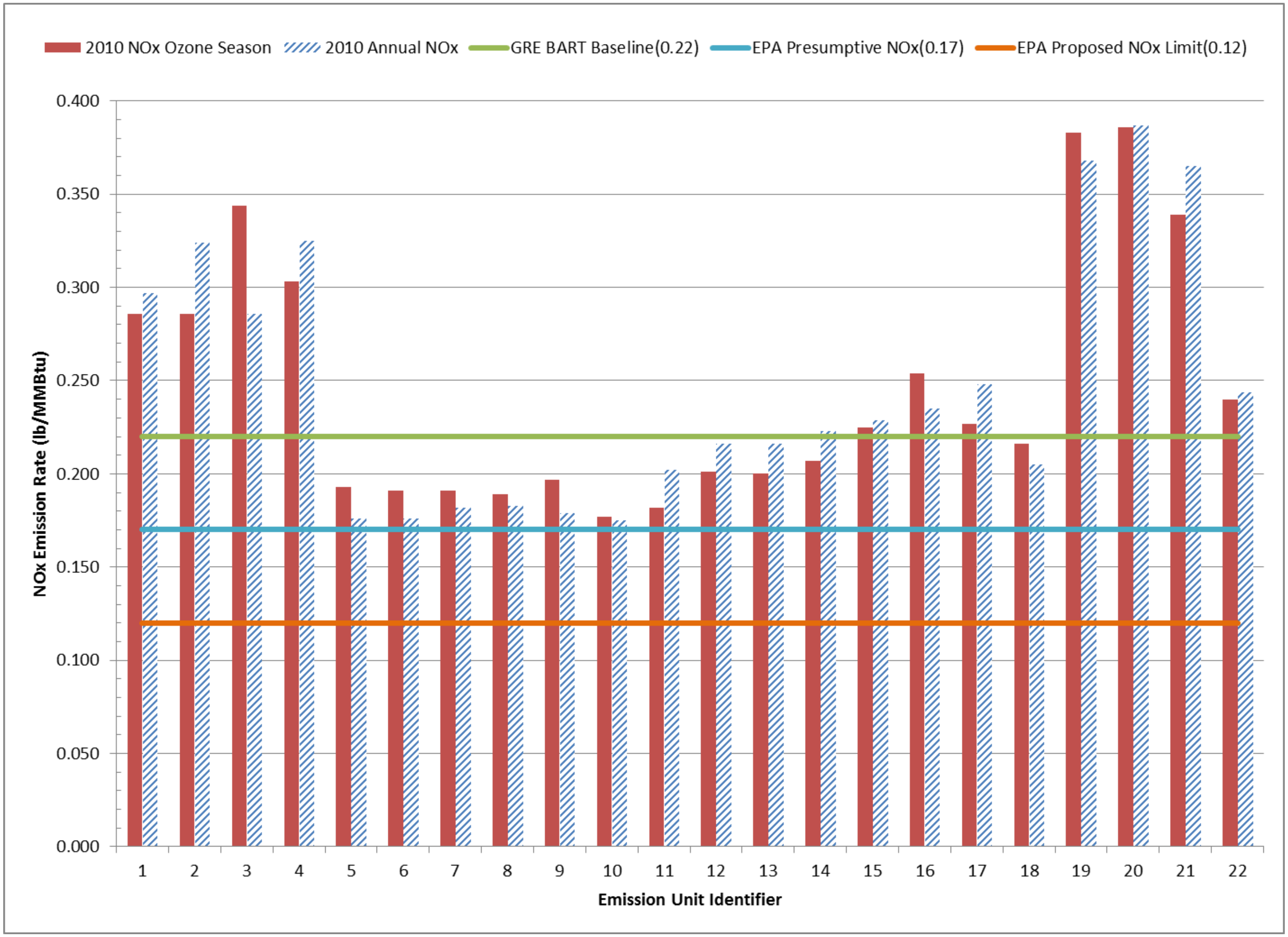

Figure 2.2 2010 NOx Emission Rates from CSAPR Rule Data for Units with SNCR and LNC3/OFA NOx Control

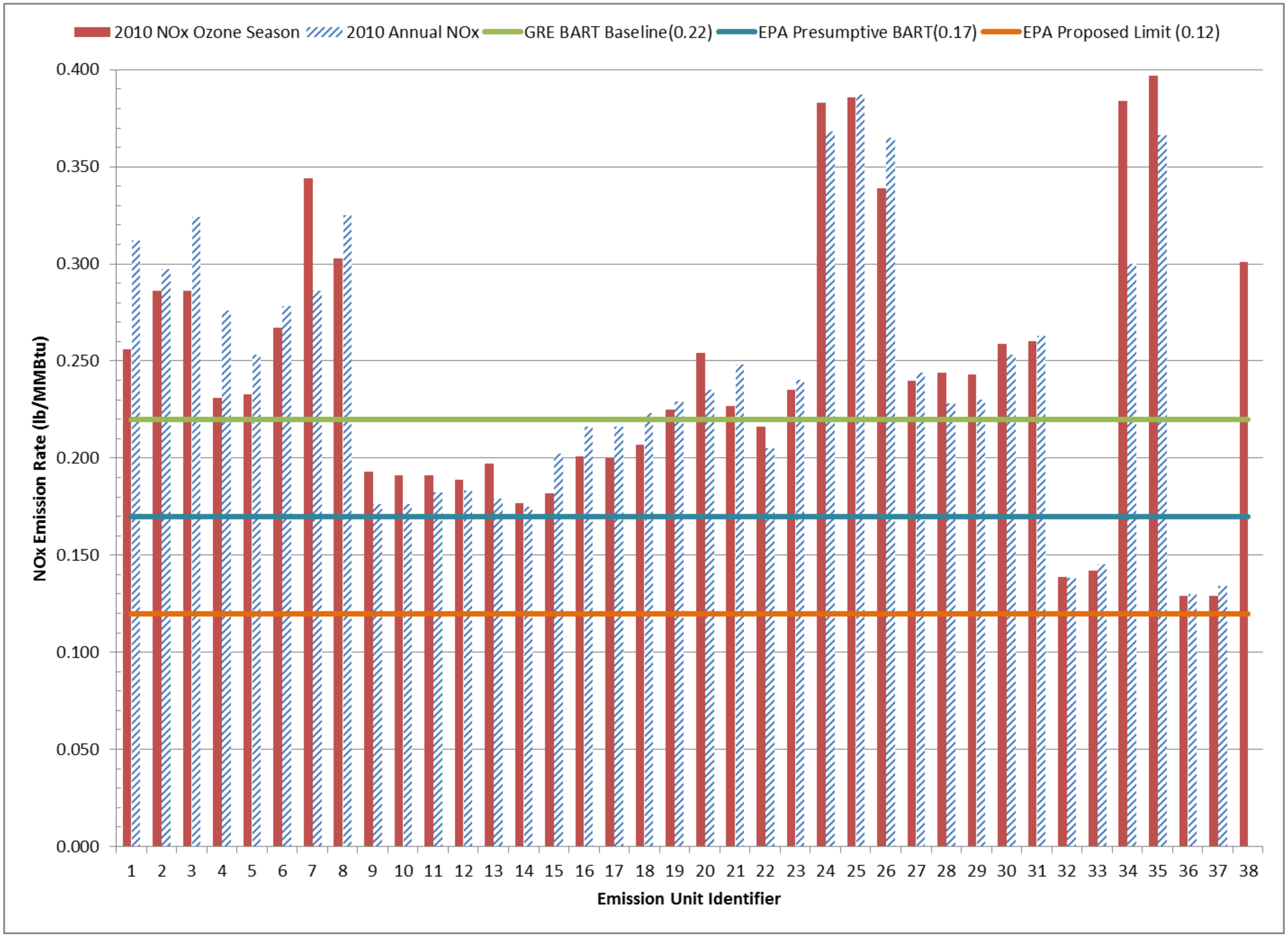

Figure 2.3 2010 NOx Emission Rates from CSAPR Rule Data for Units with SNCR and LNC2/LNC3/OFA NOx Control

2.2.4 Ash Cost Considerations

The EPA indicated in its proposed FIP that GRE fly ash sales and disposal values provided in previous submittals were in error and, when corrected, resulted in SNCR being cost effective. Great River Energy had previously submitted two estimates: $5/ton and $36/ton. Contrary to our Summer 2011 submittal, these values were not necessarily in error, but instead represented different assumptions on economic impacts of lost ash sales and associated disposal costs. Therefore, rather than rely upon these screening level values as previously submitted, GRE contracted with Golder Associates to provide a more refined analysis of ash impacts associated with the installation of SNCR. The following discussion and attached "Fly Ash Storage and Ammonia Slip Mitigation Technology Evaluation" (Appendix C) provides a more comprehensive assessment of ash implications associated with SNCR installation.

To provide some additional background on the previously submitted values, the $36/ton value represented the total freight on board (FOB) Coal Creek Station price that was paid by the end user. The $5/ton dollar per ton figure represented what GRE received as a portion of the FOB price prior to December 1, 2011.

Both of the values ($5/ton and $36/ton) attempted to capture lost revenue from decreased ash sales. In each case, an additional $5/ton cost was added as GRE's cost to dispose of the unsalable ash. This additional $5/ton disposal value was the result of a screening level analysis and had not taken into account all of the internal costs associated with ash disposal. This disposal value also had not accounted for anticipated cost increases based on changing ash disposal regulations, nor did it take into account various ash disposal levels as could be anticipated due to lost fly ash sales.

GRE and Headwaters Resources, Inc (HRI), GRE's strategic partner in the sales and distribution of fly ash, have invested heavily into fly ash sales infrastructure including terminals and storage facilities, conveying equipment, scales and train car shuttles. HRI financed GRE's portion of the infrastructure through a per ton payment on fly ash sales. The current ash sales contract requires payments to GRE that total 30% of the $41 FOB price or $12.30 per ton of ash that is delivered.

Considerable effort has been taken to clarify the impacts that SNCR installation will have on GRE's ash management methods, overall disposal costs and reduction in ash sales revenues. In short, Great River Energy firmly believes, and EPA acknowledges in its proposed FIP, that SNCR may have a detrimental impact to ash sales. The Golder analysis represents these risk ranging from a worst case 100% lost fly ash sales, to an optimistic 30% lost sales, as shown in their Scenarios B and C, respectively. For the sole purpose of defining a baseline, a hypothetical Scenario A "No Ash Impacts," has also been included as a reference point.

2.2.5 SNCR's Impact on Ash Management Options

Fly ash from CCS is used throughout the Upper Midwest to replace a portion of Portland cement in concrete production, making the concrete more durable and longer lasting. Ash generated at Coal Creek Station has chemical and physical properties that make it an extremely desirable ash in the concrete market. Coal Creek Station currently generates approximately 525,000 tons of fly ash per year. Approximately 415,000 tons of that ash is sold as a Portland cement replacement. Coal Creek fly ash has been used in many large-scale projects such as construction of the new Interstate-35W Bridge after its collapse.

The beneficial use of fly ash also has a strong positive economic benefit to Great River Energy, and the regional economy. We started selling fly ash nearly three decades ago. In that time, we have grown this activity into a sizable annual revenue stream. The addition of SNCR will have a negative impact on the marketability, value and perception of Coal Creek Station's fly ash. The addition of ammonia into the combustion process leaves an ammonia residue on the ash that can cause aesthetic and worker safety issues during the use of the ash. The residual ammonia in the ash eventually off-gases and creates odors which are offensive, are potentially dangerous to human health, and can even pose an explosion risk. Section 1-2 of EPA's Pollution Control Cost Manual recognizes this fact and states the following:

> *Ammonia sulfates also deposit on the fly ash that is collected by particulate removal equipment. The ammonia sulfates are stable until introduced into an aqueous environment with an elevated pH levels. Under these conditions, ammonia gas can release into the atmosphere. These results in an odor problem or, in extreme instances, a health and safety concern. Plants that burn alkali coal or mix the fly ash with alkali materials can have fly ash with high pH. In general, fly ash is either disposed of as waste or sold as a byproduct for use in processes such as concrete admixture. <u>Ammonia content in the fly ash greater than 5 ppm can result in off-gassing which would impact the salability of the ash as a byproduct and the storage and disposal of the ash by landfill.</u>*[8] (emphasis added)

8

The range of residual ammonia left with the fly ash can vary with each installation of SNCR. Ammonia slip of only 5 ppm, generally accepted as the minimum that can be achieved with SNCR, can render fly ash unmarketable. (URS, Appendix B) Even in those systems where residual ammonia is generally low, there will be times of increased ammonia slip based on plant operations. As the plant output varies due to market demand or startup/shutdown activity, varying levels of ammonia will be used to control NOx and, consequently, the levels in the ash will change. Variable ammonia levels in the ash create additional complexity to both sales and/or treatment, and will result in increased disposal.

2.2.6 Ammonia Mitigation Technology

Great River Energy is committed to ash re-use due to its economic and environmental benefits. Therefore, we anticipate additional capital and operating costs to treat the ash in order to ideally preserve a percentage of ash sales. With respect to ammoniated ash treatment, Ammonia Slip Mitigation (ASM) technology refers to a variety of technologies that have been designed to improve the marketability of ammoniated ash. These technologies fall into two rough categories, combustion or carbon burn out (CBO) and chemical treatment. CBO is the process of running the ash through an additional combustion unit that would combust and burn out the residual carbon and ammonia that is with the ash. This is a capital intensive technology that also has high operating costs. The second category of ASM technology is generally referred to as chemical treatment. These treatment technologies involve creating a chemical or physical reaction that results in the off-gassing of the residual ammonia. These treatment technologies are generally less costly than CBO. For purposes of this more refined analysis, GRE contracted with Golder Associates to provide a detailed cost estimate of one particular chemical treatment technology as a potentially cost effective option. The detailed cost estimate can be found in Appendix C.

Even with a cost effective ASM technology installed, there will be times when the residual ammonia levels in the ash are too high to treat. Ammonia injection rates will vary during periods of startup and shutdown, in addition to variable load operation, in order to maintain compliance with the BART limits. Variable ammonia injection rates and associated changes in ash concentrations will result in frequent testing and periodic rejection of ash for on-site disposal. Further, variable ammoniated ash levels will put GRE’s generated ash in a very vulnerable position with respect to competitors in the fly ash marketplace, reducing ash sales and increasing on-site disposal.

2.2.7 Ash Disposal Scenario Cost Summaries

Appendix C contains a technical assessment and cost analysis of ammonia slip mitigation technology and ash disposal under RCRA Subtitle D design standards. To address the uncertainty regarding costs associated with ammoniated ash management and disposal, a range of costs is presented. These costs are based on three scenarios described below. Table 1 shows the volumes of ash produced, sold and disposed of in each scenario. For a more detailed description please see Appendix C.

Scenario A (current ash sales levels) – This scenario is the base case with fly ash sales equal to the average sales over the past few years. The scenario assumes that fly ash will be disposed of in a new landfill with a design based on RCRA Subtitle D practices, and has a 20-year disposal capacity. No post processing of the fly ash is required to maintain 100% marketability. (Golder 2011) This hypothetical scenario is not considered to be a possible option for future ash management costs but serves as a point of reference for understanding future impacts.

Scenario B (No ash sales) – This "worst case" scenario assumes that the ammonia slip impact of SNCR makes fly ash at CCS completely unsalable. The scenario also assumes that fly ash will be disposed of in a new landfill with a design based on RCRA Subtitle D practices, and has a 20-year disposal capacity. (Golder 2011)

***Scenario C* (30% sales reduction, ASM costs)** – This "realistic" scenario assumes that Headwater's ASM technology will be viable for ammonia-impacted fly ash at CCS. However, sales will be reduced from current sales levels due to load swing impacts on ammonia slip, market conditions, and other factors previously identified. The scenario also assumes that fly ash will be disposed of in a new landfill with a design based on RCRA Subtitle D practices, and has a 20-year disposal capacity. (Golder 2011)

Table 2.3.1: Fly Ash Sales and Disposal Tons

	Scenario A (Current Sales)	Scenario B (No Sales)	Scenario C (Reduced Sales, ASM)
Fly Ash Produced (ton/yr)	525,000	525,000	525,000
Fly Ash Sold (ton/yr)	415,000	0	290,500
Fly Ash Disposed (ton/yr)	110,000	525,000	234,500

It is clear in EPA's proposed FIP that the installation of SNCR may negatively impact ash sales[9].

Our knowledge of the ash marketplace, SNCR systems, and treatment technologies confirm that the installation of SNCR will have a detrimental impact on the salability of fly ash. GRE believes that Scenario A, which represents no impact to ash sales, is extremely unlikely. Nevertheless, we present it as a point of reference for better quantifying the ash impacts from SNCR installation.

GRE believes that scenario B (zero ash sales) is a likely outcome, but we hope that through investment in ASM technology we will be able to preserve some of the ash sales. To model partial ash sales, we created Scenario C. Scenario C assumes an investment in ASM technology and a reduction of ash sales by 30%. We consider this scenario to be a very optimistic view of the future that relies on the successful implementation of technology that cannot currently be guaranteed by the vendor and has never been installed on lignite fired units. This scenario also quantifies increased disposal costs, in addition to some GRE-specific economic benefit from preserved ash sales. None of the scenarios attempt to capture economic impacts to GRE's strategic partners or other regional entities, but these impacts are mentioned in Section 3.2 and should also be taken into consideration when making a final BART determination.

2.2.8 Ash Management Costs

There are three major cost categories to be considered in each of these scenarios;

- Fly ash disposal cost estimates,
- Ammonia slip mitigation costs, and
- Lost fly ash sales revenue

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[9] Federal Register / Vol. 76, No. 183 / Wednesday, September 21, 2011 / Page 58620.

"Regarding this value for fly ash sales, North Dakota concluded that SCR and SNCR use at Coal Creek would likely result in NH_3 in the fly ash due to NH_3 slip which would negatively affect fly ash salability. According to Great River Energy and North Dakota, fly ash that is currently beneficially used in the production of concrete would, instead, be landfilled. While we have opted to agree that fly ash will not be saleable for the SNCR and SCR options for purposes of our cost analyses, we are seeking comment on this issue, particularly related to the levels of NH_3 that fly ash marketers deem problematic, and the availability, applicability, and cost of applying NH_3 mitigation techniques to fly ash derived from lignite coal."

Each cost area is summarized below. For a more detailed assessment, see Appendix C.

2.2.9 Fly Ash Disposal Cost Estimates

Given significant uncertainty with pending regulatory requirements such as RCRA Subtitles C and D, with ammonia slip treatment technologies, and with market reactions to ammoniated ash, Great River Energy has developed essentially three scenarios that attempt to capture a range of possibilities associated with SNCR installation. For all three scenarios, a 20-year disposal capacity and a RCRA Subtitle D design is assumed. It is also assumed that the landfill will be built on property not currently owned by GRE, as GRE does not currently have a suitable location for siting a Subtitle D landfill. For this cost estimate, it is assumed that property just west of the plant property would be purchased for the new facility. Landfill size is based on a 20-year fly ash disposal capacity. For the three scenarios, this varies between 2.2 million and 10.5 million tons of capacity. For each scenario, Golder developed a simplified landfill footprint that would provide the 20-year fly ash disposal capacity.

The cost estimate includes costs for the life of the disposal facility including engineering, design, and permitting; construction; and operations and maintenance, including closure and post-closure care. Golder used actual costs from similar projects at CCS, local contractor rates, RS Means manuals (RS Means 2010), and professional judgment to develop this cost estimate. Sources and assumptions are documented. Some general assumptions for the cost estimate include:

- All costs are estimated in 2011 dollars.
- Capital costs are annualized based on a 20-year life and 5.5% interest rate.
- Existing fly ash processing equipment (silos, unloaders, etc.) is not included. Disposal costs begin once the haul trucks are loaded with fly ash.
- Existing fly ash sales infrastructure (silos, scales, rail facilities) and operations and maintenance are not included.
- Disposal costs only include fly ash disposal and not facility airspace or operations and maintenance for other coal combustion products produced at CCS. (Golder 2011)

Table 2.3.2: Disposal Cost Summary

	Scenario A (Current Sales)	Scenario B (No Sales)	Scenario C (Reduced Sales, ASM)
Fly Ash Disposed (ton/yr)	110,000	525,000	234,500
Total Disposal Cost ($/ton)	$18.06	$11.18	$13.91
Annual Disposal Cost ($/yr)	$1,987,000	$5,870,000	$3,262,000
Annual Increase in Disposal Cost Compared to Scenario A ($/yr)	-	$3,883,000	$1,275,000
Incremental Increase in Disposal Cost Compared to Scenario A ($/ton) *	-	$7.40	$5.44

*These values are used in the BART analysis as they represent the only the incremental costs above the baseline costs which would be incurred with or without the installation of SNCR.

2.2.10 Ammonia Slip Mitigation Costs

Post-processing of ammonia slip impacted fly ash by Headwater's ASM technology is proposed as an option to maintain fly ash sales. This post-processing is only being applied to the sold fly ash tonnage in Scenario C. Depending upon the plant power profile and how the fly ash distribution system is setup, it is likely that additional tons of fly ash will be treated and disposed, but these potential cost impacts are not included. The cost impact for ASM post-processing is shown in Table 2.3.3. (Golder 2011)

Table 2.3.3: ASM Post-Processing Costs (Golder 2011)

	Scenario A (Current Sales)	Scenario B (No Sales)	Scenario C (Reduced Sales, ASM)
ASM Unit Rate Capital and O&M ($/ton sold)	$0.00	$0.00	$5.61
ASM Annual Capital and O&M ($/yr)	$0	$0	$1,629,000

2.2.11 Lost Fly Ash Sales Revenue

The current fly ash sales are supported by a large investment in capital infrastructure as well as a large operations and maintenance contingency. Changes to the quantity of fly ash marketed and sold will have a direct impact on fly ash management costs, as the revenue currently used to offset fly ash management will be lost. The lost fly ash sales revenue is based on the 2010 average price per ton FOB of $41.00; with 30% of the sale price going to GRE as revenue. The cost impact of the potential loss in fly ash sales in shown in Table 2.3.4. (Golder 2011)

Table 2.3.4: Lost Fly Ash Sales (Golder 2011)

	Scenario A (Current Sales)	Scenario B (No Sales)	Scenario C (Reduced Sales, ASM)
Lost Fly Ash Sales Revenue ($/ton lost sales)	$12.30	$12.30	$12.30
Annual Lost Fly Ash Sales Revenue ($/yr)	$0	$5,105,000	$1,531,000

2.2.12 Total Fly Ash Management Costs

The combination of the ASM post-processing, fly ash disposal, and lost fly ash sales revenue is shown in 5. This table represents the total economic impact of SNCR installation on GRE's fly ash management in two likely scenarios; a total loss of ash sales and a 30% reduction in ash sales. (Table 2.3.5)

Table 2.3.5: Total Fly Ash Management Costs (Golder 2011)

	Scenario A (Current Sales)	Scenario B (No Sales)	Scenario C (Reduced Sales, ASM)
Total (Disposal + Post Processing + Lost Sales)			
Annual Cost ($/yr)	$1,987,000	$10,975,000	$6,422,000
Unit Cost ($/ton produced)	$3.79	$20.91	$12.23
Additional Cost (Scenario B/C - Scenario A)			
Fly Ash Management Cost ($/yr)	-	$8,988,000	$4,435,000
Fly Ash Management Cost ($/ton produced)	-	$17.12	$8.45

2.2.13 BART Analysis Ash Disposal Cost Summary

While the exact impacts to Coal Creek Station's ash are unknown, mandating SNCR will leave GRE in a vulnerable position where we would expect to incur significantly higher costs from lost ash sales and increased landfilling. Based on the detailed technical review discussed above and included as Appendix C, GRE proposes a range of ash disposal costs and lost ash sales revenue figures in the BART analysis.

Scenario B represents the highest cost scenario with a total annual additional cost of $8,988,000. The total cost includes lost ash sales revenue of $5,105,000 (Table 2.3.4) and an additional annual ash disposal cost of $3,883,000 or $7.40 per ton disposed (Table 2.3.2).

Scenario C represents an optimistically low cost scenario with a total annual additional cost of $4,435,000. The total cost includes lost ash sales revenue of $1,531,000 (Table 2.3.4) and an additional annual ash disposal cost of $1,275,000 or $5.44 per ton disposed (Table 2.3.2). Scenario C also includes a Ammonia Slip Mitigation cost of $5.61 per ton of ash reused for an additional annual cost of $1,629,000 (Table 2.3.3).

3.0 Integrated NOx Control and Ash Impact Impacts Analyses

This section will integrate the revised baseline emissions, the refined URS SNCR Analysis and the Golder Ash Impact Analysis. It will then provide a summary table with associated cost per ton and incremental cost per ton values.

3.1 SNCR Control Cost Analysis

As discussed in Section 2.1.3, baseline NOx emissions are adjusted to reflect existing controls. Based on the updated baseline, Table 3.1 summarizes the anticipated control costs for additional NOx controls. It includes more refined SNCR costs for CCS Units 1 and 2 (See URS Report Appendix B). It also includes cost scenarios from the Golder Associates Fly Ash Storage and Ammonia Slip Mitigation Technology Evaluation (See Appendix C). It should be noted that the controlled NOx emission concentrations and mass rates have been evaluated on an annual average basis and are not representative of anticipated operation on a shorter scale averaging period (30-day rolling or 24-hour rolling), consistent with BART guidance that costs be normalized to the expected annual emissions reduction. The 30-day rolling limits are intended to be inclusive of unit startup and shutdown as well as variability in load. Consequently, associated BART limits must be higher than stated annual averages used for estimating cost effectiveness. Costs are valued on a present (2011) dollars basis.

Considerable effort has been taken to clarify the impacts that SNCR installation will have on GRE's ash management methods, overall disposal costs and reduction in ash sales revenues. In short, Great River Energy firmly believes, and EPA acknowledges in its proposed FIP, that SNCR may have a detrimental impact to ash sales. The Golder analysis represents these risk ranging from a worst case

100% lost fly ash sales, to an optimistic 30% lost sales, as shown in their Scenarios B and C, respectively. For the sole purpose of defining a baseline, a hypothetical Scenario A "No Ash Impacts," has also been included as a reference point.

Table 3.1 Control Cost Summary

Unit ID	Control Description	NOx Emissions (lb/MMBtu)	Control Eff. From Baseline (%)	Installed Capital Cost ($MM)	Annualized Operating Cost ($MM)	Pollution Control Cost ($/ton)	Incremental Cost $/ton
Unit 1	SNCR,LNC3+,100% Lost Ash Sales	0.122	33%	$17.88	$8.88	$11,202	$229
	SNCR,LNC3+,30% Lost Ash Sales				$6.81	$8,523	
	SNCR,LNC3+,No Ash Impacts				$4.39	$5,385	
	SNCR, 100% Lost Ash Sales	0.150	25%	$12.18	$8.79	$7,629	$143,275
	SNCR, 30% Lost Ash Sales				$6.73	$5,834	$120,894
	SNCR, No Ash Impacts				$4.30	$3,731	$63,111
	LNC3+	0.153	24%	$6.08	$0.76	$696	$696
	Baseline (LNC3)	0.200	NA-Base	NA-Base	NA-Base	NA-Base	NA-Base
Unit 2	SNCR, 100% Lost Ash Sales	0.122	20%	$11.80	$8.12	$10,506	$10,506
	SNCR, 30% Lost Ash Sales				$6.05	$7,827	$8,882
	SNCR, No Ash Impacts				$3.62	$4,689	$4,689
	Baseline – LNC3+	0.153	NA-Base	NA-Base	NA-Base	NA-Base	NA-Base

This refined economic impacts analysis confirms GRE's original conclusion that SNCR is not a cost effective NOx control option. From the table above it would appear as if Unit 1 SNCR – No Ash Impacts would be cost effect on a dollar per ton basis according to the State of ND thresholds, but in understanding that this scenario is considered hypothetical since some level of ash impacts are expected, and the incremental cost per ton is an order of magnitude higher than anything deemed cost effective. The disparity in the incremental costs occurs due to the fact that the DryFining™ with LNC3+ technology could achieve the associated emissions reduction indicated for the SNCR technology. As highlighted, the "most realistic" or optimistic scenario is 30% lost ash sales, with cost exceeding $5,000 per ton of NOx controlled. This value is higher than EPA's determination of economic infeasibility for SCR for CCS at around $4,000/ton of NOx removed stated in the FIP.

Although not directly incorporated into GRE's capital and operating control costs presented above, NDDH must also consider additional impacts, such as indirect and stranded cost components discussed in Section 3.2 and Section 3.3.

3.2 Additional Impacts

GRE provides these additional impact considerations not found in the original BART analysis as important to North Dakota in making its final BART determination.

1. The use of DryFining™ technology that has already been implemented for use at both units at a cost of $270 million. GRE has made a significant investment to achieve multi-pollutant emission reductions and visibility improvements in the region.

2. At the time of this submittal, GRE has already installed LNC3+ combustion controls at Unit 2. In 2011 dollars, this was at a cost of over $6 million and has already resulted in NOx reductions. The same system is currently tentatively scheduled to be installed on Unit 1 during the 2014 outage.

3. Ash infrastructure investments of over $31 million have been made to date for management and sale of Coal Creek Station's ash. Over $7 million of the total investment have been made by GRE, directly.

3.2.1 Regional Impact from Ash Sales Revenue

The BART analysis does not take into account additional regional economic impacts resulting from the reduction or elimination of CCS ash sales. In order to estimate these regional impacts, one can use the freight on board (FOB) price of the ash at $41, and subtract GRE's share of that revenue at $12.30. Therefore, SNCR installation would reduce or eliminate ash sales, eliminating an additional $28.70/ton from the local and regional economy. This could result in a loss of as much as $11,910,500 per year from the local and regional economy. In addition to these regional economic impacts, there are other impacts that must also be considered.

3.2.2 Fly Ash is Important to the National Economy

Fly ash is an important part of the regional and national economy. The National Association of Manufacturers reported in 2010 that Coal Combustion Residuals (CCRs) contribute $6-11 billion annually to the U.S. economy through revenues from sales for beneficial use, avoided cost of disposal, and savings from use as a sustainable building material.[10] The beneficial use of fly ash and other CCRs are directly responsible for a large number of jobs throughout the country. A 2011 report by Veritas found that "Approximately 10.6 million tons of coal combustion residuals were used in concrete-related products during 2009. Those products provided employment for 240,100 manufacturing workers, 78,480 foundation, structure, and building exterior workers and many of the 102,350 nonresidential building construction workers during 2010." (Veritas 2011[11])

3.2.3 Fly Ash is Important to Regional and National Infrastructure

The American Road and Transportation Builders Association[12] completed a report in 2011 that highlighted the importance of fly ash as a component of road and bridge construction across the country. Their research found that the elimination of fly ash as a construction material would increase the average annual cost of building roads, runways and bridges in the United States by nearly $5.23 billion. This total includes $2.5 billion in materials price increases, $930 million in additional repair work and $1.8 billion in bridge work. The additional costs would total $104.6 billion over 20 years.

3.2.4 Environmental Benefits of Ash Reuse

The use of fly ash as a replacement for cement has many environmental benefits. As a result of the increased use of fly ash, less land is disturbed for quarrying raw materials, less land is taken out of production for landfills, and less carbon dioxide (CO_2) is emitted into the atmosphere to make cement. Using one ton of fly ash instead of Portland cement reduces up to one ton of greenhouse gas emissions. Inversely, by contaminating the ash with ammonia, and increasing ash disposal, there will be a corresponding 1-to-1 ton increase in CO_2 emissions from using more Portland cement. These CO_2 emissions are not trivial.

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[10]Report available at: http://www.regulations.gov/#!documentDetail;D=EPA-HQ-RCRA-2009-0640-6992.

[11] Available at: http://www.recyclingfirst.org/pdfs/101.pdf.

[12] Available at: http://www.artba.org/mediafiles/study2011flyash.pdf.

3.2.5 Additional Ash Management Cost Considerations

The ash management costs detailed in this report are considered to be conservative figures from reasonable assumptions that most likely underestimate GRE's future expenditures on ash management.

The ash analysis envisions that all future disposal facilities will be designed and constructed to RCRA subtitle D standards. EPA is currently proceeding with an ash disposal rulemaking that will create uniform national disposal standards under RCRA subtitle D, the far more stringent Subtitle C (Hazardous Waste), or some hybrid approach that takes some requirements from each Subtitle D and C. The cost of complying with a Subtitle C rule would vastly exceed the amounts discussed in this report. This analysis reasonably assumes Subtitle D.

The ash disposal costs discussed above are portrayed as three scenario costs: a baseline which represents current ash sales figures; a scenario where all ash must be disposed of; and a scenario where ash sales are reduced by 30% from the baseline. There is significant uncertainty regarding specific impacts to beneficial reuse if SNCR were installed. The zero ash sales scenario (Scenario B) is very possible and is an outcome that we hope to avoid. Scenario C captures a "hybrid" estimate of the future where some ash is beneficially used and some additional ash must be disposed. For the hybrid scenario, we chose a 30% reduction in sales. This 30% estimate is an optimistic figure of preserved ash sales at 70%. It is quite possible that the amount of ash requiring disposal could easily represent a 50%, 70% or larger reduction in fly ash sales. For this reason, Scenario C is likely to produce ash management costs that are lower than will actually be encountered.

As discussed above, there are a variety of different Ammonia Slip Mitigation (ASM) technologies available. Most of these technologies have only been installed at a small number of generating units and, to GRE's knowledge, no lignite-fired unit is currently operating SNCR and ASM technology.[13] Of all ASM technologies that were investigated, the Headwaters technology was the least expensive. If the Headwaters ASM technology fails to function properly on lignite, it is likely that we would incur significantly larger costs to preserve the beneficial reuse of some portion of our fly ash.

[13] It is important to note that Headwaters ASM technical staff have stated that this technology has not been tested on a lignite unit and they would not guarantee any level of performance if installed at CCS.

The EPA Pollution Control Cost Manual (2002) does not allow GRE to include in our BART analysis the value of previously purchased assets that would be rendered useless by the elimination or reduction of fly ash sales. GRE and its strategic partner, Headwaters Resources, have invested $31M on ash storage, transportation and distribution infrastructure.

3.3 SNCR Visibility Impacts

It is known that NOx contributes to ammonium nitrate formation, which is predominantly a winter "haze" contributor. For purposes of valuing the welfare effects of recreational visibility, it is important to consider that the North Dakota national parks are generally not in high use during the winter season. If required to install SNCR, GRE will pay an extreme price per deciview resulting in imperceptible improvements for a time of year when the parks are generally not used.

To satisfy EPA's proposed Federal Implementation Plan, Coal Creek Station would need to install SNCR technology to reach a NOx emissions level that is 29% lower than EPA's presumptive BART. Yet, the extensive modeling performed as part of the BART analysis concludes that the installation of SNCR, at an emission rate of 0.12 lb/mmBtu, will have an imperceptible improvement in visibility, ranging from 0.05 deciview (dV) to 0.21 dV in the Class I areas near the facility. This is far less than one-half of what EPA has determined to be perceptible to the human eye (0.50 dV)[14]. As such, it is not justifiable for GRE to incur the added cost of SNCR without any appreciable improvement in visibility.

It is worth noting that SNCR will result in ammonia emissions to the atmosphere. Ammonia is a listed state toxic in North Dakota, and is viewed as a contributor to regional haze because it can bond with sulfur dioxide and nitrogen oxides to form ammonium sulfate and ammonium nitrate aerosols Consequently, GRE does not believe that SNCR is a cost effective technology for improving visibility.

3.3.1 CCS Modeled Visibility Impacts

Under EPA's modeling guidelines, it is necessary to develop a 24-hour maximum anticipated emission rate for each control technology in order to assess visibility impacts. GRE assumes that on a 30-day rolling basis, combustion and post-combustion NOx controls can experience emissions that

[14] Federal Register / Vol. 76, No. 183 / Wednesday, September 21, 2011.

FR discusses State's ability to consider potential impacts for VOC and ammonia although full analyses may not be required.

are approximately 10% higher than their annual design basis. Similarly, for assessing a 24-hour maximum emission rate, GRE assumes emissions will be up to 20% higher than the annual design rate for a given control.

GRE presented a full evaluation of anticipated cost per unit visibility impairment (Δ-dV) in its final BART analysis (Dec 2007). Pollutant interaction has an impact on modeled visibility impairment and, as such, GRE believes that modeling changes to NOx emission rates alone will not provide visibility modeling results that are representative of actual emission controls. This may overstate visibility improvement as compared to modeling NOx, SO_2 and fine PM together. However, for the purpose of illustrating the relative visibility impacts of SNCR and LNC3+, an analysis of the incremental modeled impacts and cost per dV is presented in Table 3.

Table 3.3.1. Visibility Improvement

Control Scenario	Design Rate (Annual)	30-Day Rolling	24-hr max	Avg. Improvement (dv)	Incremental Improvement from "Baseline" (dv)	Annual Cost (MM$)	MM$/dV
Approximate Baseline [1]							
Unit 1	0.17	0.19	0.20	1.100	0.000	--	--
Units 1 & 2				1.760	0.000	--	--
LNC3+ with Tuning							
Unit 1	0.15	0.17	0.18	1.151	0.051	$ 0.76	$ 15.11
Units 1 & 2				1.852	0.092	$ 1.53	$ 16.50
Selective Non-Catalytic Reduction (SNCR)							
Unit 1 (30% lost sales)	0.13 [2]	0.14	0.15	1.209	0.109	$ 6.73	$ 61.56
Units 1 & 2 (30% lost sales)				1.967	0.207	$ 13.53	$ 65.38
Unit 1 (100% lost sales)				1.209	0.109	$ 8.79	$ 80.50
Units 1 & 2 (100% lost sales)				1.967	0.207	$ 16.91	$ 81.69

This incremental visibility analysis demonstrates that SNCR will not result in perceptible improvements to visibility in North Dakota's affected Class I areas. It also demonstrates that SNCR's cost effectiveness is excessive on a dollar per deciview basis. This makes sense because utilities in North Dakota only contribute ~6% to total NOx emissions in the State. Consequently, any additional utility NOx reductions will not have an appreciable effect on visibility improvement.

4.0 Conclusions

Until now, Great River Energy has provided screening level analyses and assumptions with respect to SNCR installation. Due to EPA's proposed FIP, and its assertion that SNCR is cost effective for Coal Creek Station, Great River Energy responds with more refined analyses in three primary areas.

First, URS provides a site specific evaluation of SNCR effectiveness at Coal Creek Station, which results in lower projected emissions reductions from this control. These emission estimates clearly change the basis for any cost effective determination. Consideration for startup and shutdown emissions, circumferential cracking and load variations should also factor into this determination as discussed in Section 2.2.

Second, URS reviewed and updated both capital and operating costs for SNCR, based on their expertise and site specific investigation. These values were relatively consistent with values presented to EPA in June and July 2011, but are somewhat higher than the screening values presented in the original BART analysis.

Third, Golder Associates conducted a detail ash impact analysis associated with a range of costs from contaminating the fly ash with ammonia from SNCR. While the exact impacts to Coal Creek Station's ash management and sales are unknown, mandating SNCR will leave GRE in a vulnerable position where we would expect to incur significantly higher costs from lost ash sales and increased landfilling. Based on a detailed technical review GRE would expect to incur additional ash annual costs somewhere between $4,435,000 and $8,988,000.

When these three refined analyses are combined and evaluated, it clearly demonstrates that the presumptive NOx limit of 0.17 lb/mmBtu is both cost effective and results in significant visibility improvements in North Dakota's Class I areas.

On strictly a cost effective basis, SNCR can be ruled not cost effective, especially when the GRE specific risks and costs associated with this technology are included. As noted, there are additional economic and visibility impacts associated with SNCR that further preclude it from consideration.

Appendix A

Pollution Control Cost Evaluations

Great River Energy Coal Creek Station
BART Supplement - NOx Emission Control Cost Analysis

Table A-1: Cost Summary

NO_x Control Cost Summary - Unit 1

Case	Control Technology [1]	Annual Designed Emissions lb/MMBtu	Control Eff % from Baseline	Controlled Emissions T/yr	Emission Reduction T/yr	Installed Capital Cost MM$	Annualized Operating Cost MM$/yr	Pollution Control Cost $/ton	Annual Incremental Cost $/ton	See Table XX for additional information
3	SNCR + LNC3+ - 100% Lost Ash Sales	0.122	33%	3,089.8	1,521.6	$17.88	$8.88	$11,202	$229	A-4, A-10
	SNCR + LNC3+ - 30% Lost Ash Sales						$7.62	$9,578	$229	A-4, A-9
	SNCR + LNC3+ - No Ash Impacts						$4.39	$5,385	$229	A-4, A-8
2	SNCR - 100% Lost Ash Sales	0.150	25%	3,458.5	1,152.8	$12.18	$8.79	$7,629	$143,275	A-7
	SNCR - 30% Lost Ash Sales						$7.54	$6,540	$120,894	A-6
	SNCR - No Ash Impacts						$4.30	$3,731	$63,111	A-5
1	LNC3+	0.153	24%	3,514.6	1,096.8	$6.08	$0.76	$696	$696	A-4
0	Baseline Control - Standard LNC3	0.200	NA-Base	4,611.4	NA-Base	NA-Base	NA-Base	NA-Base	NA-Base	A-3

NO_x Control Cost Summary - Unit 2

Case	Control Technology [1]	Annual Designed Emissions lb/MMBtu	Control Eff % from Baseline	Controlled Emissions T/yr	Emission Reduction T/yr	Installed Capital Cost MM$	Annualized Operating Cost MM$/yr	Pollution Control Cost $/ton	Annual Incremental Cost $/ton	See Table XX for additional information
1	SNCR - 100% Lost Ash Sales	0.122	20%	3,089.8	772.5	$11.80	$8.12	$10,506	$10,506	A-10
	SNCR - 30% Lost Ash Sales					$11.80	$6.86	$8,882	$8,882	A-9
	SNCR - No Ash Impacts					$11.80	$3.62	$4,689	$4,689	A-8
0	Baseline Control - LNC3+	0.153	NA-Base	3,862.3	NA-Base	NA-Base	NA-Base	NA-Base	NA-Base	A-3

[1] Ash impact scenarios align with November 2011 Golder report.

Great River Energy Coal Creek Station

BART Supplement - NOx Emission Control Cost Analysis

Table A-2: Emission Inventory Data / Baseline Emission Rate for BART Control Cost Analysis

Equipment Information: GRE Coal Creek Unit I				6015	MMBtu/hr
Year (12-Month Avg. Period)	Jul 2010 - Jun 2011	Aug 2010 - Jul 2011	Sep 2010 - Aug 2011	Oct 2010 - Sep 2011	Nov 2010 -Oct 2011
Hours of Operation	7,700	7,700	7,635	7,599	7,629
Fuels Used:					
Quanity of Lignite - Tons	3,356,248	3,352,605	3,296,938	3,268,966	3,282,270
Percent Sulfur in Coal (Average)	0.64%	0.65%	0.65%	0.66%	0.61%
BTU per Unit of Coal (Average)	6,415	6,448	6,482	6,517	6,003
Heat Input	4.410E+07	4.422E+07	4.356E+07	4.320E+07	4.346E+07
MMBtu/hr	5,727	5,743	5,705	5,685	5,697
% of Capacity	95.2%	95.5%	94.8%	94.5%	94.7%
NOx lb/MMBtu	0.200	0.200	0.199	0.200	0.203
Total Stack Emissions:					
NOx Emitted Tons Per Year:	4,416.3	4,412.0	4,333.1	4,330.2	4,402.3
NOx Emitted Lb Per Hour:	1,204.8	1,200.3	1,196.7	1,205.8	1,218.5
Stack Emissions --- Lignite:					
NOX CEM Annual Average lb/MMBtu	0.201	0.200	0.200	0.201	0.203

Baseline Emis	
Unit 1	**Unit 2**
7,653	8,410
3,311,405	3,688,805
0.64%	0.64%
6,373	6,373
43,708,554	47,761,077
5,712	5,679
95.0%	94.3%
0.200	0.153
4,378.8	3,642.5
1205.2	918.5
0.201	0.153

Equipment Information: GRE Coal Creek Unit II				6022	MMBtu/hr
Year	Jul 2010 - Jun 2011	Aug 2010 - Jul 2011	Sep 2010 - Aug 2011	Oct 2010 - Sep 2011	Nov 2010 -Oct 2011
Hours of Operation	8,430	8,430	8,397	8,401	8,390
Fuels Used:					
Quanity of Lignite - Tons	3,730,674	3,718,253	3,676,481	3,672,436	3,646,178
Percent Sulfur in Coal (Average)	0.64%	0.65%	0.65%	0.66%	0.61%
BTU per Unit of Coal (Average)	6,415	6,448	6,482	6,517	6,003
Heat Input	4.810E+07	4.799E+07	4.757E+07	4.764E+07	4.751E+07
MMBtu/hr	5,706	5,692	5,665	5,671	5,662
% of Capacity	94.9%	94.6%	94.2%	94.3%	94.1%
NOx lb/MMBtu	0.152	0.153	0.152	0.152	0.153
Total Stack Emissions:					
NOx Emitted Tons Per Year:	3,662.4	3,666.8	3,610.4	3,626.8	3,646.1
Stack Emissions --- Lignite:					
NOX CEM Annual Average lb/MMBtu	0.152	0.153	0.152	0.153	0.154

Great River Energy Coal Creek Station

BART Supplement - NOx Emission Control Cost Analysis

Table A-3: Summary of Utility, Chemical and Supply Costs

Operating Unit:	Unit 1 or 2	**Study Year**		2011		
From Golder Report			**Reference**			
Item	**Unit Cost**	**Units**	**Cost**	**Year**	**Data Source**	**Notes**
Operating Labor	37	$/hr	25.86	2002	Stone & Webster 2002 Cost Estimate; confirmed by GRE	
Maintenance Labor	37	$/hr	26.25	2002	Stone & Webster 2002 Cost Estimate; confirmed by GRE	
Electricity	0.060	$/kwh	0.049	2004	DOE Average Retail Price of Industrial Electricity, 2004	http://www.eia.doe.gov/emeu/aer/txt/ptb0810.html
Water	0.31	$/kgal	0.79	2002	Stone & Webster 2002 Cost Estimate; confirmed by GRE	
Cooling Water	0.32	$kgal	0.23	1999	EPA Air Pollution Control Cost Manual, 6th ed. Section 3.1 Ch 1	Ch 1 Carbon Adsorbers, 1999 $0.15 - $0.30 Avg of 22.5 and 7 yrs and 3% inflation
Compressed Air	0.37	$/kscf	0.25	1998	EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1	Example problem; Dried & Filtered, Ch 1.6 '98 cost adjusted for 3% inflation
Wastewater Disposal Neutralization	1.96	$/kgal	1.50	2002	EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 2 Chapter 2.5.5.5	Section 2 lists $1- $2/1000 gal. Cost adjusted for 3% inflation Sec 6 Ch 3 lists $1.30 - $2.15/1,000 gal
Wastewater Disposal Bio-Treat	4.96	$/kgal	3.80	2002	EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 5.2 Chapter 1	Ch 1lists $1.00 - $6.00 for municipal treatment, $3.80 is average. Cost adjusted for 3% inflation
Solid Waste Disposal - No Impact	0.00	$/ton	0.00	2011	Assume no change in GRE landfill cost for ash	
Solid Waste Disposal - 30% Lost	5.44	$/ton	5.44	2011	Golder Fly Ash Management Evaluation - Nov. 2011	
Solid Waste Disposal - 100% Lost	7.40	$/ton	7.40	2011	Golder Fly Ash Management Evaluation - Nov. 2011	
Hazardous Waste Disposal	326.19	$/ton	250.00	2002	EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 2 Chapter 2.5.5.5	Section 2 lists $200 - $300/ton Used $250/ton. Cost adjusted for 3% inflation
Waste Transport	0.65	$/ton-mi	0.50	2002	EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 3	Example problem. Cost adjusted for 3% inflation
Ash Sales	12.30	$/ton	12.30	2011	Golder Fly Ash Management Evaluation - Nov. 2011	$/ton received for sale of ash; this amount is lost if ash cannot be sold
Ammonia Mitigation	5.61	$/ton	5.61	2011	Golder Fly Ash Management Evaluation - Nov. 2011	
Chemicals & Supplies						
Lime	90.00	$/ton	72.19	2005	GRE per Diane Stockdill 12/6/05 email	Cost adjusted for 3% inflation
Caustic	364	$/ton	305.21	2005	GRE per Diane Stockdill 12/6/05 email	Cost adjusted for 3% inflation
Urea	500	$/ton	500	2011	URS SNCR Report - November 2011	
Oxygen	17.91	kscf	15.00	2005	Get cost from Air Prod Website	Cost adjusted for 3% inflation
EPA Urea	179.1	$/ton				
Ammonia	1	$/lb	0.92	2005	GRE per Diane Stockdill	Cost adjusted for 3% inflation
Other						
Sales Tax	0	%			GRE per Diane Stockdill 12/6/05 email	
Interest Rate	5.50%	%			GRE per Diane Stockdill 12/6/05 email	Estimated prime rate plus 3%
Please note, for units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal						
Operating Information	**Unit 1**	**Unit 2**				
Annual Op. Hrs	7,653	8,410	Hours		July 2010 to October 2011 Coal Creek Emission Data	
Utilization Rate	100.0%	100.0%			GRE per Diane Stockdill 12/6/05 email	
Equipment Life	20	20	yrs			Engineering Estimate
Coal Ash	11.70	11.70	wt % ash		2010 Coal Creek Emission Inventory	
Coal Sulfur	0.64	0.64	% Coal Sulfur Content		July 2010 to October 2011 Coal Creek Emission Data	
Coal Heating Value	6,373	6,373	Btu/lb of coal		July 2010 to October 2011 Coal Creek Emission Data	
Design Capacity	6,015	6,022	MMBtu/hr			
ID Fan Flow Rates	Assumes coal drying with DryFining™					
Standardized Flow Rate	866,294	866,294	scfm @ 32º F			
Temperature	330	330	Deg F		GRE per G. Riveland 4/5/06 email	
Moisture Content	0	13.3%			GRE per G. Riveland 4/5/06 email	
Actual Flow Rate	2,234,300	2,234,300	acfm		GRE per G. Riveland 4/5/06 email	
Standardized Flow Rate	1,391,000	1,391,000	scfm @ 330º F		GRE per G. Riveland 4/5/06 email	
Dry Std Flow Rate	1,205,997	1,205,997	dscfm @ 330º F			
NOx Pollutant Data						
Max Emis (lb/hr)	1,205	919			July 2010 to October 2011 Coal Creek Emission Data	
Max Emis (tpy)	4,611	3,862				
Baseline Emiss (lb/MMBtu)	0.200	0.153				

Great River Energy Coal Creek Station
BART Supplement - NOx Emission Control Cost Analysis
Table A-4: Unit 1 NOx Control - Foster Wheeler LNC3+

Operating Unit: **Unit 1**

Emission Unit Number	EU-1		Stack/Vent Number	SV-1		CEPCI	
Desgin Capacity	6,015	MMBtu/hr	Standardized Flow Rate	866,294	scfm @ 32º F	2005	468.2
Expected Utiliztion Rate	100%		Temperature	330	Deg F	2011	588.9
Expected Annual Hours of Operation	7,653	Hours	Moisture Content	13.3%		Inflation Factor	1.26
Annual Interest Rate	5.5%		Actual Flow Rate	2,234,300	acfm		
Expected Equipment Life	20	yrs	Standardized Flow Rate	1,391,000	scfm @ 330º F		
Baseline NOx	0.200	lb/MMBtu	Dry Std Flow Rate	1,205,997	dscfm @ 330º F		

CONTROL EQUIPMENT COSTS

Capital Costs		
Direct Capital Costs		
Purchased Equipment (A)		1,257,796
Purchased Equipment Total (B)		**1,958,057**
Installation - Standard Costs		1,958,057
Installation - Site Specific Costs		NA
Installation Total		3,729,632
Total Direct Capital Cost, DC		5,687,689
Total Indirect Capital Costs, IC		391,611
Total Capital Investment (TCI) = DC + IC		**6,079,300**
Operating Costs		
Total Annual Direct Operating Costs	Labor, supervision, materials, replacement parts, utilities, etc.	7,079
Total Annual Indirect Operating Costs	Sum indirect oper costs + capital recovery cost	756,131
Total Annual Cost (Annualized Capital Cost + Operating Cost)		**763,210**

Emission Control Cost Calculation

Pollutant	Max Emis Lb/Hr	Annual T/Yr	Cont Eff %	Exit Conc	Conc Units	Cont Emis T/yr	Reduction T/yr	Cont Cost $/Ton Rem
Nitrous Oxides (NOx)	1,205.2	4,611.4	24%			3514.6	1,096.8	696

Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 2 (Used PM Scrubber which has lowest installed cost multiplier)

Notes & Assumptions

1. Sept 2005 Cost Estimate from Foster Wheeler, Option 2, inflated to 2011 dollars. Ratio based on actual cost for Unit 2 instalaltion.
2. Total capital investment reflects actual installed costs for Unit 2 installation, infllated to 2011 dollars.
3. Assumed 0.1 hr/shift operatior and maintenance labor for LNB
4. Process, emissions and cost data listed above is for one unit.
5. For units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal

Great River Energy Coal Creek Station
BART Supplement - NOx Emission Control Cost Analysis
Table A-4: Unit 1 NOx Control - Foster Wheeler LNC3+

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) (1)			**1,257,796**
Purchased Equipment Costs (A) - Absorber + packing + auxillary equipment, EC			
Instrumentation			
Sales Taxes			
Freight			
Purchased Equipment Total (B)			**1,958,057**
Installation			
Foundations & supports			
Handling & erection			
Electrical			
Piping			
Insulation			
Painting			
Installation Subtotal Standard Expenses (1)			**1,958,057**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Site Specific - Other		Site Specific	NA
Total Site Specific Costs			NA
Installation Total			**3,729,632**
Total Direct Capital Cost, DC			**5,687,689**
Indirect Capital Costs			
Engineering, supervision	5%	of purchased equip cost (B)	97,903
Construction & field expenses	10%	of purchased equip cost (B)	195,806
Contractor fees	0%	of purchased equip cost (B)	0
Start-up	1%	of purchased equip cost (B)	19,581
Performance test	1%	of purchased equip cost (B)	19,581
Model Studies	NA	of purchased equip cost (B)	NA
Contingencies	3%	of purchased equip cost (B)	58,742
Total Indirect Capital Costs, IC	20%	of purchased equip cost (B)	**391,611**
Ozone Generator, Installed Cost			**0**
Total Capital Investment (TCI) = DC + IC (2)			**6,079,300**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**6,079,300**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	NA		-
Supervisor	NA		-
Maintenance			
Maintenance Labor	37.00	$/Hr, 0.1 hr/8 hr shift, 7652.6 hr/yr	3,539
Maintenance Materials	100%	of maintenance labor costs	3,539
Utilities, Supplies, Replacements & Waste Management			
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
Total Annual Direct Operating Costs			**7,079**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	4,247
Administration (2% total capital costs)	2%	of total capital costs (TCI)	121,586
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	60,793
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	60,793
Capital Recovery	0.0837	for a 20- year equipment life and a 5.5% interest rate	508,712
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**756,131**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**763,210**

Great River Energy Coal Creek Station
BART Supplement - NOx Emission Control Cost Analysis
Table A-4: Unit 1 NOx Control - Foster Wheeler LNC3+

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Parts & Equipment:		
Equipment Life	5	years
CRF	0.0000	
Rep part cost per unit	0	$\$/ft^3$
Amount Required	0	ft^3
Packing Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:			
Equipment Life	3		
CRF	0.3707		
Rep part cost per unit	0	$ each	
Amount Required	0	Number	
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax	
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr	OAQPS list replacement times from 5 - 20 min per bag.
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	
Annualized Cost	**0**		

Electrical Use							
	Flow acfm		D P in H2O	Efficiency	Hp	kW	
Blower, Scrubber	2,234,300		0	0.7	-	0.0	EPA Cost Cont Manual 6th ed Section 5.2 Chapter 1 Eq 1.48
	Flow	Liquid SPGR	D P ft H2O	Efficiency	Hp	kW	
Circ Pump	000 gpm	1	0	0.7	-	0.0	EPA Cost Cont Manual 6th ed Section 5.2 Chapter 1 Eq 1.49
H2O WW Disch	0 gpm	1	0	0.7	-	0.0	EPA Cost Cont Manual 6th ed Section 5.2 Chapter 1 Eq 1.49
			lb/hr O_3				
LTO Electric Use	4.5 kW/lb O_3					0	
Other							
Total						0.0	

Reagent Use & Other Operating Costs						
Ozone Needed	1.8	lb O3/lb NOx	-	lb/hr O3		
Oxygen Needed	10%	wt O2 to O3 conversion		0 lb/hr O2		0 scfh O2
LTO Cooling Water	150	gal/lb O3	0	gpm		
Liquid/Gas ratio	0.0	* L/G = Gal/1,000 acf				
Circulating Water Rate	0	gpm				
Water Makeup Rate/WW Disch =	20%	of circulating water rate =		0 gpm		
Scrubber Cost	10	$/scfm Gas	$0		Incremental cost per BOC. Need to increase vessel size over standard absorber.	
Ozone Generator	$350	lb O3/day	$0	Installed	Installed cost factor per BOC.	

Operating Cost Calculations			**Annual hours of operation:**			**7,653**	
			Utilization Rate:			**100%**	
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Operating Labor							
Op Labor	0	$/Hr	0.1	hr/8 hr shift	96	0	$/Hr, 0.1 hr/8 hr shift, 7652.6 hr/yr
Supervisor	15%	of Op.			NA	-	15% of Operator Costs
Maintenance							
Maint Labor	37.00	$/Hr	0.1	hr/8 hr shift	96	3,539	$/Hr, 0.1 hr/8 hr shift, 7652.6 hr/yr
Maint Mtls	100	% of Maintenance Labor			NA	3,539	100% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.060	$/kwh	0.0	kW-hr	0	0	$/kwh, 0 kW-hr, 7652.6 hr/yr, 100% utilization
Water	0.31	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 7652.6 hr/yr, 100% utilization
Cooling Water	0.32	$kgal	0.0	gpm	0	0	$kgal, 0 gpm, 7652.6 hr/yr, 100% utilization
Comp Air	0.37	$/kscf	0	kscfm	0	0	$/kscf, 0 kscfm, 7652.6 hr/yr, 100% utilization
WW Treat Neutralization	1.96	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 7652.6 hr/yr, 100% utilization
WW Treat Biotreatement	4.96	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 7652.6 hr/yr, 100% utilization
SW Disposal	0.00	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 7652.6 hr/yr, 100% utilization
Haz W Disp	326	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 7652.6 hr/yr, 100% utilization
Waste Transport	5.61	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 7652.6 hr/yr, 100% utilization
Lost Ash Sales	12.30	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 7652.6 hr/yr, 100% utilization
Lime	90.0	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 7652.6 hr/yr, 100% utilization
Caustic	364.4	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 7652.6 hr/yr, 100% utilization
Oxygen	17.9	kscf	0.0	kscf/hr	0	0	kscf, 0 kscf/hr, 7652.6 hr/yr, 100% utilization

*annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

Great River Energy Coal Creek Station

BART Supplement - NOx Emission Control Cost Analysis

Table A-5: Unit 1 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (Maintain Ash Sales)

Operating Unit: **Unit 1**

Emission Unit Number	EU-1		Stack/Vent Number	SV-1	
Desgin Capacity	6,015	MMBtu/hr	Standardized Flow Rate	866,294	scfm @ 32º F
Expected Utiliztion Rate	100%		Temperature	330	Deg F
Expected Annual Hours of Operation	7,653	Hours	Moisture Content	13.3%	
Annual Interest Rate	5.5%		Actual Flow Rate	2,234,300	acfm
Expected Equipment Life	20	yrs	Standardized Flow Rate	1,391,000	scfm @ 330º F
Baseline NOx	0.200	lb/MMBtu	Dry Std Flow Rate	1,205,997	dscfm @ 330º F

CONTROL EQUIPMENT COSTS

Capital Costs			
Direct Capital Costs			
Purchased Equipment (A)			3,700,000
Purchased Equipment Total (B)	43%	of control device cost (A) + Retrofit Factor	**8,465,600**
Installation - Standard Costs	42%	of purchased equip cost (B)	1,540,000
Installation - Site Specific Costs			0
Installation Total			0
Total Direct Capital Cost, DC			0
Total Indirect Capital Costs, IC	0%	of purchased equip cost (B)	0
Total Capital Investment (TCI) = DC + IC			**12,176,084**
Operating Costs			
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.	3,282,068
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	1,018,887
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**4,300,954**

Emission Control Cost Calculation

Pollutant	**Max Emis Lb/Hr**	**Annual T/Yr**	**Cont Eff %**	**Exit Conc**	**Conc Units**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
Nitrous Oxides (NOx)	1,205.2	4,611.4	25.0%			3458.5	1,152.8	3,731

Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1

Notes & Assumptions

1. November 2011 SNCR Evaluation from URS
2. SNCR Maintenance Costs EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.21
3. Process, emissions and cost data listed above is for one unit.
4. For units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal
5. Retrofit factor of 60% used by URS based on site visit to Coal Creek Station.
6. SW disposal and fly ash sales data from Nov. 2011 Golder Fly Ash Evaluation, Appendix B2

Great River Energy Coal Creek Station

BART Supplement - NOx Emission Control Cost Analysis

Table A-5: Unit 1 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (Maintain Ash Sales)

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) (1)			**3,700,000**
Purchased Equipment Costs (A)			
Instrumentation	10%	of control device cost (A)	370,000
Site Specific and Prime Contractor Markup	28%	of control device cost (A)	1,036,000
Freight	5%	of control device cost (A)	185,000
Purchased Equipment Total (A)	43%		5,291,000
Purchased Equipment Total (A) + Retrofit Factor			**8,465,600**
Indirect Installation			
General Facilities	5%	of purchased equip cost (A)	420,000
Engineering & Home Office	10%	of purchased equip cost (A)	850,000
Process Contingency	6%	of purchased equip cost (A)	488,000
Total Indirect Installation Costs (B)	21%	of purchased equip cost (A)	**1,758,000**
Project Contingeny (C)	42%	of (A + B)	**1,540,000**
Total Plant Cost D		A + B + C	**11,763,600**
Allowance for Funds During Construction (E)		0 for SNCR	**0**
Royalty Allowance (F)		0 for SNCR	**0**
Pre Production Costs (G)	2%	of (D+E))	**236,000**
Inventory Capital (H)		Reagent Vol * $/gal	**134,484**
Intial Catalyst and Chemicals (I)		0 for SNCR	**0**
Prepaid Rayalties (J)			**42,000**
Total Capital Investment (TCI) = DC + IC		D + E + F + G +H + I + J	**12,176,084**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**12,176,084**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	NA		-
Supervisor	NA		-
Maintenance			
Maintenance Total	1.50	% of Total Capital Investment	182,641
Maintenance Materials	NA	% of Maintenance Labor	-
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.06	$/kwh, 61 kW-hr, 7652.6 hr/yr, 100% utilization	28,218
Water	0.31	$/kgal, 3,480 gph, 7652.6 hr/yr, 100% utilization	8,256
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
Urea	500.00	$/ton, 1 ton/hr, 7652.6 hr/yr, 100% utilization	3,062,953
NA	NA		-
Total Annual Direct Operating Costs			**3,282,068**
Indirect Operating Costs			
Overhead	NA	of total labor and material costs	NA
Administration (2% total capital costs)	NA	of total capital costs (TCI)	NA
Property tax (1% total capital costs)	NA	of total capital costs (TCI)	NA
Insurance (1% total capital costs)	NA	of total capital costs (TCI)	NA
Capital Recovery	0.0837	for a 20- year equipment life and a 5.5% interest rate	1,018,887
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**1,018,887**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**4,300,954**

Great River Energy Coal Creek Station

BART Supplement - NOx Emission Control Cost Analysis

Table A-5: Unit 1 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (Maintain Ash Sales)

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Catayst		<- Enter Equipment Name to Get Cost
Equipment Life	5	years
CRF	0.2342	
Rep part cost per unit	0	$\$/ft^3$
Amount Required	12	ft^3
Packing Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:		<- Enter Equipment Name to Get Cost	
Equipment Life	2	years	
CRF	0.0000		
Rep part cost per unit	0	$\$/ft^3$	
Amount Required	0	Cages	
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax	See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs
Installation Labor	0	10 min per bag, Labor + Overhead (68% = $29.65/hr)	
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	EPA CCM list replacement times from 5 - 20 min per bag.
Annualized Cost	**0**		

Electrical Use			
NOx in	0.20	lb/MMBtu	kW
NSR	0.60		
Power			61.0
Total			61.0

Reagent Use & Other Operating Costs					
NOx in	0.20	lb/MMBtu	Urea Use	1601	lb/hr
Efficiency	25%		Volume 14 day inventory	269	ton
Duty	6,015	MMBtu/hr	Inventory Cost	$134,484	
Water Use	3480	gal/hr			

Operating Cost Calculations — **Annual hours of operation: 7,653** — **Utilization Rate: 100%**

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Operating Labor							
Op Labor	37	$/Hr	0.0	hr/8 hr shift	0	0	$/Hr, 0.0 hr/8 hr shift, 7652.6 hr/yr
Supervisor	15%	of Op.			NA	-	15% of Operator Costs
Maintenance							
Maintenance Total	1.5	% of Total Capital Investment				182,641	% of Total Capital Investment
Maint Mtls	0	% of Maintenance Labor			NA	0	0% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.060	$/kwh	61.0	kW-hr	466,809	28,218	$/kwh, 61 kW-hr, 7652.6 hr/yr, 100% utilization
Water	0.31	$/kgal	3,480.0	gph	26,631	8,256	$/kgal, 3,480 gph, 7652.6 hr/yr, 100% utilization
Cooling Water	0.32	$kgal	0.0	gpm	0	0	$kgal, 0 gpm, 7652.6 hr/yr, 100% utilization
Comp Air	0.37	$/kscf	0.0	scfm/kacfm**	0	0	$/kscf, 0 scfm/kacfm**, 7652.6 hr/yr, 100% utilization
WW Treat Neutralization	1.96	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 7652.6 hr/yr, 100% utilization
WW Treat Biotreatement	4.96	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 7652.6 hr/yr, 100% utilization
SW Disposal	0.00	$/ton	7.2	ton/hr	55,000	0	$/ton, 7 ton/hr, 7652.6 hr/yr, 100% utilization
Haz W Disp	326	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 7652.6 hr/yr, 100% utilization
Waste Transport	5.61	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 7652.6 hr/yr, 100% utilization
Lost Ash Sales	12.30	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 7652.6 hr/yr, 100% utilization
Lime	90.00	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 7652.6 hr/yr, 100% utilization
Urea	500.00	$/ton	0.8005	ton/hr	6,126	3,062,953	$/ton, 1 ton/hr, 7652.6 hr/yr, 100% utilization
Oxygen	17.91	kscf	0.0	kscf/hr	0	0	kscf, 0 kscf/hr, 7652.6 hr/yr, 100% utilization

** Std Air use is 2 scfm/kacfm

*annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

Great River Energy Coal Creek Station
BART Supplement - NOx Emission Control Cost Analysis
Table A-6: Unit 1 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (30% Lost Ash Sales)

Operating Unit: **Unit 1**

Emission Unit Number	EU-1		Stack/Vent Number	SV-1	
Desgin Capacity	6,015	MMBtu/hr	Standardized Flow Rate	866,294	scfm @ 32º F
Expected Utiliztion Rate	100%		Temperature	330	Deg F
Expected Annual Hours of Operation	7,653	Hours	Moisture Content	13.3%	
Annual Interest Rate	5.5%		Actual Flow Rate	2,234,300	acfm
Expected Equipment Life	20	yrs	Standardized Flow Rate	1,391,000	scfm @ 330º F
Baseline NOx	0.200	lb/MMBtu	Dry Std Flow Rate	1,205,997	dscfm @ 330º F

CONTROL EQUIPMENT COSTS

Capital Costs			
Direct Capital Costs			
Purchased Equipment (A)			3,700,000
Purchased Equipment Total (B)	43%	of control device cost (A) + Retrofit Factor	**8,465,600**
Installation - Standard Costs	42%	of purchased equip cost (B)	1,540,000
Installation - Site Specific Costs			0
Installation Total			0
Total Direct Capital Cost, DC			0
Total Indirect Capital Costs, IC	0%	of purchased equip cost (B)	0
Total Capital Investment (TCI) = DC + IC			**12,176,084**
Operating Costs			
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.	6,521,143
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	1,018,887
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**7,540,029**

Emission Control Cost Calculation

Pollutant	**Max Emis Lb/Hr**	**Annual T/Yr**	**Cont Eff %**	**Exit Conc**	**Conc Units**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
Nitrous Oxides (NOx)	1,205.2	4,611.4	25.0%			3458.5	1,152.8	6,540

Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1

Notes & Assumptions

1. November 2011 SNCR Evaluation from URS
2. SNCR Maintenance Costs EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.21
3. Process, emissions and cost data listed above is for one unit.
4. For units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal
5. Retrofit factor of 60% used by URS based on site visit to Coal Creek Station.
6. SW disposal and fly ash sales data from Nov. 2011 Golder Fly Ash Evaluation, Appendix B2

Great River Energy Coal Creek Station
BART Supplement - NOx Emission Control Cost Analysis
Table A-6: Unit 1 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (30% Lost Ash Sales)

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) (1)			**3,700,000**
Purchased Equipment Costs (A)			
Instrumentation	10%	of control device cost (A)	370,000
Site Specific and Prime Contractor Markup	28%	of control device cost (A)	1,036,000
Freight	5%	of control device cost (A)	185,000
Purchased Equipment Total (A)	43%		5,291,000
Purchased Equipment Total (A) + Retrofit Factor			**8,465,600**
Indirect Installation			
General Facilities	5%	of purchased equip cost (A)	420,000
Engineering & Home Office	10%	of purchased equip cost (A)	850,000
Process Contingency	6%	of purchased equip cost (A)	488,000
Total Indirect Installation Costs (B)	21%	of purchased equip cost (A)	**1,758,000**
Project Contingeny (C)	42%	of (A + B)	**1,540,000**
Total Plant Cost D		A + B + C	**11,763,600**
Allowance for Funds During Construction (E)		0 for SNCR	**0**
Royalty Allowance (F)		0 for SNCR	**0**
Pre Production Costs (G)	2%	of (D+E))	**236,000**
Inventory Capital (H)		Reagent Vol * $/gal	**134,484**
Intial Catalyst and Chemicals (I)		0 for SNCR	**0**
Prepaid Rayalties (J)			**42,000**
Total Capital Investment (TCI) = DC + IC		D + E + F + G +H + I + J	**12,176,084**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**12,176,084**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	NA		-
Supervisor	NA		-
Maintenance			
Maintenance Total	1.50	% of Total Capital Investment	182,641
Maintenance Materials	NA	% of Maintenance Labor	-
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.06	$/kwh, 61 kW-hr, 7652.6 hr/yr, 100% utilization	28,218
Water	0.31	$/kgal, 3,480 gph, 7652.6 hr/yr, 100% utilization	8,256
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
SW Disposal	5.44	$/ton, 15 ton/hr, 7652.6 hr/yr, 100% utilization	637,648
NA	NA		-
Ammonia Mitigation	5.61	$/ton, 19 ton/hr, 7652.6 hr/yr, 100% utilization	814,853
Lost Ash Sales	12.30	$/ton, 19 ton/hr, 7652.6 hr/yr, 100% utilization	1,786,575
NA	NA		-
Urea	500.00	$/ton, 1 ton/hr, 7652.6 hr/yr, 100% utilization	3,062,953
NA	NA		-
Total Annual Direct Operating Costs			**6,521,143**
Indirect Operating Costs			
Overhead	NA	of total labor and material costs	NA
Administration (2% total capital costs)	NA	of total capital costs (TCI)	NA
Property tax (1% total capital costs)	NA	of total capital costs (TCI)	NA
Insurance (1% total capital costs)	NA	of total capital costs (TCI)	NA
Capital Recovery	0.0837	for a 20- year equipment life and a 5.5% interest rate	1,018,887
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**1,018,887**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**7,540,029**

Great River Energy Coal Creek Station

BART Supplement - NOx Emission Control Cost Analysis

Table A-6: Unit 1 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (30% Lost Ash Sales)

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Catayst		<- Enter Equipment Name to Get Cost
Equipment Life	5	years
CRF	0.2342	
Rep part cost per unit	0	$/ft^3
Amount Required	12	ft^3
Packing Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:		<- Enter Equipment Name to Get Cost	
Equipment Life	2	years	
CRF	0.0000		
Rep part cost per unit	0	$/ft^3	
Amount Required	0	Cages	
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax	See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs
Installation Labor	0	10 min per bag, Labor + Overhead (68% = $29.65/hr)	
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	EPA CCM list replacement times from 5 - 20 min per bag.
Annualized Cost	**0**		

Electrical Use			
NOx in	0.20	lb/MMBtu	kW
NSR	0.60		
Power			61.0
Total			61.0

Reagent Use & Other Operating Costs					
NOx in	0.20	lb/MMBtu	Urea Use	1601	lb/hr
Efficiency	25%		Volume 14 day inventory	269	ton
Duty	6,015	MMBtu/hr	Inventory Cost	$134,484	
Water Use	3480	gal/hr			

Operating Cost Calculations — **Annual hours of operation: 7,653** — **Utilization Rate: 100%**

Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
Operating Labor							
Op Labor	37	$/Hr	0.0	hr/8 hr shift	0	0	$/Hr, 0.0 hr/8 hr shift, 7652.6 hr/yr
Supervisor	15%	of Op.			NA	-	15% of Operator Costs
Maintenance							
Maintenance Total	1.5	% of Total Capital Investment				182,641	% of Total Capital Investment
Maint Mtls	0	% of Maintenance Labor			NA	0	0% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.060	$/kwh	61.0	kW-hr	466,809	28,218	$/kwh, 61 kW-hr, 7652.6 hr/yr, 100% utilization
Water	0.31	$/kgal	3,480.0	gph	26,631	8,256	$/kgal, 3,480 gph, 7652.6 hr/yr, 100% utilization
Cooling Water	0.32	$kgal	0.0	gpm	0	0	$kgal, 0 gpm, 7652.6 hr/yr, 100% utilization
Comp Air	0.37	$/kscf	0.0	scfm/kacfm**	0	0	$/kscf, 0 scfm/kacfm**, 7652.6 hr/yr, 100% utilization
WW Treat Neutralization	1.96	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 7652.6 hr/yr, 100% utilization
WW Treat Biotreatement	4.96	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 7652.6 hr/yr, 100% utilization
SW Disposal	5.44	$/ton	15.3	ton/hr	117,250	637,648	$/ton, 15 ton/hr, 7652.6 hr/yr, 100% utilization
Haz W Disp	326	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 7652.6 hr/yr, 100% utilization
Ammonia Mitigation	5.61	$/ton	19.0	ton/hr	145,250	814,853	$/ton, 19 ton/hr, 7652.6 hr/yr, 100% utilization
Lost Ash Sales	12.30	$/ton	19.0	ton/hr	145,250	1,786,575	$/ton, 19 ton/hr, 7652.6 hr/yr, 100% utilization
Lime	90.00	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 7652.6 hr/yr, 100% utilization
Urea	500.00	$/ton	0.8005	ton/hr	6,126	3,062,953	$/ton, 1 ton/hr, 7652.6 hr/yr, 100% utilization
Oxygen	17.91	kscf	0.0	kscf/hr	0	0	kscf, 0 kscf/hr, 7652.6 hr/yr, 100% utilization
					4,168,675		

** Std Air use is 2 scfm/kacfm

*annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

Great River Energy Coal Creek Station

BART Supplement - NOx Emission Control Cost Analysis

Table A-7: Unit 1 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (100% Lost Ash Sales)

Operating Unit: **Unit 1**

Emission Unit Number	EU-1		Stack/Vent Number	SV-1	
Desgin Capacity	6,015	MMBtu/hr	Standardized Flow Rate	866,294	scfm @ 32º F
Expected Utiliztion Rate	100%		Temperature	330	Deg F
Expected Annual Hours of Operation	7,653	Hours	Moisture Content	13.3%	
Annual Interest Rate	5.5%		Actual Flow Rate	2,234,300	acfm
Expected Equipment Life	20	yrs	Standardized Flow Rate	1,391,000	scfm @ 330º F
Baseline NOx	0.200	lb/MMBtu	Dry Std Flow Rate	1,205,997	dscfm @ 330º F

CONTROL EQUIPMENT COSTS

Capital Costs								
Direct Capital Costs								
Purchased Equipment (A)								3,700,000
Purchased Equipment Total (B)	43%	of control device cost (A) + Retrofit Factor						**8,465,600**
Installation - Standard Costs	42%	of purchased equip cost (B)						1,540,000
Installation - Site Specific Costs								0
Installation Total								0
Total Direct Capital Cost, DC								0
Total Indirect Capital Costs, IC	0%	of purchased equip cost (B)						0
Total Capital Investment (TCI) = DC + IC								**12,176,084**
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.						7,775,768
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost						1,018,887
Total Annual Cost (Annualized Capital Cost + Operating Cost)								**8,794,654**

Emission Control Cost Calculation

Pollutant	**Max Emis Lb/Hr**	**Annual T/Yr**	**Cont Eff %**	**Exit Conc**	**Conc Units**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
Nitrous Oxides (NOx)	1,205.2	4,611.4	25.0%			3458.5	1,152.8	7,629

Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1

Notes & Assumptions

1 November 2011 SNCR Evaluation from URS
2 SNCR Maintenance Costs EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.21
3 Process, emissions and cost data listed above is for one unit.
4 For units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal
5 Retrofit factor of 60% used by URS based on site visit to Coal Creek Station.
6 SW disposal and fly ash sales data from Nov. 2011 Golder Fly Ash Evaluation, Appendix B2

Great River Energy Coal Creek Station
BART Supplement - NOx Emission Control Cost Analysis
Table A-7: Unit 1 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (100% Lost Ash Sales)

CAPITAL COSTS		
Direct Capital Costs		
Purchased Equipment (A) (1)		**3,700,000**
Purchased Equipment Costs (A)		
Instrumentation	10% of control device cost (A)	370,000
Site Specific and Prime Contractor Markup	28% of control device cost (A)	1,036,000
Freight	5% of control device cost (A)	185,000
Purchased Equipment Total (A)	43%	5,291,000
Purchased Equipment Total (A) + Retrofit Factor		**8,465,600**
Indirect Installation		
General Facilities	5% of purchased equip cost (A)	420,000
Engineering & Home Office	10% of purchased equip cost (A)	850,000
Process Contingency	6% of purchased equip cost (A)	488,000
Total Indirect Installation Costs (B)	21% of purchased equip cost (A)	**1,758,000**
Project Contingeny (C)	42% of (A + B)	**1,540,000**
Total Plant Cost D	A + B + C	**11,763,600**
Allowance for Funds During Construction (E)	0 for SNCR	**0**
Royalty Allowance (F)	0 for SNCR	**0**
Pre Production Costs (G)	2% of (D+E))	**236,000**
Inventory Capital (H)	Reagent Vol * $/gal	**134,484**
Intial Catalyst and Chemicals (I)	0 for SNCR	**0**
Prepaid Rayalties (J)		**42,000**
Total Capital Investment (TCI) = DC + IC	D + E + F + G +H + I + J	**12,176,084**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost		**12,176,084**
OPERATING COSTS		
Direct Annual Operating Costs, DC		
Operating Labor		
Operator	NA	-
Supervisor	NA	-
Maintenance		
Maintenance Total	1.50 % of Total Capital Investment	182,641
Maintenance Materials	NA % of Maintenance Labor	-
Utilities, Supplies, Replacements & Waste Management		
Electricity	0.06 $/kwh, 61 kW-hr, 7652.6 hr/yr, 100% utilization	28,218
Water	0.31 $/kgal, 3,480 gph, 7652.6 hr/yr, 100% utilization	8,256
NA	NA	-
NA	NA	-
NA	NA	-
NA	NA	-
SW Disposal	7.40 $/ton, 34 ton/hr, 7652.6 hr/yr, 100% utilization	1,941,450
NA	NA	-
NA	NA	-
Lost Ash Sales	12.30 $/ton, 27 ton/hr, 7652.6 hr/yr, 100% utilization	2,552,250
NA	NA	-
Urea	500.00 $/ton, 1 ton/hr, 7652.6 hr/yr, 100% utilization	3,062,953
NA	NA	-
Total Annual Direct Operating Costs		**7,775,768**
Indirect Operating Costs		
Overhead	NA of total labor and material costs	NA
Administration (2% total capital costs)	NA of total capital costs (TCI)	NA
Property tax (1% total capital costs)	NA of total capital costs (TCI)	NA
Insurance (1% total capital costs)	NA of total capital costs (TCI)	NA
Capital Recovery	0.0837 for a 20- year equipment life and a 5.5% interest rate	1,018,887
Total Annual Indirect Operating Costs	Sum indirect oper costs + capital recovery cost	**1,018,887**
Total Annual Cost (Annualized Capital Cost + Operating Cost)		**8,794,654**

Great River Energy Coal Creek Station

BART Supplement - NOx Emission Control Cost Analysis

Table A-7: Unit 1 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (100% Lost Ash Sales)

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Catayst		<- Enter Equipment Name to Get Cost
Equipment Life	5	years
CRF	0.2342	
Rep part cost per unit	0	$/ft^3
Amount Required	12	ft^3
Packing Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:		<- Enter Equipment Name to Get Cost	
Equipment Life	2	years	
CRF	0.0000		
Rep part cost per unit	0	$/ft^3	
Amount Required	0	Cages	
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax	See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs
Installation Labor	0	10 min per bag, Labor + Overhead (68% = $29.65/hr)	
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	EPA CCM list replacement times from 5 - 20 min per bag.
Annualized Cost	**0**		

Electrical Use			
NOx in	0.20	lb/MMBtu	kW
NSR	0.60		
Power			61.0
Total			61.0

Reagent Use & Other Operating Costs					
NOx in	0.20	lb/MMBtu	Urea Use	1601	lb/hr
Efficiency	25%		Volume 14 day inventory	269	ton
Duty	6,015	MMBtu/hr	Inventory Cost	$134,484	
Water Use	3480	gal/hr			

Operating Cost Calculations — **Annual hours of operation: 7,653**; **Utilization Rate: 100%**

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Operating Labor							
Op Labor	37	$/Hr	0.0	hr/8 hr shift	0	0	$/Hr, 0.0 hr/8 hr shift, 7652.6 hr/yr
Supervisor	15%	of Op.			NA	-	15% of Operator Costs
Maintenance							
Maintenance Total	1.5	% of Total Capital Investment				182,641	% of Total Capital Investment
Maint Mtls	0	% of Maintenance Labor			NA	0	0% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.060	$/kwh	61.0	kW-hr	466,809	28,218	$/kwh, 61 kW-hr, 7652.6 hr/yr, 100% utilization
Water	0.31	$/kgal	3,480.0	gph	26,631	8,256	$/kgal, 3,480 gph, 7652.6 hr/yr, 100% utilization
Cooling Water	0.32	$kgal	0.0	gpm	0	0	$kgal, 0 gpm, 7652.6 hr/yr, 100% utilization
Comp Air	0.37	$/kscf	0.0	scfm/kacfm**	0	0	$/kscf, 0 scfm/kacfm**, 7652.6 hr/yr, 100% utilization
WW Treat Neutralization	1.96	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 7652.6 hr/yr, 100% utilization
WW Treat Biotreatement	4.96	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 7652.6 hr/yr, 100% utilization
SW Disposal	7.40	$/ton	34.3	ton/hr	262,500	1,941,450	$/ton, 34 ton/hr, 7652.6 hr/yr, 100% utilization
Haz W Disp	326	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 7652.6 hr/yr, 100% utilization
Waste Transport	5.61	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 7652.6 hr/yr, 100% utilization
Lost Ash Sales	12.30	$/ton	27.1	ton/hr	207,500	2,552,250	$/ton, 27 ton/hr, 7652.6 hr/yr, 100% utilization
Lime	90.00	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 7652.6 hr/yr, 100% utilization
Urea	500.00	$/ton	0.8005	ton/hr	6,126	3,062,953	$/ton, 1 ton/hr, 7652.6 hr/yr, 100% utilization
Oxygen	17.91	kscf	0.0	kscf/hr	0	0	kscf, 0 kscf/hr, 7652.6 hr/yr, 100% utilization
						5,955,250	

** Std Air use is 2 scfm/kacfm

*annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

Great River Energy Coal Creek Station

BART Supplement - NOx Emission Control Cost Analysis

Table A-8: Unit 2 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (Maintain Ash Sales)

Operating Unit: **Unit 2**

Emission Unit Number	EU-2		Stack/Vent Number	SV-2	
Desgin Capacity	6,022	MMBtu/hr	Standardized Flow Rate	866,294	scfm @ 32º F
Expected Utiliztion Rate	100%		Temperature	330	Deg F
Expected Annual Hours of Operation	8,410	Hours	Moisture Content	13.3%	
Annual Interest Rate	5.5%		Actual Flow Rate	2,234,300	acfm
Expected Equipment Life	20	yrs	Standardized Flow Rate	1,391,000	scfm @ 330º F
Baseline NOx	0.153	lb/MMBtu	Dry Std Flow Rate	1,205,997	dscfm @ 330º F

CONTROL EQUIPMENT COSTS

Capital Costs			
Direct Capital Costs			
Purchased Equipment (A)			3,600,000
Purchased Equipment Total (B)	43%	of control device cost (A) + Retrofit Factor	**8,236,800**
Installation - Standard Costs	41%	of purchased equip cost (B)	1,490,000
Installation - Site Specific Costs			0
Installation Total			0
Total Direct Capital Cost, DC			0
Total Indirect Capital Costs, IC	0%	of purchased equip cost (B)	0
Total Capital Investment (TCI) = DC + IC			**11,803,820**
Operating Costs			
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.	2,634,266
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	987,736
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**3,622,002**

Emission Control Cost Calculation

Pollutant	**Max Emis Lb/Hr**	**Annual T/Yr**	**Cont Eff %**	**Exit Conc**	**Conc Units**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
Nitrous Oxides (NOx)	918.5	3,862.3	20.0%			3089.8	772.5	4,689

Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1

Notes & Assumptions

1. November 2011 SNCR Evaluation from URS
2. SNCR Maintenance Costs EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.21
3. Process, emissions and cost data listed above is for one unit.
4. For units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal
5. Retrofit factor of 60% used by URS based on site visit to Coal Creek Station.
6. SW disposal and fly ash sales data from Nov. 2011 Golder Fly Ash Evaluation, Appendix B2

Great River Energy Coal Creek Station

BART Supplement - NOx Emission Control Cost Analysis

Table A-8: Unit 2 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (Maintain Ash Sales)

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) (1)			**3,600,000**
Purchased Equipment Costs (A)			
Instrumentation	10%	of control device cost (A)	360,000
Site Specific and Prime Contractor Markup	28%	of control device cost (A)	1,008,000
Freight	5%	of control device cost (A)	180,000
Purchased Equipment Total (A)	43%		5,148,000
Purchased Equipment Total (A) + Retrofit Factor			**8,236,800**
Indirect Installation			
General Facilities	5%	of purchased equip cost (A)	420,000
Engineering & Home Office	10%	of purchased equip cost (A)	820,000
Process Contingency	6%	of purchased equip cost (A)	472,000
Total Indirect Installation Costs (B)	21%	of purchased equip cost (A)	**1,712,000**
Project Contingeny (C)	41%	of (A + B)	**1,490,000**
Total Plant Cost D		A + B + C	**11,438,800**
Allowance for Funds During Construction (E)		0 for SNCR	**0**
Royalty Allowance (F)		0 for SNCR	**0**
Pre Production Costs (G)	2%	of (D+E))	**227,000**
Inventory Capital (H)		Reagent Vol * $/gal	**97,020**
Intial Catalyst and Chemicals (I)		0 for SNCR	**0**
Prepaid Rayalties (J)			**41,000**
Total Capital Investment (TCI) = DC + IC		D + E + F + G +H + I + J	**11,803,820**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**11,803,820**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	NA		-
Supervisor	NA		-
Maintenance			
Maintenance Total	1.50	% of Total Capital Investment	177,057
Maintenance Materials	NA	% of Maintenance Labor	-
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.06	$/kwh, 44 kW-hr, 8409.6 hr/yr, 100% utilization	22,367
Water	0.31	$/kgal, 2,520 gph, 8409.6 hr/yr, 100% utilization	6,570
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
Urea	500.00	$/ton, 1 ton/hr, 8409.6 hr/yr, 100% utilization	2,428,272
NA	NA		-
Total Annual Direct Operating Costs			**2,634,266**
Indirect Operating Costs			
Overhead	NA	of total labor and material costs	NA
Administration (2% total capital costs)	NA	of total capital costs (TCI)	NA
Property tax (1% total capital costs)	NA	of total capital costs (TCI)	NA
Insurance (1% total capital costs)	NA	of total capital costs (TCI)	NA
Capital Recovery	0.0837	for a 20- year equipment life and a 5.5% interest rate	987,736
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**987,736**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**3,622,002**

Great River Energy Coal Creek Station

BART Supplement - NOx Emission Control Cost Analysis

Table A-8: Unit 2 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (Maintain Ash Sales)

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Catayst		<- Enter Equipment Name to Get Cost
Equipment Life	5	years
CRF	0.2342	
Rep part cost per unit	0	$/ft^3
Amount Required	12	ft^3
Packing Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:		<- Enter Equipment Name to Get Cost	
Equipment Life	2	years	
CRF	0.0000		
Rep part cost per unit	0	$/ft^3	
Amount Required	0	Cages	
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax	See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs
Installation Labor	0	10 min per bag, Labor + Overhead (68% = $29.65/hr)	
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	EPA CCM list replacement times from 5 - 20 min per bag.
Annualized Cost	**0**		

Electrical Use			
NOx in	0.15	lb/MMBtu	kW
NSR	0.44		
Power			44.0
Total			44.0

Reagent Use & Other Operating Costs					
NOx in	0.15	lb/MMBtu	Urea Use	1155	lb/hr
Efficiency	20%		Volume 14 day inventory	194	ton
Duty	6,022	MMBtu/hr	Inventory Cost	$97,020	
Water Use	2520	gal/hr			

Operating Cost Calculations — **Annual hours of operation: 8,410** — **Utilization Rate: 100%**

Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
Operating Labor							
Op Labor	37	$/Hr	0.0	hr/8 hr shift	0	0	$/Hr, 0.0 hr/8 hr shift, 8409.6 hr/yr
Supervisor	15%	of Op.			NA	-	15% of Operator Costs
Maintenance							
Maintenance Total	1.5	% of Total Capital Investment				177,057	% of Total Capital Investment
Maint Mtls	0	% of Maintenance Labor			NA	0	0% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.060	$/kwh	44.0	kW-hr	370,022	22,367	$/kwh, 44 kW-hr, 8409.6 hr/yr, 100% utilization
Water	0.31	$/kgal	2,520.0	gph	21,192	6,570	$/kgal, 2,520 gph, 8409.6 hr/yr, 100% utilization
Cooling Water	0.32	$kgal	0.0	gpm	0	0	$kgal, 0 gpm, 8409.6 hr/yr, 100% utilization
Comp Air	0.37	$/kscf	0.0	scfm/kacfm**	0	0	$/kscf, 0 scfm/kacfm**, 8409.6 hr/yr, 100% utilization
WW Treat Neutralization	1.96	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 8409.6 hr/yr, 100% utilization
WW Treat Biotreatement	4.96	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 8409.6 hr/yr, 100% utilization
SW Disposal	0.00	$/ton	6.5	ton/hr	55,000	0	$/ton, 7 ton/hr, 8409.6 hr/yr, 100% utilization
Haz W Disp	326	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8409.6 hr/yr, 100% utilization
Waste Transport	5.61	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8409.6 hr/yr, 100% utilization
Lost Ash Sales	12.30	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8409.6 hr/yr, 100% utilization
Lime	90.00	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 8409.6 hr/yr, 100% utilization
Urea	500.00	$/ton	0.5775	ton/hr	4,857	2,428,272	$/ton, 1 ton/hr, 8409.6 hr/yr, 100% utilization
Oxygen	17.91	kscf	0.0	kscf/hr	0	0	kscf, 0 kscf/hr, 8409.6 hr/yr, 100% utilization

** Std Air use is 2 scfm/kacfm

*annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

Great River Energy Coal Creek Station

BART Supplement - NOx Emission Control Cost Analysis

Table A-9: Unit 2 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (30% Lost Ash Sales)

Operating Unit: **Unit 2**

Emission Unit Number	EU-2		Stack/Vent Number	SV-2	
Desgin Capacity	6,022	MMBtu/hr	Standardized Flow Rate	866,294	scfm @ 32º F
Expected Utiliztion Rate	100%		Temperature	330	Deg F
Expected Annual Hours of Operation	8,410	Hours	Moisture Content	13.3%	
Annual Interest Rate	5.5%		Actual Flow Rate	2,234,300	acfm
Expected Equipment Life	20	yrs	Standardized Flow Rate	1,391,000	scfm @ 330º F
Baseline NOx	0.153	lb/MMBtu	Dry Std Flow Rate	1,205,997	dscfm @ 330º F

CONTROL EQUIPMENT COSTS

Capital Costs			
Direct Capital Costs			
Purchased Equipment (A)			3,600,000
Purchased Equipment Total (B)	43%	of control device cost (A) + Retrofit Factor	**8,236,800**
Installation - Standard Costs	41%	of purchased equip cost (B)	1,490,000
Installation - Site Specific Costs			0
Installation Total			0
Total Direct Capital Cost, DC			0
Total Indirect Capital Costs, IC	0%	of purchased equip cost (B)	0
Total Capital Investment (TCI) = DC + IC			**11,803,820**
Operating Costs			
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.	5,873,341
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	987,736
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**6,861,077**

Emission Control Cost Calculation

Pollutant	**Max Emis Lb/Hr**	**Annual T/Yr**	**Cont Eff %**	**Exit Conc**	**Conc Units**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
Nitrous Oxides (NOx)	918.5	3,862.3	20.0%			3089.8	772.5	8,882

Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1

Notes & Assumptions

1. November 2011 SNCR Evaluation from URS
2. SNCR Maintenance Costs EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.21
3. Process, emissions and cost data listed above is for one unit.
4. For units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal
5. Retrofit factor of 60% used by URS based on site visit to Coal Creek Station.
6. SW disposal and fly ash sales data from Nov. 2011 Golder Fly Ash Evaluation, Appendix B2

Great River Energy Coal Creek Station
BART Supplement - NOx Emission Control Cost Analysis
Table A-9: Unit 2 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (30% Lost Ash Sales)

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) (1)			**3,600,000**
Purchased Equipment Costs (A)			
Instrumentation	10%	of control device cost (A)	360,000
Site Specific and Prime Contractor Markup	28%	of control device cost (A)	1,008,000
Freight	5%	of control device cost (A)	180,000
Purchased Equipment Total (A)	43%		5,148,000
Purchased Equipment Total (A) + Retrofit Factor			**8,236,800**
Indirect Installation			
General Facilities	5%	of purchased equip cost (A)	420,000
Engineering & Home Office	10%	of purchased equip cost (A)	820,000
Process Contingency	6%	of purchased equip cost (A)	472,000
Total Indirect Installation Costs (B)	21%	of purchased equip cost (A)	**1,712,000**
Project Contingeny (C)	41%	of (A + B)	**1,490,000**
Total Plant Cost D		A + B + C	**11,438,800**
Allowance for Funds During Construction (E)		0 for SNCR	**0**
Royalty Allowance (F)		0 for SNCR	**0**
Pre Production Costs (G)	2%	of (D+E))	**227,000**
Inventory Capital (H)		Reagent Vol * $/gal	**97,020**
Intial Catalyst and Chemicals (I)		0 for SNCR	**0**
Prepaid Rayalties (J)			**41,000**
Total Capital Investment (TCI) = DC + IC		D + E + F + G +H + I + J	**11,803,820**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**11,803,820**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	NA		-
Supervisor	NA		-
Maintenance			
Maintenance Total	1.50	% of Total Capital Investment	177,057
Maintenance Materials	NA	% of Maintenance Labor	-
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.06	$/kwh, 44 kW-hr, 8409.6 hr/yr, 100% utilization	22,367
Water	0.31	$/kgal, 2,520 gph, 8409.6 hr/yr, 100% utilization	6,570
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
SW Disposal	5.44	$/ton, 14 ton/hr, 8409.6 hr/yr, 100% utilization	637,648
NA	NA		-
Ammonia Mitigation	5.61	$/ton, 17 ton/hr, 8409.6 hr/yr, 100% utilization	814,853
Lost Ash Sales	12.30	$/ton, 17 ton/hr, 8409.6 hr/yr, 100% utilization	1,786,575
NA	NA		-
Urea	500.00	$/ton, 1 ton/hr, 8409.6 hr/yr, 100% utilization	2,428,272
NA	NA		-
Total Annual Direct Operating Costs			**5,873,341**
Indirect Operating Costs			
Overhead	NA	of total labor and material costs	NA
Administration (2% total capital costs)	NA	of total capital costs (TCI)	NA
Property tax (1% total capital costs)	NA	of total capital costs (TCI)	NA
Insurance (1% total capital costs)	NA	of total capital costs (TCI)	NA
Capital Recovery	0.0837	for a 20- year equipment life and a 5.5% interest rate	987,736
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**987,736**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**6,861,077**

Great River Energy Coal Creek Station

BART Supplement - NOx Emission Control Cost Analysis

Table A-9: Unit 2 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (30% Lost Ash Sales)

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Catayst		<- Enter Equipment Name to Get Cost
Equipment Life	5	years
CRF	0.2342	
Rep part cost per unit	0	$/ft^3
Amount Required	12	ft^3
Packing Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:		<- Enter Equipment Name to Get Cost	
Equipment Life	2	years	
CRF	0.0000		
Rep part cost per unit	0	$/ft^3	
Amount Required	0	Cages	
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax	See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs
Installation Labor	0	10 min per bag, Labor + Overhead (68% = $29.65/hr)	
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	EPA CCM list replacement times from 5 - 20 min per bag.
Annualized Cost	**0**		

Electrical Use			
NOx in	0.15	lb/MMBtu	kW
NSR	0.44		
Power			44.0
Total			44.0

Reagent Use & Other Operating Costs					
NOx in	0.15	lb/MMBtu	Urea Use	1155	lb/hr
Efficiency	20%		Volume 14 day inventory	194	ton
Duty	6,022	MMBtu/hr	Inventory Cost	$97,020	
Water Use	2520	gal/hr			

Operating Cost Calculations — **Annual hours of operation: 8,410** — **Utilization Rate: 100%**

Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
Operating Labor							
Op Labor	37	$/Hr	0.0	hr/8 hr shift	0	0	$/Hr, 0.0 hr/8 hr shift, 8409.6 hr/yr
Supervisor	15%	of Op.			NA	-	15% of Operator Costs
Maintenance							
Maintenance Total	1.5	% of Total Capital Investment				177,057	% of Total Capital Investment
Maint Mtls	0	% of Maintenance Labor			NA	0	0% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.060	$/kwh	44.0	kW-hr	370,022	22,367	$/kwh, 44 kW-hr, 8409.6 hr/yr, 100% utilization
Water	0.31	$/kgal	2,520.0	gph	21,192	6,570	$/kgal, 2,520 gph, 8409.6 hr/yr, 100% utilization
Cooling Water	0.32	$kgal	0.0	gpm	0	0	$kgal, 0 gpm, 8409.6 hr/yr, 100% utilization
Comp Air	0.37	$/kscf	0.0	scfm/kacfm**	0	0	$/kscf, 0 scfm/kacfm**, 8409.6 hr/yr, 100% utilization
WW Treat Neutralization	1.96	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 8409.6 hr/yr, 100% utilization
WW Treat Biotreatement	4.96	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 8409.6 hr/yr, 100% utilization
SW Disposal	5.44	$/ton	13.9	ton/hr	117,250	637,648	$/ton, 14 ton/hr, 8409.6 hr/yr, 100% utilization
Haz W Disp	326	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8409.6 hr/yr, 100% utilization
Ammonia Mitigation	5.61	$/ton	17.3	ton/hr	145,250	814,853	$/ton, 17 ton/hr, 8409.6 hr/yr, 100% utilization
Lost Ash Sales	12.30	$/ton	17.3	ton/hr	145,250	1,786,575	$/ton, 17 ton/hr, 8409.6 hr/yr, 100% utilization
Lime	90.00	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 8409.6 hr/yr, 100% utilization
Urea	500.00	$/ton	0.5775	ton/hr	4,857	2,428,272	$/ton, 1 ton/hr, 8409.6 hr/yr, 100% utilization
Oxygen	17.91	kscf	0.0	kscf/hr	0	0	kscf, 0 kscf/hr, 8409.6 hr/yr, 100% utilization

** Std Air use is 2 scfm/kacfm

*annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

Great River Energy Coal Creek Station

BART Supplement - NOx Emission Control Cost Analysis

Table A-10: Unit 2 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (100% Lost Ash Sales)

Operating Unit: **Unit 2**

Emission Unit Number	EU-2		Stack/Vent Number	SV-2	
Desgin Capacity	6,022	MMBtu/hr	Standardized Flow Rate	866,294	scfm @ 32º F
Expected Utiliztion Rate	100%		Temperature	330	Deg F
Expected Annual Hours of Operation	8,410	Hours	Moisture Content	13.3%	
Annual Interest Rate	5.5%		Actual Flow Rate	2,234,300	acfm
Expected Equipment Life	20	yrs	Standardized Flow Rate	1,391,000	scfm @ 330º F
Baseline NOx	0.153	lb/MMBtu	Dry Std Flow Rate	1,205,997	dscfm @ 330º F

CONTROL EQUIPMENT COSTS

Capital Costs			
Direct Capital Costs			
Purchased Equipment (A)			3,600,000
Purchased Equipment Total (B)	43%	of control device cost (A) + Retrofit Factor	**8,236,800**
Installation - Standard Costs	41%	of purchased equip cost (B)	1,490,000
Installation - Site Specific Costs			0
Installation Total			0
Total Direct Capital Cost, DC			0
Total Indirect Capital Costs, IC	0%	of purchased equip cost (B)	0
Total Capital Investment (TCI) = DC + IC			**11,803,820**
Operating Costs			
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.	7,127,966
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	987,736
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**8,115,702**

Emission Control Cost Calculation

Pollutant	**Max Emis Lb/Hr**	**Annual T/Yr**	**Cont Eff %**	**Exit Conc**	**Conc Units**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
Nitrous Oxides (NOx)	918.5	3,862.3	20.0%			3089.8	772.5	10,506

Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1

Notes & Assumptions

1. November 2011 SNCR Evaluation from URS
2. SNCR Maintenance Costs EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.21
3. Process, emissions and cost data listed above is for one unit.
4. For units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal
5. Retrofit factor of 60% used by URS based on site visit to Coal Creek Station.
6. SW disposal and fly ash sales data from Nov. 2011 Golder Fly Ash Evaluation, Appendix B2

Great River Energy Coal Creek Station

BART Supplement - NOx Emission Control Cost Analysis

Table A-10: Unit 2 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (100% Lost Ash Sales)

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) (1)			**3,600,000**
Purchased Equipment Costs (A)			
Instrumentation	10%	of control device cost (A)	360,000
Site Specific and Prime Contractor Markup	28%	of control device cost (A)	1,008,000
Freight	5%	of control device cost (A)	180,000
Purchased Equipment Total (A)	43%		5,148,000
Purchased Equipment Total (A) + Retrofit Factor			**8,236,800**
Indirect Installation			
General Facilities	5%	of purchased equip cost (A)	420,000
Engineering & Home Office	10%	of purchased equip cost (A)	820,000
Process Contingency	6%	of purchased equip cost (A)	472,000
Total Indirect Installation Costs (B)	21%	of purchased equip cost (A)	**1,712,000**
Project Contingeny (C)	41%	of (A + B)	**1,490,000**
Total Plant Cost D		A + B + C	**11,438,800**
Allowance for Funds During Construction (E)		0 for SNCR	**0**
Royalty Allowance (F)		0 for SNCR	**0**
Pre Production Costs (G)	2%	of (D+E))	**227,000**
Inventory Capital (H)		Reagent Vol * $/gal	**97,020**
Intial Catalyst and Chemicals (I)		0 for SNCR	**0**
Prepaid Rayalties (J)			**41,000**
Total Capital Investment (TCI) = DC + IC		D + E + F + G +H + I + J	**11,803,820**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**11,803,820**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	NA		-
Supervisor	NA		-
Maintenance			
Maintenance Total	1.50	% of Total Capital Investment	177,057
Maintenance Materials	NA	% of Maintenance Labor	-
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.06	$/kwh, 44 kW-hr, 8409.6 hr/yr, 100% utilization	22,367
Water	0.31	$/kgal, 2,520 gph, 8409.6 hr/yr, 100% utilization	6,570
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
SW Disposal	7.40	$/ton, 31 ton/hr, 8409.6 hr/yr, 100% utilization	1,941,450
NA	NA		-
NA	NA		-
Lost Ash Sales	12.30	$/ton, 25 ton/hr, 8409.6 hr/yr, 100% utilization	2,552,250
NA	NA		-
Urea	500.00	$/ton, 1 ton/hr, 8409.6 hr/yr, 100% utilization	2,428,272
NA	NA		-
Total Annual Direct Operating Costs			**7,127,966**
Indirect Operating Costs			
Overhead	NA	of total labor and material costs	NA
Administration (2% total capital costs)	NA	of total capital costs (TCI)	NA
Property tax (1% total capital costs)	NA	of total capital costs (TCI)	NA
Insurance (1% total capital costs)	NA	of total capital costs (TCI)	NA
Capital Recovery	0.0837	for a 20- year equipment life and a 5.5% interest rate	987,736
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**987,736**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**8,115,702**

Great River Energy Coal Creek Station

BART Supplement - NOx Emission Control Cost Analysis

Table A-10: Unit 2 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (100% Lost Ash Sales)

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Catayst		<- Enter Equipment Name to Get Cost
Equipment Life	5	years
CRF	0.2342	
Rep part cost per unit	0	$/ft^3
Amount Required	12	ft^3
Packing Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:		<- Enter Equipment Name to Get Cost	
Equipment Life	2	years	
CRF	0.0000		
Rep part cost per unit	0	$/ft^3	
Amount Required	0	Cages	
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax	See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs
Installation Labor	0	10 min per bag, Labor + Overhead (68% = $29.65/hr)	
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	EPA CCM list replacement times from 5 - 20 min per bag.
Annualized Cost	**0**		

Electrical Use			
NOx in	0.15	lb/MMBtu	kW
NSR	0.44		
Power			44.0
Total			44.0

Reagent Use & Other Operating Costs					
NOx in	0.15	lb/MMBtu	Urea Use	1155	lb/hr
Efficiency	20%		Volume 14 day inventory	194	ton
Duty	6,022	MMBtu/hr	Inventory Cost	$97,020	
Water Use	2520	gal/hr			

Operating Cost Calculations — **Annual hours of operation: 8,410** — **Utilization Rate: 100%**

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Operating Labor							
Op Labor	37	$/Hr	0.0	hr/8 hr shift	0	0	$/Hr, 0.0 hr/8 hr shift, 8409.6 hr/yr
Supervisor	15%	of Op.			NA	-	15% of Operator Costs
Maintenance							
Maintenance Total	1.5	% of Total Capital Investment				177,057	% of Total Capital Investment
Maint Mtls	0	% of Maintenance Labor			NA	0	0% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.060	$/kwh	44.0	kW-hr	370,022	22,367	$/kwh, 44 kW-hr, 8409.6 hr/yr, 100% utilization
Water	0.31	$/kgal	2,520.0	gph	21,192	6,570	$/kgal, 2,520 gph, 8409.6 hr/yr, 100% utilization
Cooling Water	0.32	$kgal	0.0	gpm	0	0	$kgal, 0 gpm, 8409.6 hr/yr, 100% utilization
Comp Air	0.37	$/kscf	0.0	scfm/kacfm**	0	0	$/kscf, 0 scfm/kacfm**, 8409.6 hr/yr, 100% utilization
WW Treat Neutralization	1.96	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 8409.6 hr/yr, 100% utilization
WW Treat Biotreatement	4.96	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 8409.6 hr/yr, 100% utilization
SW Disposal	7.40	$/ton	31.2	ton/hr	262,500	1,941,450	$/ton, 31 ton/hr, 8409.6 hr/yr, 100% utilization
Haz W Disp	326	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8409.6 hr/yr, 100% utilization
Waste Transport	5.61	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8409.6 hr/yr, 100% utilization
Lost Ash Sales	12.30	$/ton	24.7	ton/hr	207,500	2,552,250	$/ton, 25 ton/hr, 8409.6 hr/yr, 100% utilization
Lime	90.00	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 8409.6 hr/yr, 100% utilization
Urea	500.00	$/ton	0.5775	ton/hr	4,857	2,428,272	$/ton, 1 ton/hr, 8409.6 hr/yr, 100% utilization
Oxygen	17.91	kscf	0.0	kscf/hr	0	0	kscf, 0 kscf/hr, 8409.6 hr/yr, 100% utilization

** Std Air use is 2 scfm/kacfm

*annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

Appendix B

SNCR Evaluation for Coal Creek Station

COAL CREEK STATION
SELECTIVE NON-CATALYTIC REDUCTION (SNCR)
COST AND PERFORMANCE REVIEW

UNDERWOOD, MCLEAN COUNTY, NORTH DAKOTA

PROJECT NUMBER 28966-007

GREAT RIVER ENERGY

A Touchstone Energy Cooperative

URS ENERGY & CONSTRUCTION
7800 E. UNION AVE., SUITE 100
DENVER, CO 80237

Revision: 0 Status: Final

Introduction

Great River Energy (GRE) contracted URS Energy & Construction (URS) to conduct a review of the costs and performance capability of Selective Non-Catalytic Reduction (SNCR) at their Coal Creek Station (CCS) Units 1 & 2. This review was requested to provide; an estimate of the current capital cost for the installation of SNCR, operating and maintenance costs for SNCR, and the level of NOx reductions that can be achieved by SNCR.

The CCS units are identical 605 MW (gross - nominal) CE tangentially-fired furnaces burning North Dakota lignite. Each unit is equipped with Low NOx Burners (LNB) and Over-Fire Air (OFA). Unit 2's LNBs are 2nd generation technology while Unit 1's are the 1st generation installation. Unit 1 currently has a NOx emission rate of 0.20 lbs/MMBtu while Unit 2's NOx emission rate is 0.16 lbs/MMBtu.

The Final Best Achievable Retrofit Technology (BART) analysis submitted in 2007 was based on an inlet NOx concentration of 0.22 lbs/MMBtu and an SNCR removal efficiency of 50%. The current review uses the existing CCS NOx values presented in the previous paragraph and updated removal efficiencies. The following sections present data on SNCR capabilities and cost.

SNCR Capabilities

SNCR was originally developed in Japan in the 1970s for use on oil- and gas-fired units. Coal plant applications began in the late 1980s in Western Europe. Commercial U.S. installations on coal-fired utility boilers started in the early 1990s. More than 2 GW of capacity have been installed on coal-fired plants worldwide. SNCR requires injection of ammonia or urea into the proper temperature window within the back-pass of the furnace. The ammonia or urea reacts with NOx species to form nitrogen and water. Emission reduction capabilities range from 25% at 5-ppm ammonia slip to 30% at 10-ppm ammonia slip in most commercial installations.

An SNCR system will require the installation of reagent storage and transfer equipment, a multilevel injection grid and the necessary control instrumentation. Due to the elimination of the catalyst used in the SCR process, the SNCR consumption rates for ammonia or urea are typically 3-4 times the rates required for an SCR system on a per mole of NOx basis.

SNCR performance is dependent upon factors that are specific to each source. These factors are; flue gas temperature, flue gas residence time at temperatures within the reaction temperature range, reagent distribution, uncontrolled NOx levels, mixing between the injected reagent and the flue gas, and the CO and O2 concentrations in the flue gas stream. NOx reductions ranging from 25-75% have been reported with SNCR but the higher levels of reduction are only possible with high inlet NOx levels and

optimum temperatures and residence time. Typical SNCR performance for utility boilers is in the range of 20-35% NOx reductions.

The gas temperature at the point of injection is critical to the NOx reduction performance of an SNCR system. This window falls in a range of 1600-2000°F with an optimum temperature of approximately 1800°F. Above this temperature, ammonia begins to thermally decompose and below this temperature, the reaction rate for NOx reduction decreases, resulting in increased ammonia slip. The temperature profile in any given boiler changes with fluctuations in boiler load. Therefore, the optimum injection point will move during cycling operation and multiple injection points will be required. It should also be noted that the longer the ammonia or urea stays within the optimum temperature window, the higher the NOx reduction that is achieved. Residence times in excess of one second are desirable to achieve the maximum reduction efficiency. The minimum residence time is approximately 0.3 seconds for moderate performance. However, most large utility boilers have heat transfer surfaces (pendants and platens) positioned in this flue gas temperature zone. This reduces the effective use of the SNCR system, even when multiple injection levels are installed. In some cases, these internal obstructions will make the application of SNCR impractical.

Figure 1 shows SNCR NOx removal efficiency as a function of Inlet NOx concentration for 55 existing SNCR installations. The data shows the majority of the installations achieving 20-35% reductions in NOx and only a few installations achieving 50% or greater reductions. There is only one installation achieving 50% reduction at an inlet NOx concentration less than 0.4 lb/MMBtu. This single installation is a cyclone boiler burning a PRB/Illinois coal blend and is the only unit in the data set showing greater than 35% reduction for inlet NOx concentrations less than 0.4 lb/MMBtu.

This figure shows that there are no installations operating with Coal Creek's NOx levels that are achieving greater than 20-25% NOx reductions. The figure also shows that the majority of installations are achieving NOx reductions in the range of 20-30%. Based on the available data, from existing installations operating at the CCS inlet NOx levels used in the BART, the highest level of NOx reduction that could be expected is 30%. At the present CCS NOx levels, it is expected that the highest level of NOx reduction that could be expected is 20%.

Another factor to be considered in the application of SNCR is its effect upon fly ash sales. An ammonia slip of only 5 ppm, which is generally accepted as the minimum that can be achieved in an SNCR application, can render the fly ash produced by the unit unmarketable. CCS currently sells 400,000 tons/yr of fly ash. With SNCR, this fly ash will have to be disposed of in a landfill.

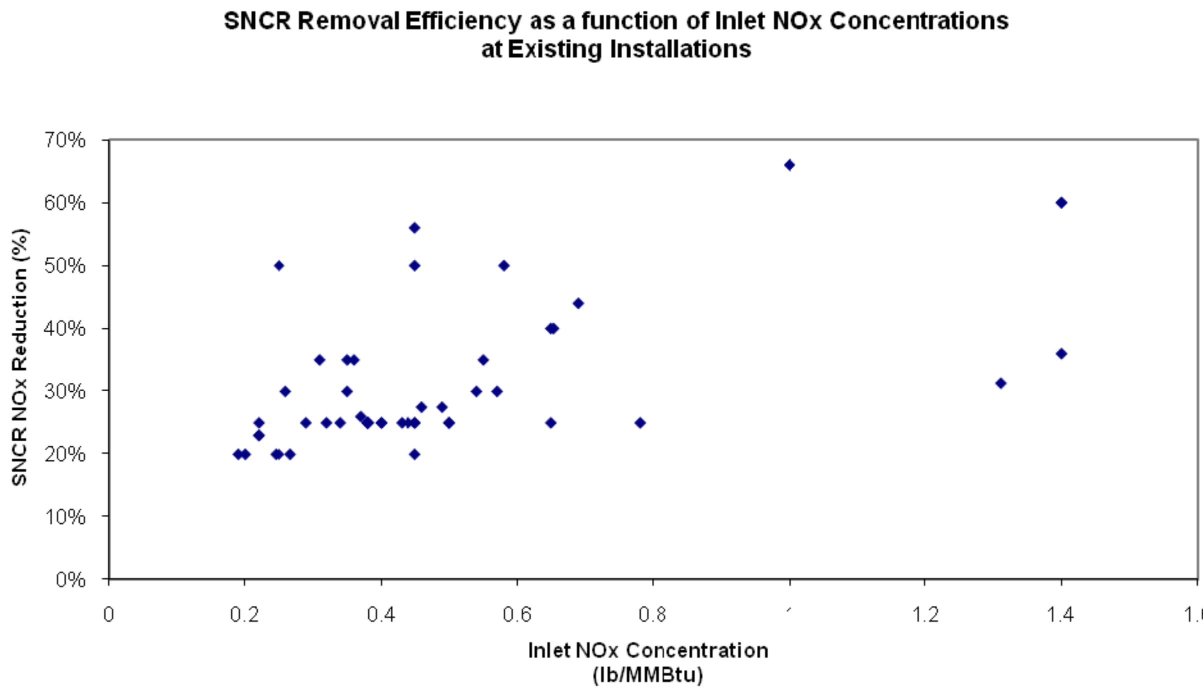

Figure 1 – SNCR Removal Efficiency

SNCR Costs

SNCR capital and operating costs were developed for five (5) different cases utilizing the Electric Power Research Institute's (EPRI) IECCOST model (Rev 3, Nov. 2010) with CCS site specific factors and cost components. The Integrated Emissions Control Cost Model (IECCOST) economic analysis workbook was first published by the Electric Power Research Institute in December 2004. IECCOST produces rough-order-of-magnitude (ROM) cost estimates (stated accuracy of ± 30%) of the installed capital and levelized annual operating costs for Integrated Emission Control (IEC) systems installed on coal-fired power plants. The IECCOST model allows comparison of cost information for conventional and developing SO_2, NOx, particulate, mercury, and integrated emissions control technologies. Costs for utility emission control systems are site-specific, and vary with technology, labor rates, construction conditions and material costs. The site-specific characteristics, operating conditions, process performance requirements and economic criteria serve as input to IECCOST.

IECCOST is able to calculate both new and retrofit plant costs. IECCOST calculates a retrofit factor for each cost area based on site congestion, existence of underground obstructions, soil conditions, seismic zone and state productivity. A series of combustion calculations are carried out based on the ultimate coal analysis provided by the utility and

the operating conditions specified for the boiler(s). The resulting flue gas composition serves as the basis for the calculation of a material balance for the control equipment. The material balance provides data for equipment sizing and calculation of the variable operating costs. The process-specific design criteria, including flue gas flow rate, pollutant removal rate, chemical consumption rate and waste production rate all are incorporated into the production of each process- and site-specific material balance.

The five (5) cases estimated for CCS are:

1. 0.22 lb/MMBtu inlet NOx with 30% reduction
2. 0.20 lb/MMBtu inlet NOx with 25% reduction
3. 0.16 lb/MMBtu inlet NOx with 20% reduction
4. 0.15 lb/MMBtu inlet NOx with 20% reduction
5. 0.22 lb/MMBtu inlet NOx with 50% reduction

These represent the initial BART assessment NOx rate of 0.22 lb/MMBtu with a commercially achievable reduction of 30% for case 1. Cases 2-4 are representative of CCS's existing NOx emission rates and commercially achievable reductions. The final case is the BART assessment case using 2011 dollars. The costs are for a urea-based SNCR system with 14 days of reagent storage. Urea pricing from a source local to CCS was obtained and the current cost of urea is $500/ton delivered to the site. The general plant input data and IECCOST outputs for SNCR capital and operation and maintenance costs are presented in the following section.

IECCOST DATA

Table 1 – Coal Creek Station Data

General Plant Technical Inputs

Total Gross Rating	MW	605
Gross Plant Heat Rate (GPHR)	Btu/KWhr	9,760
Total Net Rating (Less Auxiliary Power)	MW	572.0
Net Plant Heat Rate (NPHR, Without FGD)	Btu/KWhr	10,500
Plant Capacity Factor	%	90%
TECHNICAL INPUTS FOR BOILER:		
Boiler Heat Input	MMBtu/Hr	5,900
Boiler Heat Output	MMBtu/Hr	4,780
Total Air Downstream of Economizer	%	117.0%
Air Heater Leakage (% of econ. flue gas)	%	7.0%
Air Heater Outlet Gas Temp.	°F	300
Inlet Air Temp.	°F	80
Ambient Absolute Pressure	in. Hg	27.9
Pressure After Air Heater	in. H2O	-11
Moisture in Air	lb/lb dry air	0.013
Carbon Loss	%	0.5%
ASH SPLIT		
Fly Ash or Ash Overhead	%	76%
Bottom Ash	%	24%

Table 2 – SNCR Equipment Sizing

SNCR Equipment Sizing and Capacity Calcs			0.22 Inlet & 30% Reduction	0.20 Inlet & 25% Reduction	0.16 Inlet & 20% Reduction	0.15 Inlet & 20% Reduction	0.22 & 50% Reduction
Chosen Reagent			Urea	Urea	Urea	Urea	Urea
Required Reagent Injection	lb/hr		1991	1601	1188	1155	3318
Total Reagent Injection Flowrate	lb/hr		3982	3202	2375	2310	6636
NOx Removed	lb/hr		384	291	186	170	640
NOx Removed	tons/yr		1513	1147	734	670	2522
NOx Emissions	lb/hr		896	873	745	679	640
NOx Emissions	tons/yr		3531	3440	2935	2678	2522
Power Consumption	kW		75	61	45	44	126

Table 3 – Material Costs

SNCR Material Costs			0.22 Inlet & 30% Reduction	0.20 Inlet & 25% Reduction	0.16 Inlet & 20% Reduction	0.15 Inlet & 20% Reduction	0.22 & 50% Reduction
Cost Basis Year			2011	2011	2011	2011	2011
SNCR Equipment Cost	$		$3,800,000	$3,700,000	$3,600,000	$3,600,000	$4,200,000
Installation Factor			1.30	1.30	1.30	1.30	1.30
Installed Equipment Cost	$		$4,970,000	$4,800,000	$4,700,000	$4,700,000	$5,500,000
Prime Contractor's Markup	$		$497,000	$480,000	$470,000	$470,000	$550,000
Total Installed Cost	$		$5,500,000	$5,300,000	$5,100,000	$5,100,000	$6,000,000
Retrofit Factor			1.6	1.6	1.6	1.6	1.6
Total Equipment Cost	$		$8,750,000	$8,500,000	$8,200,000	$8,200,000	$9,600,000
General Facilities	$		$440,000	$420,000	$410,000	$410,000	$480,000
Engineering Fees	$		$875,000	$850,000	$820,000	$820,000	$960,000
Process Contingencies	$		$503,000	$488,000	$472,000	$472,000	$553,000
Project Contingencies	$		$1,580,000	$1,540,000	$1,490,000	$1,490,000	$1,740,000
Total Plant Cost (TPC)	$		$12,145,000	$11,790,000	$11,420,000	$11,400,000	$13,350,000
Total Cash Expended (TCE)	$		$12,145,000	$11,790,000	$11,420,000	$11,400,000	$13,350,000
Allowance for Funds During Constru	$		0	0	0	0	0
Total Plant Investment (TPI)	$		$12,145,000	$11,790,000	$11,420,000	$11,400,000	$13,350,000
Preproduction Costs	$		$243,000	$236,000	$228,000	$227,000	$267,000
Inventory Capital	$		$167,000	$134,000	$100,000	$98,000	$280,000
Initial Catalyst and Chemicals	$		$0	$0	$0	$0	$0
Prepaid Royalties	$		$44,000	$42,000	$41,000	$41,000	$48,000
Total Capital Requirement (TCR)	$		$12,600,000	$12,200,000	$11,800,000	$11,800,000	$13,900,000
Market Demand Escalation	$		$0	$0	$0	$0	$0
Power Outage Penalty	$		$0	$0	$0	$0	$0
Land Cost	$		$0	$0	$0	$0	$0
TCR w/ Market Dem., Power Outag	$		$12,600,000	$12,200,000	$11,800,000	$11,800,000	$13,900,000
	$/kW		21.80	21.10	20.40	20.40	24.00
	Mills/KWh		0.40	0.38	0.37	0.37	0.44

Table 4 – Operation & Maintenance Costs

SNCR O&M Costs			0.22 Inlet & 30% Reduction	0.20 Inlet & 25% Reduction	0.16 Inlet & 20% Reduction	0.15 Inlet & 20% Reduction	0.22 & 50% Reduction
Cost Basis Year			2011	2011	2011	2011	2011
Reagent Type			Urea	Urea	Urea	Urea	Urea
Reagent Consumption	lb/hr		1991	1601	1188	1155	3318
	tons/yr		7848	6310	4681	4553	13080
Water	gpm		72	58	43	42	119
Electricity	kW		75	61	45	44	126
NOx allowances generated	tons/yr		n/a	n/a	n/a	n/a	n/a
Reagent Cost	$/yr		$3,924,000	$3,155,000	$2,340,000	$2,280,000	$6,540,000
Water Cost	$/yr		$410,000	$330,000	$250,000	$240,000	$688,000
Additional Power Costs	$/yr		$24,000	$19,000	$142,000	$13,800	$40,000
NOx Credit	$/yr		$0	$0	$0	$0	$0
Total First Year Variable O&M Cost	$/yr		$4,360,000	$3,500,000	$2,600,000	$2,530,000	$7,270,000
Maintenance	$/yr		$189,000	$183,000	$177,000	$176,000	$210,000
Total First Year Fixed O&M Costs	$/yr		$189,000	$183,000	$177,000	$176,000	$210,000

Attachments

URS SNCR Experience
ICAC White Paper – SNCR for Controlling NOx Emissions – 2000
ICAC White Paper – SNCR for Controlling NOx Emissions – 2008 Update

ATTACHMENTS

The following table presents a listing a URS's SNCR experience. Additionally, a partial listing of the Integrated Emission Control (IEC) Technologies that URS has evaluated for the Electric Power Research Institute (EPRI) follows the SNCR experience list.

NO_X CONTROL EXPERIENCE – SNCR

Client	Project	Unit #	Location	Size (MW)	Fuel	PRB	Equipment Supplier	New (N) vs. Retrofit I	Completion Date	Scope
NRG Energy	5 Stations	14 Units	Various	2350	Coal		NA	R	Dec 02	FS, CE
Dayton Power & Light	Total System (6 plants)	15	Various	60-800	Coal		NA	R	1998	FS
Niagara Mohawk	Four Stations	1, 2, 3, 4	NY		Oil, Gas, Coal		NA	R	Dec 94	FS, CE
New York State Electric and Gas	System-wide	10 units	NY	Various	Coal			R	Dec 94	FS, CE
Duquesne Light and Power	System-wide		PA	Various	Coal		NA	R	Dec 93	FS, CE
Atlantic Electric	B. L. England Station			290	Coal		NA	R	Dec 93	FS, CE
Pennsylvania Power & Light	Brunner Island Station	3	PA	790	Coal		NA	R	Dec 93	FS, CE
PEPCO	Various	1, 2, 3, 4, 5, 6	Various	N/A	Coal, Oil, Gas		NA	R	Dec 93	FS, CE
Niagara Mohawk	Huntley Station	6, 7	Syracuse, NY	2 x 420	Coal		NA	R	Apr 93	FS, CE

NO_X CONTROL EXPERIENCE – SNCR

Client	Project	Unit #	Location	Size (MW)	Fuel	PRB	Equipment Supplier	New (N) vs. Retrofit I	Completion Date	Scope
Inland Steel and Nippon Steel (I/N Tek)	Furnaces and Aux. Boiler Continuous Galvanizing Line (9,000,000 tons/yr capacity)	N/A	IN	N/A	Gas		NA	N	Dec 92	FS, CE
Centerior Energy				72 thru 680	Coal			R	1992	FS, CE
Allegheny Energy Supply	Harrison Station	1, 2, 3	Shinnston, WV	3 x 685	Coal		NA	R	1992	E
San Diego Gas & Electric	System-Wide NO_X Compliance	13 Units	CA	Various	Various		NA	R	1991	PE
Entergy Services, Inc.	System-Wide NO_X Reduction Assessment	54 Units	Various	Various	Various		NA	R		FS
Chevron	El Segundo Refinery		CA		Refinery off-gas		NA	R		FS, CE
AES	Warrior Run	1	Cumberland, MD	180	Coal		NA	N	1998	E, P, C
PEPCO	Various	1, 2, 3, 4, 5, 6	Various	N/A	T-fired oil and coal Wall-fired oil and gas		NA	R	Dec 93	E
Tennessee Valley Authority	Johnsonville	6 units	Johnsonville , TN	6 x 100	Coal		NA	R	Dec 92	E
Los Angeles Dept. of Water & Power	Haynes	1, 2	Long Beach, CA	2 x 230	Gas/Oil		Ammonia injection	R	1992	E, C

NO_X CONTROL EXPERIENCE – SNCR

Client	Project	Unit #	Location	Size (MW)	Fuel	PRB	Equipment Supplier	New (N) vs. Retrofit I	Completion Date	Scope
Air Products	Stockton Cogeneration	1	Stockton, CA	50	Coal		NA	N	1988	D, E, CS
Chevron	El Segundo Refinery				Refinery off-gas		NA	R		FS
Texaco	Los Angeles Refinery		Los Angeles, CA	22	Refinery off-gas		NA	R		FS
Air Products	Cambria County	1	Pennsylvania		Waste Coal		NA	N		E, P

Legend:

BE	Bid Evaluation	D	Design	S	Startup
C	Construction	E	Engineering	STG	Steam Turbine Generator
CA	Construction Advisory	FS	Feasibility Study	T	Testing
CE	Cost Estimate	OE	Owner's Engineer	PRB	Powder River Basin Coal
CM	Construction Management	P	Procurement		

Integrated Emission Control Technologies evaluated for EPRI.

Gas Phase Oxidation Systems

Chem-Mod
ECO™
ECO2™
ISCA

Lextran SO2/NOx/Hg
LoTOx

Low-Temperature Multi-Pollutant Control System (MPCS)
THERMALONOx
Plasma/Electron Beam Systems
EBFGT
e-SCRUB™
Pioneer Industrial Technologies (PIT)
Pulsatech
WOWClean

Combustion Modification/Fuel Processing
Ashworth Combustor
Clean Combustion System (CCS)
Coal Tech
Emulsified Fuel Technology
Green Coal
High-Sodium Lignite-Derived Chars
K-Fuel
K-Lean
Lignite Cleaning System
The Mobotec System
N-Viro Fuel
Oxycombustion
Soot Free Catalyst
WRI Coal Processing

Wet Scrubbing Systems
Airborne

Aqueous Foam Air (AFA) Filter
CEFCO
Dry-Wet Hybrid Electrostatic Precipitator (ESP)
DynaWave
Eco Technologies
Envirolution/PureStream Gas-Liquid Contactor
FLU-ACE
Integrated Flue Gas Treatment
Integrated Advanced Tower
Ispra by SRT Group
LABSORB
Membrane Wet ESP
MercOx
PEA
Rapid Absorption Process (RAP)/Dry Absorption Process (DAP)
SkyMine

Dry Technologies
Argonne Spray Dryer
NOxOUT CASCADE / Turbosorp Technology (formerly CDS/SCR)
ClearGas Dry Scrubber
Copper Oxide
EMx (previously SCONOx/SCOSOx)
Indigo MAPS
Kuttner Luehr Filter Technology
Low Temperature Mercury Control (LTMC)
Novacon
PahlmanTM Process
ReACT Technology
SNOX

SOx-NOx-Rox Box (SNRB)
Trona Injection

Other Technologies
Argonne Hg/NOx Process
CANSOLV SO2/CO2 Process
GreenFuel
Integrated Pollutant Removal (IPR)
Low Temperature Sulfur Trioxide Removal System (LT-STRS) / Mitsubishi Mercury Treatment System (Mi-MeTS) (Previously MHI High Efficiency System / HCl Injection)
TIPS
Combined Plasma Scrubbing Technology (CPS)
Consummator
ECOBIK
Aqua Ammonia Process
BioDeNOx
Fungal Bioreactor
Plasma Enhanced ESP
ElectroCore

Appendix C

Fly Ash Storage and ASM Technology Evaluation

FLY ASH STORAGE AND AMMONIA SLIP MITIGATION TECHNOLOGY EVALUATION

Great River Energy

Coal Creek Station

REPORT

Submitted To: Great River Energy
Coal Creek Station
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November 15, 2011 **113-82161**

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EXECUTIVE SUMMARY

Great River Energy (GRE) has requested that Golder Associates Inc. prepare a third-party review of potential ammonia slip mitigation (ASM) technology and cost comparisons for associated RCRA Subtitle D ash storage facility design for their Coal Creek Station (CCS) located in Underwood, North Dakota.

These evaluations are prepared in response to the United States Environmental Protection Agency's (EPA's) proposed Federal Implementation Plan (FIP) for the state of North Dakota. As part of the FIP process, the North Dakota Department of Health (NDDH) has requested that GRE prepare a Best Available Retrofit Technology (BART) analysis for nitrogen oxides (NOx) emissions, specifically evaluating the application of selective non-catalytic reduction (SNCR) emission control technology. Due to the potential for unreacted ammonia in the flue gas downstream of the SNCR (ammonia slip) reacting with sulfur compounds to form ammonia sulfates that deposit in the fly ash, there is concern over the significant impact on current fly ash sales. Therefore, GRE is evaluating an ASM technology at CCS as an option for treating ammonia slip impacted fly ash to allow continued beneficial use and sale of fly ash. This ASM technology is not proven for lignite derived fly ash and is presented as a potential option to reduce the impact of an SNCR on fly ash management. This evaluation includes an ASM technology cost estimation, fly ash disposal cost comparisons, and evaluation of the total cost impact of an SNCR on fly ash management at CCS.

Golder recently visited the Eastlake Station where Headwaters Energy Services' patented ASM technology is currently applied to manage ammonia levels in the fly ash. Based on this operation and Golder's knowledge of CCS and lignite coal-fired power plants, a cost estimate to apply ASM at CCS was prepared. The cost estimate includes costs for the ASM infrastructure including engineering and design, construction, and operations and maintenance. Costs are based on 2011 dollars and capital costs are annualized for a 20-year life and 5.5% interest rate. Existing fly ash sales infrastructure and operations and maintenance are not included in the cost estimate. ASM post-processing costs are estimated to be $5.61 per ton of fly ash treated.

Fly ash that cannot be marketed for beneficial use is disposed of in engineered and permitted facilities at CCS. Golder prepared a cost estimate for three potential operating scenarios: Scenario A – fly ash sales equal to the average sales over the past few years, Scenario B – ammonia slip impact of an SNCR makes fly ash at CCS unsalable, and Scenario C – ASM technology will be viable for ammonia impacted fly ash at CCS allowing a reduced amount of fly ash sales. A summary of the total estimated fly ash disposal costs is shown in the following table.

	Scenario A (Current Sales)	Scenario B (No Sales)	Scenario C (Reduced Sales, ASM)
Fly Ash Disposed (ton/yr)	110,000	525,000	234,500
Disposal Cost ($/ton)	$18.06	$11.18	$13.91
Annual Disposal Cost ($/yr)	$1,987,000	$5,870,000	$3,262,000
Annual Increase in Disposal Cost Compared to Scenario A ($/yr)	-	$3,883,000	$1,275,000

The landfill design included the specific size, location, infrastructure, liner, and cover relevant to each scenario. Costs for each scenario included the specific landfill design, engineering, and permitting costs, land acquisition, infrastructure development, liner construction, post-closure care, construction management and construction quality assurance (CQA), GRE internal costs, project contingencies, and operational costs. Based on the annual disposal cost estimate shown in the table above, the potential impact of an SNCR on the fly ash disposal costs at CCS may be an additional $3.9 million per year if fly ash is no longer marketable or an additional $1.3 million per year if the ASM technology proves successful.

The total cost impact of an SNCR on fly ash management at CCS includes ASM post-processing costs, fly ash disposal costs, and the loss in revenue generated from the sale of fly ash. Golder evaluated this total cost impact for each scenario, and is summarized in the table that follows. Based on this evaluation, the total additional cost impact to fly ash management as a result of an SNCR is between $4.4 and $9.0 million per year.

	Scenario A (Current Sales)	Scenario B (No Sales)	Scenario C (Reduced Sales, ASM)
Total (Disposal + Post Processing + Lost Sales)			
Annual Cost ($/yr)	$1,987,000	$10,975,000	$6,422,000
Unit Cost ($/ton produced)	$3.79	$20.91	$12.23
Additional Cost (Scenario B/C - Scenario A)			
Fly Ash Management Cost ($/yr)	-	$8,988,000	$4,435,000
Fly Ash Management Cost ($/ton produced)	-	$17.12	$8.45

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1.0 INTRODUCTION

Great River Energy (GRE) has requested that Golder prepare a third party review of ammonia slip mitigation technology, and cost comparisons for associated RCRA Subtitle D ash storage facility design for Coal Creek Station (CCS) located in Underwood, North Dakota. These evaluations are prepared in response to the United States Environmental Protection Agency's (EPA's) proposed Federal Implementation Plan (FIP) for the state of North Dakota. Based on the proposed FIP, GRE is evaluating selective non-catalytic reduction (SNCR) control technology to reduce nitrogen oxide (NO_x) emissions from CCS. If SNCR is installed at CCS, there is potential for unreacted ammonia in the flue gas downstream of the SNCR, called ammonia slip, and higher ammonia in fly ash. Due to the significant impact on current ash sales, GRE is evaluating a potential ammonia slip mitigation (ASM) technology patented by Headwaters Energy Services. In addition, GRE is evaluating three potential management scenarios for fly ash based on the potential impact of ammonia concentrations to the sale of fly ash.

Golder performed a third party review and estimated costs associated with implementation of Headwaters' ASM technology as applied to CCS. The review includes an estimate of the capital and operating and maintenance (O&M) costs for implementation of the ASM technology at CCS, with a focus on potential impacts to ash marketing and future sales to assist GRE in determining the feasibility of the ASM technology for operations at CCS. This evaluation is limited in scope given that "Headwaters has not conducted any field scale assessment on application of this technology to lignite derived fly ash. The limited current experience in commercial application and lack of field trials is not adequate for Headwaters to be able to provide any guarantee that the process can be successfully applied to treat lignite ash at the Coal Creek Station," per an email from Rafic Minkara (Headwaters) to John Weeda (GRE) on July 15, 2011.

Golder also prepared a cost comparison for three fly ash storage facility scenarios:

- Scenario 1: CCS's current fly ash sales rate (most fly ash sold);
- Scenario 2: No fly ash sales;
- Scenario 3: Application of ASM technology (allowing for some fly ash sales).

The cost evaluation includes a comparison of capital and O&M costs for each scenario assuming a new facility that meets EPA RCRA Subtitle D type regulations.

1.1 Qualifications

Golder Associates Corporation is an international employee-owned consulting engineering company specializing in the application of earth sciences and engineering to environmental, natural resources, and civil engineering projects. Operating since 1960, our company maintains a network of approximately

160 offices. Current worldwide employment exceeds 7,000 people. The United States operating company, Golder Associates Inc., employs approximately 1,200 people in 51 offices.

This project was conducted by a team based in our Denver, Colorado and Fort Collins, Colorado, offices. The project team was well-suited to perform the proposed services at CCS because of the experience of our technical staff on comparable projects, and our familiarity with the geotechnical and engineering properties of Subtitle D landfill designs. In addition, our team has a firm understanding of the engineering practice and regulatory environment surrounding coal-fired power plants, both in North Dakota and nationally, including ongoing rulemaking efforts by the EPA.

2.0 BACKGROUND

2.1 Regulatory Basis

In order to attain and maintain the National Ambient Air Quality Standards (NAAQS) within a state, state air quality agencies prepare State Implementation Plans (SIP) for EPA approval. If EPA disapproves of the SIP, either partially or fully, EPA will develop a Federal Implementation Plan (FIP) to address the deficiencies in the SIP.

On September 21, 2011, EPA proposed to partially disapprove the North Dakota SIP, specifically addressing regional haze and proposed a FIP to address the deficiency "concerning non-interference with programs to protect visibility in other states"[1]. As part of this process North Dakota Department of Health (NDDH) has requested a Best Available Retrofit Technology (BART) analysis for nitrogen oxides (NOx) emissions. This analysis was submitted by GRE in 2007 and additional evaluations and response to questions were submitted in 2010 and on July 15, 2011 to NDDH. NDDH is requesting additional analyses of selective non-catalytic reduction technology. This report does not include an SNCR evaluation, but provides a cost evaluation to address the potential impact the installation of SNCR would have on the existing GRE fly ash storage and sales.

2.2 SNCR and Ammonia Slip

Selective non-catalytic reduction (SNCR) technology is a post-combustion technology based on the chemical reduction of NOx into molecular nitrogen (N_2) and water vapor (H_2O). A nitrogen based reagent, such as urea, is injected into the post-combustion flue gas. The injection causes mixing of the reagent and flue gas while the heat in the flue gas provides energy for the reaction. The primary byproduct of the reaction is nitrous oxide (N_2O), which is a potent greenhouse gas (GHG).

Unreacted reagent in the flue gas downstream of the SNCR is called slip. This unreacted reagent will appear as ammonia, and reacts with sulfur compounds (from sulfur containing fuels) to form ammonia sulfates which deposit on the fly ash that is collected by the particulate emissions control equipment. The ammonia sulfates are stable in a dry state, but ammonia gas can release if the fly ash becomes wet. Ammonia content in the fly ash greater than 5 parts per million (ppm) (based on Headwaters' experience this level is 35 ppm) can result in release of ammonia gases which impact either the sale or storage and disposal of fly ash.

[1] Federal Register, EPA, 9/21/2011, www.federalregister.gov/articles/2011/9/21/2011-23372

3.0 AMMONIA SLIP MITIGATION

3.1 Background

Headwaters has developed an ammonia slip mitigation (ASM) technology to manage ammonia levels in the fly ash, so that a portion of the fly ash produced can be sold as a concrete additive. The Headwaters' ASM technology was initially developed in 2001 with the first US patent issued in 2004. The first commercial installation of ASM technology was installed at RG&E Russell Station in Rochester, New York in 2004. Russell Station used an SNCR and burned eastern bituminous coal.

The second commercial installation was installed at Eastlake Station in Ohio. Eastlake Station has a 600 megawatt (MW) unit that is fired with a 50/50 blend of Power River Basin (PRB) and eastern bituminous coal while generating approximately 100,000 TPY of fly ash. Headwaters is able to blend, treat, and market approximately 85% of the fly ash produced at Eastlake station. Fly ash is not treated during periods of highly variable ammonia concentrations, typically occurring during SNCR upset or plant load swings.

Currently, there are no commercial applications of ASM technology at a lignite-fired power plant, and Headwaters has not conducted any research on the application of the technology to lignite derived fly ash. Due to the lack of commercial experience with lignite derived fly ash, Headwaters will not provide a guarantee that the ASM technology can be successfully applied to lignite derived fly ash.

3.2 Process Description

The ASM technology mixes approximately 0.5-pound (lb) calcium hypochlorite (Cal-Hypo) with approximately 3,000-lb of fly ash in a hopper. The dose of cal-hypo, which is fed into the hopper using a rotary screw, is based on the ammonia concentration in the fly ash. Typical ammonia range for treatment is 50 to 150 ppm with a dosage of 0.2 to 1.3 lb of Cal-Hypo, resulting in ammonia concentrations after treatment of about 35 to 80 ppm.

Golder visited a current commercial application of ASM technology at the Eastlake Station (Figure 1). Fly ash from the electrostatic precipitator (ESP) is sent to one of two fly ash silos where the fly ash is tested daily to determine ammonia concentrations (Figure 2). If the ammonia concentrations are above 150 ppm, the fly ash is diverted for disposal. Fly ash with ammonia concentrations less than 150 ppm are sent to the third silo, after which it is "dosed" with Cal-Hypo and sent to the fourth silo (Figure 3 through Figure 5). The SNCR at Eastlake cannot keep the ammonia slip consistent, and often over-treats a portion of the fly ash stream. To increase the amount of treatable and marketable fly ash, fly ash with no ammonia from other sources is regularly blended into the Eastlake fly ash to keep the initial ammonia content below 150 ppm. Through the operation of the SNCR and by blending non-ammonia impacted fly ash with Eastlake's ammonia impacted fly ash, Eastlake is able to market approximately 85% of what

they produce because this fly ash is considered "treatable" (i.e., ammonia concentration levels are < 150 ppm). Diagrams of the East Lake Station system provided by Headwaters are shown in Appendix A. Subsequent to these diagrams, Headwaters has added a weigh hopper under the silo as shown in Figure 5.

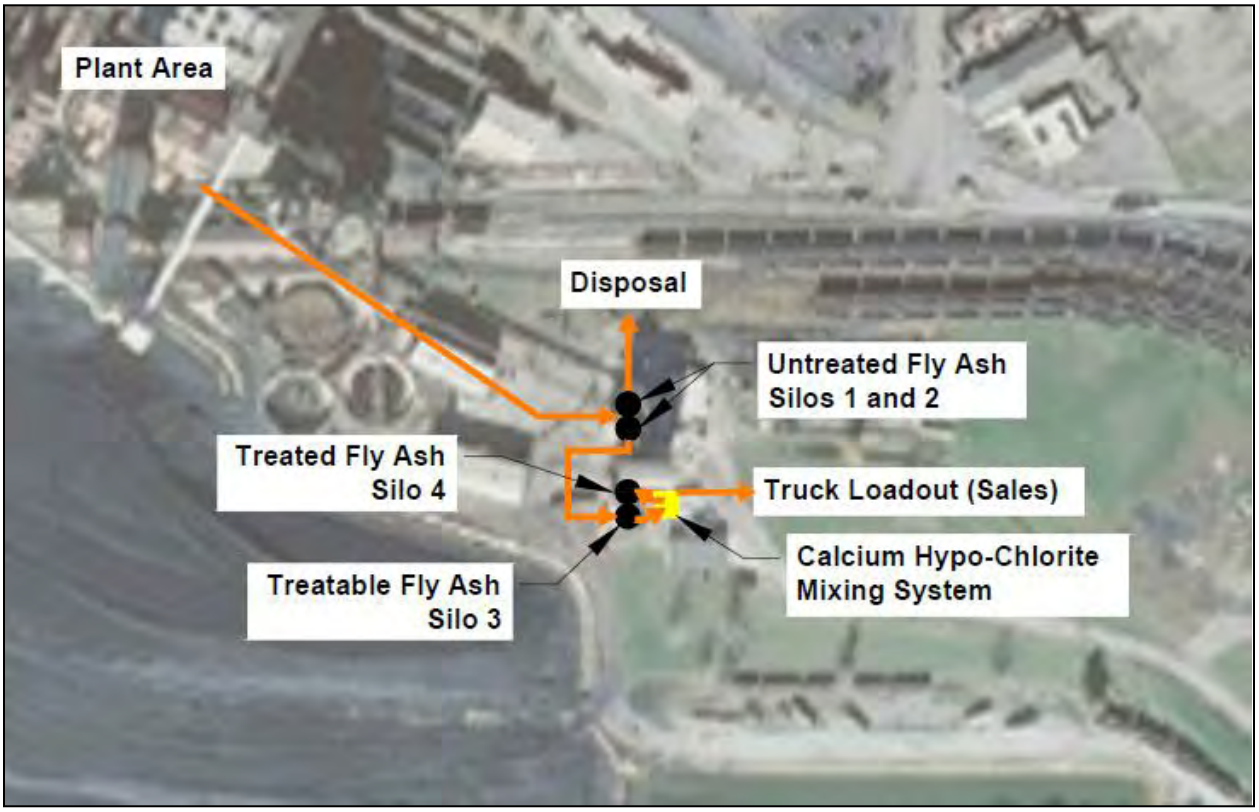


Figure 1: Eastlake Station ASM Schematic

Figure 2: Eastlake Station ASM Lab

Figure 3: Eastlake Station Silo 3, Silo 4, and ASM Setup


Figure 4: Eastlake Station ASM Control Panel


Figure 5: Eastlake Station ASM Mixing Hopper

3.3 Design and Limitations

Based on the Eastlake Station application, ASM is applied to fly ash with ammonia concentration levels less than 150 ppm. Ammonia levels can fluctuate based on plant load variations and SNCR operation. Ammonia concentrations are more consistent at base load conditions and dosing levels are typically based on this condition. Therefore, during load “swings,” it can be difficult to properly adjust the amount of ammonia injected into the flue gas resulting in varying concentrations of ammonia in the fly ash. If there is a plant upset condition, it may be several days until the ammonia concentrations in the fly ash being produced are at “treatable” levels again. The concern is two-fold. If the fly ash is not treated with enough Cal-Hypo, objectionable levels of ammonia will be released when the fly ash is mixed with water. Ammonia gas at low levels is an irritant but can be dangerous to life and health at high concentrations. If too much Cal-Hypo is added, chlorine gas will be released when the fly ash is mixed with water. Chlorine gas even at low concentrations is dangerous to life and health.

3.4 ASM Application at CCS

The application of ASM technology at CCS is being evaluated as an option for treating ammonia slip impacted fly ash to allow continued beneficial use and sale of fly ash.

3.4.1 Potential Design at CCS

For cost estimating, a potential layout for the application of ASM at CCS is shown in Figure 6. This potential layout utilizes the existing fly ash infrastructure including the truck load-out silos (91 and 92), the rail load-out silo (93), and the fly ash storage dome (94). To utilize ASM, the layout adds a new truck load-out silo south of Silos 91 and 92, and adds ASM Cal-Hypo feed systems at both the new truck load-out silo and the existing rail load-out silo (93). The general flow of material is treatable fly ash being routed to either the new truck load-out silo, the fly ash dome (94) or the rail load-out silo. From these silos, the fly ash is tested, and then mixed with Cal-Hypo as it is loaded into the trucks or rail cars. Additional testing of the resultant product would also be performed. Fly ash that is expected not to be treatable or saleable is routed to the exiting truck load-out silos (91 and 92) where it will be loaded into haul trucks and disposed at on-site disposal facilities.

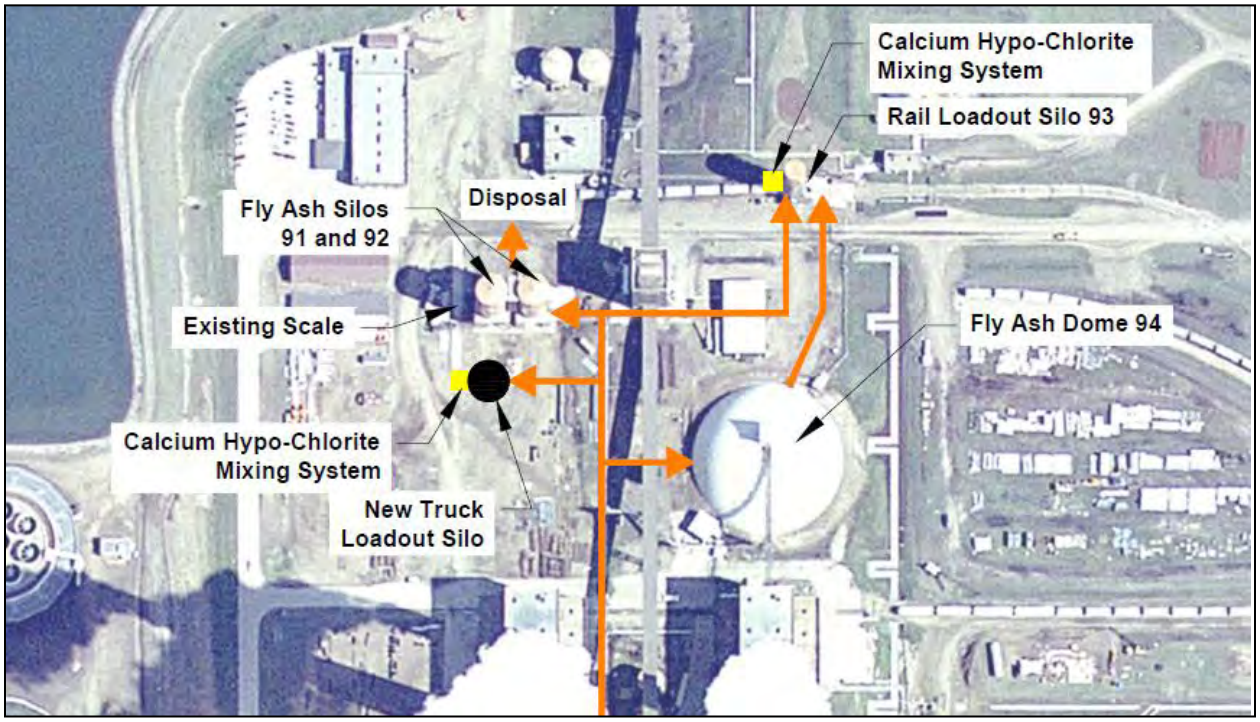


Figure 6: Coal Creek Station ASM Schematic

As discussed earlier, not all of the fly ash coming from the precipitators is expected to be within treatable levels of ammonia. In general, when the power generation units are operating at steady load and the SNCR ammonia injection system is operating properly, the fly ash produced should be treatable using the ASM system and will be collected in the rail load silo (93), the fly ash dome (94), or the new truck loadout silo (95). Conditions under which the ammonia content of the produced fly ash will be questionable include:

- Unit load swings causing variations in ash ammonia concentration (load swings may be due to regional wind penetration or variable load consistent with MISO);
- SNCR ammonia injection feed system problems; and
- Unit startup and shutdown which results in oily ash.

Golder expects that when any of these conditions occur, the fly ash produced will automatically be directed to the disposal silos (91 & 92). Fly ash will not be redirected to the sales silos (93, 94 or 95) until the upset is over and the fly ash collected in the first two rows of the electrostatic precipitator (ESP) has been tested and proven to have less than 150 ppm of ammonia in it.

Based on a review of the recent load profile at CCS, historic information on marketable fly ash at CCS, and an estimate of the reliability of the SNCR and ASM systems, approximately 30% of the fly ash now sent to the sales silos is assumed to have ammonia concentrations which will make it untreatable if an SNCR system is installed.

3.5 Cost Estimate

The cost estimate includes costs for the ASM infrastructure including engineering and design; construction; and operations and maintenance. Golder used actual costs from similar projects, and professional judgment to develop this cost estimate. Sources and assumptions are documented where appropriate. Some general assumptions for the cost estimate include:

- All costs are estimated in 2011 dollars.
- Capital costs are annualized based on a 20-year life and 5.5% interest rate.
- Existing fly ash sales infrastructure (silos, scales, rail facilities) and operations and maintenance are not included.

3.5.1 System Engineering and Design

This item is estimated as 10% of the total construction costs to develop the new facilities. Ten percent is based on Golder's professional judgment.

3.5.2 New Truck Load-Out Silo

The costs for the new truck load-out silo include site preparation, permit application, the silo and handling equipment, dust collection equipment, and feed piping. The costs for this construction are based on the construction of a similar fly ash sales terminal constructed for GRE in 2003. This silo had a 5,000-ton capacity and was used to transfer fly ash from rail cars to trucks (Figure 7). The total estimated cost for this item is $1.6 million and includes the following:

- Silo and truck scale similar to the Irondale, CO unit:
  - Silo slab on grade;
  - Starvrac reclaimer;
  - Truck scale beside the silo on grade;
  - Screw conveyor from discharge of the Starvrac reclaimer;
  - Bucket elevator to overhead;
  - Air slide ;
  - Building with the scale and ASM controls
- Additional items needed at CCS:
  - Feed piping and valves from each of the four fly ash conveying lines;
  - Higher capacity dust collectors to handle the high air flow from ESP.

Details for this cost estimate are included in Appendix B.

Figure 7: Typical Silo used in Cost Estimate

3.5.3 Cal-Hypo Feed System

The costs for the Cal-Hypo feed systems are estimated at $574,500 and include:

- Rail loadout silo (93):
  - Cal-Hypo storage and conveying building;
  - Day storage hopper for Cal-Hypo on the silo weigh bin floor;
  - Conveying system from the storage building to the day storage hopper;
  - Variable speed screw conveyor to feed Cal-Hypo into existing weigh hopper;
  - ASM system controls
- New truck loadout silo (95):
  - Weigh hopper above truck loadout spout;
  - Cal-Hypo storage and conveying building;
  - Day storage hopper for Cal-Hypo on the silo weigh bin floor;
  - Conveying system from the storage building to the day storage hopper;
  - Variable speed screw conveyor to feed Cal-Hypo into existing weigh hopper;
  - ASM system controls.

3.5.4 GRE Internal Costs

Internal costs for GRE to manage consultants, contractors, and in-house staff is estimated as 10% of the total costs (construction, engineering, permitting, CQA). Ten percent is based on GRE's experience with projects at CCS.

3.5.5 Project Contingency

Due to the order-of-magnitude scope of this cost estimate a contingency of 15% on the construction costs was added.

3.5.6 Operational and Maintenance Costs

ASM post-processing operations and maintenance costs are estimated as an annual cost. Operations costs include the cost of Cal-Hypo, fly ash sampling and testing costs, and labor to operate the system. Maintenance costs include labor and materials to maintain and repair the added equipment at the rail load-out silo (93) and the new truck load-out silo (95).

The estimated cost for this item, based on annual sale/processing of 290,500 tons, is approximately $1.4 million per year. Details for this cost estimate are included in Appendix B.

3.6 ASM Post-Processing Cost Summary

Using the quantities and the unit pricing described above, ASM post-processing costs are estimated as $5.61 per ton of fly ash treated.

4.0 FLY ASH DISPOSAL

Fly ash that cannot be marketed for beneficial use is disposed of in engineered and permitted facilities at CCS. Golder has prepared this order-of-magnitude cost estimate to compare costs between three scenarios defined to assess the potential impact of an SNCR on fly ash sales and disposal at CCS. Summary costs and key inputs are included in Table 1 through Table 3, and Figure 8 through Figure 10, with cost estimate details provided in Appendix B.

4.1 Fly Ash Disposal Scenarios

Three scenarios were evaluated to estimate the annual cost and the cost per ton to dispose of fly ash at CCS. These scenarios include:

- ***Scenario A*** – This scenario is the base case with fly ash sales equal to the average sales over the past few years. The scenario assumes that fly ash will be disposed of in a new landfill with a design based on RCRA Subtitle D practices, and has a 20-year disposal capacity. No post processing of the fly ash is required to make it marketable.
- ***Scenario B*** – This scenario assumes that the ammonia slip impact of an SNCR makes fly ash at CCS unsalable. The scenario also assumes that fly ash will be disposed of in a new landfill with a design based on RCRA Subtitle D practices, and has a 20-year disposal capacity.
- ***Scenario C*** – This scenario assumes that Headwater's ASM technology will be viable for ammonia impacted fly ash at CCS. However, sales will be reduced from current sales due to load swing impacts on ammonia slip, market conditions, and other factors previously identified. The scenario also assumes that fly ash will be disposed of in a new landfill with a design based on RCRA Subtitle D practices, and has a 20-year disposal capacity.

A summary of the fly ash production, sales, and disposal annual tonnages for these scenarios is provided in Table 1.

Table 1: Fly Ash Sales and Disposal Tons

	Scenario A (Current Sales)	Scenario B (No Sales)	Scenario C (Reduced Sales, ASM)
Fly Ash Produced (ton/yr)	525,000	525,000	525,000
Fly Ash Sold (ton/yr)	415,000	0	290,500
Fly Ash Disposed (ton/yr)	110,000	525,000	234,500

The total tonnage of fly ash produced is variable based on items such as plant load, plant efficiency, coal quality, and coal processing. Tonnage used in this analysis is meant to represent a typical or average amount of fly ash produced, sold, and disposed at CCS.

4.2 Landfill Design

For all three scenarios a 20-year disposal capacity and a RCRA Subtitle D design is assumed. It is also assumed that the landfill will be built on property not currently owned by GRE. For this cost estimate, it is assumed that property just west of the plant property would be purchased for the new facility. Figure 8 shows a potential location for these new facilities just west of the plant property and represents the approximate footprint required for Scenario A.

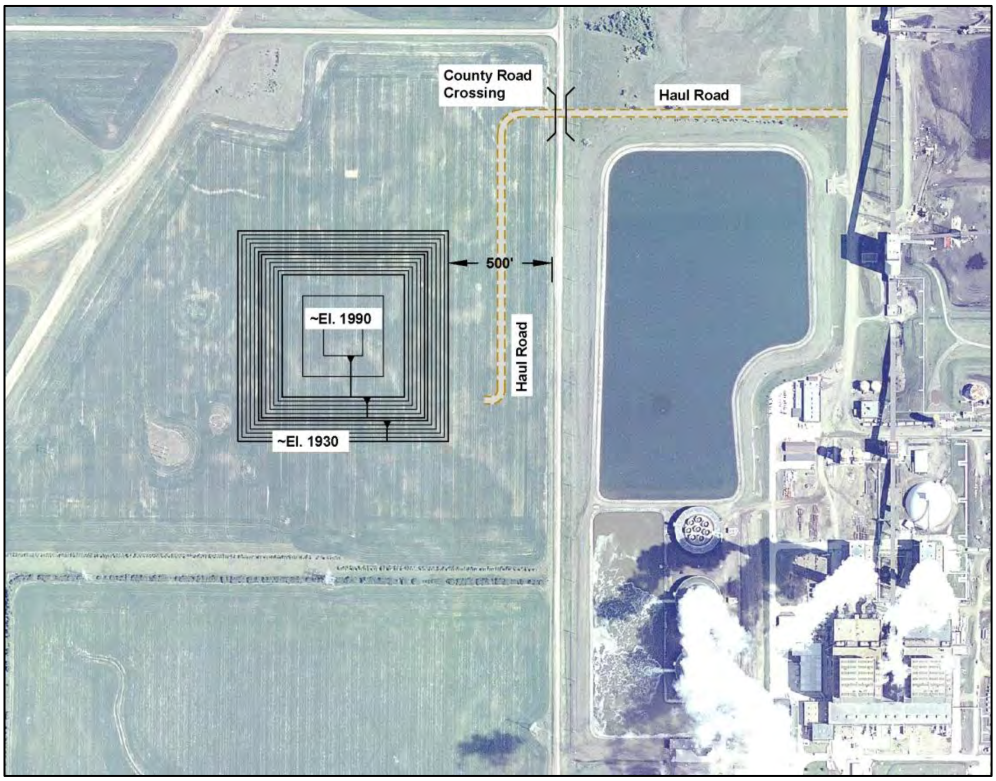


Figure 8: Potential Landfill Location (Scenario A)

4.2.1 Landfill Size

Landfill size is based on a 20-year fly ash disposal capacity. For the three scenarios this varies between 2.2 million and 10.5 million tons of capacity. For each Scenario, Golder developed a simplified landfill footprint that would provide the 20-year fly ash disposal capacity. The simplified landfill design assumes 10 feet of cut, 12-foot high soil berm, 3H:1V soil berm slopes, and 4H:1V fly ash slopes with a 5% crown. Based on preliminary engineering, the landfill capacity ranges between 75,000 and 118,000 cubic yards (cy) per lined acre due to the increased height capacity of a larger footprint facility. Figures showing the size of each Scenario are included in Appendix B.

The amount of cover area in relationship to the liner area has also been estimated based on preliminary engineering as 1.1 acres of cover for every 1 acre of liner.

The amount of land required is assumed to encompass at least a 500-foot buffer beyond this lined footprint to allow for access roads, fencing, support structures, and groundwater monitoring. For the land acquisition purchase estimate, the nearest whole or partial section of land to the required footprint was assumed.

Table 2 provides a summary of the estimated facility liner area, cover area, and site area for the three scenarios.

Table 2: Scenario Landfill Size

	Scenario A (Current Sales)	Scenario B (No Sales)	Scenario C (Reduced Sales, ASM)
Liner Acres (acres)	24.0	73.5	41.0
Cover Area (acres)	26.5	81.0	45.0
Site Area (acres)	160.0	240.0	160.0

4.2.2 Infrastructure Development

With the landfill constructed on a new property, considerable site development is required, which may include a haul truck access road, fencing and gates around the property, power to the new site, monitoring wells up- and down-gradient of the new facility, and a water return pipeline to allow the pumping of excess contact water from the site to the ash water tanks within the plant.

In addition, haul trucks will be required to cross a county road to deliver fly ash from the plant to the new facility. For safety and operational flexibility, a new country road bridge should be constructed to allow haul truck traffic under the county road. This bridge would include the bridge structure as well as the grading and embankment costs associated with the approach on the county road.

4.2.3 Liner

A liner design based on RCRA Subtitle D standards and historic practice at CCS was utilized. The assumed liner system is shown in Figure 9 and consists of (from bottom to top) a compacted clay layer ($1x10^{-7}$ cm/sec maximum permeability), a geomembrane liner, a leachate collection layer consisting of drainage material, piping and sumps, and a protective cover layer.

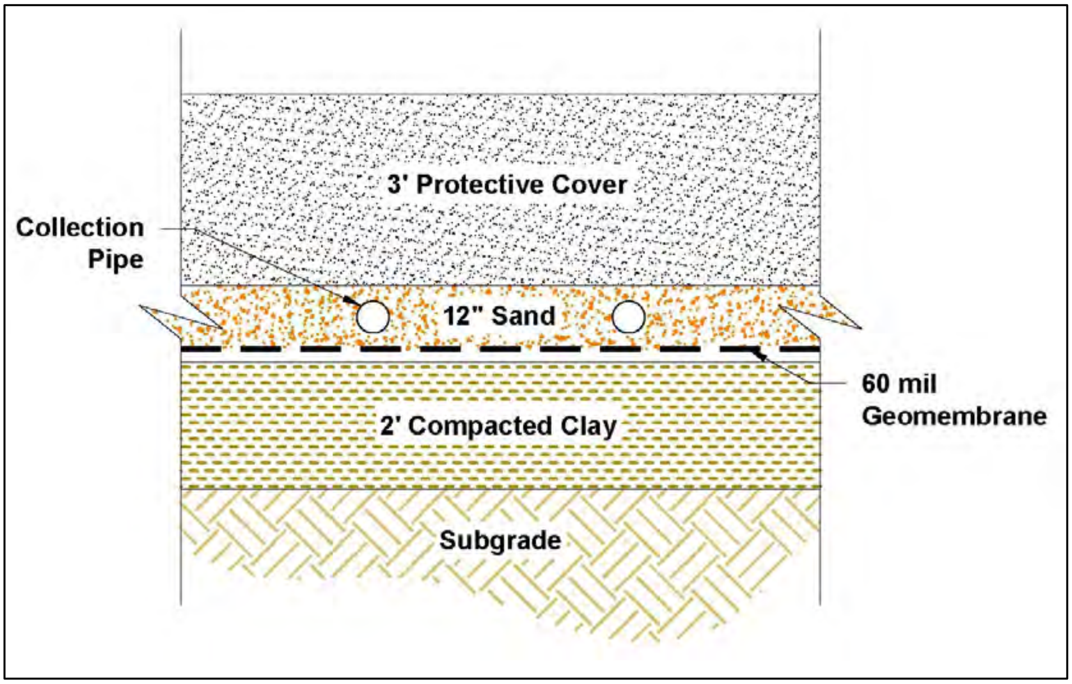


Figure 9: Composite Liner Detail

4.2.4 Cover

The final cover is also design based on RCRA Subtitle D standards and historic practice at CCS. The assumed cover system is shown in Figure 10 and consists of (from bottom to top) a compacted soil layer ($1x10^{-5}$ cm/sec maximum permeability), a textured geomembrane, a drainage layer consisting of drainage material and piping, and a vegetation layer. The drainage layer over the geomembrane is required to control the head on the liner and the resulting stability of growth medium. In addition, the cover will utilize terrace channels and armored down-chute channels to manage surface water runoff and reduce erosion.

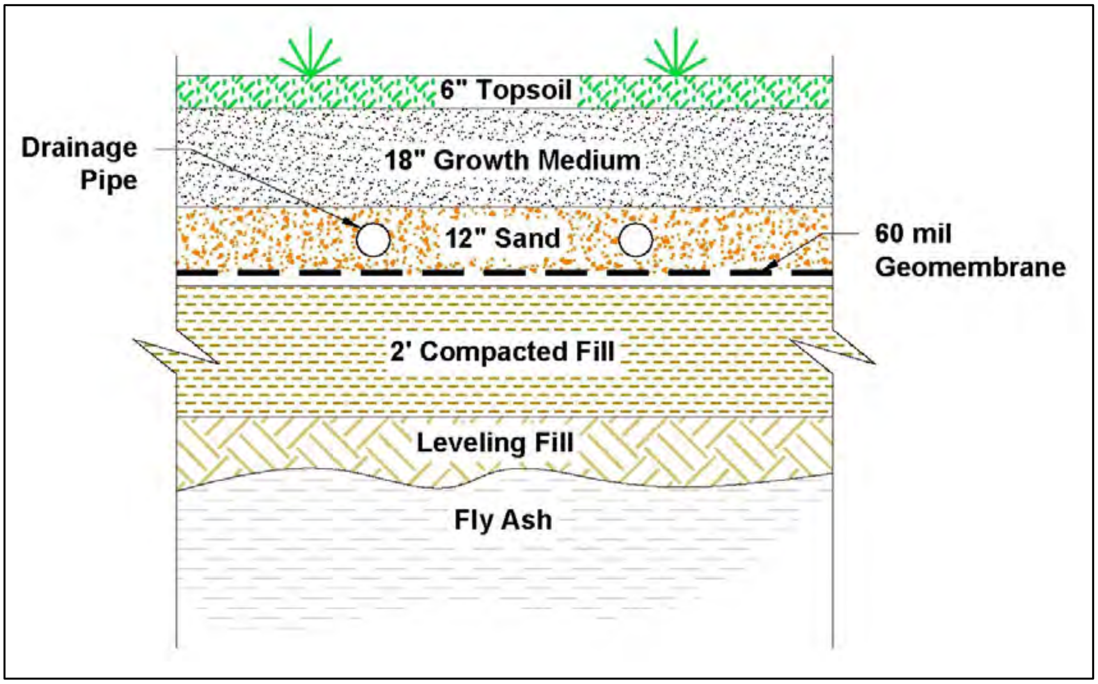


Figure 10: Composite Cover Detail

4.3 Cost Estimate

The cost estimate includes costs for the life of the disposal facility including engineering, design, and permitting; construction; and operations and maintenance, including closure and post-closure care. Golder used actual costs from similar projects at CCS, local contractor rates, RS Means manuals (RS Means 2010), and professional judgment to develop this cost estimate. Sources and assumptions are documented. Some general assumptions for the cost estimate include:

- All costs are estimated in 2011 dollars.
- Capital costs are annualized based on a 20-year life and 5.5% interest rate.
- Existing fly ash processing equipment (silos, unloaders, etc.) is not included. Disposal costs begin once the haul trucks are loaded with fly ash.
- Existing fly ash sales infrastructure (silos, scales, rail facilities) and operations and maintenance are not included.
- Disposal costs only include fly ash disposal and not facility airspace or operations and maintenance for other coal combustion products produced at CCS.

4.3.1 Engineering, Design, and Permitting

This item is estimated as 10% of the total construction costs to develop the facility. Ten percent is based on Golder's experience with coal combustion product facilities within the Midwest. The components included in this cost may include a facility siting evaluation, design of the facility, submittal of a solid waste landfill permit as well as permit renewals, submittal of air permits and NDPES permits, and creation of construction and bid packages for the facility.

The siting evaluation may include a hydrogeological characterization of the site, which includes drilling, soil testing, establishing groundwater baseline data, and preparing a hydrogeologic characterization report. Additional siting efforts may include a wetlands delineation, a site topographic survey, as well as other required evaluations.

Facility design includes both landfill design and infrastructure design. This includes grading plans, deposition plans, contact and surface water management plans, design of haul roads, and the design of the country bridge crossing.

Permitting may include the solid waste landfill permit, air permits, and an NPDES permit. This includes the development of operations plans for the facility, closure plans, post-closure care plans, groundwater sampling and analysis plans, a Stormwater Pollution Prevention (SWPP) plan, and other required submittals associated with the construction and operation of a new fly ash disposal facility.

4.3.2 Land Acquisition

Land acquisition of the property for the new facility includes site due diligence, and property purchase. Site due diligence may include survey, geotechnical characterization, environmental audit, and a landfill siting suitability evaluation. The property purchase may include legal fees as well as the purchase price. At this time, good crop land in the vicinity of CCS is selling for as much as $1,500 per acre. A unit cost of $2,000 per acre is used in the analysis to account for both the cost of the land and the site due diligence.

4.3.3 Infrastructure Development

The costs for the infrastructure development include fencing, monitoring well installation, power from the plant to landfill, facility access haul road, a return water pipeline, and a county road bridge crossing. The costs for this construction are estimated to be between $649,500 and $924,000 for the different scenarios. Details for the quantities and unit rates applied to this work are included in Appendix B.

4.3.4 Liner Construction

Liner construction includes several elements as described above including a compacted clay layer, a geomembrane liner, a leachate collection system, and protective cover. In addition, this construction effort will include clearing and grubbing, topsoil stripping and stockpiling, construction of temporary roads, soil excavation and stockpiling to be used for perimeter berms, compacted liner, and cover, and application of site controls such as erosion controls. The costs for this construction are estimated to be between $174,500 and $178,300 per acre for the different scenarios. Details for the quantities and unit rates applied to this work are included in Appendix B.

4.3.5 Final Cover Construction

Final cover construction includes leveling fill, compacted soil layer, a geomembrane liner, a drainage collection system, growth medium, topsoil, armored down-chute channels, and vegetation of the site. The costs for this construction are estimated to be between $132,400 and $143,000 per acre for the different scenarios. Details for the quantities and unit rates applied to this work are included in Appendix B.

4.3.6 Post-Closure Care

Post-closure care includes groundwater monitoring and reporting, annual site inspections, repair and maintenance of the final cover (soil, seeding, mowing, surface water structures), maintenance of the facility access roads and fencing, as well as permit required record keeping. Post closure care will occur for 30 years following the closure of the facility and is included in the capital/direct costs for this cost analysis. The costs for post closure care are estimated to be between $50,000 and $108,500 per year for the different scenarios. Details for the quantities and unit rates applied to this work are included in Appendix B.

4.3.7 Construction Management and Construction Quality Assurance

Throughout the construction effort, a construction manager will be on-site to communicate between the contractors and the design engineer. In addition to the construction manager, one or several construction quality assurance (CQA) monitors will be on-site during the construction. This item is estimated as 10% of the total construction costs to develop the facility. Ten percent is based on Golder's experience with coal combustion product facilities within the Midwest.

4.3.8 GRE Internal Costs

Internal costs for GRE to manage consultants, contractors, and in-house staff is estimated as 10% of the total costs (construction, engineering, permitting, CQA). Ten percent is based on GRE's experience with projects at CCS.

4.3.9 Project Contingency

Due to the order-of-magnitude scope of this cost estimate and the associated engineering and unit rate development, a contingency of 15% on the construction and land acquisition costs was added.

4.3.10 Operational Costs

Landfill operations and maintenance costs are estimated as an annual cost and include both engineering support and site operations. Engineering support includes design support; permit support, an annual inspection, groundwater monitoring, and an annual survey. Site operations include the ownership and operation of site haul and placement equipment, full-time site staff, and material expenses.

Estimated costs for this work are broken into haul costs, placement costs, and site management and maintenance costs.

Haul costs were estimated at $2.14 per ton based on haul distance, equipment capacity, operator costs, and equipment costs. Placement costs were estimated at $1.71 per ton based on dozer spreading with minimal compaction. Details on the haul and placement costs are included in Appendix B.

Site management and maintenance costs were estimated between $154,500 and $396,000 per year for the different scenarios. Details on the annual site management and maintenance costs are included in Appendix B.

4.4 Disposal Cost Summary

Using the quantities and the unit pricing described above, disposal costs were estimated for the three scenarios and are summarized in Table 3.

Table 3: Disposal Cost Summary

	Scenario A (Current Sales)	**Scenario B (No Sales)**	**Scenario C (Reduced Sales, ASM)**
Fly Ash Disposed (ton/yr)	110,000	525,000	234,500
Disposal Cost ($/ton)	$18.06	$11.18	$13.91
Annual Disposal Cost ($/yr)	$1,987,000	$5,870,000	$3,262,000
Annual Increase in Disposal Cost Compared to Scenario A ($/yr)	-	$3,883,000	$1,275,000

The disposal cost per ton is reduced with increased disposal quantity due to the efficiency of the landfill footprint (larger landfill can be built higher and has larger capacity), and the distribution of fixed costs (roads, bridge, fence) across a larger amount of disposed fly ash.

Based on the annual disposal cost estimate, the potential impact of an SNCR to the fly ash disposal costs at CCS may be an additional $3.9 million per year if fly ash is no longer marketable or an additional $1.3 million per year if the ASM technology proves successful.

5.0 COST IMPACT

The total cost impact of an SNCR on fly ash management at CCS requires the aggregation of the post-processing costs (ASM), the disposal costs, and the loss in revenue generated from the sale of fly ash. This total cost impact was evaluated for the three Scenarios discussed previously. As a basis for the cost comparison, Table 4 provides a summary of the annual tons of fly ash produced, sold, disposed, and the loss in fly ash sales in comparison to Scenario A (current sales).

Table 4: Fly Ash Sales and Disposal Tons

	Scenario A (Current Sales)	Scenario B (No Sales)	Scenario C (Reduced Sales, ASM)
Fly Ash Produced (ton/yr)	525,000	525,000	525,000
Fly Ash Sold (ton/yr)	415,000	0	290,500
Fly Ash Disposed (ton/yr)	110,000	525,000	234,500
Lost Fly Ash Sales (ton/yr)	0	415,000	124,500

5.1 Ammonia Slip Mitigation

Post-processing of ammonia slip impacted fly ash by Headwater's ASM technology is proposed as an option to maintain fly ash sales. This post-processing is only being applied to the sold fly ash tonnage in Scenario C. Depending upon the plant power profile and how the fly ash distribution system is setup, it is likely that additional tons of fly ash will be treated and disposed, but these potential costs impacts are not included. The cost impact for ASM post-processing is shown in Table 5.

Table 5: ASM Post-Processing Costs

	Scenario A (Current Sales)	Scenario B (No Sales)	Scenario C (Reduced Sales, ASM)
ASM Unit Rate Capital and O&M ($/ton sold)	$0.00	$0.00	$5.61
ASM Annual Capital and O&M ($/yr)	$0	$0	$1,629,000

5.2 Fly Ash Disposal

Disposal costs vary between the Scenarios with the per ton cost being reduced by disposal volume. The cost impact for fly ash disposal is shown in Table 6.

Table 6: Disposal Costs

	Scenario A (Current Sales)	Scenario B (No Sales)	Scenario C (Reduced Sales, ASM)
Unit Rate Capital and O&M ($/ton disposed)	$18.06	$11.18	$13.91
Annual Capital and O&M ($/yr)	$1,987,000	$5,870,000	$3,262,000

5.3 Lost Sales

The current fly ash sales are supported by a large investment in capital infrastructure as well as a large operations and maintenance contingency. Changes to the quantity of fly ash marketed and sold will have a direct impact on fly ash management costs, as the revenue currently used to offset fly ash management will be lost. The lost fly ash sales revenue is based on the 2010 average price per ton FOB of $41.00; with 30% of the sale price going to GRE as revenue. The cost impact of the potential loss in fly ash sales in shown in Table 7.

Table 7: Lost Fly Ash Sales

	Scenario A (Current Sales)	Scenario B (No Sales)	Scenario C (Reduced Sales, ASM)
Lost Fly Ash Sales Revenue ($/ton lost sales)	$12.30	$12.30	$12.30
Annual Lost Fly Ash Sales Revenue ($/yr)	$0	$5,105,000	$1,531,000

5.4 Combined Impact to Fly Ash Management

The combination of the ASM post-processing, fly ash disposal, and lost fly ash sales revenue is shown in Table 8. This table also shows the additional cost impact of Scenario B and Scenario C in comparison with the current sales (Scenario A).

Table 8: Total Fly Ash Management Costs

	Scenario A (Current Sales)	Scenario B (No Sales)	Scenario C (Reduced Sales, ASM)
Total (Disposal + Post Processing + Lost Sales)			
Annual Cost ($/yr)	$1,987,000	$10,975,000	$6,422,000
Unit Cost ($/ton produced)	$3.79	$20.91	$12.23
Additional Cost (Scenario B/C - Scenario A)			
Fly Ash Management Cost ($/yr)	-	$8,988,000	$4,435,000
Fly Ash Management Cost ($/ton produced)	-	$17.12	$8.45

The total additional cost impact to fly ash management as a result of an SNCR is between $4.4 and $9.0 million per year.

We appreciate the opportunity to provide this third-party review of Headwater's ASM technology, and an estimate of the potential impact of SNCR on fly ash management costs including disposal and sales. Please contact us if you have any questions about the information provided.

GOLDER ASSOCIATES INC.

Fawn W. Bergen, PE
Senior Project Engineer

Ron Jorgenson
Principal

FWB/TS/dls

6.0 REFERENCES

1. *EPA Air Pollution Control Cost Manual*, Sixth Edition, EPA/452/B-02-001, January 2002.

2. Email from Rafic Minkara, PhD, PE, Vice President – Technology, Headwaters Energy Services, July 15, 2011.

3. RSMeans, 2010. *Heavy Construction Cost Data, 24th Annual Edition*. Construction Publishers & Consultants; Kingston, MA.

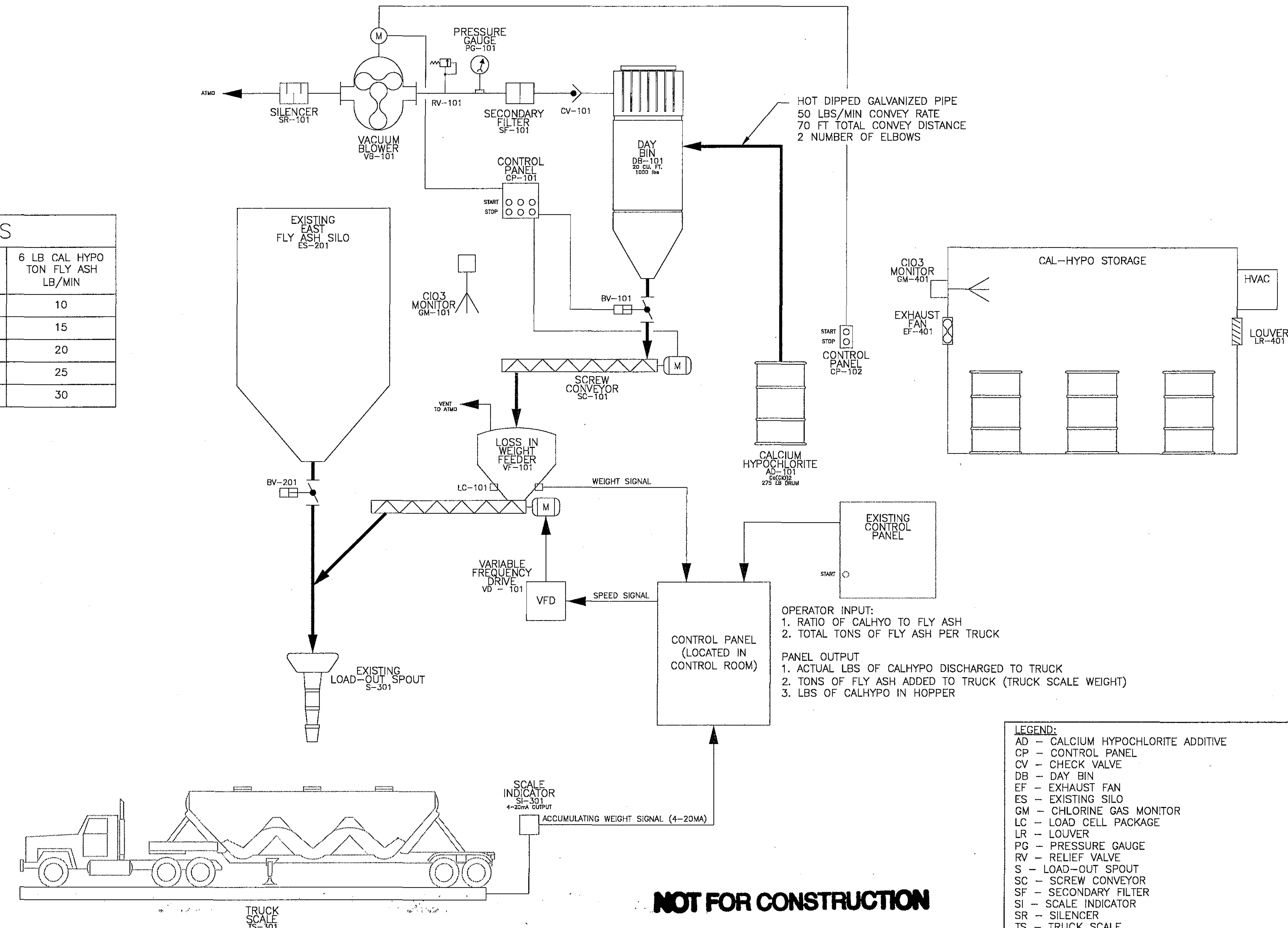
APPENDIX A

EASTLAKE ASM DESIGN DRAWINGS (HEADWATERS RESOURCES)

NOTES:
1. APPROXIMATELY 1½ TO 6 LBS CALCIUM HYPOCHLORITE/TON FLY ASH OR 38 LBS (1½*25) TO 150 LBS (6*25)/TRUCK
2. 30 TRUCKS MAX PER DAY. 1140 LBS (38*30) TO 4500 LBS (150*30) PER DAY
3. FLY ASH FEED RATE 300 TONS/HR TO 150 TONS/HR
4. CALCIUM HYPOCHLORITE FEED RATE 2.5 LBS/MIN TO 30 LBS/MIN
5. TRUCK LOAD TIME BETWEEN 5 AND 10 MINUTES
6. FLY ASH PH BETWEEN 11.5 TO 12
7. FLY ASH DENSITY 70 LBS LOOSE 100 LBS VIBRATED
8. CALHYPO APPROX. 50 LBS/FT^3
9. CALHYPO DRUM 275 LBS

LOSS IN WEIGHT FEEDER RATES

FLY ASH LOAD-OUT TON/HR	1.5 LB CAL HYPO TON FLY ASH LB/MIN	2 LB CAL HYPO TON FLY ASH LB/MIN	4 LB CAL HYPO TON FLY ASH LB/MIN	6 LB CAL HYPO TON FLY ASH LB/MIN
100	2.5	3.3	6.7	10
150	3.75	5.0	10.0	15
200	5	6.7	13.3	20
250	6.25	8.3	16.7	25
300	7.5	10.0	20.0	30



LEGEND:
AD - CALCIUM HYPOCHLORITE ADDITIVE
CP - CONTROL PANEL
CV - CHECK VALVE
DB - DAY BIN
EF - EXHAUST FAN
ES - EXISTING SILO
GM - CHLORINE GAS MONITOR
LC - LOAD CELL PACKAGE
LR - LOUVER
PG - PRESSURE GAUGE
RV - RELIEF VALVE
S - LOAD-OUT SPOUT
SC - SCREW CONVEYOR
SF - SECONDARY FILTER
SI - SCALE INDICATOR
SR - SILENCER
TS - TRUCK SCALE
VB - VACUUM BLOWER
VD - VARIABLE SPEED DRIVE
VF - VIBRATORY FEEDER

HEADWATERS RESOURCES

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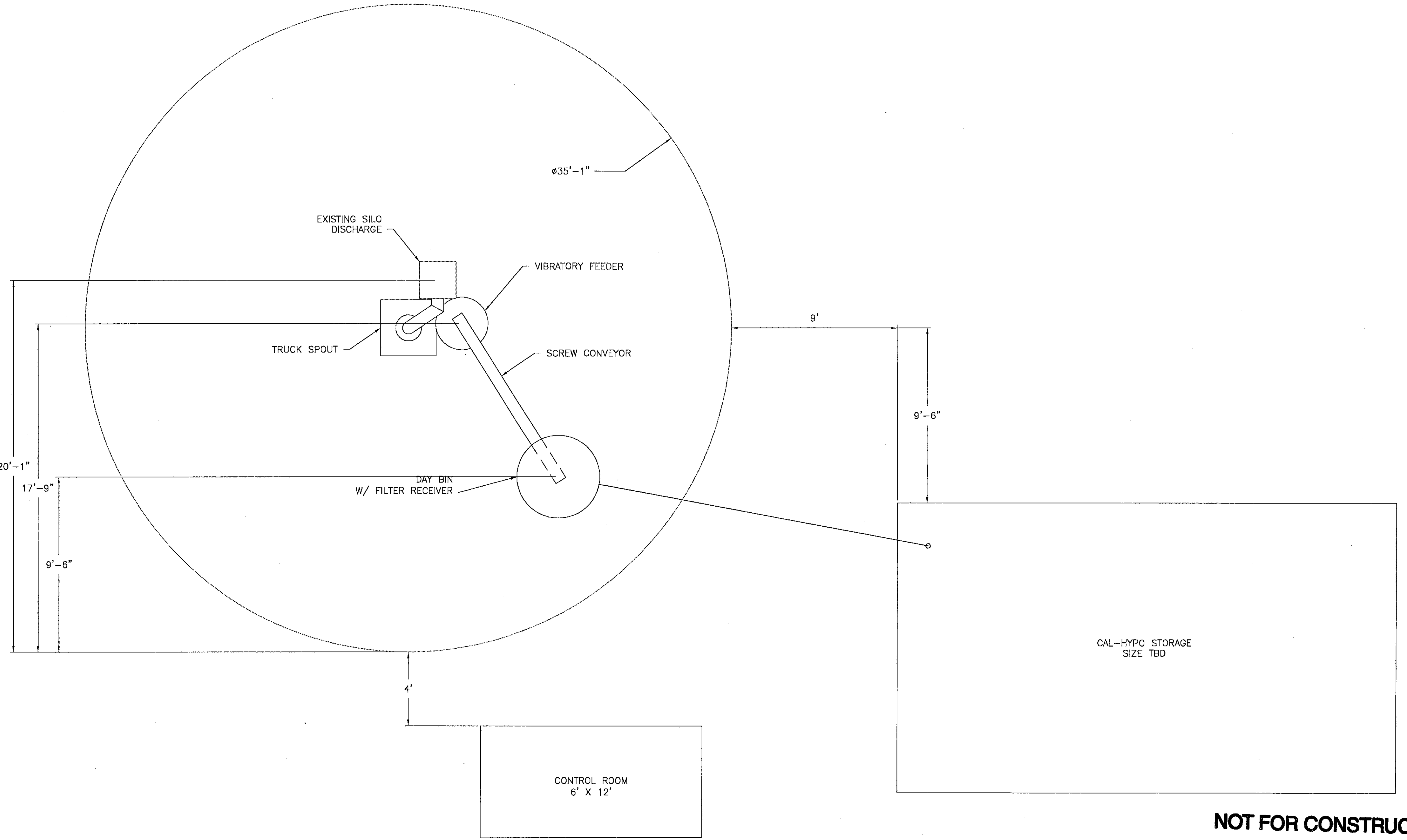
DATE	NO.	REVISION DESCRIPTION	BY
8/13/07	G	ADDED EXHAUST FAN & LOUVER	DCB
8/2/07	F	ADDED CONTROL PANELS	DCB
7/16/07	E	ADDED GAS MONITORS AND STORAGE BUILDING	DCB
5/21/07	B	GENERAL REV.	DCB

EAST LAKE
AMMONIA SLIP MITIGATION
PROCESS FLOW DIAGRAM
EAST LAKE, OH

SCALE: NO SCALE	SHEET NO. PF100
DATE: 05-18-07	
DESIGN BY: LS	
DRAWN BY: DCB	REVISION NO. G
CHECKED BY:	PROJECT NO. R070H0
APPROVED BY:	



NOT FOR CONSTRUCTION

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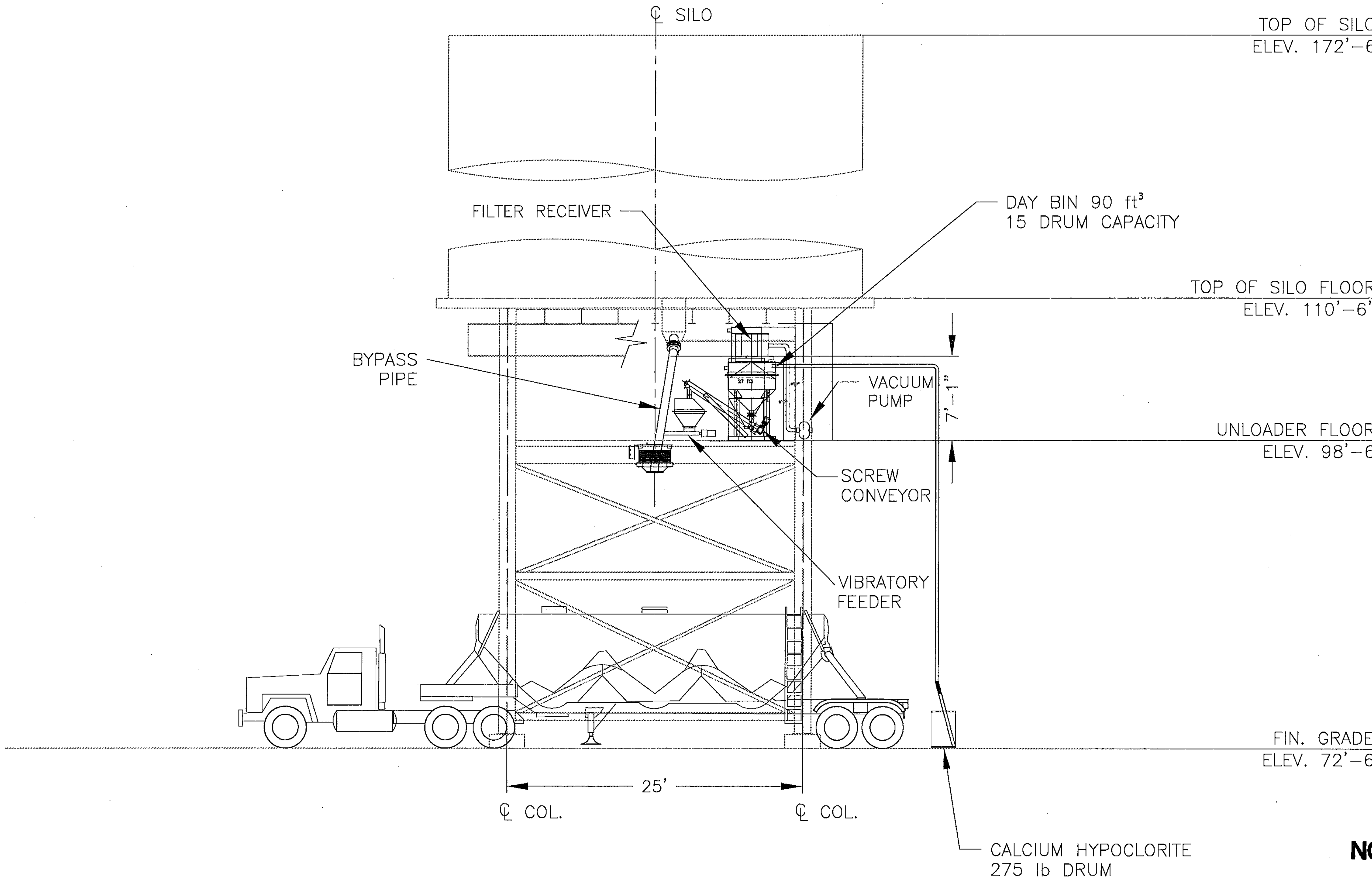
DATE	NO.	REVISION DESCRIPTION	BY
7/18/07	A	DRAWING CREATED	DCB

EAST LAKE
AMMONIA SLIP MITIGATION
PLAN VIEW
EAST LAKE, OH

SCALE: 3/16" = 1'	
DATE: 07-18-07	
DESIGN BY:	LAS
DRAWN BY:	DCB
CHECKED BY:	
APPROVED BY:	

SHEET NO. M100
REVISION NO. A
PROJECT NO. R07OH0



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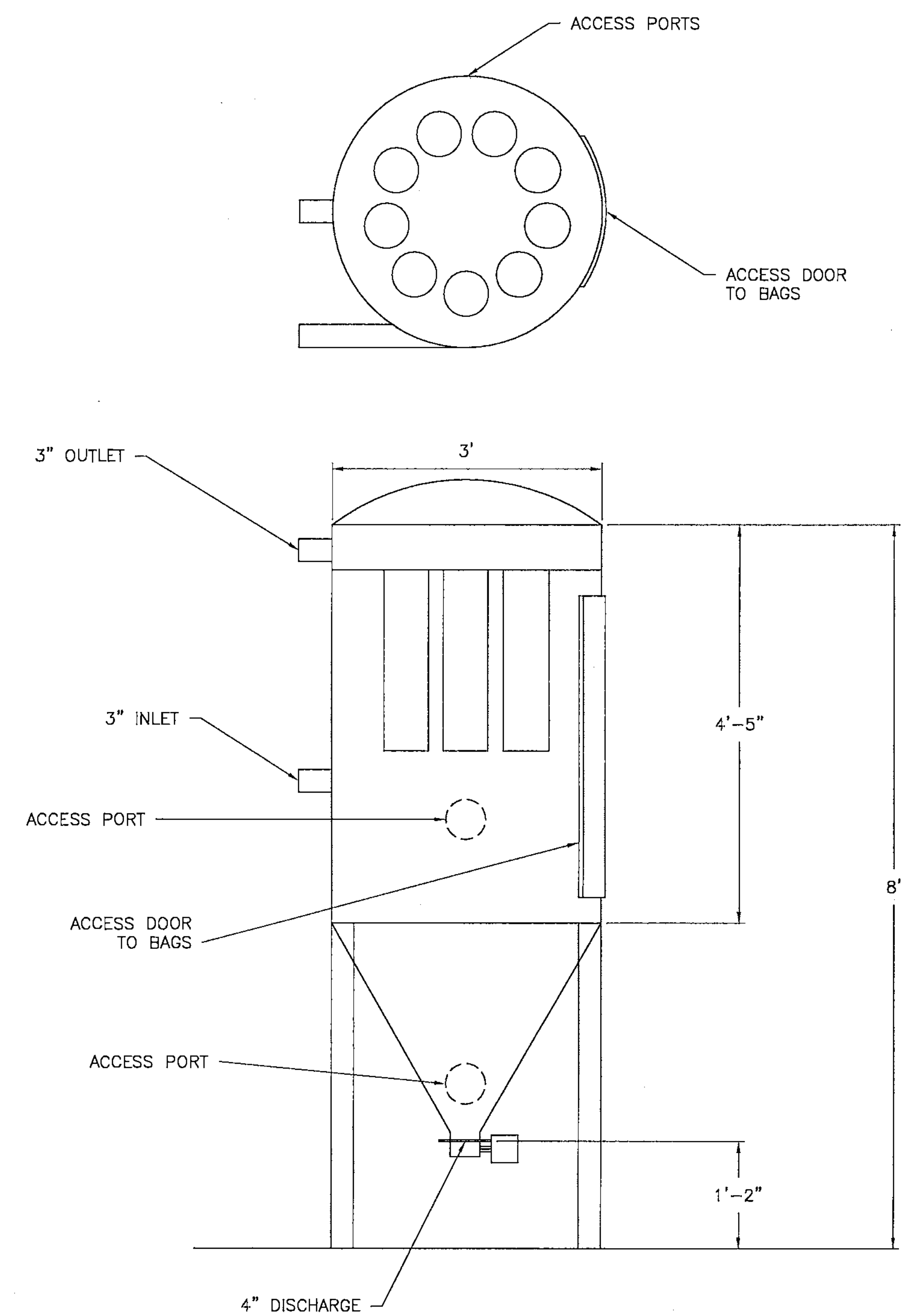
DATE	NO.	REVISION DESCRIPTION	BY
7/18/07	A	DRAWING CREATED	DCB

EAST LAKE
AMMONIA SLIP MITIGATION
ELEVATION
EAST LAKE, OH

SCALE: 1"=10'	
DATE: 07-18-07	
DESIGN BY:	LAS
DRAWN BY:	DCB
CHECKED BY:	
APPROVED BY:	

SHEET NO. M101
REVISION NO. A
PROJECT NO. R070H0

NOTE:
1. EPOXY PAINT INSIDE AND OUT
2. TOTAL CAPACITY – 17 FT^3
3. USE 2' TEFLON-COATED BAGS



NOT FOR CONSTRUCTION

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DATE	NO.	REVISION DESCRIPTION	BY
8/6/07	B	RELOCATED ACCESS PORTS	DCB
8/3/07	A	DRAWING CREATED	DCB

EAST LAKE
AMMONIA SLIP MITIGATION
FILTER RECEIVER
EAST LAKE, OH

SCALE: 1/2" = 1'	
DATE: 08-03-07	
DESIGN BY:	LAS
DRAWN BY:	DCB
CHECKED BY:	
APPROVED BY:	

SHEET NO. M200
REVISION NO. B
PROJECT NO. R07OH0

APPENDIX B
COST ESTIMATE DETAILS

Legend

Fly Ash Stream

Calcium Hypo–Chlorite Mixing System

Notes

1. Eastlake Generating Plant has a truck loadout for both untreatable fly ash destined for disposal (silos 1 and 2) and treated fly ash (silo 4).

250 0 250

SCALE FEET

FOR DISCUSSION PURPOSES ONLY

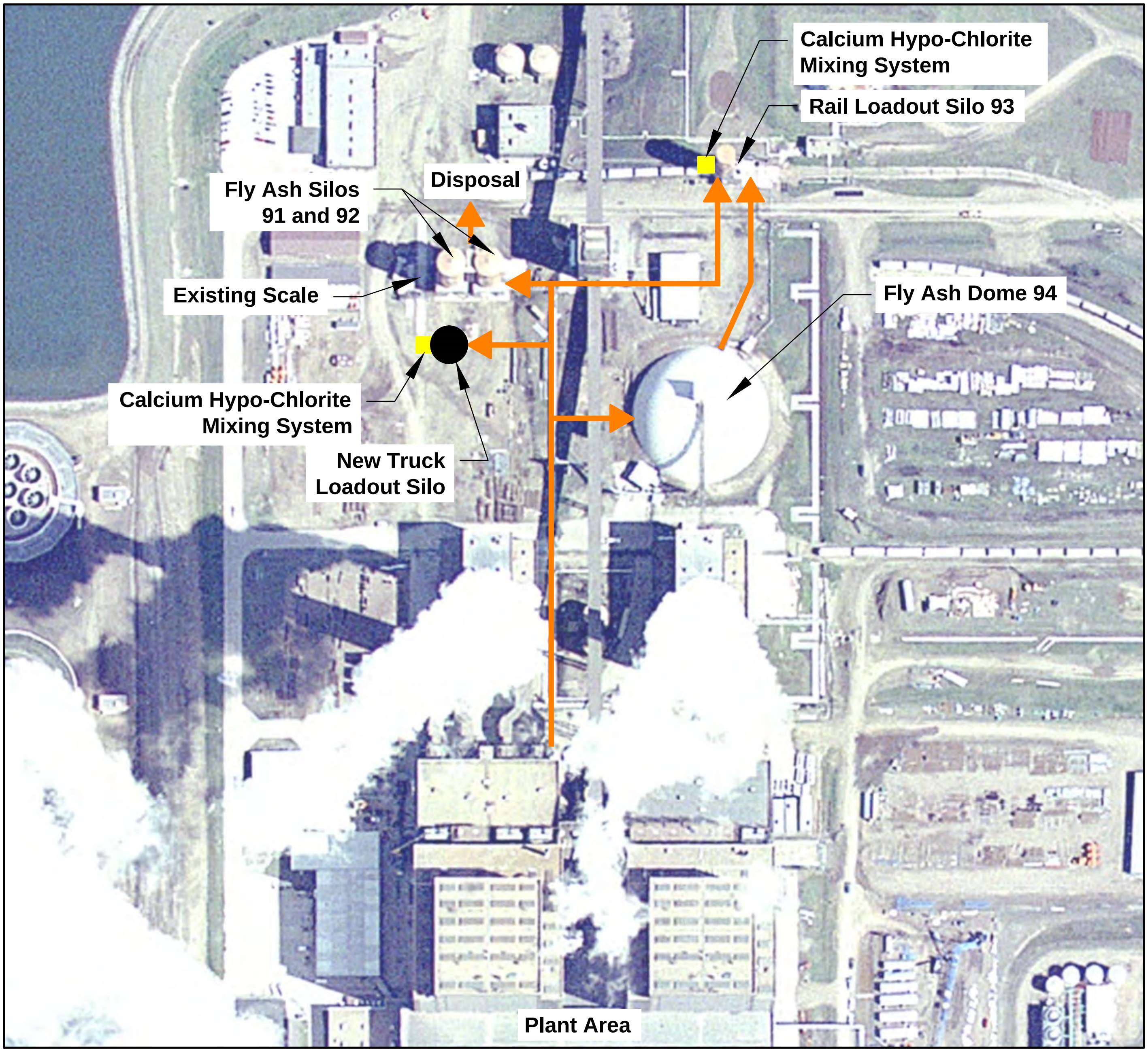
Golder Associates

Fly Ash Loadout Schematic
Eastlake Generating Plant

FIGURE 1

PROJECT No. 113–82161 CADD CCS DATE 11/1/11 FILE No. 11382161_Figures.dwg

Drawing File: J:\11JOBS\113-82161 GRE SNCR\Figures\ 11382161_Figures.dwg | Layout: Fly Ash Loadout-Eastlake | Modified: Nov 02, 2011 16:04 CSchuettpelz | Plotted: 11/02/11 4:05pm CSchuettpelz



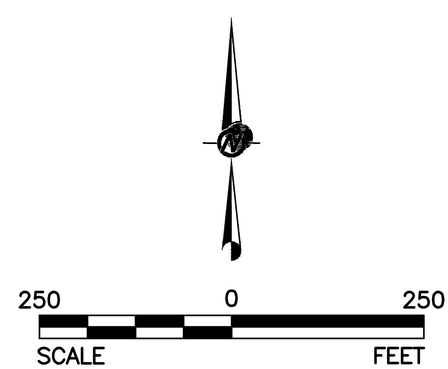
Legend

Fly Ash Stream

Calcium Hypo–Chlorite Mixing System

Notes

1. New truck loadout silo and scale are required to store treatable fly ash for sale.
2. Two Calcium Hypo–Chlorite Mixing Systems would be required near the new truck loadout silo and the rail loadout silo (93) for treating fly ash available for sale.
3. The existing fly ash silos (91 and 92) are available to store untreatable fly ash for disposal.
4. The existing Fly Ash Dome (94) is available to store treatable fly ash for rail sale.



Fly Ash Loadout Schematic Coal Creek Station

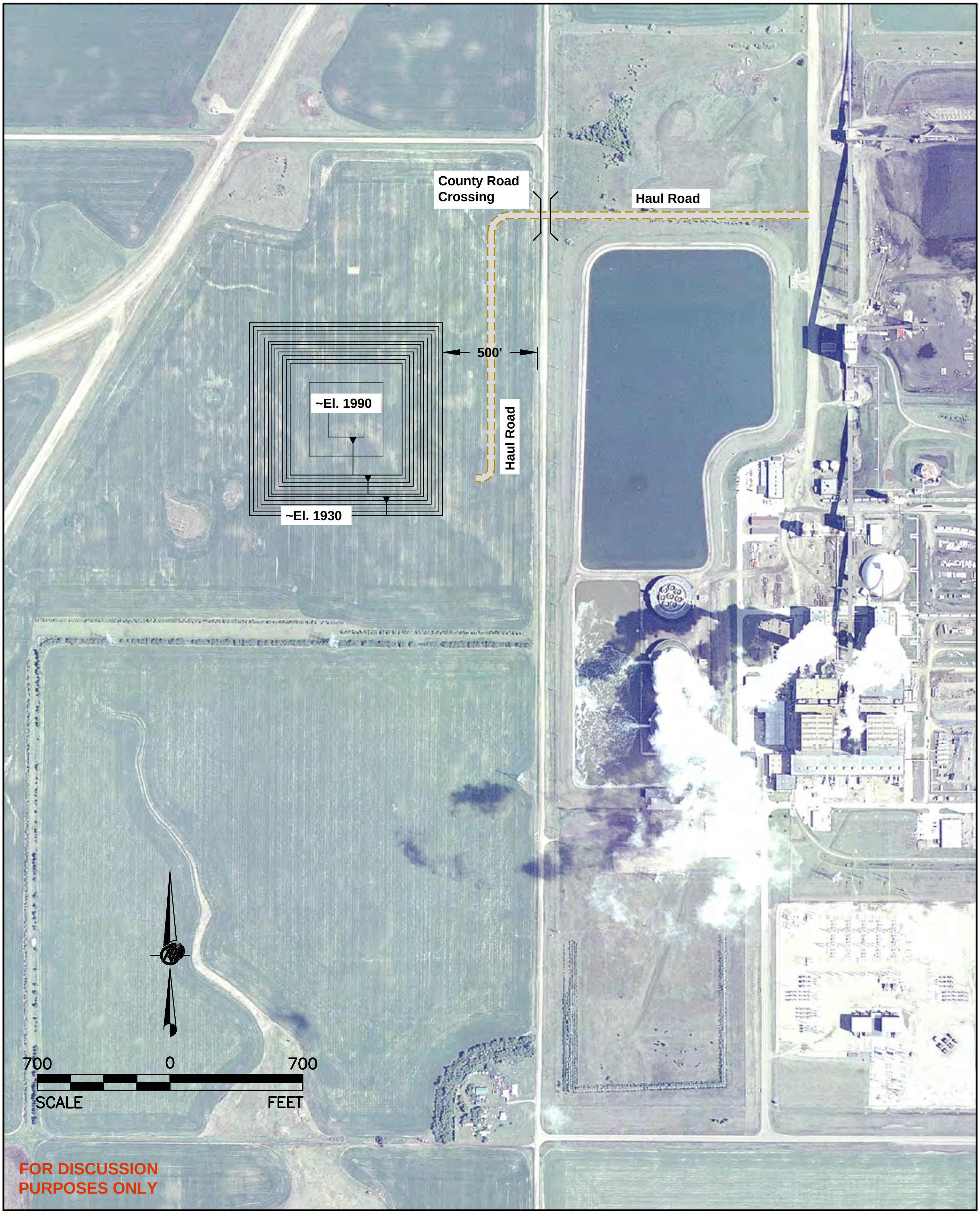
Golder Associates

FOR DISCUSSION PURPOSES ONLY

FIGURE 2

PROJECT No. 113–82161 CADD CCS DATE 11/1/11 FILE No. 11382161_Figures.dwg

Drawing File: J:\11JOBS\113-82161 GRE SNCR\Figures\11382161_Figures.dwg | Layout: Fly Ash Loadout-CCS | Modified: Nov 02, 2011 16:04 CSchuettpelz | Plotted: 11/02/11 4:05pm CSchuettpelz



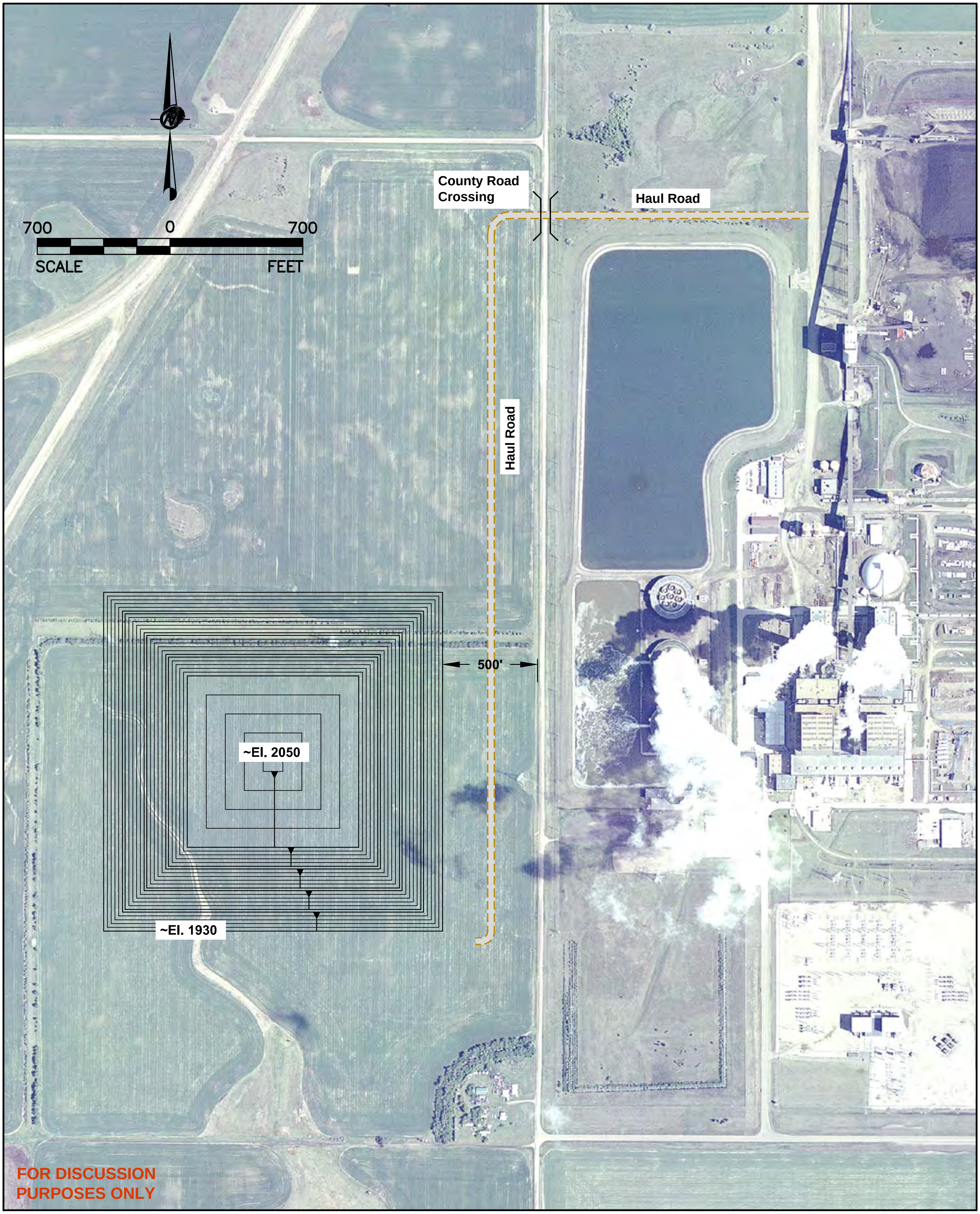
Scenario A
Fly Ash Containment Facility

Golder Associates

FIGURE 3

PROJECT No. 113-82161 CADD CCS DATE 11/1/11 FILE No. 11382161_Figures.dwg

Drawing File: J:\11JOBS\113-82161 GRE SNCR\Figures\ 11382161_Figures.dwg | Layout: Small Facility | Modified: Nov 02, 2011 16:04 CSchuettpelz | Plotted: 11/02/11 4:05pm CSchuettpelz



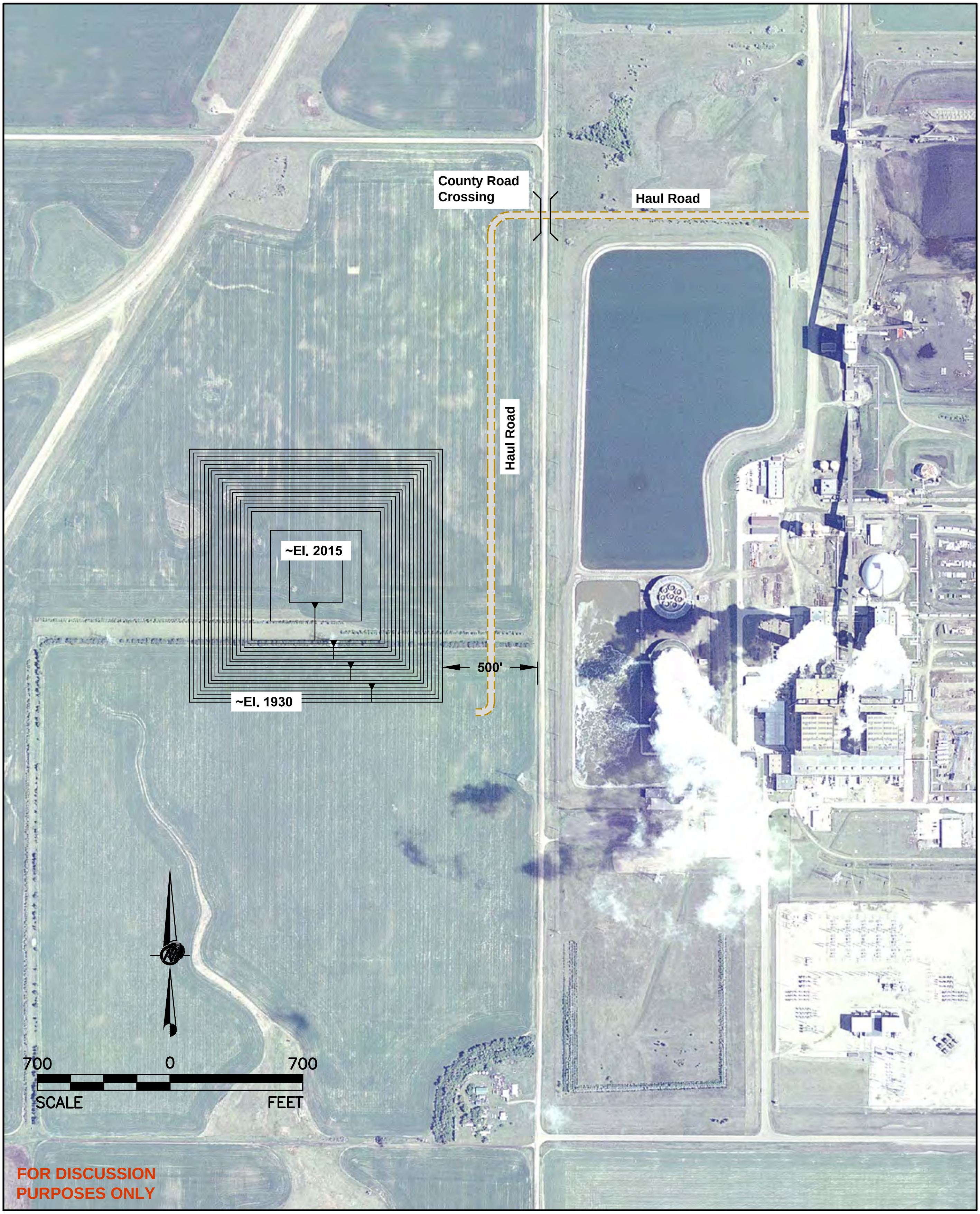
Scenario B
Fly Ash Containment Facility

Golder Associates

FIGURE 4

PROJECT No. 113-82161 CADD CCS DATE 11/1/11 FILE No. 11382161_Figures.dwg

Drawing File: J:\11JOBS\113-82161 GRE SNCR\Figures\ 11382161_Figures.dwg | Layout: Large Facility | Modified: Nov 02, 2011 16:04 CSchuettpelz | Plotted: 11/02/11 4:05pm CSchuettpelz



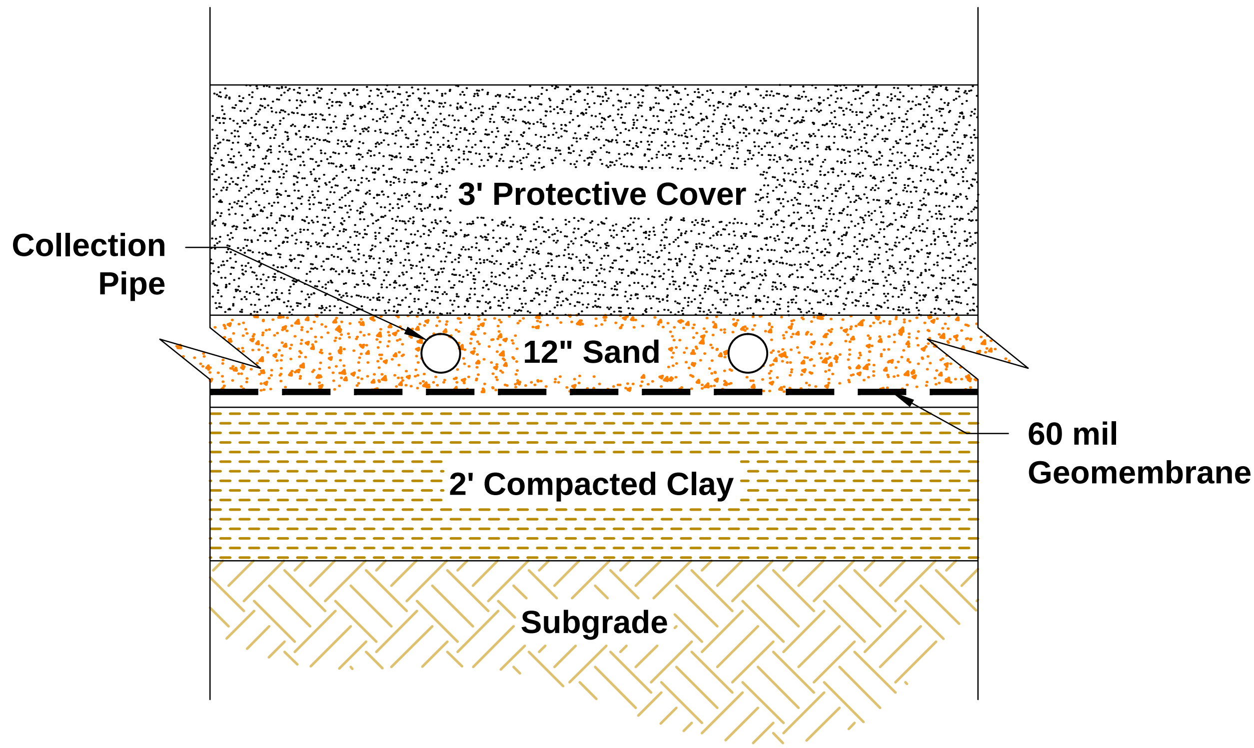
Scenario C
Fly Ash Containment Facility

Golder Associates

FIGURE 5

PROJECT No. 113-82161 CADD CCS DATE 11/1/11 FILE No. 11382161_Figures.dwg

Drawing File: J:\11JOBS\113-82161 GRE SNCR\Figures\ 11382161_Figures.dwg | Layout: Medium Facility | Modified: Nov 02, 2011 16:04 CSchuettpelz | Plotted: 11/02/11 4:05pm CSchuettpelz



FOR DISCUSSION
PURPOSES ONLY

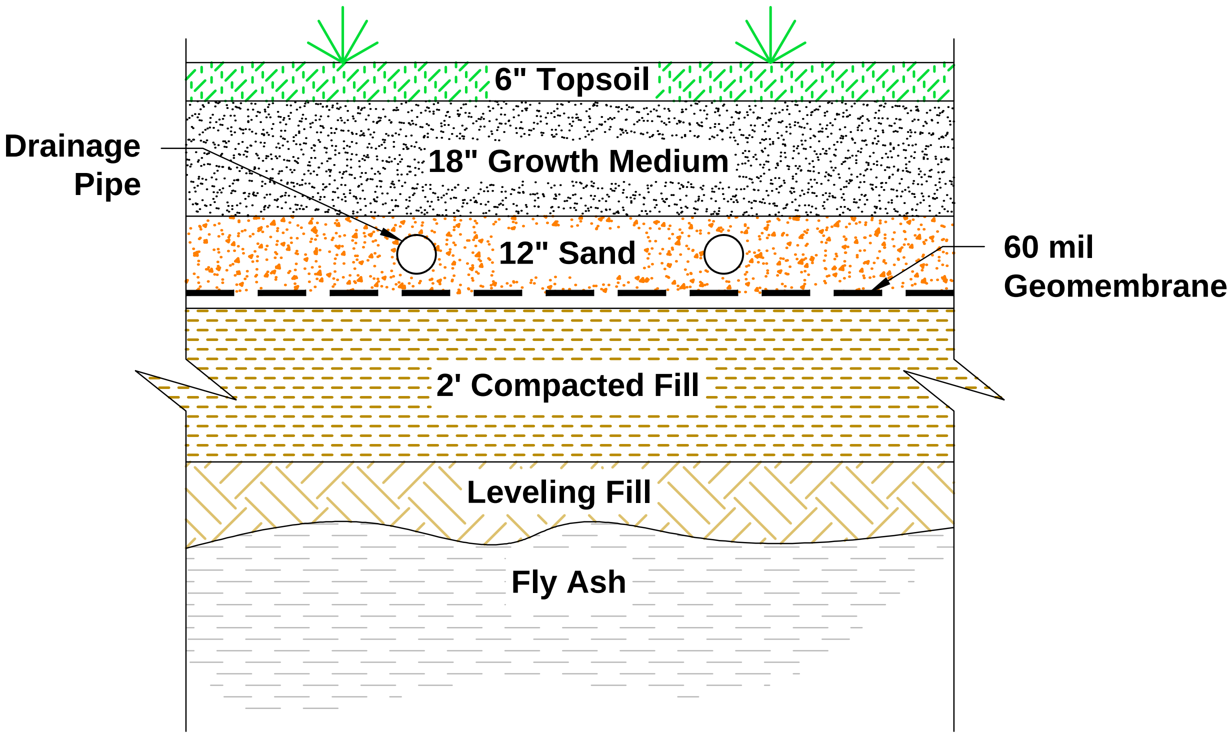
Golder Associates

Composite Liner

FIGURE 6

PROJECT No. 113-82161 CADD CCS DATE 11/1/11 FILE No. 11382161_Figures.dwg

Drawing File: J:\11JOBS\113-82161 GRE SNCR\Figures\ 11382161_Figures.dwg | Layout: Liner | Modified: Nov 02, 2011 16:04 CSchuettpelz | Plotted: 11/02/11 4:05pm CSchuettpelz



FOR DISCUSSION
PURPOSES ONLY

Golder Associates

Cover

FIGURE 7

PROJECT No. 113-82161 CADD CCS DATE 11/1/11 FILE No. 11382161_Figures.dwg

Drawing File: J:\11JOBS\113-82161 GRE SNCR\Figures\ 11382161_Figures.dwg | Layout: Cover | Modified: Nov 02, 2011 16:04 CSchuettpelz | Plotted: 11/02/11 4:06pm CSchuettpelz

Fly Ash Management Impact Evaluation Summary (November 15, 2011)

	Option A	Option B	Option C
	Current fly ash sales with new RCRA Subtitle D landfill	No fly ash sales with new RCRA Subtitle D landfill	ASM technology to allow reduced fly ash sales with new RCRA Subtitle D landfill
Fly Ash Quantities			
Fly Ash production (ton/yr)	525,000	525,000	525,000
Fly Ash Sales (ton/yr)	415,000	0	290,500
Fly Ash Disposal (ton/yr)	110,000	525,000	234,500
Lost Fly Ash Sales (ton/yr)	0	415,000	124,500
ASM Fly Ash Post Processing			
ASM Unit Rate Capital and O&M ($/ton sold)	$ -	$ -	$ 5.61
ASM Annual Capital and O&M ($/yr)	$ -	$ -	$ 1,629,000
Fly Ash Disposal			
Lined Footprint (acres)	24.0	73.5	41.0
Unit Rate Capital and O&M ($/ton disposed)	$ 18.06	$ 11.18	$ 13.91
Annual Capital and O&M ($/yr)	$ 1,987,000	$ 5,870,000	$ 3,262,000
Lost Fly Ash Sales			
Lost Fly Ash Sales Revenue ($/ton lost sales)	$ 12.30	$ 12.30	$ 12.30
Annual Lost Fly Ash Sales Revenue ($/yr)	$ -	$ 5,105,000	$ 1,531,000
Total (Disposal + Post Processing + Lost Sales)			
Annual Cost ($/yr)	$ 1,987,000	$ 10,975,000	$ 6,422,000
Unit Cost ($/ton produced)	$ 3.79	$ 20.91	$ 12.23
Additional Cost (Scenario B/C - Scenario A)			
Fly Ash Management Cost ($/yr)	-	$ 8,988,000	$ 4,435,000
Fly Ash Management Cost ($/ton produced)	-	$ 17.12	$ 8.45

Notes:

Capital costs annualized based on 20-year life and 5.5% interest rate.

Disposal costs based on new facility built across county road from Coal Creek Station with 20-year life.

RCRA Subtitle D type facility (composite liner, leachate collection system, and composite cover).

Disposal costs only include fly ash disposal and not facility airspace or O&M for other CCPs.

Ammonia slip mitigation costs based on existing facility site visit and historic costs for fly ash infrastructure.

All costs are in 2011 dollars.

Lost fly ash sales revenue based on expected 2011 average price per ton FOB of $43 and 30% of sale price to GRE.

Existing fly ash sales infrastructure and O&M costs are not included.

Scenario A - Current Sales

Project	113-82161
Date	11/15/2011
By	TJS
Checked	JJS

Sizing Information

Annual Fly Ash Disposal	110,000	tn	
20yr Fly Ash Disposal	2,200,000	tn	
Fly Ash Dry Density (in-situ)	90	pcf	
20yr Fly Ash Quantity	1,811,000	cy	
Lined Footprint	24.0	ac	75,000 cy/ac
Disturbance Footprint	34.5	ac	100' offset on liner footprint
Berm Length	4,240	ft	20' offset on liner footprint
Total Footprint	160		500' offset on liner footprint, nearest 1/8 section
Total Cover Area	26.5	ac	1.1 ration of cover area to liner area

Direct/Capital Costs

Item	Rate		#		Total Cost	
Land Acquisition	$ 2,000	/ac	160.0	ac	$ 320,000	
Infrastructure Development	$ 649,500	ea	1.0	LS	$ 649,500	
County Road Crossing	$ 1,730,500	ea	1.0	LS	$ 1,730,500	
Liner Construction	$ 178,300	/ac	24.0	ac	$ 4,279,200	
Final Cover Construction	$ 143,000	/ac	26.5	ac	$ 3,789,500	
Post-Closure Care	$ 50,000	/yr	30.0	yr	$ 1,500,000	
Facility Design & Permitting (on construction)	10.0%	-	$ 10,448,700	LS	$ 1,044,870	
Construction Quality Assurance (on construction)	5.0%	-	$ 10,448,700	LS	$ 522,435	
GRE Internal Costs (on construction, design, CQA, & land purchase)	10.0%	-	$ 13,836,005	-	$ 1,384,000	
Project Contingency (on construction & land)	15.0%	-	$ 10,768,700	-	$ 1,615,000	
			Total Direct/Capital Costs		$ 16,835,005	
			Annualized Capital Cost*		$ 1,409,000	/yr
			Capital Costs		$ 12.81	/tn

Operational Costs

Hauling Costs	$ 2.14	/tn	110,000	tn/yr	$ 235,469	/yr
Placement Costs	$ 1.71	/tn	110,000	tn/yr	$ 188,000	/yr
Maintenance Costs	$ 154,500	/yr	1	yr	$ 154,500	/yr
			Annual Operational Costs		$ 578,000	/yr
			Operational Costs		$ 5.26	/tn

TOTAL DISPOSAL COSTS

Annual Costs	$ 1,987,000	/yr
20-Year Total Costs	$ 39,740,000	
Per Ton Cost	$ 18.06	/tn

Notes:
*Annualized capital cost based on 20-year life and 5.5% interest rate.
All costs are in 2011 dollars.

Scenario B - No Fly Ash Sales

Project	113-82161
Date	11/15/2011
By	TJS
Checked	JJS

Sizing Information

Annual Fly Ash Disposal	525,000	tn	
20yr Fly Ash Disposal	10,500,000	tn	
Fly Ash Dry Density (in-situ)	90	pcf	
20yr Fly Ash Quantity	8,642,000	cy	
Lined Footprint	73.5	ac	118,000 cy/ac
Disturbance Footprint	91.0	ac	100' offset on liner footprint
Berm Length	7,320	ft	20' offset on liner footprint
Total Footprint	240		500' offset on liner footprint, nearest 1/8 section
Total Cover Area	81.0	ac	1.1 ration of cover area to liner area

Direct/Capital Costs

Item	Rate		#		Total Cost	
Land Acquisition	$ 2,000	/ac	240.0	ac	$ 480,000	
Infrastructure Development	$ 924,000	ea	1.0	LS	$ 924,000	
County Road Crossing	$ 1,730,500	ea	1.0	LS	$ 1,730,500	
Liner Construction	$ 174,500	/ac	73.5	ac	$ 12,825,750	
Final Cover Construction	$ 132,400	/ac	81.0	ac	$ 10,724,400	
Post-Closure Care	$ 108,500	/yr	30.0	yr	$ 3,255,000	
Facility Design & Permitting (on construction)	10.0%	-	$ 26,204,650	LS	$ 2,620,465	
Construction Quality Assurance (on construction)	5.0%	-	$ 26,204,650	LS	$ 1,310,233	
GRE Internal Costs (on construction, design, CQA, & land purchase)	10.0%	-	$ 33,870,348	-	$ 3,387,000	
Project Contingency (on construction & land)	15.0%	-	$ 26,684,650	-	$ 4,003,000	
			Total Direct/Capital Costs		$ 41,260,348	
			Annualized Capital Cost*		$ 3,453,000	/yr
			Capital Costs		$ 6.58	/tn

Operational Costs

Hauling Costs	$ 2.14	/tn	525,000	tn/yr	$ 1,123,830	/yr
Placement Costs	$ 1.71	/tn	525,000	tn/yr	$ 897,273	/yr
Maintenance Costs	$ 396,000	/yr	1	yr	$ 396,000	/yr
			An. Operational Costs		$ 2,417,000	/yr
			Operational Costs		$ 4.60	/tn

TOTAL DISPOSAL COSTS

Annual Costs	$ 5,870,000	/yr
20-Year Total Costs	$ 117,400,000	
Per Ton Cost	$ 11.18	/tn

Notes:
*Annualized capital cost based on 20-year life and 5.5% interest rate.
All costs are in 2011 dollars.

Scenario C - Partial Fly Ash Sales with ASM

Project	113-82161
Date	11/15/2011
By	TJS
Checked	JJS

Sizing Information

Annual Fly Ash Disposal	234,500	tn	
20yr Fly Ash Disposal	4,690,000	tn	
Fly Ash Dry Density (in-situ)	90	pcf	
20yr Fly Ash Quantity	3,860,000	cy	
Lined Footprint	41.0	ac	94,000 cy/ac
Disturbance Footprint	54.0	ac	100' offset on liner footprint
Berm Length	5,500	ft	20' offset on liner footprint
Total Footprint	160		500' offset on liner footprint, nearest 1/8 section
Total Cover Area	45.0	ac	1.1 ration of cover area to liner area

Direct/Capital Costs

Item	**Rate**		**#**		**Total Cost**	
Land Acquisition	$ 2,000	/ac	160.0	ac	$ 320,000	
Infrastructure Development	$ 779,500	ea	1.0	LS	$ 779,500	
County Road Crossing	$ 1,730,500	ea	1.0	LS	$ 1,730,500	
Liner Construction	$ 175,600	/ac	41.0	ac	$ 7,199,600	
Final Cover Construction	$ 138,500	/ac	45.0	ac	$ 6,232,500	
Post-Closure Care	$ 72,500	/yr	30.0	yr	$ 2,175,000	
Facility Design & Permitting (on construction)	10.0%	-	$ 15,942,100	LS	$ 1,594,210	
Construction Quality Assurance (on construction)	5.0%	-	$ 15,942,100	LS	$ 797,105	
GRE Internal Costs (on construction, design, CQA, & land purchase)	10.0%	-	$ 20,828,415	-	$ 2,083,000	
Project Contingency (on construction & land)	15.0%	-	$ 16,262,100	-	$ 2,439,000	
				Total Direct/Capital Costs	$ 25,350,415	
				Annualized Capital Cost*	$ 2,121,000	/yr
				Capital Costs	$ 9.05	/tn

Operational Costs

Hauling Costs	$ 2.14	/tn	234,500	tn/yr	$ 501,977	/yr
Placement Costs	$ 1.71	/tn	234,500	tn/yr	$ 400,782	/yr
Maintenance Costs	$ 238,500	/yr	1	yr	$ 238,500	/yr
				An. Operational Costs	$ 1,141,000	/yr
				Operational Costs	$ 4.87	/tn

TOTAL DISPOSAL COSTS

Annual Costs	$ 3,262,000	/yr
20-Year Total Costs	$ 65,240,000	
Per Ton Cost	$ 13.91	/tn

Notes:

*Annualized capital cost based on 20-year life and 5.5% interest rate.

All costs are in 2011 dollars.

ASM Post-Processing

Project	113-82161
Date	11/15/2011
By	REN
Checked	TJS

Sizing Information

Annual Fly Ash Sales 290,500 tn

Direct/Capital Costs

Item	Rate		#		Total Cost	
New Truck Load-out Silo	$ 1,568,500	ea	1.0	LS	$ 1,568,500	
Cal-Hypo Feed Systems (Rail silo)	$ 246,000	ea	1.0	LS	$ 246,000	
Cal-Hypo Feed Systems (New silo)	$ 328,500	ea	1.0	LS	$ 328,500	
System Design & Engineering (on construction)	10.0%	-	$ 2,143,000	-	$ 214,000	
GRE Internal Costs (on all)	10.0%	-	$ 2,357,000	-	$ 236,000	
Project Contingency (on construction)	15.0%	-	$ 2,143,000	-	$ 321,000	
			Total Direct/Capital Costs		$ 2,914,000	
			Annualized Capital Cost*		$ 244,000	/yr
			Capital Costs		$ 0.84	/tn

Operational Costs

Maintenance	$ 75.00	$/hr	4,600	hr	$ 345,000	/yr
Maintenance Materials	50%	-	$ 345,000	-	$ 172,500	/yr
Operations Materials	$ 75.00	$/hr	5,750	hr	$ 431,250	/yr
Operations Materials (Cal-Hypo)	$ 0.50	/tn	290,500	tn/yr	$ 145,250	/yr
Technology Royalty	$ 1.00	/tn	290,500	tn/yr	$ 290,500	/yr
			An. Operational Costs		$ 1,385,000	/yr
			Operational Costs		$ 4.77	/tn

TOTAL ASM COSTS

Annual Costs	$ 1,629,000	/yr
20-Year Total Costs	$ 32,580,000	
Per Ton Cost	$ 5.61	/tn

Notes:

*Annualized capital cost based on 20-year life and 5.5% interest rate.
Capital costs based on previous silo construction and discussions with Headwaters.
Assumed calcium hypo-chlorite cost of $1.00/lb.
Calcium hypo-chlorite mix rate is estimated between 0.3 and 1.3 lbs per 3,000 lbs of fly ash.

Scenario A (Current Sales) Unit Rate Details

PROJECT COMPONENT	QTY	UNIT	UNIT PRICE	TOTAL	Source	NOTES
Infrastructure Development			Total	$ 649,325	$ 649,500	
General						
Mobilize/Demobilize	5%	%	$ -	$ 29,515		
Miscellaneous Site Work & Materials	5%	%	$ -	$ 29,515		Erosion controls, offices, toilets, temporary roads, survey control, etc.
Civil						
Road Topsoil Stripping and Stockpiling	7,778	CY	$ 2.21	$ 17,181	Ames 2005 construction bid	18" topsoil
Access Road Construction	140,000	SF	$ 1.55	$ 217,101	RSMeans 2010 (01 55 23.50-0100)	8" Gravel temporary road ($13.55/SY = $1.51/sf), 4,000' x 35'
Return Water Pipeline	2,640	LF	$ 41.52	$ 109,622	RSMeans 2008 (33 11 13.25-4160)	6" PVC, 3' deep
Fence	8,090	LF	$ 23.66	$ 191,391	GRE Estimate	7' Chain link fence, GRE paid $22.30/ft in 2009
Overhead Power (Plant to Landfill)	1	EA	$ 25,000	$ 25,000	Golder Estimate	$25,000 for 1/2 mile distribution w/ transformer
Monitoring Well Installation	5	EA	$ 6,000	$ 30,000	Golder Estimate	
County Road Crossing			Total	$ 1,730,693	$ 1,730,500	
General						
Mobilize/Demobilize	5%	%	$ -	$ 78,668		
Misc. (erosion controls, toilets, etc)	5%	%	$ -	$ 78,668		Erosion controls, offices, toilets, temporary roads, survey control, etc.
Civil						
Topsoil Stripping and Stockpiling	4,577	CY	$ 2.21	$ 10,111	Ames 2005 construction bid	18" topsoil
Embankment Fill	35,591	CY	$ 3.59	$ 127,906	Northern 2006 construction bid	
County Road Sub-Base Course	2,385	CY	$ 3.59	$ 8,572	Northern 2006 construction bid	2' Sub-base preparation
County Road Base Course	32,200	SF	$ 1.55	$ 49,933	RSMeans 2010 (01 55 23.50-0100)	8" Gravel temporary road ($13.55/SY = $1.51/sf) 920' x35'
Bridge Deck Construction	5,250	SF	$ 262	$ 1,376,836	2008 California DOT Average	150 ft bridge deck, 35 ft wide
Liner Construction			Total	$ 4,278,853	Cost Per Acre of Liner	$ 178,300
General						
Mobilize/Demobilize	5%	%	$ -	$ 194,493		
Miscellaneous Site Work & Materials	5%	%	$ -	$ 194,493		Erosion controls, offices, toilets, temporary roads, survey control, etc.
Civil						
Clearing and Grubbing	35	AC	$ 6,077.00	$ 209,657	RSMeans 2010 (31 11 10.10-0200)	Clear & grub brush including stumps
Topsoil Stripping & Stockpiling (18")	-	CY	$ 2.21		Ames 2005 construction bid	
	35	AC	$ 5,346	$ 184,429		
Subgrade Cut to Stockpile	291,093	CY	$ 3.00	$ 873,280	Golder Estimate	10' across liner area: for liner, berms and cover
Subgrade Cut/Embankment Fill	96,107	CY	$ 3.59	$ 345,383	Northern 2006 construction bid	612 ft2 cross section area
Low Permeability Soil Liner (24")	-	CY	$ 4.32		Northern 2008 construction bid	
	24	AC	$ 13,927	$ 334,252		
60-mil HDPE Liner	-	SF	$ 0.76		Northern 2008 construction bid	materials, waste, conformance testing, installation
	24	AC	$ 33,319	$ 799,666		
Leachate Collection Layer, Sand (12")		CY	$ 25.00		Golder Estimate	
	24	AC	$ 40,333	$ 968,000		
Protective Cover (3')	-	CY	$ 4.04		Northern 2008 construction bid	fly ash as protective cover
	6	AC	$ 19,569	$ 117,411		contractor place 25% (side slopes, haul routes)
Piping						
LCS 4" Piping	4,475	LF	$ 5.25	$ 23,472	Northern 2008 construction bid	4" ADS N-12
LCS 8" Piping	900	LF	$ 12.02	$ 10,818	Northern 2008 construction bid	8" ADS N-12
LCS Sump/Riser	1	EA	$ 17,314	$ 17,314	Northern 2005 construction bid	
Equipment and Electrical						
Power Posts at Pumps/Sumps	1	EA	$ 1,185	$ 1,185	RSMeans 2010 (26 24 16.30-0150)	Panelboard/utility box with outlets
Collection pump	1	EA	$ 5,000	$ 5,000	Golder Estimate	

Scenario A (Current Sales) Unit Rate Details

PROJECT COMPONENT	QTY	UNIT	UNIT PRICE	TOTAL	Source	NOTES
Final Cover			Total	$ 3,790,408	Cost Per Acre of Cover	$ 143,000
General						
Mobilize/Demobilize	5%	%	$ -	$ 172,291		
Miscellaneous Site Work & Materials	5%	%	$ -	$ 172,291		Erosion controls, offices, toilets, temporary roads, survey control, etc.
Civil						
Leveling Fill (6") & Compacted Fill (24")	-	CY	$ 3.59		Northern 2006 construction bid	
	27	AC	$ 14,495	$ 384,112		
60-mil HDPE Liner	-	SF	$ 0.76		Northern 2008 construction bid	materials, waste, conformance testing, installation
	27	AC	$ 33,319	$ 882,965		
Leachate Collection Layer, Sand (12")		CY	$ 25.00		Golder Estimate	
	27	AC	$ 40,333	$ 1,068,833		
Growth Medium (18")		CY	$ 4.92		Northern 2010 construction bid	
	27	AC	$ 11,915	$ 315,738		
Topsoil (6")		CY	$ 4.92		Same as Growth Medium	
	27	AC	$ 3,972	$ 105,246		
Downchute Channels	57,600	SF	$ 10.82	$ 622,944	Northern 2010 construction bid	36' wide, 4 downchutes
Seed and Mulch	27	AC	$ 2,490.11	$ 65,988	RSMeans 2010 (32 92 19.14-4600)	Slope mix, with mulch & fertilizer
Post Closure Care			Total	$ 50,020	$ 50,000	
Groundwater Monitoring & Reporting	1	EA	$ 15,000	$ 15,000	Golder Estimate	$1,000 per well + $10,000 for the report
Annual Site Inspection	1	EA	$ 1,060	$ 1,060	Golder Estimate	$1,000 per 25 acres
Final Cover Repair	1	EA	$ 4,210	$ 4,210	Golder Estimate	2% of cover area, 12" growth medium/topsoil fill
Seeding Repair	1	EA	$ 6,600	$ 6,600	Golder Estimate	10% of cover area
Mowing and/or rodent, weed, & tree control	1	EA	$ 2,120	$ 2,120	Golder Estimate	$2,000 per 25 acres
Surface Water Controls Maintenance	1	EA	$ 12,230	$ 12,230	Golder Estimate	1% of armored channel replaced + other repairs
Gate and/or fence Maintenance	1	EA	$ 1,910	$ 1,910	Golder Estimate	1% of fence
Recordkeeping	1	EA	$ 1,590	$ 1,590	Golder Estimate	$1,500 per 25 acres
Direct Expenses	1	EA	$ 5,300	$ 5,300	Golder Estimate	$5,000 per 25 acres
Annual Operations & Maintenance Costs (not haul and place)			Total	$ 154,710	$ 154,500	
Groundwater Monitoring & Reporting	1	EA	$ 15,000	$ 15,000	Golder Estimate	$1,000 per well + $10,000 for the report
Annual Site Inspection	1	EA	$ 12,000	$ 12,000	Golder Estimate	$1,000 per 25 acres of liner per month
Engineering Support	1	EA	$ 48,000	$ 48,000	Golder Estimate	$50,000 per 25 acres of liner
Survey Control	1	EA	$ 25,000	$ 25,000	Golder Estimate	GPS unit(s), $25,000 per year
Gate and/or fence Maintenance	1	EA	$ 1,910	$ 1,910	Golder Estimate	1% of fence
Recordkeeping	1	EA	$ 4,800	$ 4,800	Golder Estimate	$5,000 per 25 acres
Misc Work (contact water, dust, erosion, grading, etc)	1	EA	$ 48,000	$ 48,000	Golder Estimate	$50,000 per 25 acres
Haul & Place Costs						
Haul Cost	1	CY	$ 2.14	$ 2.14	RSMeans 2010 (32 23 23.20-8180)	60cy Off-road, 20 min wait, 15 mph, 2 mile cycle
Haul Cost	1	TON	$ 2.14	$ 2.14	Golder Estimate	75pcf haul density (1 ton/cy)
Place Cost	1	CY	$ 1.42	$ 1.42	RSMeans 2010 (31 23 23.17-0020)	Dozer, no compaction
Place Cost	1	TON	$ 1.71	$ 1.71	Golder Estimate	90pcf placed density (1.2 ton/cy)

Scenario B (No Sales) Unit Rate Details

PROJECT COMPONENT		QTY	UNIT	UNIT PRICE	TOTAL	Source	NOTES
Infrastructure Development				Total	$ 924,006	$ 924,000	
General							
	Mobilize/Demobilize	5%	%	$ -	$ 42,000		
	Miscellaneous Site Work & Materials	5%	%	$ -	$ 42,000		Erosion controls, offices, toilets, temporary roads, survey control, etc.
Civil							
	Road Topsoil Stripping and Stockpiling	11,667	CY	$ 2.21	$ 25,772	Ames 2005 construction bid	18" topsoil
	Access Road Construction	210,000	SF	$ 1.55	$ 325,652	RSMeans 2010 (01 55 23.50-0100)	8" Gravel temporary road ($13.55/SY = $1.51/sf), 6,000' x 35'
	Return Water Pipeline	2,640	LF	$ 41.52	$ 109,622	RSMeans 2008 (33 11 13.25-4160)	6" PVC, 3' deep
	Fence	11,157	LF	$ 23.66	$ 263,960	GRE Estimate	7' Chain link fence, GRE paid $22.30/ft in 2009
	Overhead Power (Plant to Landfill)	1	EA	$ 25,000	$ 25,000	Golder Estimate	$25,000 for 1/2 mile distribution w/ transformer
	Monitoring Well Installation	15	EA	$ 6,000	$ 90,000	Golder Estimate	
County Road Crossing				Total	$ 1,730,693	$ 1,730,500	
General							
	Mobilize/Demobilize	5%	%	$ -	$ 78,668		
	Misc. (erosion controls, toilets, etc)	5%	%	$ -	$ 78,668		Erosion controls, offices, toilets, temporary roads, survey control, etc.
Civil							
	Topsoil Stripping and Stockpiling	4,577	CY	$ 2.21	$ 10,111	Ames 2005 construction bid	18" topsoil
	Embankment Fill	35,591	CY	$ 3.59	$ 127,906	Northern 2006 construction bid	
	County Road Sub-Base Course	2,385	CY	$ 3.59	$ 8,572	Northern 2006 construction bid	2' Sub-base preparation
	County Road Base Course	32,200	SF	$ 1.55	$ 49,933	RSMeans 2010 (01 55 23.50-0100)	8" Gravel temporary road ($13.55/SY = $1.51/sf) 920' x35'
	Bridge Deck Construction	5,250	SF	$ 262	$ 1,376,836	2008 California DOT Average	150 ft bridge deck, 35 ft wide
Liner Construction				Total	$ 12,827,387	Cost Per Acre of Liner	$ 174,500
General							
	Mobilize/Demobilize	5%	%	$ -	$ 583,063		
	Miscellaneous Site Work & Materials	5%	%	$ -	$ 583,063		Erosion controls, offices, toilets, temporary roads, survey control, etc.
Civil							
	Clearing and Grubbing	91	AC	$ 6,077.00	$ 553,007	RSMeans 2010 (31 11 10.10-0200)	Clear & grub brush including stumps
	Topsoil Stripping & Stockpiling (18")	-	CY	$ 2.21		Ames 2005 construction bid	
		91	AC	$ 5,346	$ 486,465		
	Subgrade Cut to Stockpile	1,019,880	CY	$ 3.00	$ 3,059,640	Golder Estimate	10' across liner area: for liner, berms and cover
	Subgrade Cut/Embankment Fill	165,920	CY	$ 3.59	$ 596,275	Northern 2006 construction bid	612 ft2 cross section area
	Low Permeability Soil Liner (24")	-	CY	$ 4.32		Northern 2008 construction bid	
		74	AC	$ 13,927	$ 1,023,647		
	60-mil HDPE Liner	-	SF	$ 0.76		Northern 2008 construction bid	materials, waste, conformance testing, installation
		74	AC	$ 33,319	$ 2,448,978		
	Leachate Collection Layer, Sand (12")		CY	$ 25.00		Golder Estimate	
		74	AC	$ 40,333	$ 2,964,500		
	Protective Cover (3')	-	CY	$ 4.04		Northern 2008 construction bid	fly ash as protective cover
		18	AC	$ 19,569	$ 359,572		contractor place 25% (side slopes, haul routes)
Piping							
	LCS 4" Piping	15,640	LF	$ 5.25	$ 82,033	Northern 2008 construction bid	4" ADS N-12
	LCS 8" Piping	3,340	LF	$ 12.02	$ 40,147	Northern 2008 construction bid	8" ADS N-12
	LCS Sump/Riser	2	EA	$ 17,314	$ 34,628	Northern 2005 construction bid	
Equipment and Electrical							
	Power Posts at Pumps/Sumps	2	EA	$ 1,185	$ 2,369	RSMeans 2010 (26 24 16.30-0150)	Panelboard/utility box with outlets
	Collection pump	2	EA	$ 5,000	$ 10,000	Golder Estimate	

Scenario B (No Sales) Unit Rate Details

PROJECT COMPONENT		QTY	UNIT	UNIT PRICE	TOTAL	Source	NOTES
Final Cover				Total	$ 10,724,703	Cost Per Acre of Cover	$ 132,400
General							
	Mobilize/Demobilize	5%	%	$ -	$ 487,486		
	Miscellaneous Site Work & Materials	5%	%	$ -	$ 487,486		Erosion controls, offices, toilets, temporary roads, survey control, etc.
Civil							
	Leveling Fill (6") & Compacted Fill (24")	-	CY	$ 3.59		Northern 2006 construction bid	
		81	AC	$ 14,495	$ 1,174,078		
	60-mil HDPE Liner	-	SF	$ 0.76		Northern 2008 construction bid	materials, waste, conformance testing, installation
		81	AC	$ 33,319	$ 2,698,874		
	Leachate Collection Layer, Sand (12")		CY	$ 25.00		Golder Estimate	
		81	AC	$ 40,333	$ 3,267,000		
	Growth Medium (18")		CY	$ 4.92		Northern 2010 construction bid	
		81	AC	$ 11,915	$ 965,085		
	Topsoil (6")		CY	$ 4.92		Same as Growth Medium	
		81	AC	$ 3,972	$ 321,695		
	Downchute Channels	103,680	SF	$ 10.82	$ 1,121,299	Northern 2010 construction bid	36' wide, 4 downchutes
	Seed and Mulch	81	AC	$ 2,490.11	$ 201,699	RSMeans 2010 (32 92 19.14-4600)	Slope mix, with mulch & fertilizer
Post Closure Care				Total	$ 108,670	$ 108,500	
	Groundwater Monitoring & Reporting	1	EA	$ 25,000	$ 25,000	Golder Estimate	$1,000 per well + $10,000 for the report
	Annual Site Inspection	1	EA	$ 3,240	$ 3,240	Golder Estimate	$1,000 per 25 acres
	Final Cover Repair	1	EA	$ 12,870	$ 12,870	Golder Estimate	2% of cover area, 12" growth medium/topsoil fill
	Seeding Repair	1	EA	$ 20,170	$ 20,170	Golder Estimate	10% of cover area
	Mowing and/or rodent, weed, & tree control	1	EA	$ 6,480	$ 6,480	Golder Estimate	$2,000 per 25 acres
	Surface Water Controls Maintenance	1	EA	$ 17,210	$ 17,210	Golder Estimate	1% of armored channel replaced + other repairs
	Gate and/or fence Maintenance	1	EA	$ 2,640	$ 2,640	Golder Estimate	1% of fence
	Recordkeeping	1	EA	$ 4,860	$ 4,860	Golder Estimate	$1,500 per 25 acres
	Direct Expenses	1	EA	$ 16,200	$ 16,200	Golder Estimate	$5,000 per 25 acres
Annual Operations & Maintenance Costs (not haul and place)				Total	$ 396,140	$ 396,000	
	Groundwater Monitoring & Reporting	1	EA	$ 25,000	$ 25,000	Golder Estimate	$1,000 per well + $10,000 for the report
	Annual Site Inspection	1	EA	$ 34,800	$ 34,800	Golder Estimate	$1,000 per 25 acres of liner per month
	Engineering Support	1	EA	$ 147,000	$ 147,000	Golder Estimate	$50,000 per 25 acres of liner
	Survey Control	1	EA	$ 25,000	$ 25,000	Golder Estimate	GPS unit(s), $25,000 per year
	Gate and/or fence Maintenance	1	EA	$ 2,640	$ 2,640	Golder Estimate	1% of fence
	Recordkeeping	1	EA	$ 14,700	$ 14,700	Golder Estimate	$5,000 per 25 acres
	Misc Work (contact water, dust, erosion, grading, etc)	1	EA	$ 147,000	$ 147,000	Golder Estimate	$50,000 per 25 acres
Haul & Place Costs							
	Haul Cost	1	CY	$ 2.14	$ 2.14	RSMeans 2010 (32 23 23.20-8180)	60cy Off-road, 20 min wait, 15 mph, 2 mile cycle
	Haul Cost	1	TON	$ 2.14	$ 2.14	Golder Estimate	75pcf haul density (1 ton/cy)
	Place Cost	1	CY	$ 1.42	$ 1.42	RSMeans 2010 (31 23 23.17-0020)	Dozer, no compaction
	Place Cost	1	TON	$ 1.71	$ 1.71	Golder Estimate	90pcf placed density (1.2 ton/cy)

Scenario C (Reduced Sales with ASM) Unit Rate Details

PROJECT COMPONENT		QTY	UNIT	UNIT PRICE	TOTAL	Source	NOTES
Infrastructure Development				Total	$ 779,431	$ 779,500	
General							
	Mobilize/Demobilize	5%	%	$ -	$ 35,429		
	Miscellaneous Site Work & Materials	5%	%	$ -	$ 35,429		Erosion controls, offices, toilets, temporary roads, survey control, etc.
Civil							
	Road Topsoil Stripping and Stockpiling	9,722	CY	$ 2.21	$ 21,476	Ames 2005 construction bid	18" topsoil
	Access Road Construction	175,000	SF	$ 1.55	$ 271,376	RSMeans 2010 (01 55 23.50-0100)	8" Gravel temporary road ($13.55/SY = $1.51/sf), 5,000' x 35'
	Return Water Pipeline	2,640	LF	$ 41.52	$ 109,622	RSMeans 2008 (33 11 13.25-4160)	6" PVC, 3' deep
	Fence	9,346	LF	$ 23.66	$ 221,099	GRE Estimate	7' Chain link fence, GRE paid $22.30/ft in 2009
	Overhead Power (Plant to Landfill)	1	EA	$ 25,000	$ 25,000	Golder Estimate	$25,000 for 1/2 mile distribution w/ transformer
	Monitoring Well Installation	10	EA	$ 6,000	$ 60,000	Golder Estimate	
County Road Crossing				Total	$ 1,730,693	$ 1,730,500	
General							
	Mobilize/Demobilize	5%	%	$ -	$ 78,668		
	Misc. (erosion controls, toilets, etc)	5%	%	$ -	$ 78,668		Erosion controls, offices, toilets, temporary roads, survey control, etc.
Civil							
	Topsoil Stripping and Stockpiling	4,577	CY	$ 2.21	$ 10,111	Ames 2005 construction bid	18" topsoil
	Embankment Fill	35,591	CY	$ 3.59	$ 127,906	Northern 2006 construction bid	
	County Road Sub-Base Course	2,385	CY	$ 3.59	$ 8,572	Northern 2006 construction bid	2' Sub-base preparation
	County Road Base Course	32,200	SF	$ 1.55	$ 49,933	RSMeans 2010 (01 55 23.50-0100)	8" Gravel temporary road ($13.55/SY = $1.51/sf) 920' x35'
	Bridge Deck Construction	5,250	SF	$ 262	$ 1,376,836	2008 California DOT Average	150 ft bridge deck, 35 ft wide
Liner Construction				Total	$ 7,200,075	Cost Per Acre of Liner	$ 175,600
General							
	Mobilize/Demobilize	5%	%	$ -	$ 327,276		
	Miscellaneous Site Work & Materials	5%	%	$ -	$ 327,276		Erosion controls, offices, toilets, temporary roads, survey control, etc.
Civil							
	Clearing and Grubbing	54	AC	$ 6,077.00	$ 328,158	RSMeans 2010 (31 11 10.10-0200)	Clear & grub brush including stumps
	Topsoil Stripping & Stockpiling (18")	-	CY	$ 2.21		Ames 2005 construction bid	
		54	AC	$ 5,346	$ 288,672		
	Subgrade Cut to Stockpile	536,800	CY	$ 3.00	$ 1,610,400	Golder Estimate	10' across liner area: for liner, berms and cover
	Subgrade Cut/Embankment Fill	124,667	CY	$ 3.59	$ 448,021	Northern 2006 construction bid	612 ft2 cross section area
	Low Permeability Soil Liner (24")	-	CY	$ 4.32		Northern 2008 construction bid	
		41	AC	$ 13,927	$ 571,014		
	60-mil HDPE Liner	-	SF	$ 0.76		Northern 2008 construction bid	materials, waste, conformance testing, installation
		41	AC	$ 33,319	$ 1,366,097		
	Leachate Collection Layer, Sand (12")		CY	$ 25.00		Golder Estimate	
		41	AC	$ 40,333	$ 1,653,667		
	Protective Cover (3')	-	CY	$ 4.04		Northern 2008 construction bid	fly ash as protective cover
		10	AC	$ 19,569	$ 200,578		contractor place 25% (side slopes, haul routes)
Piping							
	LCS 4" Piping	7,770	LF	$ 5.25	$ 40,754	Northern 2008 construction bid	4" ADS N-12
	LCS 8" Piping	1,220	LF	$ 12.02	$ 14,664	Northern 2008 construction bid	8" ADS N-12
	LCS Sump/Riser	1	EA	$ 17,314	$ 17,314	Northern 2005 construction bid	
Equipment and Electrical							
	Power Posts at Pumps/Sumps	1	EA	$ 1,185	$ 1,185	RSMeans 2010 (26 24 16.30-0150)	Panelboard/utility box with outlets
	Collection pump	1	EA	$ 5,000	$ 5,000	Golder Estimate	

Scenario C (Reduced Sales with ASM) Unit Rate Details

PROJECT COMPONENT	QTY	UNIT	UNIT PRICE	TOTAL	Source	NOTES
Final Cover			Total	$ 6,232,264	Cost Per Acre of Cover	$ 138,500
General						
Mobilize/Demobilize	5%	%	$ -	$ 283,285		
Miscellaneous Site Work & Materials	5%	%	$ -	$ 283,285		Erosion controls, offices, toilets, temporary roads, survey control, etc.
Civil						
Leveling Fill (6") & Compacted Fill (24")	-	CY	$ 3.59		Northern 2006 construction bid	
	45	AC	$ 14,495	$ 652,266		
60-mil HDPE Liner	-	SF	$ 0.76		Northern 2008 construction bid	materials, waste, conformance testing, installation
	45	AC	$ 33,319	$ 1,499,374		
Leachate Collection Layer, Sand (12")		CY	$ 25.00		Golder Estimate	
	45	AC	$ 40,333	$ 1,815,000		
Growth Medium (18")		CY	$ 4.92		Northern 2010 construction bid	
	45	AC	$ 11,915	$ 536,158		
Topsoil (6")		CY	$ 4.92		Same as Growth Medium	
	45	AC	$ 3,972	$ 178,719		
Downchute Channels	80,640	SF	$ 10.82	$ 872,122	Northern 2010 construction bid	36' wide, 4 downchutes
Seed and Mulch	45	AC	$ 2,490.11	$ 112,055	RSMeans 2010 (32 92 19.14-4600)	Slope mix, with mulch & fertilizer
Post Closure Care			Total	$ 72,390	$ 72,500	
Groundwater Monitoring & Reporting	1	EA	$ 20,000	$ 20,000	Golder Estimate	$1,000 per well + $10,000 for the report
Annual Site Inspection	1	EA	$ 1,800	$ 1,800	Golder Estimate	$1,000 per 25 acres
Final Cover Repair	1	EA	$ 7,150	$ 7,150	Golder Estimate	2% of cover area, 12" growth medium/topsoil fill
Seeding Repair	1	EA	$ 11,210	$ 11,210	Golder Estimate	10% of cover area
Mowing and/or rodent, weed, & tree control	1	EA	$ 3,600	$ 3,600	Golder Estimate	$2,000 per 25 acres
Surface Water Controls Maintenance	1	EA	$ 14,720	$ 14,720	Golder Estimate	1% of armored channel replaced + other repairs
Gate and/or fence Maintenance	1	EA	$ 2,210	$ 2,210	Golder Estimate	1% of fence
Recordkeeping	1	EA	$ 2,700	$ 2,700	Golder Estimate	$1,500 per 25 acres
Direct Expenses	1	EA	$ 9,000	$ 9,000	Golder Estimate	$5,000 per 25 acres
Annual Operations & Maintenance Costs (not haul and place)			Total	$ 238,610	$ 238,500	
Groundwater Monitoring & Reporting	1	EA	$ 20,000	$ 20,000	Golder Estimate	$1,000 per well + $10,000 for the report
Annual Site Inspection	1	EA	$ 19,200	$ 19,200	Golder Estimate	$1,000 per 25 acres of liner per month
Engineering Support	1	EA	$ 82,000	$ 82,000	Golder Estimate	$50,000 per 25 acres of liner
Survey Control	1	EA	$ 25,000	$ 25,000	Golder Estimate	GPS unit(s), $25,000 per year
Gate and/or fence Maintenance	1	EA	$ 2,210	$ 2,210	Golder Estimate	1% of fence
Recordkeeping	1	EA	$ 8,200	$ 8,200	Golder Estimate	$5,000 per 25 acres
Misc Work (contact water, dust, erosion, grading, etc)	1	EA	$ 82,000	$ 82,000	Golder Estimate	$50,000 per 25 acres
Haul & Place Costs						
Haul Cost	1	CY	$ 2.14	$ 2.14	RSMeans 2010 (32 23 23.20-8180)	60cy Off-road, 20 min wait, 15 mph, 2 mile cycle
Haul Cost	1	TON	$ 2.14	$ 2.14	Golder Estimate	75pcf haul density (1 ton/cy)
Place Cost	1	CY	$ 1.42	$ 1.42	RSMeans 2010 (31 23 23.17-0020)	Dozer, no compaction
Place Cost	1	TON	$ 1.71	$ 1.71	Golder Estimate	90pcf placed density (1.2 ton/cy)

ASM Unit Rate Details

PROJECT COMPONENT	QTY	UNIT OF MEASURE	UNIT PRICE	TOTAL	Source	NOTES
New Silo			Total	$ 1,568,494	$ 1,568,500	
Miscellaneous Site Work & Materials	10%	%	$ -	$ 142,590		Erosion controls, offices, toilets, temporary roads, survey control, etc.
Silo slab on grade	1	EA	$ 536,796	$ 536,796	2003 Irondale CO Unit less RR & land	Site prep, silo & handling equipment, permit
Starvac reclaimer	1	EA	$ 83,455	$ 83,455		
Truck scale	1	EA	$ 81,474	$ 81,474		Beside the silo on grade
Screw conveyor	1	EA	$ 24,626	$ 24,626		From Starvac reclaimer to bucket elevator
Bucket Elevator	1	EA	$ 88,927	$ 88,927		From screw conveyor to overhead airslide
Air Slide	1	EA	$ 26,906	$ 26,906		From bucket elevator to new weigh hopper
Truck load-out spout	1	EA	$ 45,604	$ 45,604		From new weigh hopper to truck
Building	1	EA	$ 11,401	$ 11,401		With scales and ASM controls
Feed piping & valves	1	EA	$ 329,202	$ 329,202	Golder Estimate	From each of the four fly ash conveying lines
Dust collectors	1	EA	$ 197,512	$ 197,512	Golder Estimate	Higher capacity to handle high air flow from ESP
Cal-Hypo Feed System (Rail Load-out Silo)			Total	$ 245,960	$ 246,000	
Miscellaneous Site Work & Materials	10%	%	$ -	$ 22,360		
Storage & Conveying Building	1,000	SF	$ 50.00	$ 50,000	GRE 2009 Construction Project	$35/sf for large insulated bldg, use $50/sf
Building Foundation	62	CY	$ 300.00	$ 18,600	Worley Parsons Jul09	12' x 40' x 1' thick plus 1' x 5' perimeter
Day Storage Hopper	1	EA	$ 15,000	$ 15,000	Golder Estimate	On the silo weigh bin floor
Conveying System	1	EA	$ 20,000	$ 20,000	Golder Estimate	From stroage building to the day storage hopper
Variable speed conveyor	1	EA	$ 20,000	$ 20,000	Golder Estimate	To feed cal-hypo into the existing weigh hopper
ASM System Controls	1	EA	$ 100,000	$ 100,000	Golder Estimate	
Cal-Hypo Feed System (New Truck Load-out Silo)			Total	$ 328,460	$ 328,500	
Miscellaneous Site Work & Materials	10%	%	$ -	$ 29,860		
Weigh Hopper	1	EA	$ 75,000	$ 75,000	Golder Estimate	Above truck load-out spout
Storage & Conveying Building	1,000	SF	$ 50.00	$ 50,000	GRE 2009 Construction Project	$35/sf for large insulated bldg, use $50/sf for 25'x40
Building Foundation	62	CY	$ 300.00	$ 18,600	Worley Parsons Jul09	25' x 40' x 1' thick plus 1' x 5' perimeter
Day Storage Hopper	1	EA	$ 15,000	$ 15,000	Golder Estimate	On the silo weigh bin floor
Conveying System	1	EA	$ 20,000	$ 20,000	Golder Estimate	From stroage building to the day storage hopper
Variable speed conveyor	1	EA	$ 20,000	$ 20,000	Golder Estimate	To feed cal-hypo into the existing weigh hopper
ASM System Controls	1	EA	$ 100,000	$ 100,000	Golder Estimate	

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Golder Associates

Bachman, Tom A.

From:	Nelson, Debra GRE-MG [dnelson@grenergy.com]
Sent:	Wednesday, June 15, 2011 10:53 AM
To:	Dendy, Lewis H.
Cc:	Bachman, Tom A.
Subject:	RE: Coal Creek fly ash cost documentation

I am rounding off the final data and should be able to get it to you either late today or early tomorrow.

Deb Nelson
Environmental Services
Great River Energy
(763)445-5208
dnelson@grenergy.com

-----Original Message-----
From: Dendy, Lewis H. [mailto:ldendy@nd.gov]
Sent: Wednesday, June 15, 2011 10:38 AM
To: Nelson, Debra GRE-MG
Cc: Bachman, Tom A.
Subject: RE: Coal Creek fly ash cost documentation

Hello Deb,

Can you provide an updated estimate of when you will be able to respond to EPA's request below? EPA is approaching their deadline for publishing their determination.

Thanks,

Lew Dendy
Environmental Scientist
ND Division of Air Quality
918 E. Divide Ave., Bismarck, ND 58501-1947 Ph 701.328.5188, Fax 701.328.5185
http://www.ndhealth.gov/AQ/Airhomepage.htm

-----Original Message-----
From: Nelson, Debra GRE-MG [mailto:dnelson@grenergy.com]
Sent: Thursday, June 02, 2011 7:59 AM
To: Dendy, Lewis H.
Subject: RE: Coal Creek fly ash cost documentation

Lew,
I will gather the information. May take a few days!

Deb Nelson
Environmental Services
Great River Energy
(763)445-5208
dnelson@grenergy.com

-----Original Message-----
From: Dendy, Lewis H. [mailto:ldendy@nd.gov]
Sent: Wednesday, June 01, 2011 2:23 PM
To: Nelson, Debra GRE-MG
Cc: Bachman, Tom A.; Semerad, Jim L.
Subject: FW: Coal Creek fly ash cost documentation

Hello Deb,

Please see the EPA/R8 email below for an additional request for supporting information to assist them with their decision on BART for Coal Creek Station. We request that GRE provide any available information in response to the questions. I'll review our file for anything that we might have.

Please let Tom or I know if we can be of assistance.

Thanks,

Lew Dendy
Environmental Scientist
ND Division of Air Quality
918 E. Divide Ave., Bismarck, ND 58501-1947 Ph 701.328.5188, Fax 701.328.5185
http://www.ndhealth.gov/AQ/Airhomepage.htm

-----Original Message-----
From: Fallon.Gail@epamail.epa.gov [mailto:Fallon.Gail@epamail.epa.gov]
Sent: Wednesday, June 01, 2011 1:31 PM
To: Bachman, Tom A.; Dendy, Lewis H.
Subject: Coal Creek fly ash cost documentation

Tom and Lew,

Per our phone conversation yesterday, we are looking for additional documentation to support your NOx BART determination for Coal Creek.
Specifically, we are interested in the following cost information pertaining to lost fly ash sales which is a large component of the cost for SCR and SNCR:

1. Supporting documentation (such as invoices/bills of sale) for fly ash pricing and tonnage
   - Several years of data would be helpful to show any price and tonnage fluctuations

2. Supporting documentation regarding landfill costs

3. Cost to remediate the ammonia in the ash
   - Headwaters Resources' web literature indicates that it can add a chemical reagent to the ash to convert the ammonia to harmless compounds. The cost of this process would seem to be relevant to the BART analysis.

Perhaps some of this information has already been provided somewhere in the SIP. Lew mentioned you may have provided something in response to FLM comments on ammonia mitigation. In Appendix J.1.2 of the SIP, I found where ND references a couple of Great River Energy emails and a Univ. of Kentucky study regarding ammonia in fly ash that are supposed to be attached but are not. Maybe there is something relevant there.
Please provide these attachments as well.

Thanks for any assistance you can offer.

Gail

Gail Fallon
Regional Haze Program Manager
Air Quality Planning Unit (8P-AR)
US EPA Region 8
1595 Wynkoop Street
Denver, CO 80202-1129
Phone: 303-312-6281
Fax: 303-312-6064
Email: Fallon.Gail@epa.gov

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Bachman, Tom A.

From:	Nelson, Debra GRE-MG [dnelson@grenergy.com]
Sent:	Wednesday, June 15, 2011 4:10 PM
To:	Dendy, Lewis H.
Cc:	Bachman, Tom A.; Semerad, Jim L.
Subject:	RE: Coal Creek fly ash cost documentation
Attachments:	NH4MitigationCosts.pdf; FlyashSales2006-2010.pdf; NDDH- Landfill.pdf

Lew,
We respectfully submit our response to the questions raised by US EPA Region 8.

1. Fly ash Pricing and tonnage: Fly ash sales at Coal Creek Station are paid from the weigh tickets obtained from the fly ash loaded trucks. The marketer of the fly ash will pay GRE directly from the accumulated truck weigh tickets on a monthly basis. GRE does not invoice the marketer for the ash. The existing records for sales are the individual truck weigh tickets. The attached document, FlyashSales2006-2010.pdf, contains the total fly ash sales in tonnage and in dollars received, and a calculated $/ton. This data was compiled from the thousands of individual weigh tickets obtained from the ash haulers. If there is still a need for the supporting documentation for these years we can provide copies of all the weigh tickets. This process will take some time to complete and some resources dedicated to completing. Please let me know if further documentation is required.
2. Landfill disposal costs: During the development of the Coal Creek Station BART analysis, CCS was also re-evaluating the model for landfill disposal costs. When the revised BART analysis was submitted to NDDH the Landfill model was predicting a $6/ton disposal cost - the model was not finalized at that time. The value used in the BART analysis was $6/ton based upon an email message from the plant to the engineering firm contracted to conduct the analysis. Upon refinement and finalization of the model, the final value contained within the model puts our landfill disposal costs at $7.19/ton (in 2007 dollars). The attached document, LandfillDisposal.pdf, is a presentation of the final model values.
3. Inclusion of ammonia mitigation in BART analysis: A quick evaluation of the BART Analysis data reveals that the inclusion of ammonia mitigation technology has the same effect on the BART analysis as land filling the ash. The estimated installed cost for ammonia mitigation was roughly estimated by Headwaters at $5-$10 per ton of ash. Landfill costs are estimated by the final landfill model at around $7.19 (in 2007 dollars) per ton of ash. The attached tables (NH4MitigationCosts.pdf) include the ammonia mitigation technology in the SCR and SNCR economic analysis. The final cost summary table has remained virtually the same. Whether the analysis utilizes landfill costs or ammonia mitigation costs, it does not change the conclusions of the BART analysis that SCR and SNCR technologies are not cost effective.

If there are further questions please feel free to contact me. I will be unavailable June 16 & 17th but will be available to address further questions starting June 20th.

Deb Nelson
Environmental Services
Great River Energy
(763)445-5208
dnelson@grenergy.com

-----Original Message-----
From: Dendy, Lewis H. [mailto:ldendy@nd.gov]
Sent: Wednesday, June 01, 2011 2:23 PM
To: Nelson, Debra GRE-MG
Cc: Bachman, Tom A.; Semerad, Jim L.
Subject: FW: Coal Creek fly ash cost documentation

Hello Deb,

Please see the EPA/R8 email below for an additional request for supporting information to assist them with their decision on BART for Coal Creek Station. We request that GRE provide any available information in response to the questions. I'll review our file for anything that we might have.

Please let Tom or I know if we can be of assistance.

Thanks,

Lew Dendy
Environmental Scientist
ND Division of Air Quality
918 E. Divide Ave., Bismarck, ND 58501-1947 Ph 701.328.5188, Fax 701.328.5185
http://www.ndhealth.gov/AQ/Airhomepage.htm

-----Original Message-----
From: Fallon.Gail@epamail.epa.gov [mailto:Fallon.Gail@epamail.epa.gov]
Sent: Wednesday, June 01, 2011 1:31 PM
To: Bachman, Tom A.; Dendy, Lewis H.
Subject: Coal Creek fly ash cost documentation

Tom and Lew,
Per our phone conversation yesterday, we are looking for additional documentation to support your NOx BART determination for Coal Creek.

Specifically, we are interested in the following cost information pertaining to lost fly ash sales which is a large component of the cost for SCR and SNCR:

1. Supporting documentation (such as invoices/bills of sale) for fly ash pricing and tonnage
   - Several years of data would be helpful to show any price and tonnage fluctuations

2. Supporting documentation regarding landfill costs

3. Cost to remediate the ammonia in the ash
   - Headwaters Resources' web literature indicates that it can add a chemical reagent to the ash to convert the ammonia to harmless compounds. The cost of this process would seem to be relevant to the BART analysis.

Perhaps some of this information has already been provided somewhere in the SIP. Lew mentioned you may have provided something in response to FLM comments on ammonia mitigation. In Appendix J.1.2 of the SIP, I found where ND references a couple of Great River Energy emails and a Univ. of Kentucky study regarding ammonia in fly ash that are supposed to be attached but are not. Maybe there is something relevant there.
Please provide these attachments as well.

Thanks for any assistance you can offer.

Gail

Gail Fallon
Regional Haze Program Manager
Air Quality Planning Unit (8P-AR)
US EPA Region 8
1595 Wynkoop Street
Denver, CO 80202-1129
Phone: 303-312-6281
Fax: 303-312-6064
Email: Fallon.Gail@epa.gov

copying, distributing or using the information. Please contact the sender immediately by return email and delete the original message.

Bachman, Tom A.

From: Nelson, Debra GRE-MG [dnelson@grenergy.com]
Sent: Thursday, June 16, 2011 3:24 PM
To: Semerad, Jim L.
Cc: Bachman, Tom A.; Dendy, Lewis H.
Subject: RE: Coal Creek fly ash cost documentation

Jim,
The $36/ton was a error propagated with our 2nd "original" submittal in 2007. I looked into our original 2006 submittal (which we had recalled) and the $/ton was $5. So in reconfiguring the spreadsheets the value was mistyped and GRE submitted the improper number.

Deb Nelson
Environmental Services
Great River Energy
(763)445-5208
dnelson@grenergy.com

-----Original Message-----
From: Semerad, Jim L. [mailto:jsemerad@nd.gov]
Sent: Thursday, June 16, 2011 11:42 AM
To: Nelson, Debra GRE-MG
Cc: Bachman, Tom A.; Dendy, Lewis H.
Subject: RE: Coal Creek fly ash cost documentation

Deb:

I am attaching an email from EPA that poses a follow-up question to the submittal referenced below.

Please reply so that we can respond to EPA.

Note that Lew is out until next week.

Thanks.

Jim Semerad
Division of Air Quality
State Dept. of Health
(701) 328-5188

jsemerad@nd.gov
Division Website:
http://www.health.state.nd.us/AQ/Airhomepage.htm

-----Original Message-----
From: Dendy, Lewis H.
Sent: Thursday, June 16, 2011 6:53 AM
To: Nelson, Debra GRE-MG
Cc: Semerad, Jim L.; Bachman, Tom A.
Subject: RE: Coal Creek fly ash cost documentation

Deb,

I appreciate your effort and GRE's quick response.

Thank you very much,

Lew Dendy
Environmental Scientist
ND Division of Air Quality
918 E. Divide Ave., Bismarck, ND 58501-1947 Ph 701.328.5188, Fax 701.328.5185
http://www.ndhealth.gov/AQ/Airhomepage.htm

-----Original Message-----
From: Nelson, Debra GRE-MG [mailto:dnelson@grenergy.com]
Sent: Wednesday, June 15, 2011 4:10 PM
To: Dendy, Lewis H.
Cc: Bachman, Tom A.; Semerad, Jim L.
Subject: RE: Coal Creek fly ash cost documentation

Lew,
We respectfully submit our response to the questions raised by US EPA Region 8.

1. Fly ash Pricing and tonnage: Fly ash sales at Coal Creek Station are paid from the weigh tickets obtained from the fly ash loaded trucks. The marketer of the fly ash will pay GRE directly from the accumulated truck weigh tickets on a monthly basis. GRE does not invoice the marketer for the ash. The existing records for sales are the individual truck weigh tickets. The attached document, FlyashSales2006-2010.pdf,

contains the total fly ash sales in tonnage and in dollars received, and a calculated $/ton. This data was compiled from the thousands of individual weigh tickets obtained from the ash haulers. If there is still a need for the supporting documentation for these years we can provide copies of all the weigh tickets. This process will take some time to complete and some resources dedicated to completing. Please let me know if further documentation is required.

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Deb Nelson
Environmental Services
Great River Energy
(763)445-5208
dnelson@grenergy.com

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From: Dendy, Lewis H. [mailto:ldendy@nd.gov]
Sent: Wednesday, June 01, 2011 2:23 PM
To: Nelson, Debra GRE-MG
Cc: Bachman, Tom A.; Semerad, Jim L.
Subject: FW: Coal Creek fly ash cost documentation

Hello Deb,

Please see the EPA/R8 email below for an additional request for supporting information to assist them with their decision on BART for Coal Creek Station. We request that GRE provide any available information in response to the questions. I'll review our file for anything that we might have.

Please let Tom or I know if we can be of assistance.

Thanks,

Lew Dendy
Environmental Scientist
ND Division of Air Quality
918 E. Divide Ave., Bismarck, ND 58501-1947 Ph 701.328.5188, Fax 701.328.5185
http://www.ndhealth.gov/AQ/Airhomepage.htm

-----Original Message-----
From: Fallon.Gail@epamail.epa.gov [mailto:Fallon.Gail@epamail.epa.gov]
Sent: Wednesday, June 01, 2011 1:31 PM
To: Bachman, Tom A.; Dendy, Lewis H.
Subject: Coal Creek fly ash cost documentation

Tom and Lew,
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Specifically, we are interested in the following cost information pertaining to lost fly ash sales which is a large component of the cost for SCR and SNCR:

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Please provide these attachments as well.

Thanks for any assistance you can offer.

Gail

Gail Fallon
Regional Haze Program Manager
Air Quality Planning Unit (8P-AR)
US EPA Region 8
1595 Wynkoop Street
Denver, CO 80202-1129
Phone: 303-312-6281
Fax: 303-312-6064
Email: Fallon.Gail@epa.gov

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Bachman, Tom A.

From:	Roth, Mary Jo GRE-MG [mjroth@GREnergy.com]
Sent:	Friday, July 15, 2011 2:35 PM
To:	O'Clair, Terry L.
Cc:	Bachman, Tom A.; Stockdill, Diane GRE-CC; Weeda, John GRE-CC; Nelson, Debra GRE-MG
Subject:	FW: Headwaters' Ammonia Slip Mitigation Technology

Terry,

Below is information we received today from Headwaters, developer of the ammonia-in-ash mitigation technology. This affirms the information provided in my letter from earlier today.

MJ

Mary Jo Roth
Manager, Environmental Services
Great River Energy
12300 Elm Creek Blvd.
Maple Grove, MN 55369
763.445.5212 (o)
612.810.4677 (c)

From: Rafic Minkara [mailto:rminkara@headwaters.com]
Sent: Friday, July 15, 2011 10:47 AM
To: Weeda, John GRE-CC
Cc: Jerry Smith
Subject: Headwaters' Ammonia Slip Mitigation Technology

John,

In reference to Headwaters' Ammonia slip mitigation (ASM) technology, the ASM technology was initially developed in 2001 with the first US patent issued in 2004. This first generation of ASM technology consisted of treating fly ash with a chemical oxidizer (calcium hypochlorite) to destroy ammonia in solution after water addition to ash or concrete mix containing fly ash. The 1st commercial ASM system was installed at RG&E Russell Station in Rochester NY in 2004. The Russell Station which was burning eastern bituminous coal and equipped with SNCR's has since shut-down. The 2nd ASM system was installed at the East Lake Station in Ohio. This 600 MW unit is fired with a 50/50 blend of PRB and eastern bituminous and generates about 100,000 tpy of fly ash. Up to 70% of the fly ash with moderate levels of ammonia ranging between 50-200 ppm have been treated at Eastlake for sale into concrete applications. The East Lake Plant fly ash is not treated during periods of high or highly variable ammonia in ash concentrations which are typical during SNCR upset or plant load variability.

We don't have an installation at a lignite fired station. Headwaters has not conducted any research on application of this technology to lignite derived fly ash. The limited current experience in commercial application and lack of research is not adequate for Headwaters to be able to provide any guarantee that the process can be successfully applied to treat lignite ash at the Coal Creek Station.

Let me know if you need any more information.

Regards,

Rafic,

Rafic Minkara, PhD., PE
Vice President – Technology
Headwaters Energy Services
204 Lakeside Drive
Kennesaw, GA 30144
• 770-330-0689
•770-590-9534
•rminkara@headwaters.com<mailto:rminkara@headwaters.com>

Bachman, Tom A.

From: Nelson, Debra GRE-MG [dnelson@grenergy.com]
Sent: Monday, July 18, 2011 11:34 AM
To: (Fallon.Gail@epamail.epa.gov)
Cc: Dendy, Lewis H.; Bachman, Tom A.; Roth, Mary Jo GRE-MG; Stockdill, Diane GRE-CC
Subject: RE: EPA Question

Gail,
The information we provided in the submittal to NDDH on July 18, 2011 was not intended to be confidential information. It will be our official response to questions raised about our BART Analysis.

Deb Nelson
Environmental Services
Great River Energy
(763)445-5208
dnelson@grenergy.com

-----Original Message-----
From: Bachman, Tom A. [mailto:tbachman@nd.gov]
Sent: Monday, July 18, 2011 11:26 AM
To: Nelson, Debra GRE-MG
Cc: Dendy, Lewis H.
Subject: EPA Question

Deb:

See EPA's question below. I assume the information is not confidential. If so, please send an email to Gail Fallon indicating as such a.s.a.p. If it is confidential, please contact me immediately.

Tom Bachman, P.E.
Sr. Env. Engr.
ND Dept. of Health
(701) 328-5188

-----Original Message-----
From: Gail Fallon [mailto:Fallon.Gail@epamail.epa.gov]
Sent: Monday, July 18, 2011 10:01 AM
To: Bachman, Tom A.
Subject: Re: FW: Response to EPA questions

Tom,

We will review this additional information. Can you please clarify with GRE whether or not they intend for all the information they submitted to be confidential based on the following footer language that appears to be standard on all their emails:

NOTICE TO RECIPIENT: The information contained in this message from Great River Energy and any attachments are confidential and intended only for the named recipient(s). If you have received this message in error, you are prohibited from copying, distributing or using the information. Please contact the sender immediately by return email and delete the original message.

If they do not intend for this to be confidential, can you please have Deb send me an email confirming. If they do intend for the information to remain confidential we are probably going to have a problem considering it as we need to make it available to the public in our action.

Thanks,
Gail

Gail Fallon
Regional Haze Program Manager
Air Quality Planning Unit (8P-AR)
US EPA Region 8
1595 Wynkoop Street
Denver, CO 80202-1129
Phone: 303-312-6281
Fax: 303-312-6064
Email: Fallon.Gail@epa.gov

From: Nelson, Debra GRE-MG [mailto:dnelson@grenergy.com]
Sent: Friday, July 15, 2011 11:23 AM
To: O'Clair, Terry L.; Bachman, Tom A.
Cc: Roth, Mary Jo GRE-MG; Stockdill, Diane GRE-CC; Weeda, John GRE-CC
Subject: Response to EPA questions

Terry and Tom,
Attached is GRE's response to the questions raised by EPA concerning NOx emissions from CCS.

If you have any questions please feel free to give me a call.

Deb Nelson
Environmental Administrator
Great River Energy
12300 Elm Creek Blvd.,
Maple Grove, MN 55369-4718
direct: 763-445-5208/ fax: 763-4455239/ cell: 612-325-8210
www.GreatRiverEnergy.com
* Please consider the environment before you print this e-mail.

[attachment "SNCR Response to NDDH.PDF" deleted by Gail Fallon/R8/USEPA/US]
[attachment "Ammonia Mitigation Headwaters.pdf"
deleted by Gail Fallon/R8/USEPA/US]

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Bachman, Tom A.

From:	Nelson, Debra GRE-MG [dnelson@grenergy.com]
Sent:	Monday, July 18, 2011 12:32 PM
To:	(Fallon.Gail@epamail.epa.gov)
Cc:	Dendy, Lewis H.; Bachman, Tom A.; Roth, Mary Jo GRE-MG; Stockdill, Diane GRE-CC
Subject:	RE: EPA Question

Gail,
My apologies, I meant to type in July 15, instead of July 18 in the message below!

Deb Nelson
Environmental Services
Great River Energy
(763)445-5208
dnelson@grenergy.com

-----Original Message-----
From: Nelson, Debra GRE-MG
Sent: Monday, July 18, 2011 11:34 AM
To: (Fallon.Gail@epamail.epa.gov)
Cc: Dendy, Lewis H.; 'Bachman, Tom A.'; Roth, Mary Jo GRE-MG; Stockdill, Diane GRE-CC
Subject: RE: EPA Question

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Deb Nelson
Environmental Services
Great River Energy
(763)445-5208
dnelson@grenergy.com

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Sent: Monday, July 18, 2011 11:26 AM
To: Nelson, Debra GRE-MG
Cc: Dendy, Lewis H.
Subject: EPA Question

Deb:

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Tom Bachman, P.E.
Sr. Env. Engr.
ND Dept. of Health
(701) 328-5188

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Sent: Monday, July 18, 2011 10:01 AM
To: Bachman, Tom A.
Subject: Re: FW: Response to EPA questions

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Thanks,
Gail

Gail Fallon
Regional Haze Program Manager
Air Quality Planning Unit (8P-AR)
US EPA Region 8
1595 Wynkoop Street
Denver, CO 80202-1129
Phone: 303-312-6281
Fax: 303-312-6064

Email: Fallon.Gail@epa.gov

From: Nelson, Debra GRE-MG [mailto:dnelson@grenergy.com]
Sent: Friday, July 15, 2011 11:23 AM
To: O'Clair, Terry L.; Bachman, Tom A.
Cc: Roth, Mary Jo GRE-MG; Stockdill, Diane GRE-CC; Weeda, John GRE-CC
Subject: Response to EPA questions

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If you have any questions please feel free to give me a call.

Deb Nelson
Environmental Administrator
Great River Energy
12300 Elm Creek Blvd.,
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direct: 763-445-5208/ fax: 763-4455239/ cell: 612-325-8210
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[attachment "SNCR Response to NDDH.PDF" deleted by Gail Fallon/R8/USEPA/US]
[attachment "Ammonia Mitigation Headwaters.pdf"
deleted by Gail Fallon/R8/USEPA/US]

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Bachman, Tom A.

From:	Roth, Mary Jo GRE-MG [mjroth@GREnergy.com]
Sent:	Friday, February 10, 2012 4:14 PM
To:	O'Clair, Terry L.
Cc:	Bachman, Tom A.; Nelson, Debra GRE-MG; Stockdill, Diane GRE-CC
Subject:	Coal Creek Station BART analysis - Response to comments from January 19 letter

Terry,

We have completed an updated BART analysis for Coal Creek Station in response to comments provided in your January 19 letter. We recognize there were a number of inadvertent errors and inconsistencies in our November 21 submittal. We have reviewed the entire report, made edits responsive to your comments, and had an independent review conducted by a consultant not connected with our analysis.

It is important to note that correction of the inadvertent errors and the related revised analysis do not change the conclusions of the previous report – specifically, that the presumptive NOx limit of 0.17 lb/mmBtu is both cost effective and results in significant visibility improvements in North Dakota's Class I areas. The analysis continues to provide a solid basis for why SNCR is not a cost effective or appropriate BART technology for Coal Creek Station.

Via the following link, you can access the updated analysis along with a cover letter that provides specific responses to your January 19 letter.

ftp://ftp.grenergy.com/pub/dnelson/

I have also sent the cover letter and report via U.S. mail to you and to Tom.

Please let me know if you have any questions or require further information.

MJ

Mary Jo Roth
Manager, Environmental Services
Great River Energy
12300 Elm Creek Boulevard
Maple Grove, MN 55369-4718
office: 763.445.5212 // cell: 612.810.4677
www.GreatRiverEnergy.com

Bachman, Tom A.

From:	Roth, Mary Jo GRE-MG [mjroth@GREnergy.com]
Sent:	Tuesday, February 14, 2012 1:22 PM
To:	O'Clair, Terry L.
Cc:	Bachman, Tom A.; Joel Trinkle; Nelson, Debra GRE-MG
Subject:	RE: Coal Creek Station BART analysis - Response to comments from January 19 letter

Terry,

We will be putting in a call to Barr as well – and will get back to you.

MJ

From: O'Clair, Terry L. [mailto:toclair@nd.gov]
Sent: Tuesday, February 14, 2012 1:17 PM
To: Roth, Mary Jo GRE-MG
Cc: Bachman, Tom A.
Subject: RE: Coal Creek Station BART analysis - Response to comments from January 19 letter

Hi Mary Jo,

Thanks for getting this to us. We are in the process of reviewing. One item that appears puzzling is the Appendix D Visibility Tables. The Year 2000 Modeling Results Table, specifically the values for SNCR and SNCR with LNC3+. The rows may be switched. We have a call in to Barr asking them to take a look at it. Although the Tables for 2001 and 2002 appear ok, the summary table "Average Incremental Control Comparison for the 98th % delta deciview" is also suspect because it is built from the other three tables. We will keep you posted on other questions we may have.

Terry

From: Roth, Mary Jo GRE-MG [mailto:mjroth@GREnergy.com]
Sent: Friday, February 10, 2012 4:14 PM
To: O'Clair, Terry L.
Cc: Bachman, Tom A.; Nelson, Debra GRE-MG; Stockdill, Diane GRE-CC
Subject: Coal Creek Station BART analysis - Response to comments from January 19 letter

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Mary Jo Roth
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Maple Grove, MN 55369-4718
office: 763.445.5212 // cell: 612.810.4677
www.GreatRiverEnergy.com

Bachman, Tom A.

From: Roth, Mary Jo GRE-MG [mjroth@GREnergy.com]
Sent: Thursday, April 12, 2012 10:55 AM
To: Bachman, Tom A.
Cc: O'Clair, Terry L.
Subject: RE: Coal Creek Station NOx BART Analysis

Tom,

Thank you for forwarding the trade secrets rule. I will provide something to NDDH as soon as possible after I make further contact with EPRI concerning the trade secret claim for their report.

MJ

From: Bachman, Tom A. [mailto:tbachman@nd.gov]
Sent: Wednesday, April 11, 2012 2:04 PM
To: Roth, Mary Jo GRE-MG
Cc: O'Clair, Terry L.
Subject: RE: Coal Creek Station NOx BART Analysis

Mary Jo:

I have downloaded the document.

Regarding the confidential EPRI report, our rules (NDAC 33-15-01-16 – copy attached) require a letter requesting that the information be kept confidential as well as other information outlined in 33-15-01-16.2. Please provide the required documentation as soon as possible.

If you have any questions, please contact Terry or me.

Tom Bachman, P.E.
Sr. Env. Engr.
ND Dept. of Health
(701) 328-5188

From: Roth, Mary Jo GRE-MG [mailto:mjroth@GREnergy.com]
Sent: Wednesday, April 11, 2012 12:43 PM
To: O'Clair, Terry L.; Bachman, Tom A.
Cc: Olsen, Eric GRE-MG; 'William Bumpers'; Nelson, Debra GRE-MG
Subject: RE: Coal Creek Station NOx BART Analysis

Tom,

Per your voicemail message to Deb Nelson, I have added the following document to our ftp site: BART Supplemental Analysis (with App A-D and F-G) 04-05-2012 v.2.pdf. This Version 2 replaces the version that was originally posted. Directions for accessing the ftp site are provided below. Please let me know if you have any problem accessing the ftp site or the documents. I will also provide two hard copies of the document per U.S. mail.

MJ

From: Roth, Mary Jo GRE-MG
Sent: Thursday, April 05, 2012 3:22 PM
To: Terry O'Clair (toclair@nd.gov)
Cc: Tom Bachman - NDDH; Olsen, Eric GRE-MG; William Bumpers; Nelson, Debra GRE-MG
Subject: Coal Creek Station NOx BART Analysis

Terry,

Great River Energy has completed its supplemental BART analysis for Coal Creek Station which we believe addresses all the comments from your January 19 and February 28 letters. In addition to the supplemental analysis, we have prepared a legal and technical review of EPA's BART determination per its FIP issued March 2. Also part of the package is a transmittal letter to you.

The supplemental BART analysis includes 7 appendices (A thru G). Please note that Appendix E is a confidential report which we are submitting as confidential business information. This appendix will be provided by way of a separate, sealed envelope per Air Pollution Control Rules for the State of North Dakota at 33-15-01-16. The legal and technical review of EPA's FIP includes one attachment.

I will be mailing to you a hard copy version of the documents via U.S. mail. In the interest of supplying NDDH with the information as quickly as possible, you may also access the documents (with the exception of Appendix E) immediately via our ftp site, ftp.grenergy.com. To locate the documents, click on Directory pub, then Directory environ, and then Directory GRE_BART. Let me know if you have any problem accessing the ftp site or the documents.

I greatly appreciate NDDH's continued work on our Coal Creek Station BART determination. Please let me know if you need additional information or have any questions.

MJ

Mary Jo Roth
Manager, Environmental Services
Great River Energy
12300 Elm Creek Boulevard
Maple Grove, MN 55369-4718
office: 763.445.5212 // cell: 612.810.4677
www.GreatRiverEnergy.com

Bachman, Tom A.

From: Roth, Mary Jo GRE-MG [mjroth@GREnergy.com]
Sent: Thursday, April 26, 2012 8:28 AM
To: Bachman, Tom A.
Cc: O'Clair, Terry L.; Olsen, Eric GRE-MG; william.bumpers@bakerbotts.com; 'michael.heister@bakerbotts.com'; Nelson, Debra GRE-MG
Subject: RE: Coal Creek Station NOx BART Analysis

Tom,

I have consulted further with EPRI concerning their report which GRE provided as Appendix E under a confidential business information request. EPRI has determined that the report does not meet the NDAC standard for trade secret information. Consequently, Great River Energy is hereby withdrawing its request for confidentiality of this report (*"Low-Baseline NOx Selective Non-Catalytic Reduction Demonstration, Joppa Unit 3"*).

Please let me know if I need to provide any further information or if you need a more formal withdrawal letter.

Thank you.

MJ

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Manager, Environmental Services
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Maple Grove, MN 55369-4718
office: 763.445.5212 // cell: 612.810.4677
www.GreatRiverEnergy.com

From: Roth, Mary Jo GRE-MG
Sent: Thursday, April 12, 2012 10:55 AM
To: 'Bachman, Tom A.'
Cc: O'Clair, Terry L.
Subject: RE: Coal Creek Station NOx BART Analysis

Tom,

Thank you for forwarding the trade secrets rule. I will provide something to NDDH as soon as possible after I make further contact with EPRI concerning the trade secret claim for their report.

MJ

From: Bachman, Tom A. [mailto:tbachman@nd.gov]
Sent: Wednesday, April 11, 2012 2:04 PM
To: Roth, Mary Jo GRE-MG
Cc: O'Clair, Terry L.
Subject: RE: Coal Creek Station NOx BART Analysis

Mary Jo:

I have downloaded the document.

Regarding the confidential EPRI report, our rules (NDAC 33-15-01-16 – copy attached) require a letter requesting that the information be kept confidential as well as other information outlined in 33-15-01-16.2. Please provide the required documentation as soon as possible.

If you have any questions, please contact Terry or me.

Tom Bachman, P.E.
Sr. Env. Engr.
ND Dept. of Health
(701) 328-5188

From: Roth, Mary Jo GRE-MG [mailto:mjroth@GREnergy.com]
Sent: Wednesday, April 11, 2012 12:43 PM
To: O'Clair, Terry L.; Bachman, Tom A.
Cc: Olsen, Eric GRE-MG; 'William Bumpers'; Nelson, Debra GRE-MG
Subject: RE: Coal Creek Station NOx BART Analysis

Tom,

Per your voicemail message to Deb Nelson, I have added the following document to our ftp site: BART Supplemental Analysis (with App A-D and F-G) 04-05-2012 v.2.pdf. This Version 2 replaces the version that was originally posted. Directions for accessing the ftp site are provided below. Please let me know if you have any problem accessing the ftp site or the documents. I will also provide two hard copies of the document per U.S. mail.

MJ

From: Roth, Mary Jo GRE-MG
Sent: Thursday, April 05, 2012 3:22 PM
To: Terry O'Clair (toclair@nd.gov)
Cc: Tom Bachman - NDDH; Olsen, Eric GRE-MG; William Bumpers; Nelson, Debra GRE-MG
Subject: Coal Creek Station NOx BART Analysis

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Sent: Wednesday, April 11, 2012 12:43 PM
To: O'Clair, Terry L.; Bachman, Tom A.
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Bachman, Tom A.

From: Roth, Mary Jo GRE-MG [mjroth@GREnergy.com]
Sent: Thursday, June 07, 2012 10:58 AM
To: O'Clair, Terry L.
Cc: Bachman, Tom A.; Olsen, Eric GRE-MG; William Bumpers; Nelson, Debra GRE-MG
Subject: Technical Update - Coal Creek Station BART analysis
Attachments: Cover Letter June 7-2012.pdf; Technical Update June 7-2012.pdf; Appendix A Tables June 7-2012.pdf

Terry,

Attached please find a cover letter and technical update to the Coal Creek Station "*Supplemental Best Available Retrofit Technology Refined Analysis for NOx Emissions – April 5, 2012.*" This June 7 technical update is responsive to comments provided by NDDH during our conference call of May 21.

Please contact me if you have any questions.

MJ

Mary Jo Roth
Manager, Environmental Services
Great River Energy
12300 Elm Creek Boulevard
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www.GreatRiverEnergy.com

November 21, 2011

Via Electronic Submission

http://www.regulations.gov
Docket ID No. EPA–R08–OAR–2010–0406

RE: Comments of Great River Energy to Proposed Rule for the Approval and Promulgation of Implementation Plans; North Dakota; Regional Haze State Implementation Plan; Federal Implementation Plan for Interstate Transport of Pollution Affecting Visibility and Regional Haze (Docket ID No. EPA–R08–OAR–2010–0406)

INTRODUCTION

Great River Energy (GRE) is a not-for-profit rural electric cooperative, owned by 28 member cooperatives, who serve nearly 650,000 member consumers. GRE's system-wide load goes to a mix of industrial, commercial and residential customers including over 350,000 families.
GRE's mission is to provide reliable electricity at reasonable rates in harmony with a sustainable environment. GRE disagrees with the proposed Federal Implementation Plan (FIP) as it relates to GRE's Coal Creek Station (CCS) because: 1) it usurps the statutory discretion afforded to the State of North Dakota; 2) it is not cost effective; and 3) it will not result in perceptible visibility improvements in the affected Class I areas.

GRE's comments also incorporate additional detailed and refined analyses of SNCR costs and impact on ash re-use.[1] Lastly, we respond to EPA's request for comments on a NOx limit of 0.14 lb/mmBtu.

North Dakota has primary authority in setting BART limits for North Dakota affected units.

North Dakota has primary authority in establishing BART as defined by rule and as discussed in the Federal Register preamble. North Dakota has taken the necessary time and effort to craft a reasonable,

[1] In response to an information request from the State of North Dakota, GRE is providing a more detailed analysis of the NOx BART technology selective non-catalytic reduction (SNCR) as it applies to Coal Creek Station (the "Best Available Retrofit Technology Refined Analysis for NOx Emissions" or "Refined Analysis"). This detailed analysis, attached and incorporated herein, will be referenced throughout these comments. This detailed analysis confirms that the installation of SNCR at CCS is not cost effective based on thresholds established by North Dakota and approved by EPA.

technically sound, and appropriate State Implementation Plan (SIP). As such, EPA's proposed FIP, with respect to GRE's Coal Creek Station, usurps North Dakota's rights under the Regional Haze Rule.

EPA has affirmed the state's authority in establishing BART:

> Although we believe that these requirements [presumptive BART] are extremely likely to be appropriate for all greater than 750 MW power plants subject to BART, a State may establish different requirements if the State can demonstrate that an alternative determination is justified based on a consideration of the five statutory factors.[2] (emphasis added)
>
> Our presumption accordingly may not be appropriate for all sources. As noted, the NOx limits set forth here today are presumptions only in making a BART determination, States have the ability to consider the specific characteristics of the source at issue and to find that the presumptive limits would not be appropriate for that source.[3] (emphasis added)

It is clear from the preamble that EPA has afforded the states significant deference in developing their implementation plans and determining the appropriate level of BART emission controls required for each facility.

Cost effectiveness and visibility improvements are essential aspects of every BART determination.

EPA emphasizes that BART determinations should be both "cost effective" and "likely to result in a significant degree of visibility improvement":

> In addition, while States are not required to follow these guidelines for EGUs located at power plants with a generating capacity of less than 750 MW, based on our analysis detailed below, we believe that States will find these same presumptive controls to be highly-cost effective, and to result in a significant degree of visibility improvement, for most EGUs greater than 200 MW, regardless of the size of the plant at which they are located. A State is free to reach a different conclusion if the State believes that an alternative determination is justified based on a consideration of the five statutory factors. Nevertheless, our analysis indicates that these controls are likely to be among the most cost-effective controls available for any source subject to BART, and that they are likely to result in a significant degree of visibility improvement.[4] (emphasis added)

North Dakota finalized its SIP in early 2010 and made a BART determination for Coal Creek Station that the presumptive NOx emission rate of 0.17 lb/mmBtu, as applicable to tangentially-fired lignite units, was appropriate, consistent with the five statutory factors, and resulted in significant visibility improvement.

Upon receiving EPA's FIP on September 21, 2011, North Dakota requested that GRE provide a revised NOx BART analysis for CCS. EPA had conducted its own analysis based on its own assumptions and

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[2] Federal Register / Vol. 70, No. 128 / Wednesday, July 6, 2005 / Page 39131.

[3] Federal Register / Vol. 70, No. 128 / Wednesday, July 6, 2005 / Page 39134.

[4] Federal Register / Vol. 70, No. 128 / Wednesday, July 6, 2005 / Page 39131.

costs about ash handling, disposal and re-use resulting from the installation and operation of SNCR technology. Based on these ash assumptions and associated costs, EPA asserts that SNCR is cost effective. Consequently, North Dakota requested GRE to provide a more refined analysis to assist North Dakota in clarifying if SNCR is cost effective, as asserted by EPA in their FIP. While EPA offers reasonable comments and questions on GRE's SNCR analysis, the state is given significant deference in making the BART decision.

Great River Energy's Refined Analysis confirms that SNCR will have a detrimental impact on Coal Creek Station ash sales.

Great River Energy has provided several revisions and updates to our BART analysis over the last several years in response to various stakeholder questions and comments. The most recent information exchange occurred in the summer of 2011 and primarily dealt with ash disposal issues associated with installation of SNCR. With EPA proposing SNCR at Great River Energy's Coal Creek Station in its FIP, it is appropriate and necessary to look once more at the issue of SNCR's operational and cost impacts on ash re-use.

While the exact impacts to Coal Creek Station's ash are unknown, mandating SNCR will leave GRE in a vulnerable position where we would expect to incur significantly higher costs from lost ash sales and increased landfilling. Appendix C to the attached Refined Analysis, "Fly Ash Storage and Ammonia Slip Mitigation Technology Evaluation," provides a comprehensive assessment of ash implications associated with SNCR installation. The report provides three scenarios to characterize the range of impacts of ammonia on ash sales and disposal costs. This report illustrates that any ash impact costs add to the total cost of SNCR and make it less cost effective.

There are several social, economic and environmental benefits from re-using ash. As qualitative measures these additional risks are not outweighed by costs nor are they outweighed by the imperceptible improvements to visibility. Please refer to the attached Refined Analysis for more details on the risks and associated cost estimates of ash impacts.

The Refined Analysis demonstrates that the installation of SNCR will not result in perceptible visibility improvements in North Dakota's Class I areas.

The Regional Haze Rule and BART requirements have a goal of reducing man-made impacts on Class I areas to reach natural background by 2064. EPA acknowledged that 0.5 deciviews is imperceptible to the human eye. From GRE's BART analysis, it can be estimated that the incremental deciview improvements associated with the installation of SNCR would range from 0.109 to 0.207, which are well below what EPA has established is a perceptible level to the human eye.

In addition, it is worth noting two facts. First, combined utility NOx emissions in North Dakota represent approximately only 6% of total NOx emissions[5]. As such, it is understandable that proposed and additional BART NOx reductions from North Dakota utilities do not provide more visibility improvements in the Class I areas. This makes sense because 94% of the NOx contribution is not related to North Dakota utility sources. Second, ammonia contributes to Regional Haze, in that it bonds with oxides of nitrogen and sulfur dioxides to form ammonium nitrates, and ammonium sulfates,

[5] Federal Register / Vol. 76, No. 183 / Wednesday, September 21, 2011.

respectively. Although outside the scope of this analysis, it is quite possible that additional ammonia release (slip) from the proposed SNCR for Coal Creek may offset the relatively minor NOx reductions proposed by EPA.

Great River Energy firmly states that the proposed 0.14 lb/mmBtu NOx emission limit is unachievable with LNC3+.

EPA's proposed FIP invites comment on a NOx emission limit of 0.14 lb/mmBtu for CCS. GRE firmly believes that 0.14 lb/mmBtu cannot be achieved with LNC3+ and DryFining™, and would trigger installation of SNCR. In support, GRE presents three comments on the proposed 0.14 lb/mmBtu NOx emission limit.

GRE Comment #1 on 0.14 lb/mmBtu - NOx limits should be expressed on an annual basis rather than a 30-day basis. Great River Energy presented two "low NOx burner" options in its final BART analysis, based upon vendor estimates. One technology estimated an emission rate of 0.17 lb/mmBtu and the other technology estimated an emission rate of 0.15 lb/mmBtu. Great River Energy chose to pursue the more effective NOx technology on CCS Unit 2, and has been developing operational history since 2008. As a general comment, permitting authorities have historically used vendor guarantees as the basis for creating firm permit limits. However, vendor guarantees are provided for specific operating conditions. These conditions are very specific and do not cover the full spectrum of operations such as variable load, startups, or shutdowns, as just a couple of examples. The estimated BART emission rates should be viewed as annual averages, and not as 30-day rolling limits. This statement is confirmed by GRE's operational history in Attachment 1. The attachment illustrates Unit 2's operating history with the installation of LNC3+, and DryFining™ coal drying technology. It is important to note that while an emission rate of 0.14 lb/mmBtu was achieved for some period of time it is not a sustainable number on a 30-day rolling basis.

GRE Comment #2 on 0.14 lb/mmBtu – Circumferential cracking limits the extent and duration of LNC3+'s ability to reduce NOx. As noted, GRE has proactively installed second generation SOFA/LNB (LNC3+) on CCS Unit 2, well in advance of the BART requirements. As such, GRE is uniquely positioned to comment on a proposed 30-day rolling NOx emission rate of 0.14 lb/mmBtu. Although GRE has demonstrated in the past an annual emission rate of 0.146 lb/mmBtu, GRE firmly states that the presumptive emission limit of 0.17 lb/mmBtu is the appropriate BART limit for the LNC3+ because it contributes to circumferential cracking.

Installation of the second generation LNC3+ technology in 2008 on Unit 2, contributed to circumferential cracking on the boiler tubes as operators attempted to maintain low NOx emission rates. Circumferential cracking occurs in the reducing zone between the coal nozzles and the overfire air (OFA) registers. In 2008, GRE lowered NOx emissions in Unit 2 by expanding the OFA registers to divert more of the combustion air from the burners of the boiler to an area about 30 feet higher in the boiler. In doing so, the flame temperatures were lowered, which reduced the production of NOx generated by the combination of oxygen and nitrogen gas burned under high temperatures. Circumferential cracking was an unexpected deleterious side effect of the expanded OFA registers.

The implementation of the DryFining technology has allowed CCS to operate at lower NOx levels which could not be demonstrated with the LNC3+ alone. Upon completion of commissioning in early 2010, operators again tested the lower end of NOx operations on Unit 2 and again experienced problems with circumferential cracking. It has accelerated tube leaks in Unit 2 and has required some unplanned outages. These operational risks have not been estimated as a cost and are not included in the Revised Analysis. While it has been possible to operate at lower NOx emission rates, during ideal conditions, the risk of circumferential cracking increases significantly when operating at these lower rates. An emission rate between 0.14 and 0.17 lb/mmBtu for LNC3+ and DryFining is not consistently achievable as a 30-day rolling emission limit.

GRE has pursued several corrective actions to maintain lower NOx emission rates, while minimizing circumferential cracking. These have included:

- detailed examinations of the boiler tubes to detect the extent of the cracking,
- the installations of additional temperature monitors to determine boiler wall temperatures, and
- tuning of the boiler to minimize the circumferential cracking in the zone of concern.

Based on our analysis of work done to date, it is not clear how to eliminate the thermal spikes through operating practice, except to ensure that the burner system is tuned to avoid large variations in burner specific fuel/air ratios, adequate coal fineness, excessive wall blowing, and boiler operation at the highest stoichiometric ratio consistent with NOx emission goals. Efforts continue to further reduce this circumferential cracking problem.

These efforts have reduced unscheduled outages caused by circumferential cracking, but have required operation at slightly higher NOx emission levels. See Attachment 1.

It is clear from our experience that reducing NOx emissions to the absolute limits of the LNC3 and DryFining technologies results in collateral damage to our boilers. Our operating experience demonstrates that there are distinct limits to this technology. GRE has proposed to continue to conduct combustion optimization tests, in an effort to further lower NOx emissions with the LNC3 technologies. These additional reductions may eventually be successful and could then potentially be used to mitigate the expected effects of startup/shutdown emissions as well as variable load operations, as inclusive in a 30-day rolling limit. For the purpose of a final 30-day rolling NOx BART limit, GRE firmly believes that 0.17 lb/mmBtu is the most stringent level.

<u>**GRE Comment #3 on 0.14 lb/mmBtu – EPA's recent analyses demonstrate that 0.14 lb/mmBtu is not achievable even with SNCR**</u>. GRE has reviewed EPA's projections on low NOx burner capabilities, and SNCR capabilities in the Cross State Air Pollution Control Rule (CSAPR). From a review of EPA modeling information from the CSAPR docket, there are currently no tangentially-fired utility electricity generating units, in the CSAPR-affected states, with LNC3 combustion controls <u>and</u> selective non-catalytic reduction (SNCR) post-combustion controls that operate at or below the presumptive BART limit of 0.17 lb/mmBtu for NOx.

While reviewing the CSAPR docket for comparable technologies and associated emission rates, GRE discovered that the levels originally stated "as achievable" in the BART submission of 2007 have not been demonstrated utilizing LNC3 and OFA. In a comparison of existing units of similar design, data from the recently proposed CSAPR at Docket ID EPA-HQ-OAR-2009-0491 illustrates that <u>there are currently no tangentially-fired utility electricity generating units with LNC3 combustion controls and selective non-catalytic reduction (SNCR) post-combustion controls that operate at or below the presumptive BART limit of 0.17 lb/mmBtu for NOx.</u> Details of our findings are presented in Section 2.1.3 of the Refined Analysis.

In EPA's own annual NOx emission projections on SNCR and low NOx burner (LNB) units, there are only 4 units capable of achieving <0.14 lb/mmBtu, and they are all supercritical units with LNBs and SNCR. Therefore, since CCS does not have supercritical boilers and since there is no other example of a tangential-fired source with only LNBs, it is unrealistic to expect an annual average lower than 0.14 lb/mmBtu, much less a 30-day rolling emission limit of 0.14 on LNB alone. And further, as supported by the Refined Analysis, CCS may be able to meet 0.12 lb/mmBtu as an annual average with SNCR. So, the 0.14 lb/mmBtu emission rate would potentially be achievable only after installation of SNCR with LNC3. As demonstrated in the Refined Analysis, SNCR is not cost-effective based on thresholds established by NDDH and already approved by EPA.

GRE's experience demonstrates that the most advanced LNC3 configuration cannot achieve a 30-day rolling limit of 0.14 lb/mmBtu, which is supported by EPA's own CSAPR modeling as annual averages. This emission limit could only be met through installation of SNCR and LNC3, which is not cost-effective as described in the Refined Analysis.

Conclusion

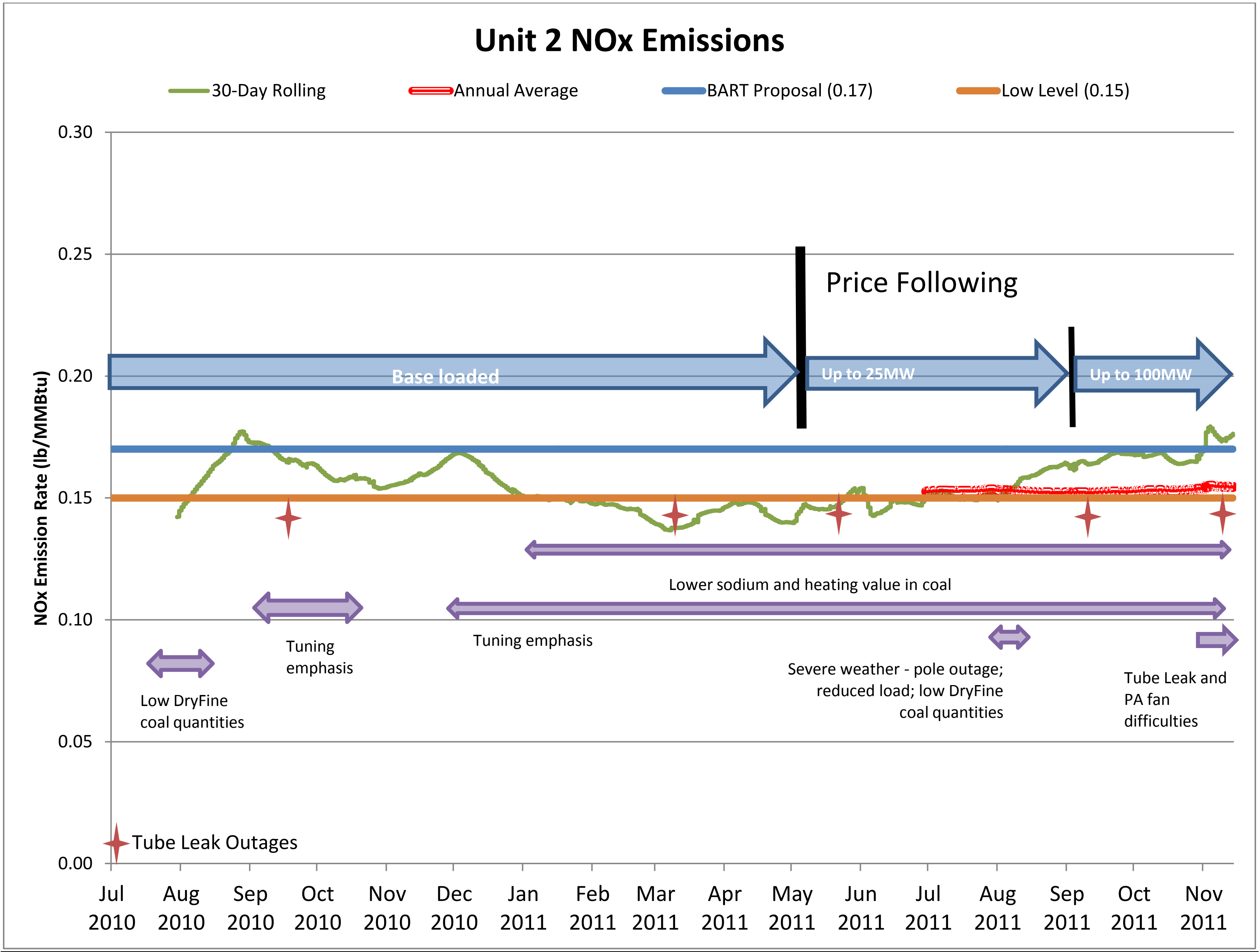
Great River Energy has refined its BART NOx analysis for CCS by updating the SNCR capital and operational costs. These updated costs were performed by URS after careful consideration of site specific information and while using updated cost information. In addition, Great River Energy contracted with Golder Associates to review and update assumptions pertaining to ash implications of SNCR. When combined, these updated values confirm that SNCR is not cost-effective, consistent with EPA's presumptive NOx analysis and consistent with North Dakota's cost-effective thresholds, as approved by both EPA and North Dakota.

As discussed, North Dakota has the authority under the Regional Haze Rule to review these refined analyses and ultimately determine the appropriate BART emission level for Coal Creek Station. We are confident that North Dakota will reach the same conclusion that we have reached, which is that the emission rate in the proposed FIP, which would require the use of SNCR technology, is not BART. Instead, Coal Creek Station will meet the presumptive BART emission level of 0.17 lb/mmBtu, through installation of LNC3, in addition to our novel DryFining technology.

EPA has also requested comment on a BART emission rate of 0.14 lb/mmBtu. Since CCS cannot achieve this 30-day rolling emission rate without installation of SNCR, it should not be considered as an appropriate BART emission level. As identified, this is consistent with EPA's own determination that a presumptive BART emission level of 0.17 lb/mmBtu is cost-effective and will result in significant visibility improvement. As demonstrated in these comments and the associated Refined Analysis, any additional NOx reductions would neither be cost-effective nor would result in perceptible visibility improvement in North Dakota's Class I areas.

Submitted on Behalf of Great River Energy
Mary Jo Roth
Manager, Environmental Services
MJRoth@GREnergy.com
763-445-5212
12300 Elm Creek Blvd.
Maple Grove, MN 55369

Attachment 1


Unit 2 NOx Emissions
30-Day Rolling
Annual Average
BART Proposal (0.17)
Low Level (0.15)
NOx Emission Rate (lb/MMBtu)
0.30
0.25
0.20
0.15
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Price Following
Base loaded
Up to 25MW
Up to 100MW
Lower sodium and heating value in coal
Tuning emphasis
Tuning emphasis
Low DryFine coal quantities
Severe weather - pole outage; reduced load; low DryFine coal quantities
Tube Leak and PA fan difficulties
Tube Leak Outages
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Nov 2011

NORTH DAKOTA
DEPARTMENT *of* HEALTH

ENVIRONMENTAL HEALTH SECTION
Gold Seal Center, 918 E. Divide Ave.
Bismarck, ND 58501-1947
701.328.5200 (fax)
www.ndhealth.gov

November 14, 2011

Via U.S. and Electronic Mail

FILE

Mr. Carl Daly
Director, Air Program
U.S. EPA, Region 8
1595 Wynkoop Street
Denver, CO 80202-1129

Re: Coal Creek NO_x BART Determination

Dear Mr. Daly:

I am writing to advise EPA Region 8 concerning developments associated with the North Dakota Regional Haze State Implementation Plan (Regional Haze SIP). As you know the Regional Haze SIP was submitted to EPA in March 2010 with a supplement submitted on July 27, 2010. EPA determined that the North Dakota SIP submittal was complete in April 2010. North Dakota subsequently submitted an Amendment to its Regional Haze SIP.

On July 15, 2011, Great River Energy (GRE) advised the Department that it had re-evaluated certain aspects of its previously submitted BART Emission Control Analysis for its Coal Creek Station (CCS). The Department had utilized and relied upon GRE's submittal in conducting its BART Determination for CCS. Specifically, GRE advised the Department that its original submittal of the cost data for selective non-catalytic reduction (SNCR) contained erroneous data. The Department has completed an initial investigation of this circumstance and determined that these errors materially and adversely affect the Department's BART assessment and determination for the CCS. Based upon the above circumstance, the Department has recently notified GRE that the Department has initiated a reevaluation of the CCS BART determination. The Department has also notified GRE that it must submit any supplemental information to the Department by December 21, 2011 (see attachment). EPA should thus be aware that these efforts may result in an amendment to the State of North Dakota's Regional Haze SIP, as these issues remain under the primary responsibility and authority of the Department.

If you have any questions, please feel free to contact me.

Sincerely,

Terry O'Clair

Terry L. O'Clair, P.E.
Director
Division of Air Quality

TLO/TB:saj
cc: Mary Jo Roth, Great River Energy

NORTH DAKOTA
DEPARTMENT *of* HEALTH

ENVIRONMENTAL HEALTH SECTION
Gold Seal Center, 918 E. Divide Ave.
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FILE

December 7, 2011

Mr. Carl Daly
Director, Air Program
U.S. EPA, Region 8
1595 Wynkoop Street
Denver, CO 80202-1129

Re: Great River Energy Coal Creek Station NO_x BART Determination

Dear Mr. Daly:

Following-up on our earlier communications, I am writing to advise EPA Region 8 concerning developments associated with the North Dakota Regional Haze State Implementation Plan (Regional Haze SIP).

As we advised you by letter dated November 14, 2011, Great River Energy (GRE) advised the Department in July of this year that it had discovered errors in its previously submitted BART Emission Control Analysis for its Coal Creek Station (CCS). The Department utilized and relied upon GRE's submittal in conducting its BART Determination for CCS. As we apprised EPA, the Department's initial investigation of this circumstance determined that these errors materially and adversely affect the Department's BART assessment and determination for the CCS. Accordingly, the Department notified GRE that the Department had initiated a reevaluation of the CCS BART determination and that any supplemental information GRE wanted the Department to review as it conducts its reevaluation must be received by December 12, 2011.

By letter dated November 21, 2011, GRE submitted to the Department a refined BART analysis for the CCS, along with a copy of GRE's comments to EPA's proposed partial Regional Haze FIP for North Dakota. As has been the Department's past practice, we are providing to EPA a copy of GRE's November 21, 2011 submission to the Department, which includes GRE's *Coal Creek Station Units 1 and 2 Best Available Retrofit Technology Refined Analysis for NOx Emissions*. The Department is evaluating GRE's submission and will determine whether the new information received from GRE requires an amendment to the State of North Dakota's Regional Haze SIP. These issues remain under the primary responsibility and authority of the Department and the State of North Dakota, and will be addressed in a reasonable and informed manner. If the Department determines that an amendment to the Regional Haze SIP is required, the public, including EPA, will of course have the opportunity to review and comment on any amendments to the SIP before they are finalized and submitted to EPA.

If you have any questions, please feel free to contact me.

Sincerely,

Terry O'Clair

Terry L. O'Clair, P.E.
Director
Division of Air Quality

TLO:saj
xc: MaryJo Roth, Great River Energy

NORTH DAKOTA
DEPARTMENT *of* HEALTH

ENVIRONMENTAL HEALTH SECTION
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March 8, 2012

FILE

Ms. Mary Jo Roth
Manager, Environmental Services
Great River Energy
12300 Elm Creek Boulevard
Maple Grove, MN 55369-4718

Re: Extension Request of March 7, 2012

Dear Ms. Roth:

We have reviewed your letter of March 7, 2012 which requested an extension to the deadline of March 9, 2012 for responding to questions regarding the Refined NO_x BART Analysis for Coal Creek Station. Based on the information in your letter, the Department hereby grants an extension of the deadline to respond to April 9, 2012.

If you have any questions, please feel free to contact us.

Sincerely,

Terry O'Clair

Terry L. O'Clair, P.E.
Director
Division of Air Quality

TLO/TB:saj
xc: Maggie Olson, Ass't. Attorney General
Paul Seby, Special Ass't to the Attorney General
Carl Daly, EPA, Region 8

NORTH DAKOTA
DEPARTMENT *of* HEALTH

ENVIRONMENTAL HEALTH SECTION
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November 3, 2011

FILE

Ms. Mary Jo Roth
Manager
Environmental Services
Great River Energy
12300 Elm Creek Boulevard
Maple Grove, MN 56369

Re: Coal Creek NO_x BART Determination

Dear Ms. Roth:

The Department has been reviewing the information that you submitted on July 15, 2011 regarding revisions to Great River Energy's NO_x BART analysis which was used by the Department to make its BART determination for the Coal Creek Station. It is our understanding that you are now planning to submit additional information and an updated cost estimate for selective non-catalytic reduction (SNCR) at Coal Creek Station. This information may include new information on the effectiveness of SNCR as well as revised cost effectiveness data. We ask that the new information be submitted to the Department by December 21, 2011 so that the Department may complete its review as expeditiously as possible.

If you have any questions, please feel free to contact Tom Bachman of my staff.

Sincerely,

Terry O'Clair

Terry L. O'Clair, P.E.
Director
Division of Air Quality

TLO/TB:saj
xc: Paul Seby, Moye White LLP Attorneys at Law
Maggie Olson, Ass't. Attorney General

GREAT RIVER
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November 21, 2011

VIA ELECTRONIC
AND U.S. MAIL

Mr. Terry L. O'Clair
Director, Division of Air Quality
North Dakota Department of Health
918 E. Divide Avenue, 2nd Floor
Bismarck, ND 58501-1947

RE: Response to NDDH Letter concerning Coal Creek Station NOx BART Determination

Dear Mr. O'Clair:

In response to your letter of November 3, 2011, and for use as part of Great River Energy's comments to U.S. Environmental Protection Agency's proposed Federal Implementation Plan (FIP), we have completed a refined BART analysis for Coal Creek Station relative to NOx emissions. Enclosed is a copy of our report titled "*Coal Creek Station Units 1 and 2, Best Available Retrofit Technology Refined Analysis for NOx Emissions*," dated November 2011. For your convenience I have also included a copy of our comments to EPA's September 21, 2011 FIP/SIP proposal. Our comments were submitted to the EPA's docket on November 21.

Please contact me if you have any questions (763-445-5212).

Sincerely,

GREAT RIVER ENERGY

Mary Jo Roth
Mary Jo Roth
Manager, Environmental Services

Enclosures

c: Tom Bachman, NDDH

Findings of Fact
Supplemental NO_x BART Determination
Coal Creek Station

December 2012

North Dakota Department of Health
Division of Air Quality
918 E Divide Avenue
Bismarck, ND 58501

Findings of Fact
Supplemental NO_x BART Determination
Coal Creek Station

The North Dakota Department of Health makes this supplemental Best Available Retrofit Technology (BART) Determination for nitrogen oxides (NO_x) pursuant to the North Dakota Century Code Chapter 23-25, the North Dakota Administrative Code Chapter 33-15-25, the federal Clean Air Act §169A, 40 CFR 51.308 and 40 CFR Part 51, Appendix Y. Having considered Great River Energy's (GRE's) submittal, the comments made and other information entered into the administrative record, and hereby incorporating its Preliminary Determination and its Response to Comments into these proceedings, the Department makes the following Findings and Conclusions.

I. Introduction

A. Background

Great River Energy operates the Coal Creek Station (CCS) near Underwood, ND. CCS consists of two tangentially fired units, each rated at 550+ megawatts. Existing air pollution control equipment on each unit consists of an electrostatic precipitation for the control of particulate matter and a lime wet scrubber for the control of sulfur dioxide emissions. Combustion controls for reducing the formation of NO_x includes low NO_x burners and a form of overfire air. Unit 1 went on line in 1979 while Unit 2 started operation in 1980.

The combustion of lignite coal creates fly ash at CCS. GRE currently markets the fly ash collected at CCS as a substitute for Portland cement in the production of concrete. This beneficial reuse of the fly ash removes the need to landfill the fly ash. GRE and its partners have invested over 31 million dollars in equipment used for the management and sale of the CCS fly ash.

B. History of BART Analysis and Determination

On August 17, 2006, GRE submitted its initial BART analysis to the Department. The Department reviewed the document and on December 1, 2006 provided comments to GRE. GRE subsequently updated the analysis in February 2007 based on the Department's comments. As the Department's review continued, GRE's BART analysis was updated in July, September and December of 2007. In March of 2010, the Department made its BART determination and submitted it to EPA as part of the State of North Dakota's Regional Haze State Implementation Plan (SIP).

EPA, during their review of the North Dakota Regional Haze SIP, discovered that GRE had used a value for ash sales based on the total sales price instead of the amount GRE would receive from the sales (see 76 FR58603, 58604, 58619). After the discrepancy was discovered, the Department requested that GRE submit a revised BART cost estimate to the Department. Before GRE provided the Department, or EPA, with all of the necessary cost data, EPA finalized a Federal Implementation Plan (FIP) which established a BART limit of 0.13 lb/10^6 Btu based on the use of selective non-catalytic reduction (SNCR). The following is the Department's understanding of the chronology of events associated with GRE's submission of its revised cost estimates:

Date	**Item**
July 15, 2011	GRE submits revised cost estimate for SNCR
September 21, 2011	EPA proposes to approve in part and disapprove in part North Dakota's Regional Haze SIP and proposes FIP
November 3, 2011	Department letter to GRE asking that revised analysis be provided by December 21, 2011
November 14, 2011	Department informs EPA by letter that it will reevaluate the Coal Creek Station BART determination
November 21, 2011	GRE submits revised BART analysis to the Department
December 7, 2011	Department letter to EPA advising it of GRE's submittal and Department's review
January 10, 2012	Conference call with GRE to discuss comments on November 21, 2011 submittal
January 19, 2012	Department letter to GRE with comments to the November 21, 2011 submittal
February 10, 2012	GRE submits revised analysis
February 28, 2012	Department letter to GRE with comments on February 10, 2012 submittal
April 5, 2012	GRE submits revised analysis in response to Department's February 10, 2012 comments
April 6, 2012	EPA publishes final FIP
April 11, 2012	GRE submits revised analysis which updated visibility impact tables
May 21, 2012	Conference call with GRE where Department indicated it did not agree with a baseline of 0.153 lb/10^6 Btu for Unit 2 and there was an error in the Unit 1 cost effectiveness analysis
June 6, 2012	GRE submits revised calculations of cost effectiveness and incremental cost for both units based on the May 21, 2012 comments
August 6 - September 12, 2012	Consultation with FLMs and EPA on Preliminary Supplemental Evaluation BART NO_x determination for CCS (Supplemental Determination)
September 15, 2012	Department completes evaluation of GRE's analysis
September 15, 2012	Notice provided to FLMs and EPA of Supplemental

	Evaluation for public comment of the Supplemental Determination
October 1-30, 2012	Public Comment Period to the Supplemental Determination
November 28, 2012	GRE provides response to public comments to the Supplemental Determination
December 14, 2012	Department response to public comments to the Supplemental Determination

C. Requirements for NO_x BART Analysis and Determination

The Clean Air Act §169A(b)(2) requires each state to include in their Regional Haze SIP BART requirements for each major stationary source which was in existence on the date of enactment of the section of the Act (August 7, 1977) and those that had been in operation no more than fifteen years prior to such date (August 7, 1962). CAA §169A(b)(2) goes on to state that "in the case of fossil-fired generating power plants having a generating capacity in excess of 750 megawatts, the [BART] emission limitations" must be determined pursuant to guidelines promulgated by the EPA Administrator, which guidelines are known as the BART Guidelines.

EPA's BART Guidelines are established in 40 CFR Part 51, Appendix Y, Guidelines for BART Determination Under the Regional Haze Rule. CAA §169A(g)(2) establishes the factors that must be considered when determining BART. These include:

1) The cost of compliance

2) The energy and non-environmental impacts of compliance

3) Any existing air pollution control equipment in use at the source

4) The remaining useful life of the source; and

5) The degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.

Pursuant to NDAC Chapter 33-15-25, the Department has required any owner or operator of any existing stationary facility (as defined in 40 CFR § 51.301) that contributes significantly to visibility improvement in a Class I Federal area to submit a BART analysis to the Department. NDAC § 33-15-25-03 requires the owner or operator of a fossil-fuel fired steam electric plant with a generating capacity greater than 750 megawatts of electricity (MWe) to comply with the guidance in 40 CFR Part 51, Appendix Y. Since the Coal Creek Station has a capacity greater than 750 MWe (1100^+ MWe), GRE was required to follow the BART Guidelines in the preparation of their BART analysis. However, nothing in the North Dakota rules or the BART Guidelines prevent the owner or operator from supplying additional information beyond that required by the BART Guidelines.

In establishing BART, the five statutory factors must be considered. However, the Department has flexibility in its evaluation of the five factors. The preamble to EPA's BART Guidelines clearly acknowledges that "However, we believe the States have flexibility in setting absolute thresholds, target levels of improvement, or de minimus levels since the deciview improvement must be weighed among the five factors, and States are free to determine the weight and significance to be assigned to each factor". (70 FR 39,130)

II. Supplemental NO_x BART Determination

With regard to control technologies for reduction of NO_x emissions at the Coal Creek Station, the Department makes the following findings and conclusions:

1) High dust SCR (HDSCR) is not technically feasible at Coal Creek Station. The high concentration of soluble sodium and potassium in the flue gas will poison, blind and plug the SCR catalyst (see ND SIP Appendix B5).

2) The cost of low dust SCR (LDSCR) is excessive. The Department's analysis indicated a cost effectiveness of $13,101 per ton and an incremental cost effectiveness of $20,678 per ton (see ND SIP Appendix B.2, page 16). The high cost is primarily due to the cost of reheating the flue gas and the operation and maintenance costs associated with an SCR system on a North Dakota lignite-fired boiler. The cost effectiveness and incremental cost of SCR are both well above the values the Department determined to be reasonable for BART (see Appendix E of the Supplemental Evaluation). The cost of tail-end SCR (TESCR) is expected to be as much or more than LDSCR because of the additional reheating of the flue gas that is required. The cost of TESCR is also excessive.

3) In its partial Federal Implementation Plan for North Dakota, EPA determined that SCR is not required as BART due to the high cost and small visibility improvement (77 FR 20,899, 76 FR 58,622-58,623).

4) Ammonia, from the application of SNCR, will likely contaminate some of the fly ash produced at Coal Creek Station to the point it is not marketable for making concrete or other uses. The amount of ash sales that will be lost cannot be determined. GRE has suggested that as much as 100% of ash sales could be lost.

5) Since the amount of ash sales cannot be determined, the cost effectiveness and incremental cost of SNCR cannot be determined precisely. The Department has

evaluated three scenarios: a) no ash sales are lost, b) 30% of ash sales are lost; and c) 100% of ash sales are lost. If 30% or 100% of the fly ash are lost, the Department considers the cost (cost effectiveness and/or incremental cost) of SNCR + LNSC3+ and SNCR alone to be excessive. If no fly ash sales are lost, the incremental cost of SNCR alone would be considered excessive. However, because of the relativity large emissions reductions achieved by LNC3+ at minimal cost, the cost of SNCR + LNC3+ is not considered excessive if no ash sales are lost.

6) The amount of visibility improvement from the use of SNCR is very small. The maximum improvement (98^{th} percentile) would be 0.106 deciviews, which is not humanly perceptible. The average improvement at North Dakota's four Class I Federal Areas is 0.056 deciviews. A source is considered to "contribute to visibility impairment" if it contributes 0.500 deciviews or more of impairment (NDAC 33-15-25-01.2). The small amount of visibility improvement from the use of SNCR does not warrant the use of SNCR as BART.

7) The use of SNCR has the potential for adverse environmental effects. For example, if ash sales are lost, the fly ash must be landfilled which eliminates useful land. Ammonia slip from the SNCR system can result in ammonia being emitted to the atmosphere. Ammonia is considered a hazardous air pollutant by the Department (*see* Policy for the Control of Hazardous Air Pollutants Emissions in North Dakota). In addition, there will be an increase in greenhouse gas emissions from Portland cement manufacturing to replace the fly ash which cannot be used in concrete production.

8) The recycling of fly ash and keeping it out of a landfill is an important environmental issue to the State. Landfilling fly ash can lead to adverse environmental impacts. Over 31 million dollars has been invested at CCS for the management and sale of fly ash. The recycling of fly ash as a Portland cement substitute in concrete eliminates the potential adverse environmental effects from landfilling fly ash.

9) The cost of SNCR cannot be determined exactly since it cannot be determined how much of the fly ash sales will be lost. The Department expects that more than likely a material portion of the fly ash sales will be lost. Because the cost of SNCR cannot be determined precisely, the Department has chosen to weigh the degree of visibility improvement heavily in this BART determination. The amount of visibility improvement is not affected by the amount of lost fly ash sales. The small amount of visibility improvement and the potential for adverse environmental effects from SNCR indicate that it is not required as BART.

10) The U.S. Environmental Protection Agency has established presumptive BART emission limits for various types of boilers based on controls that EPA considers to be cost effective and expected to provide significant visibility improvement. For tangentially fired boilers, like the Coal Creek Station boilers, the presumptive

limits are based on combustion controls like LNC3+. (70 FR 39132-39136). Presumptive BART for CCS is 0.17 lb/10^6 Btu (40 CFR Part 51, Appendix Y, Table 1). The Department has established the NO_x BART emission limit at a level equal to EPA's presumptive BART emission limit. The Department has determined such an emission limitation to be both reasonable and rationally supported by the information before the Department.

II. BART Selection

After having considered the five statutory factors and all information and data made available to it, the Department exercises its legal authority and discretion and affirms its original NO_x BART determination that BART for CCS is represented by combustion controls (LNC3+) and an emission limit of 0.17 lb/10^6 Btu (30-day rolling average). GRE is allowed to average emissions between the two units as indicated in GRE's BART Permit to Construct (ND State Implementation Plan for Regional Haze, Appendix D.2).

Confidential Business Information

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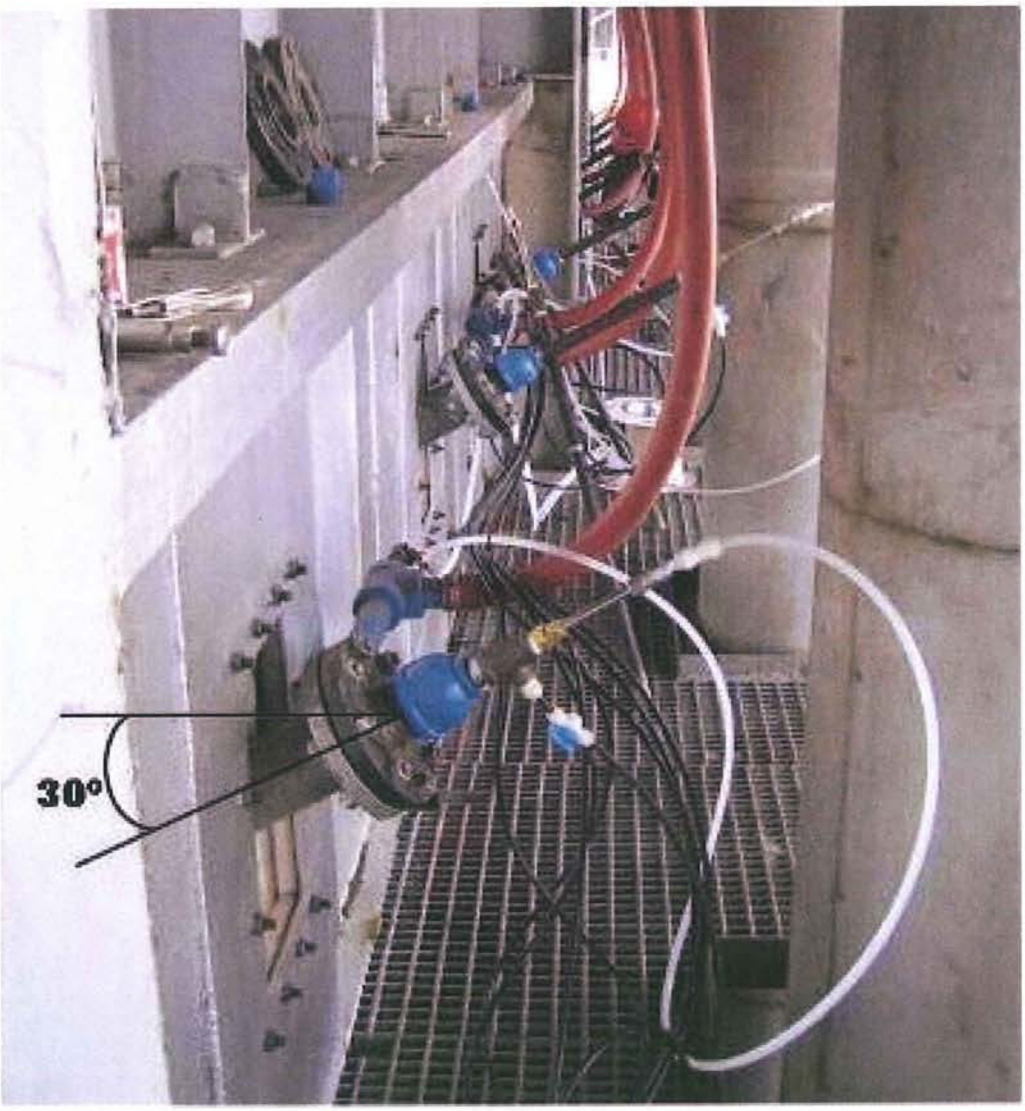
Low-Baseline NOx Selective Non-Catalytic Reduction Demonstration

Joppa Unit 3



Low-Baseline NOx Selective Non-Catalytic Reduction Demonstration

Joppa Unit 3

1018665

Final Report, March 2009

EPRI Project Manager
R. Himes

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Low-Baseline NOx Selective Non-Catalytic Reduction Demonstration: Joppa Unit 3. EPRI, Palo Alto, CA: 2009. 1018665.

PRODUCT DESCRIPTION

Increased NO_x reduction mandates are affecting some coal-fired units with NO_x emissions less than 0.12 lb/MBtu. EPRI has previously shown that a post-combustion technique—selective non-catalytic reduction (SNCR) technology—can be economically applied to a broad range of coal-fired boilers with baseline NO_x emissions in excess of 0.15 lb/MBtu. SNCR also can provide incremental NO_x reductions that can defer or eliminate the need for some selective catalytic reduction (SCR) retrofits. The current project addresses the applicability of SNCR to low-baseline NO_x emission units less than 0.12 lb/MBtu where there is currently no full-scale experience. A short-term SNCR demonstration project was conducted in Joppa, Illinois, at Electric Energy's Joppa Unit 3 with baseline NO_x emissions of nominally 70 ppm.

Results and Findings

SNCR performance appears to be significantly degraded at baseline NO_x emission levels less than 100 ppm. Increased ammonia slip levels experienced during the last day of testing indicates reagent was present at the optimum SNCR temperature window. Overall performance is likely constrained due to imperfect mixing achieved within the boiler using low-energy reagent injectors. Increased NO_x reductions with increasing urea flow rate supports the overall SNCR results at Joppa 3 being mixing-constrained at low baseline NO_x levels.

Challenges and Objective(s)

The primary objective of this short-term demonstration project was to assess the maximum NO_x reduction capabilities of a single-level, urea-based SNCR system at Joppa Unit 3 using existing ports above the nose of the boiler with baseline NO_x emission levels on the order of 0.10 lb/MBtu.

Applications, Values, and Use

Agencies at federal, state, and local levels are mandating increased reductions in NO_x emissions from fossil-fueled power plants. Available NO_x control technologies include combustion modifications and post-combustion techniques. Combustion modifications such as overfire air (OFA) and low-NO_x burners are limited in the level of NO_x reductions they can achieve by increases in either carbon monoxide or fly ash unburned carbon levels. As regulations become stricter, post-combustion processes such as SNCR and SCR must be considered.

EPRI Perspective

While the SNCR results using an identified optimum reagent injection configuration with mechanical atomizers showed unacceptable ammonia slip values, air atomized injectors may provide finer droplet size distribution "tuning capability". Based on documented differences of SNCR performance as a function of NO_x emission level, however, overall SNCR performance capabilities at baseline NO_x emission levels of 70 ppm will likely be constrained within a NO_x reduction range of 8 – 12%.

Approach

While the current project required modest NO_x reductions from SNCR, the project team did not know what actual level of SNCR performance to anticipate due to the lack of any SNCR operating experience at low-baseline NO_x levels. To determine actual SNCR NO_x reduction capability, the team conducted a comprehensive program at Joppa Unit 3 to evaluate SNCR performance at baseline NO_x levels of nominally 0.10 lb/MBtu (70 ppm) using a single-level, urea-based SNCR system. The project included O_2, CO, NO_x and ammonia slip measurements at the air heater inlet and temperature measurements at the furnace exit. The team performed testing at loads ranging from 150 to 180 MWg over a 6-day period. Several parameters were varied, including urea injection rate, atomizer type, baseline NO_x levels, and baseline CO levels.

To assess the cost-effectiveness of a SNCR system applied to a low-baseline NO_x unit, the team generated a capital cost estimate using an approach described in *SNCR Guidelines Update* (EPRI report 1004727, December 2004).

Keywords

NO_x control
Selective non-catalytic reduction
SNCR

ABSTRACT

Increasing NO_x reduction mandates are affecting a broad range of coal-fired boilers, including those of small capacity or limited remaining life where selective catalytic reduction (SCR) solutions are typically uneconomical. EPRI has shown that selective non-catalytic reduction (SNCR) Trim technology can be economically applied to a broad range of coal-fired boilers with baseline NO_x emissions in excess of 0.15 lb/MBtu and provide incremental NO_x reductions that can defer or eliminate the need for some SCR retrofits. Increased NO_x reduction mandates are recently affecting some coal-fired units with NO_x emissions less than 0.12 lb/MBtu. Additional NO_x controls beyond combustion modifications are still required. The current project addresses the applicability of SNCR to these low-baseline NO_x emission units where there is currently no full-scale experience. To this end, a short-term SNCR demonstration project was conducted at Joppa Unit 3 with baseline NO_x emissions of nominally 75 ppm. The project investigated the influence of baseline NO_x emissions, CO levels, as well as reagent injector parameters.

ACKNOWLEDGEMENTS

The authors would like to acknowledge the supplemental funding provided by Electric Energy Inc., without which this project would not have been possible. In addition, efforts by EEI and Ameren personnel at Joppa Station, including Larry Lepovitz and James Barnett, were invaluable during the project implementation and testing phases.

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1
INTRODUCTION

Background

Agencies at federal, state and local levels are requiring further reductions in NO_x emissions from fossil-fueled power plants. Available NO_x control technologies include combustion modifications and post-combustion techniques. Combustion modifications such as overfire air (OFA) and low-NO_x burners are limited in the ultimate level of NO_x reductions that they can achieve. As regulations become stricter, post-combustion processes such as Selective Non-Catalytic Reduction (SNCR), and Selective Catalytic Reduction (SCR) must be considered.

SNCR Process Description

SNCR is a post-combustion technique developed to reduce NO_x emissions from fossil-fuel combustion systems. This process typically involves injection of a urea solution where the flue gas temperature is between 1,800°F – 2,200°F (982°C – 1,204°C). The urea solution evaporates and decomposes to react selectively with NO_x in the presence of oxygen, forming primarily nitrogen and water. An overview of the reactions for urea is shown in Figure 1-1. For this project, a 40% by weight urea solution was selected to avoid heat tracing of transport lines since the precipitation temperature for this weight percent urea solution is 33°F (0.6°C). Numerous factors can alter the effectiveness of the SNCR process, which include temperature, residence time, CO levels, as well as the baseline NO_x concentration.

As seen in Figure 1-2, temperature variations and residence time can significantly impact the efficiency of the SNCR process. For urea, the optimal injection temperature is around 1,850°F (1,010°C) under well-mixed laboratory conditions. Optimal reaction efficiencies are also obtained with nominal residence times of 250 milliseconds at the optimal temperature. The relatively narrow temperature window that is associated with the SNCR processes is due to the competition between key oxidation steps and NO reduction steps and their dependence on gas temperature. The key reactions leading to NO reduction are:

$$NH_2 + NO \rightarrow NNH + OH \qquad (1)$$

$$NH_2 + NO \rightarrow N_2 + H_2O \qquad (2)$$

$$NCO + NO \rightarrow N_2O + CO \qquad (3)$$

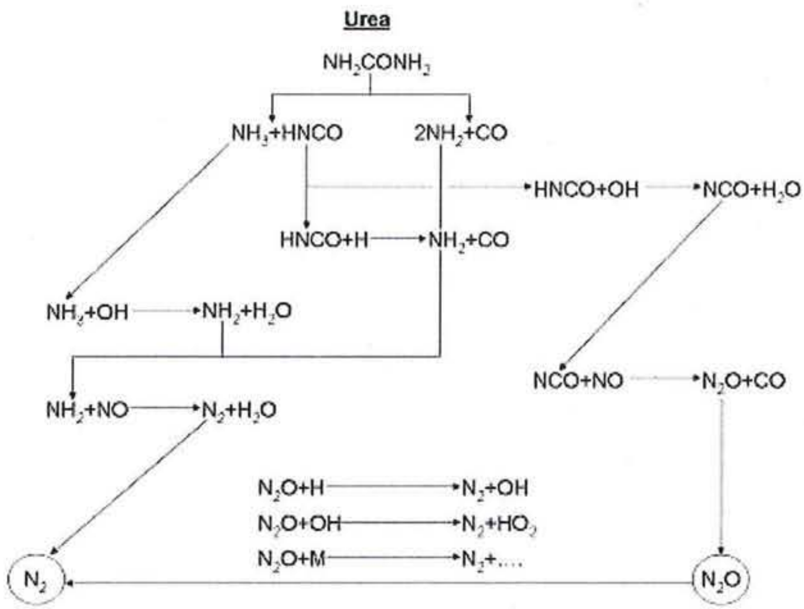


Figure 1-1
SNCR Process Reactions

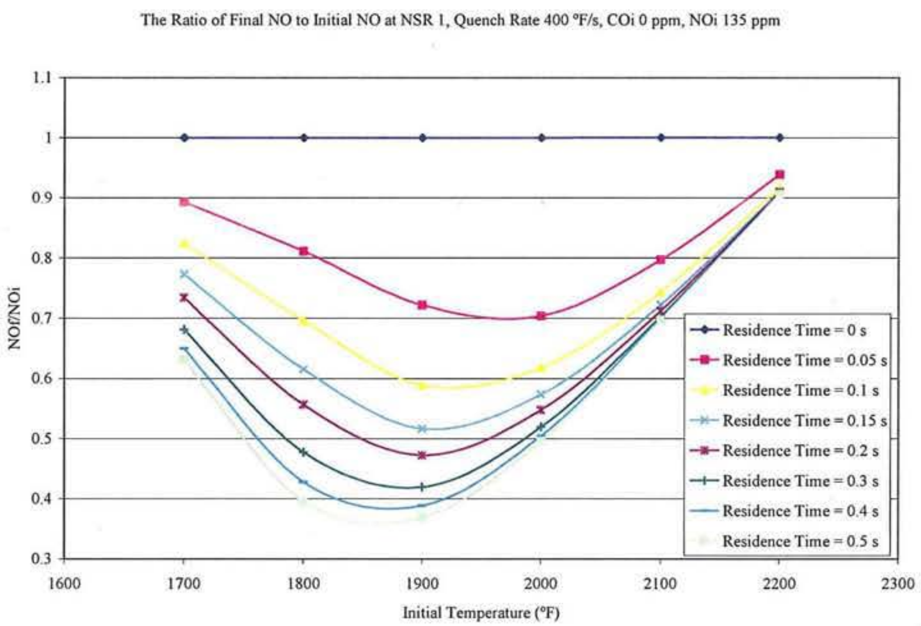


Figure 1-2
CFD Model Predictions Showing Impact of Gas Temperature and Residence Time on NO_x Reduction under Baseline Conditions (NSR=1, Quench Rate = 400°F/s [204°C/s], Initial NO = 135 ppmv, SR = 1.15) (EPRI 1004729, 2003)

In order to sustain reactions 1 – 3, there needs to be a continuous supply of O and OH radicals. These species are produced through the following key routes:

$$H + O_2 \rightarrow OH + O \quad (4)$$

$$O + H_2O \rightarrow OH + OH \quad (5)$$

At the low temperature end of the effective temperature range, the NO reduction is limited by the rates of chain termination reactions (2 and 3) that compete with chain branching reactions (4 and 5). As temperatures increase, the rate of formation of the chain carriers (i.e., O, OH) is large enough to sustain the chain termination steps. As temperatures increase above the optimal temperature range, then oxidation reactions begin to dominate and start to contribute to net NO formation. Important steps in this process include:

$$NH_2 + O \rightarrow HNO + H \quad (6)$$

$$HNO + M \rightarrow H + NO + M \quad (7)$$

$$NH_2 + OH \rightarrow NH + H_2O \quad (8)$$

$$NH + O_2 \rightarrow NO + OH \quad (9)$$

$$NCO + O \rightarrow NO + CO \quad (10)$$

The presence of CO can also alter the effectiveness of the process. As seen in Figure 1-3, greater amounts of CO will typically decrease the NO reduction levels. However, as a beneficial aspect, higher CO levels will also tend to broaden the SNCR process temperature window. CO contributes to the formation of chain carriers (OH) which are necessary to sustain the SNCR chemistry. At lower gas temperatures, the increased rate of chain branching caused by the CO addition is favorable to the SNCR process. However, at higher temperatures it is detrimental since the pathways for oxidation of the reagent begin to compete unfavorably with the NO reduction pathways. Key reactions are:

$$CO + OH \rightarrow CO_2 + H \quad (11)$$

$$H + O_2 \rightarrow OH + O \quad (4)$$

$$O + H_2O \rightarrow OH + OH \quad (5)$$

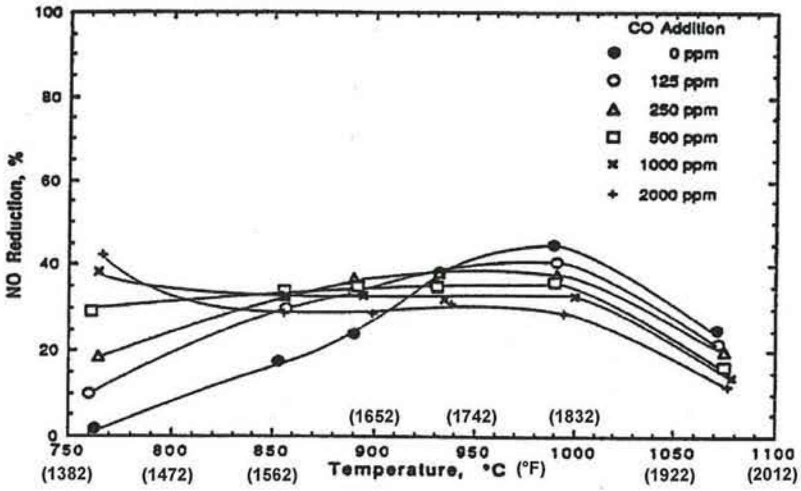


Figure 1-3
Effect of CO Levels on SNCR Performance with Urea Injection; Initial NO = 125 ppm, NSR = 2.0 (AFRC/JFRC International Conference on Environmental Control of Combustion Process, October 1991)

Concentrations of different gaseous components can also impact the process. Figure 1-4 shows the predicted effect initial NO levels have on the SNCR process, along with temperature based on CFD modeling. The more NO present in the flue gas, the greater the potential for NO reduction.

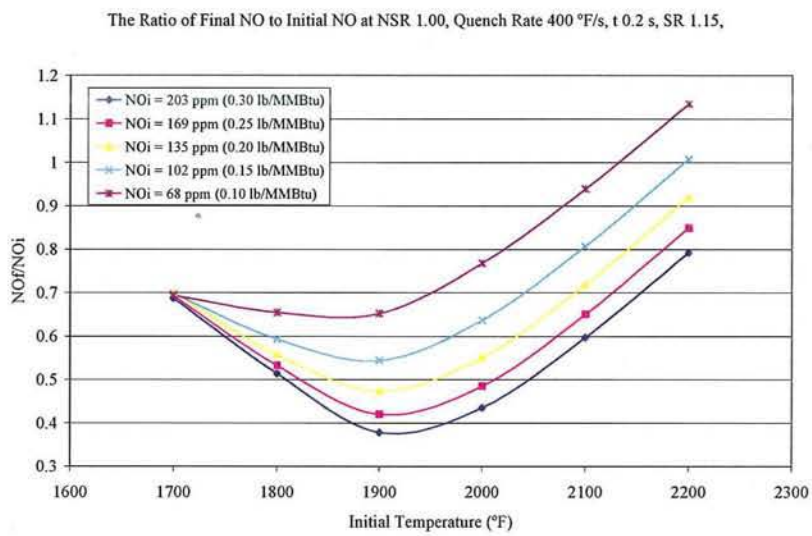


Figure 1-4
Impact of Initial NO Concentration on NO Reduction under Baseline Conditions (NSR=1, Quench Rate = 400°F/s [204°C/sec], SR = 1.15) (EPRI 1004729, 2003)

Project Objectives

The primary objective of the short-term demonstration project was to assess the maximum NO_x reduction capabilities of a single-level, urea-based SNCR system at Joppa Unit 3 using existing ports at Elevation 470 feet. The following key parameters were investigated during the optimization process:

- Urea injection rate (NSR – Normalized Stoichiometric Ratio)
- Urea dilution and drop size
- Load/temperature effects
- NO_x concentration impacts
- Carbon monoxide impacts

At optimized conditions, other objectives included evaluating ammonia slip as a function of NSR and NO_x reduction, and measuring ammonia retention on fly ash.

Project Approach

High velocity thermocouple (HVT) measurements were taken in early September 2008 under a separate contract with Innovative Combustion Technologies (ICT). HVT measurements were performed at Elevation 470 feet and 457 feet to document the temperature distribution at the point of urea injection. During this effort furnace exit gas temperatures as well as gaseous species concentrations were characterized.

In November 2008, a temporary urea storage, handling and injection system was set up for the demonstration. Urea was injected using existing ports at Elevation 470 feet, and gaseous species concentrations (O_2, CO, NO_x and NH_3) were monitored at the air heater inlet. NO_x reduction performance was optimized and documented as a function of NSR and ammonia slip at full load. Furnace exit temperatures were continuously monitored at Elevation 457 feet using optical instruments.

A detailed description of the measurement methods can be found in Appendix A.

2
UNIT DESCRIPTION

Joppa Unit 3 is a Combustion Engineering, tangential-fired furnace rated at 181 MWg. The unit currently burns Powder River Basin (PRB) coal, and utilizes close-coupled overfire air (CCOFA) and separated overfire air (SOFA) for NO_x reduction. The furnace cross section is 40 feet (12.2 meters) wide by 28 feet (8.5 meters) deep at the burner elevations. Figure 2-1 shows an elevation view of the unit identifying the urea injection and test measurement locations.

The furnace exit sootblowers were in automatic operation during the test program. The neural net boiler optimization system was turned off.

Joppa Units 3 and 4 have a common stack, so independent CEMS data for Unit 3 were not available. Plant NO_x and CO monitors are located at the Unit 3 ID fan outlet. The plant NO_x reading was useful for monitoring changes in the raw NO_x value during the SNCR tests. However, the raw NO_x values could not be directly compared to FERCo measurements since there was no means for dilution correction. At full load and normal OFA conditions, baseline NO_x values measured at the air heater inlet were as low as 70 ppmc (0.10 lb/MBtu).

High velocity thermocouple (HVT) measurements were conducted separately just prior to the current SNCR demonstration tests. Furnace exit gas temperature measurements at full load averaged 2,080°F (1,138°C). CO levels at the furnace exit averaged 10,900 ppm, and ranged between 240 to 32,000 ppm.

SNCR Demonstration Configuration

The layout of the temporary SNCR system used at Joppa Unit 3 is shown in Figure 2-2. Photos of individual components of the SNCR system are shown in Figures 2-3 through 2-7. A metering pump was used to move urea solution (40% by weight) from a 5,000 gallon (18,900 liter) tank trailer at ground level (Elevation 350 feet) up to Elevation 457 feet. After dilution water was added, the solution was pumped through a distribution header and up to the injection ports at Elevation 470 feet (oriented at a 30° downward angle). Valves and rotameters were used to adjust the amount of solution flow to each of the eight injection lances. The tip of each lance was placed flush with the furnace wall. Although each injection lance was cooled by the solution, plant air was utilized to provide further cooling and to prevent fly ash from depositing on the lances.

The system flow ranges are listed below:

- 40% by weight Urea: 0 - 2 gpm (0 - 7.6 lpm)

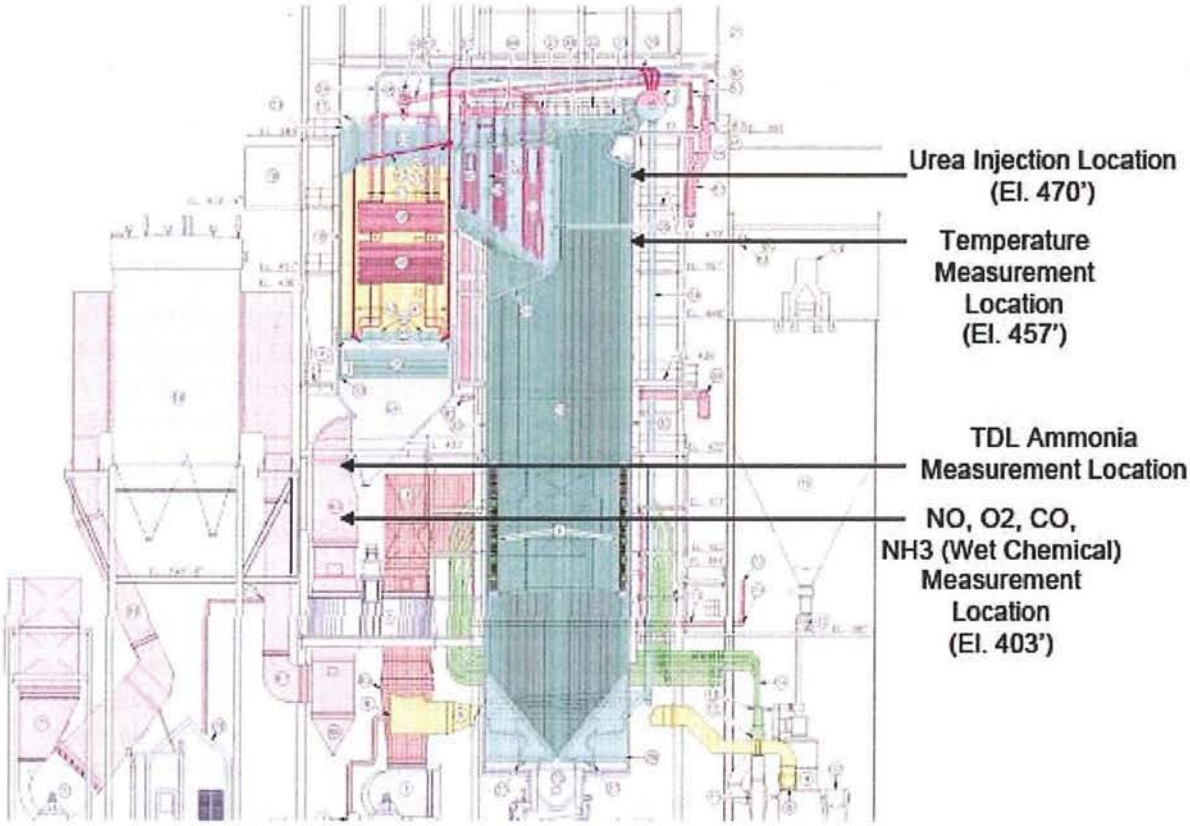


Figure 2-1
Joppa Unit 3 Elevation View

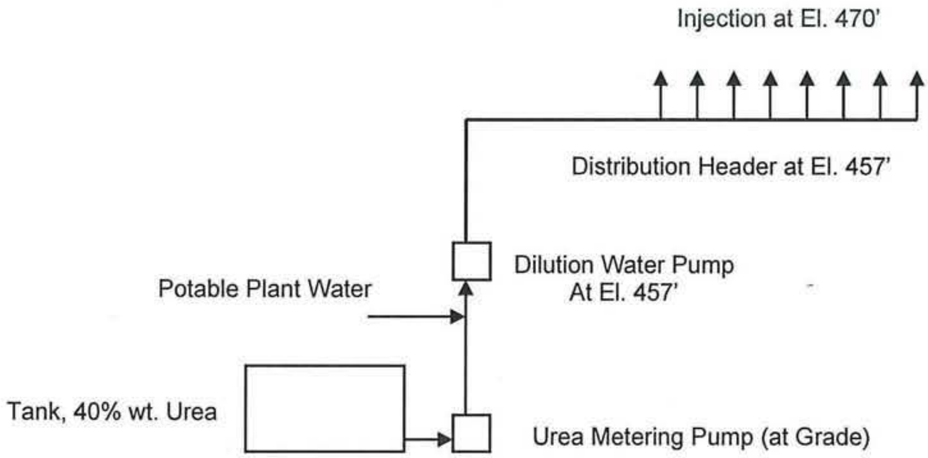


Figure 2-2
SNCR Flow System Schematic

Figure 2-3
Urea Metering Pump Attached to Urea Tanker

Figure 2-4
Dilution/Booster Pumps at Elevation 457 Feet

Figure 2-5
Distribution Header at Elevation 457 Feet

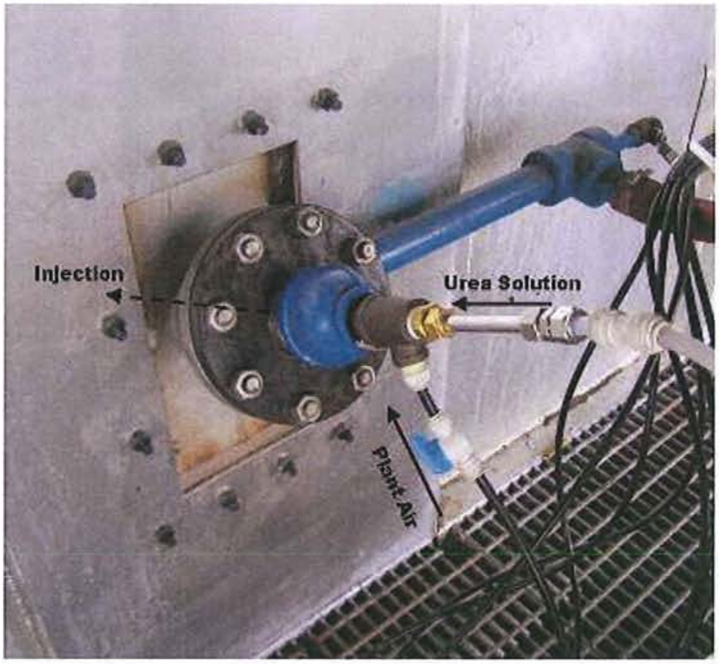


Figure 2-6
Injector Configuration on Elevation 470 Feet

Figure 2-7
Side View of Injection Configuration

- Dilution Water: 0 - 10 gpm (0 – 38.0 lpm)
- Flow per Injector: 0 - 1.5 gpm (0 – 5.7 lpm)

The system P&ID is provided in Appendix D.

Pressure Atomizer Description

The following flat-fan pressure atomizers were utilized during the field tests:

- Spraying Systems 15-055 Nozzle (0.55 gpm @ 40 psig, 15°Spray Angle)
  (2.0 lpm @ 2.7 bars)
- Spraying Systems 25-08 Nozzle (0.8 gpm @ 40 psig, 25°Spray Angle)
  (3.0 lpm @ 2.7 bars)
- McMaster Carr 0.5 gpm Nozzle (0.5 gpm @ 40 psig, 30°Spray Angle)
  (1.9 lpm @ 2.7 bars)
- McMaster Carr 1.5 gpm Nozzle (1.5 gpm @ 40 psig, 30°Spray Angle)
  (5.7 lpm @ 2.7 bars)
- McMaster Carr 3.0 gpm Nozzle (3.0 gpm @ 40 psig, 50°Spray Angle)
  (11.3 lpm @ 2.7 bars)

- Field-Modified Nozzle with 5/64 inch (0.2 cm) hole (Inconsistent Flow and Spray Angle)

Figure 2-8 shows the relationship between droplet size and pressure for a typical pressure atomizer of similar design. In general, larger droplets (i.e., lower pressures) are more effective for regions on the higher side of the SNCR temperature window due to their longer evaporation times.

In some cases, spray angle can help fine-tune SNCR performance. Smaller angles provide less side-to-side coverage and better penetration inside the furnace, and the opposite is true for larger injector spray angles.

For the purposes of the Joppa Unit 3 tests, the middle six injectors were aligned with a horizontal flat-fan spray relative to the injection port downward angle. The outside injectors near the side walls were aligned vertically to avoid tube wall impingement.

Gaseous Measurement Location

As shown in Figure 2-1, gaseous species concentrations (O_2, CO, NO_x and NH_3) were measured at the air heater inlet near Elevation 403 feet. Figure 2-9 shows a plan view arrangement of the ductwork and probe grid at this location. The air heater inlet consisted of two separate ducts. Each duct contained a four-wide by two-deep probe array, or 8 probes in each duct for a total of 16 probes. Composite and point-by-point measurements of O_2, CO, and NO_x were performed using the gas sampling grid.

As described in Figure 2-9, wet chemical ammonia slip measurements were made at the same elevation, but at different ports. Composite samples were obtained for each duct. The ammonia TDL instrument was mounted in a port on the south duct at a slightly higher elevation.

The methods for the gaseous species measurements are described in detail in Appendix A.

Temperature Measurement Locations

Measurements of the furnace exit gas temperatures during the test program were conducted at Elevation 457 feet through three observation ports. Two InfraView® optical instruments, one placed on the north wall and the other on the south, measured gaseous temperatures in the front corner along the front wall of the boiler. A SpectraTemp® optical instrument was placed in the middle of the front wall, measuring gas temperatures down the boiler centerline. The method of operation for these devices is described in Appendix A. Figure 2-10 shows the instrument locations, Figure 2-11 shows a photo of the observation port used for the North InfraView®, and Figure 2-12 shows a photo of the SpectraTemp®.

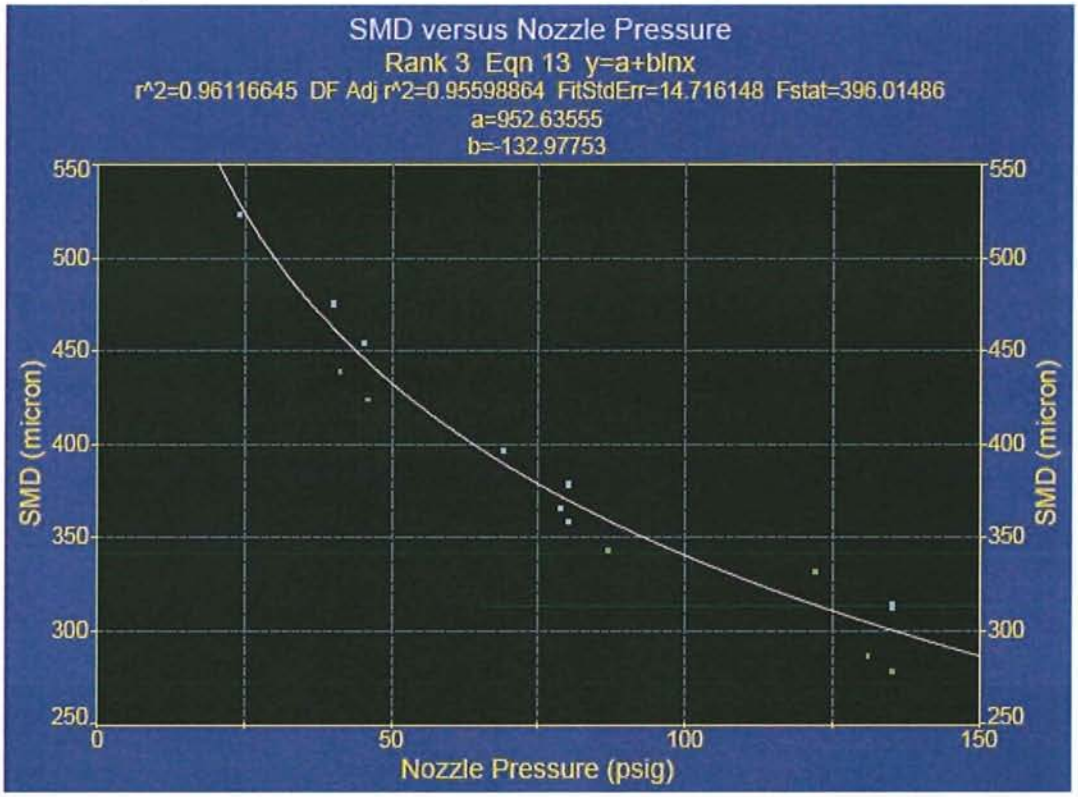


Figure 2-8
Droplet Size as a Function of Nozzle Pressure (Typical Pressure Atomizer)

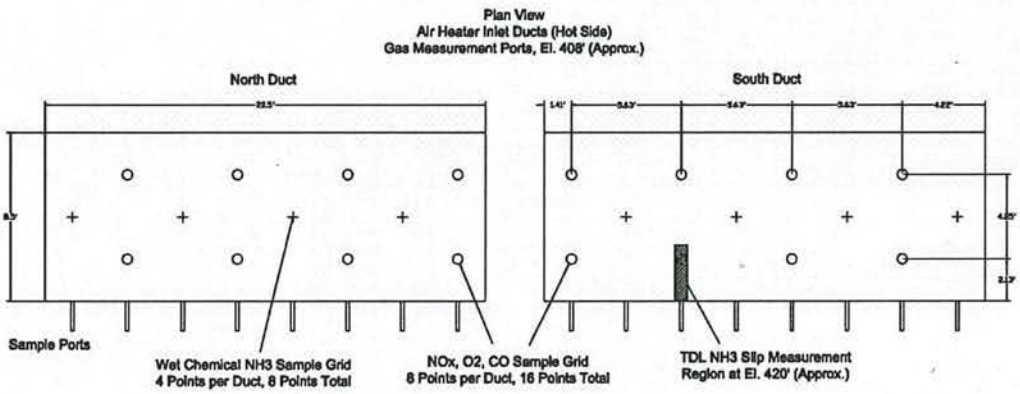


Figure 2-9
Air Heater Inlet Gaseous Probe Locations

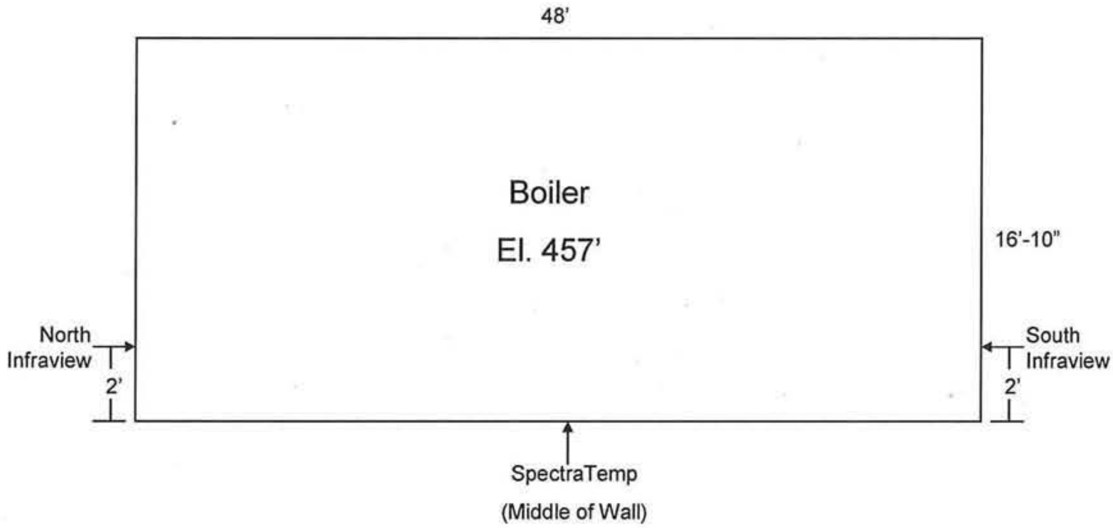


Figure 2-10
Temperature Measurement Locations

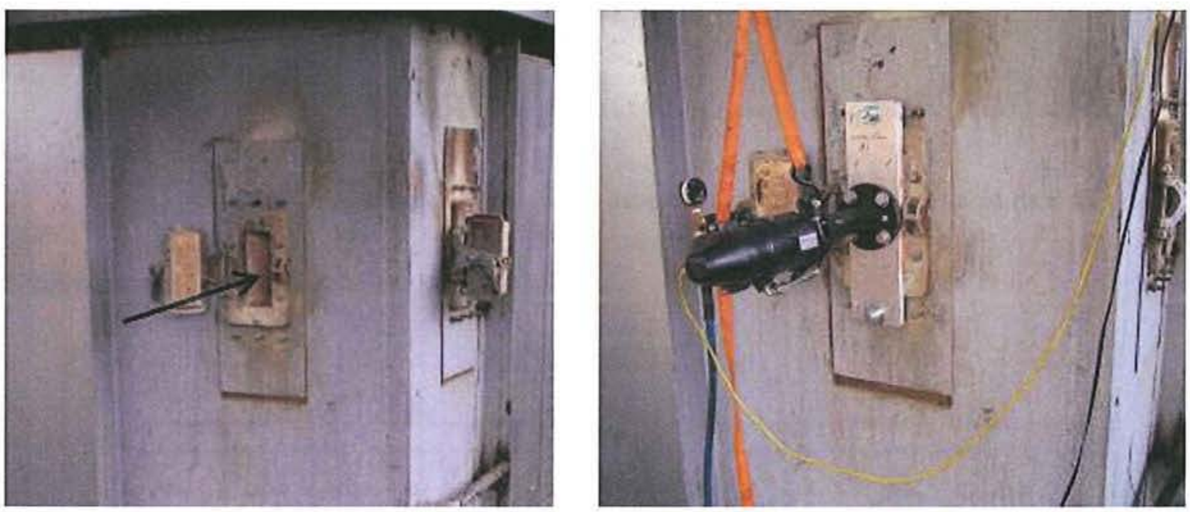


Figure 2-11
North Infraview® Observation Port

Figure 2-12
SpectraTemp® Observation Port

3
TEST RESULTS

Temperature Measurements

ICT performed furnace exit HVT measurements at Joppa Unit 3 on September 4, 2008. Table 3-1 provides a summary of the temperature data collected at Elevations 457 feet and 470 feet. Figure 3-1 shows contour plots of the temperature data. The average temperatures were on the high side of the urea temperature window. The temperature profile at Elevation 457 feet was at the nose of the boiler, showing a relatively uniform temperature distribution with the exception of the cold region in the southwest corner. At Elevation 470 feet, it is important to note that the temperature profile data was collected using the same ports for urea injection (angled downward at 30°). The cold region in the southwest corner was also evident in the 470 feet profile. Temperatures exceeded 2250°F (1,231°C) in the central region of the boiler.

Table 3-1
HVT Temperature Measurement Summary

Elevation	Minimum	Average	Maximum (°F)
457 feet	1,641°F (894°C)	2,095°F (1,146°C)	2,246°F (1,230°C)
470 feet	1,629 °F (887°C)	2,068°F (1,131°C)	2,293°F (1,256°C)

During the SNCR tests conducted in November 2008, continuous temperature measurements were made using InfraView® and SpectraTemp® optical instruments at Elevation 457 feet. Figure 3-2 shows a representation of the instrument locations, as well as their average readings compared to the HVT measurements made in September 2008. The values shown for the HVT measurements were averages of the data obtained at the same ports utilized by the optical instruments. The optical and HVT measurements show reasonable agreement, both indicating hotter temperatures in the middle of the furnace and lower temperatures in the southwest corner.

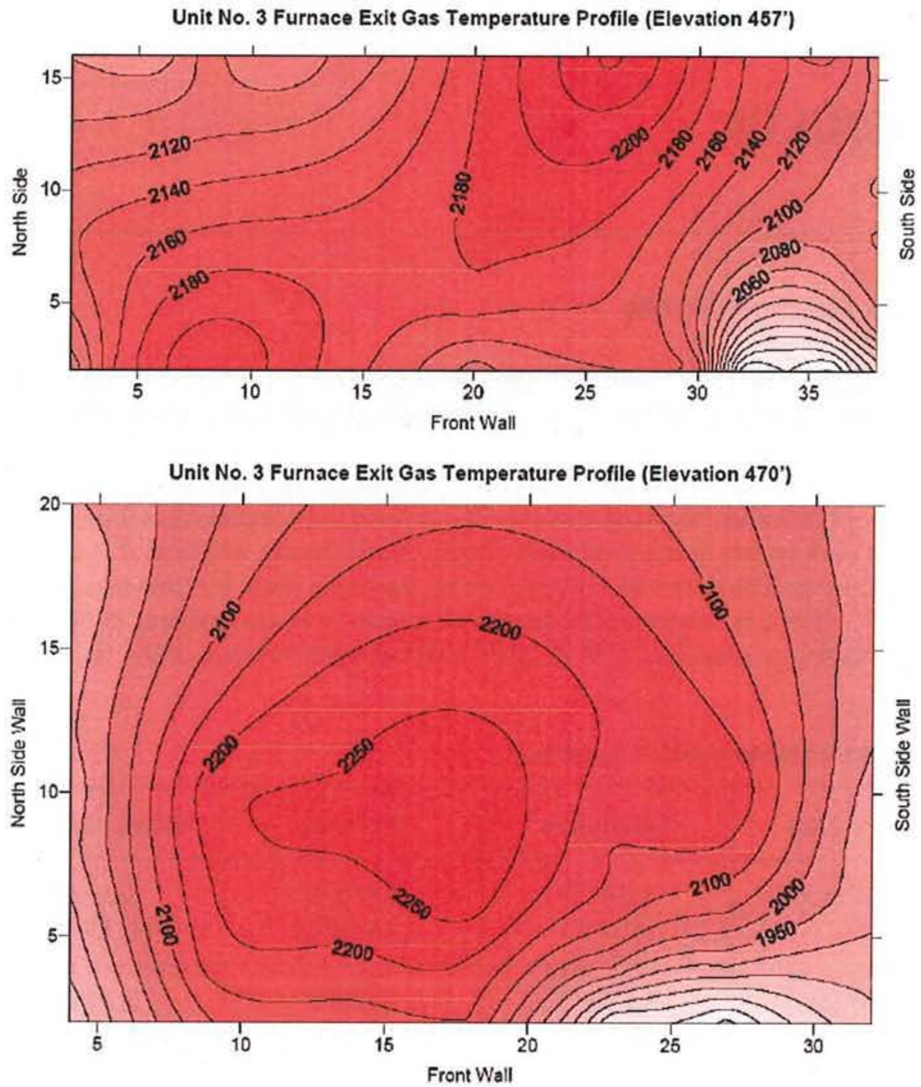
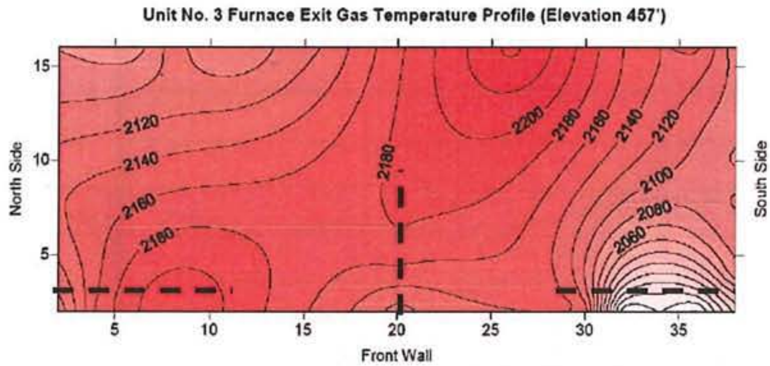


Figure 3-1
Full Load HVT Measurements (September 4, 2008)



North Infraview®

Line of Sight

Middle Spectratemp®

Line of Sight

South Infraview®

Line of Sight

Figure 3-2
Continuous Temperature Measurements Compared with HVT Temperature Measurements

Baseline NO_x Variations

Plant DCS data from November 14th and November 21st (the days just before and after the SNCR test program) were analyzed to evaluate typical baseline NO_x variations (i.e., "noise") during full-load with normal OFA operation. Figures 3-3 and 3-4 show the boiler NO_x (raw), O_2 and load for these two days. The NO_x standard deviation was nominally 1.8 ppm, or 2.8% of the average value. As a result, any NO_x variations during the SNCR test program within this range were considered to be within the normal range of variation.

SNCR Test Results

Urea injection tests were performed from November 15 through 20, 2008. A summary of NO_x reduction performance for each test day is provided in Figure 3-5. NO_x reduction was calculated in most cases by averaging the baseline NO_x values obtained before and after a urea injection test. During some tests the baseline value drifted or bumped significantly due to coal supply upsets. In these cases only the baseline value before the upset was used. Tabulated data with test descriptions, unit conditions, urea injection settings and gas concentrations are provided in Appendix B.

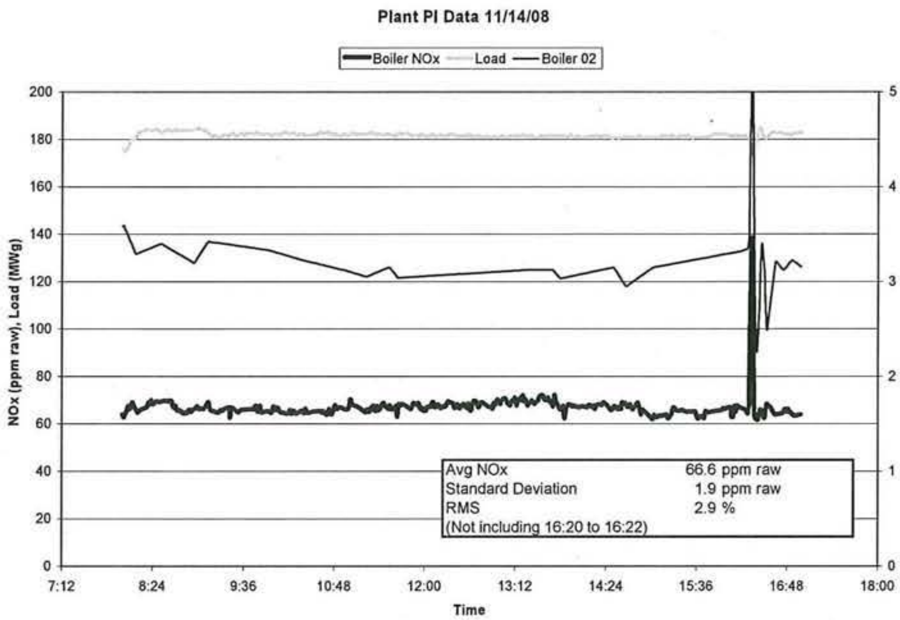


Figure 3-3
Plant Load, NO_x and O_2 Data from November 14, 2008

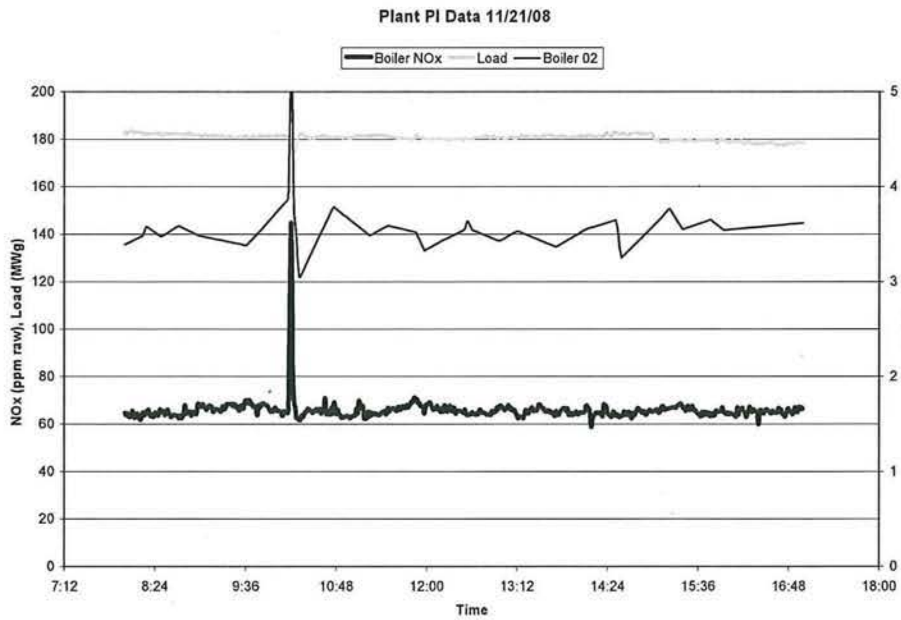


Figure 3-4
Plant Load, NO_x and O_2 Data from November 21, 2008

Gas profile plots for selected baseline and urea injection tests are provided in Appendix E. These plots include O_2, CO, NO_x and NO_x reduction profiles measured at the air heater inlet.

The following subsections will describe the day-to-day test conditions and results:

- Day 1 – Full load baseline tests
- Day 2 – Larger droplet and reduced load tests
- Day 3 – High and intermediate baseline NO_x tests with modified nozzles
- Day 4 – Higher capacity nozzle tests
- Day 5 – High baseline NO_x tests with higher capacity nozzles
- Day 6 – Extended optimum SNCR configuration tests

Day 1 (11-15-08)

The first day of testing was done at full load and normal OFA conditions. Normal OFA conditions were defined by the positioning of the OFA, auxiliary air, and fuel air dampers before testing began:

- CCOFA dampers closed
- SOFA dampers at ~ 20%, 94% and 94% open
- Aux Air damper AAS at ~ 83% open, ABS-DES holding fairly steady at 20% open
- Fuel Air dampers at 35% - 49% open on average

The baseline NO_x level was measured at 74 ppmc with an O_2 level of 3.9%. Testing was completed using the 15-055 and 25-08 nozzles. The Spraying Systems nozzle number references the fan spray angle and the flow capacity in gallons per minute at 40 psig (2.7 atmospheres) nozzle pressure. The first test utilized all eight injectors, but was not effective, so it was decided to remove the outside injectors to eliminate any possible wall impingement. Six injectors were utilized with both the 15-055 nozzles as well as the 25-08 nozzles. Pressure was varied from 10 psig to 80 psig, which varied the urea concentration from 20% to 5% respectively, due to the different dilution water flow rates. The NSR of urea to NO_x was maintained at 1.5 for each test with constant urea flow.

Figure 3-6 shows select unit data for the day, along with shaded bars representing test times and arrows designating when urea was turned on or off. The full gray bars are injection tests, while the hashed bars are baseline tests. NO_x removals were less than 5% for all tests. The highest capacity injectors achieved limited NO_x reductions, and a higher atomization pressure actually produced higher NO_x levels. This was likely the result of the furnace exit gas temperature being on the higher side of the SNCR temperature window. If SNCR performance was to be improved, higher capacity nozzles would be needed to produce a more dilute urea solution, as well as a larger drop size distribution. Low load testing during Day 2 was used to confirm this assessment.

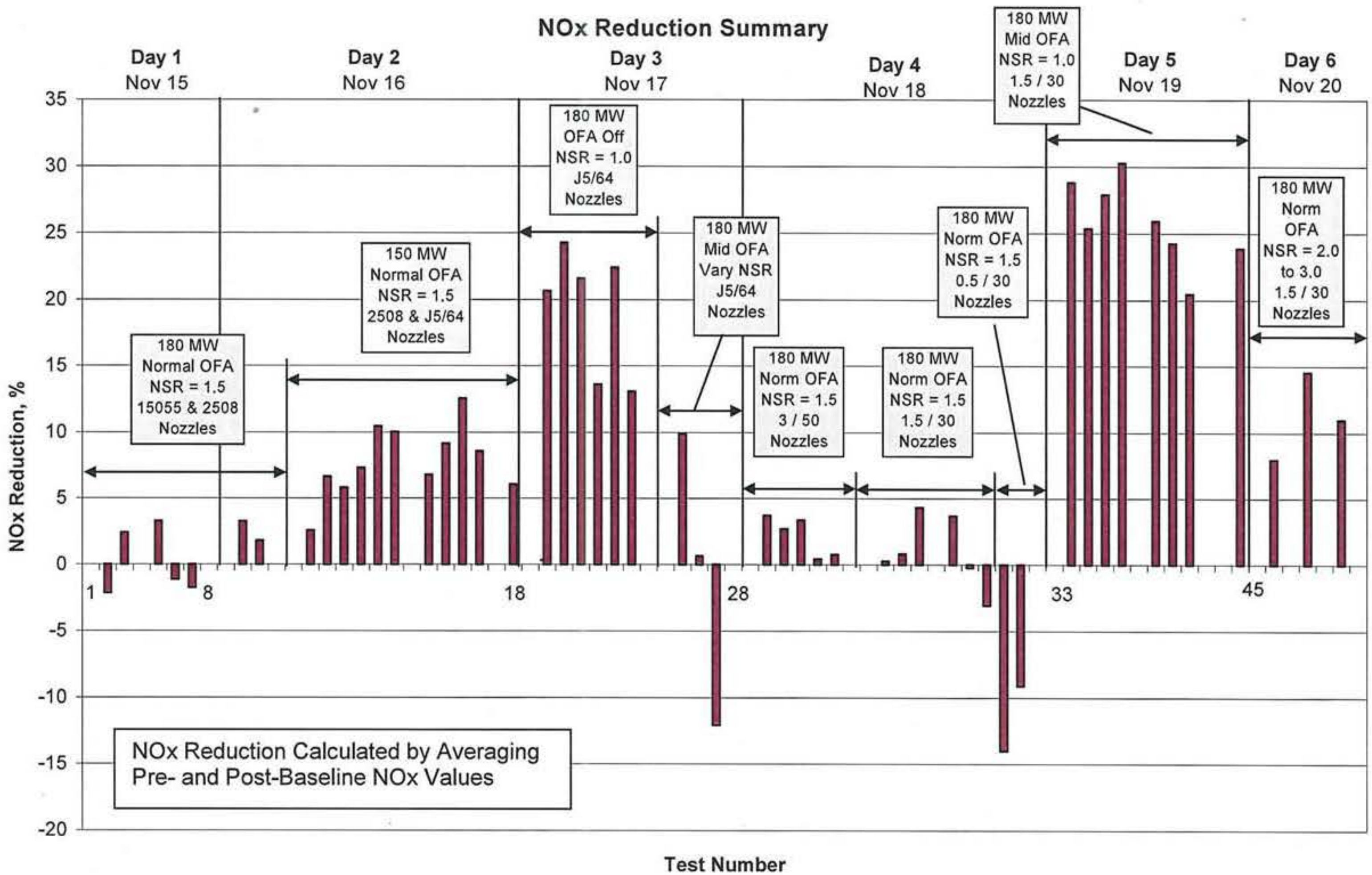


Figure 3-5
Overall Summary of NO_x Reduction Performance

Confidential Business Information

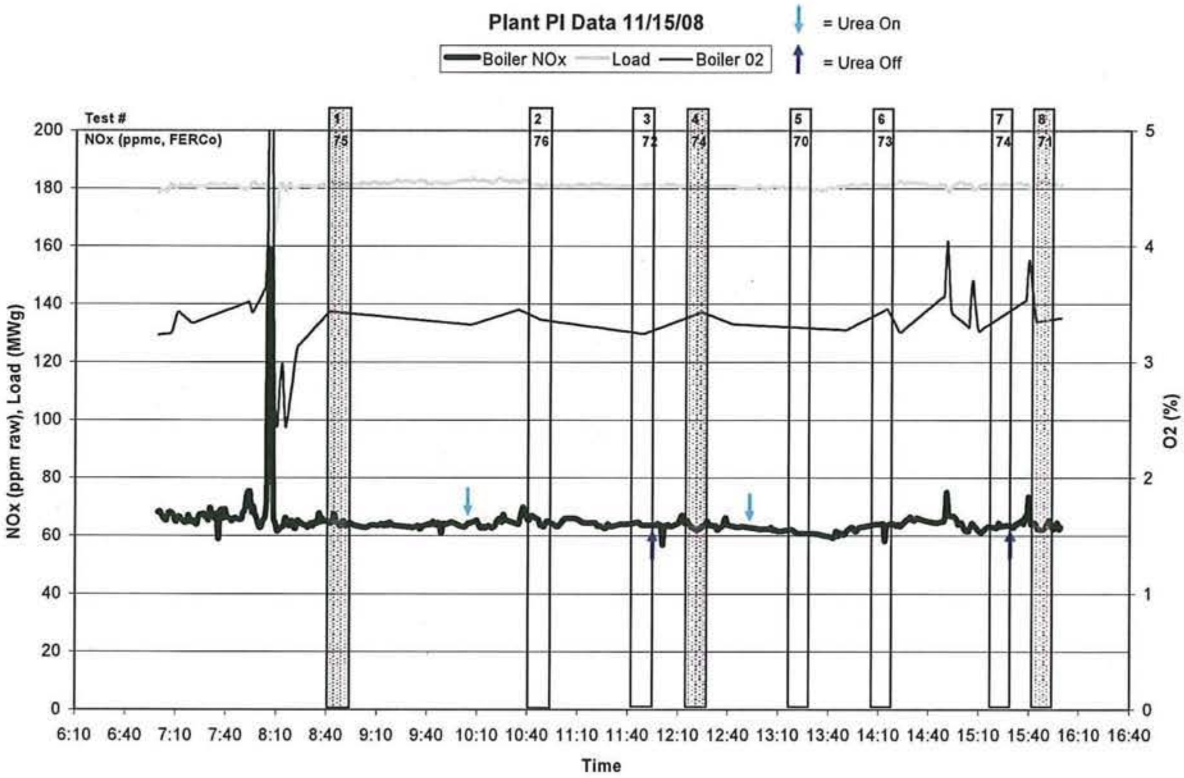


Figure 3-6
Day 1 Unit Load, NO_x, and O_2 Data with Test Numbers and Times

Day 2 (11-16-08)

On the second day of testing, several tests were initially performed at full load to verify the results from Day 1. The middle six injectors were utilized with 25-08 nozzles at low atomization pressures to produce a large droplet size. NO_x removal was again less than 5% at an NSR of 1.5, and the TDL ammonia monitor showed NH_3 slip less than 10 ppm. Both of these results suggest droplet time-temperature profiles that are inoptimum and on the hot side of the SNCR process temperature window.

The load was then reduced to 150 MWg with all mills in service while keeping normal OFA conditions (see Figure 3-7). Baseline NO_x was measured at 65 ppmc, while O_2 levels remained at 3.9%. The nozzle configuration was kept the same, while nozzle pressure was varied from 15 psig to 40 psig (2.7 atmospheres). NO_x removals were 5 to 10 % at an NSR of 1.5, with higher removals at the lowest nozzle pressure, as can be seen in Figure 3-8.

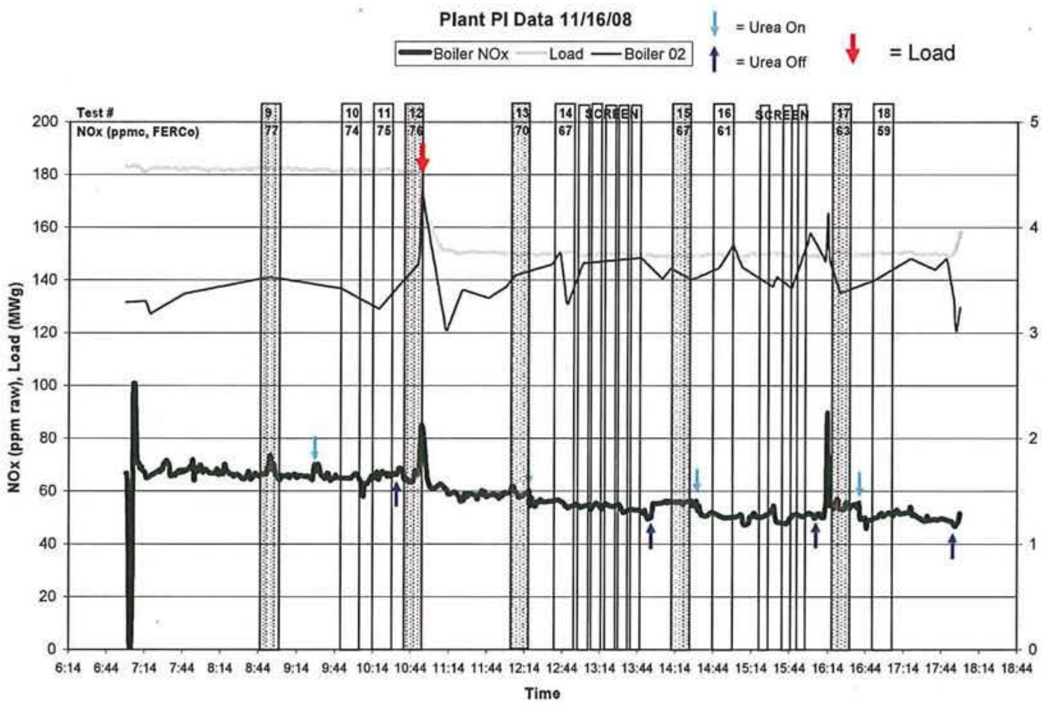


Figure 3-7
Day 2 Unit Load, NO_x, and O_2 Data with Test Numbers and Times

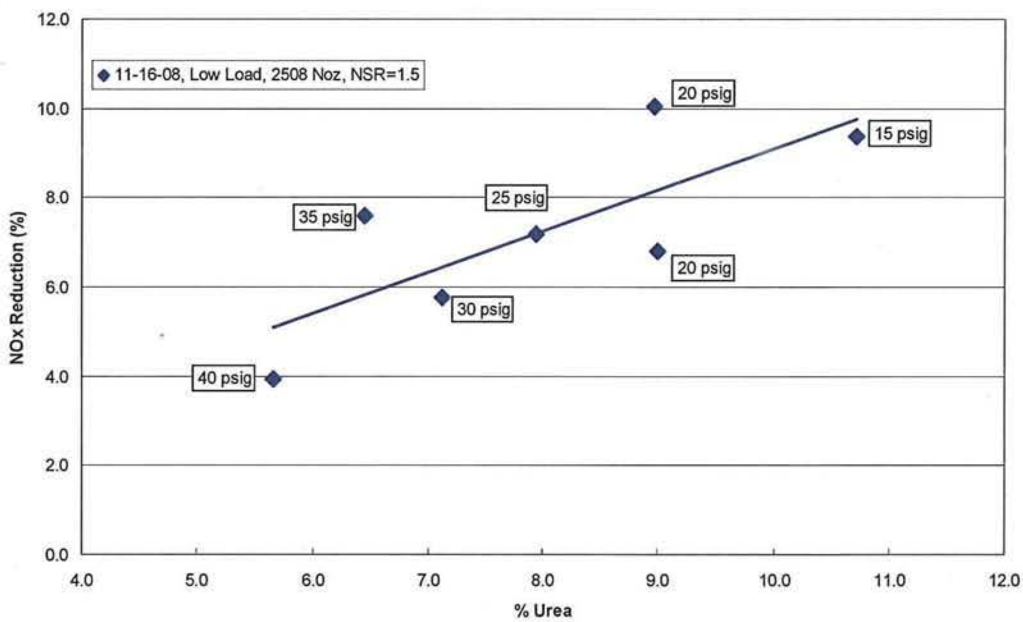


Figure 3-8
Reduced Load Test Results with Varying Nozzle Pressure

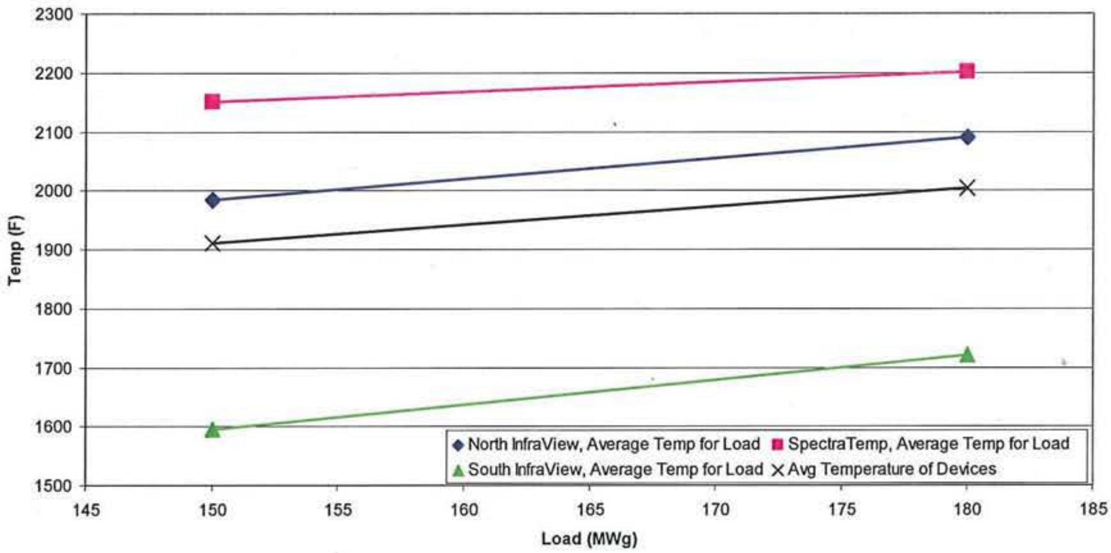


Figure 3-9
Average Upper Furnace Gas Temperature as a Function of Load Change

The improved SNCR performance was attributed to the lower temperatures (90°F (32°C) drop, as shown in Figure 3-9) and increased residence time at reduced load. This result suggested that larger drop sizes and/or more dilute urea solution would be beneficial. Larger capacity nozzles were ordered, but would not be available until Day 4. In the interim, plant personnel modified some of the existing nozzles by enlarging the holes to 5/64 inch. These nozzles provided higher capacity, but generated inconsistent flows and spray angles. With these nozzles placed on the middle six injectors, NO_x removal was 6 to 13% at an NSR of 1.5. Ammonia slip (wet chemical method) was measured at 10 ppm for a composite sample across the south duct.

Day 3 (11-17-08)

In order to assess the potential impact of the low baseline NO_x levels on SNCR performance, Day 3 testing was performed at full load with a high baseline NO_x condition. With the CCOFA and SOFA dampers closed, the baseline NO_x level was measured at nominally 190 ppmc, with excess O_2 levels around 3.5%. The six middle injectors were utilized, with the 5/64 inch modified nozzles. Nozzle pressure was varied from 20 psig to 30 psig, and NSR was varied from 0.5 to 1.4. NO_x removal for these conditions ranged from 13 to 24%, while wet chemical ammonia measurements showed slip levels below 10 ppm.

SOFA dampers were then opened slightly to provide a full-load, intermediate baseline NO_x condition (see Figure 3-10). Under this condition baseline NO_x was 95 ppmc. Again, the middle six injectors were utilized with the modified 5/64 inch nozzles, and NSR varied from 0.5 to 1.5. Measured NO_x removals ranged from -12% to 10%, with wet chemical NH_3 slip less than 10 ppm.

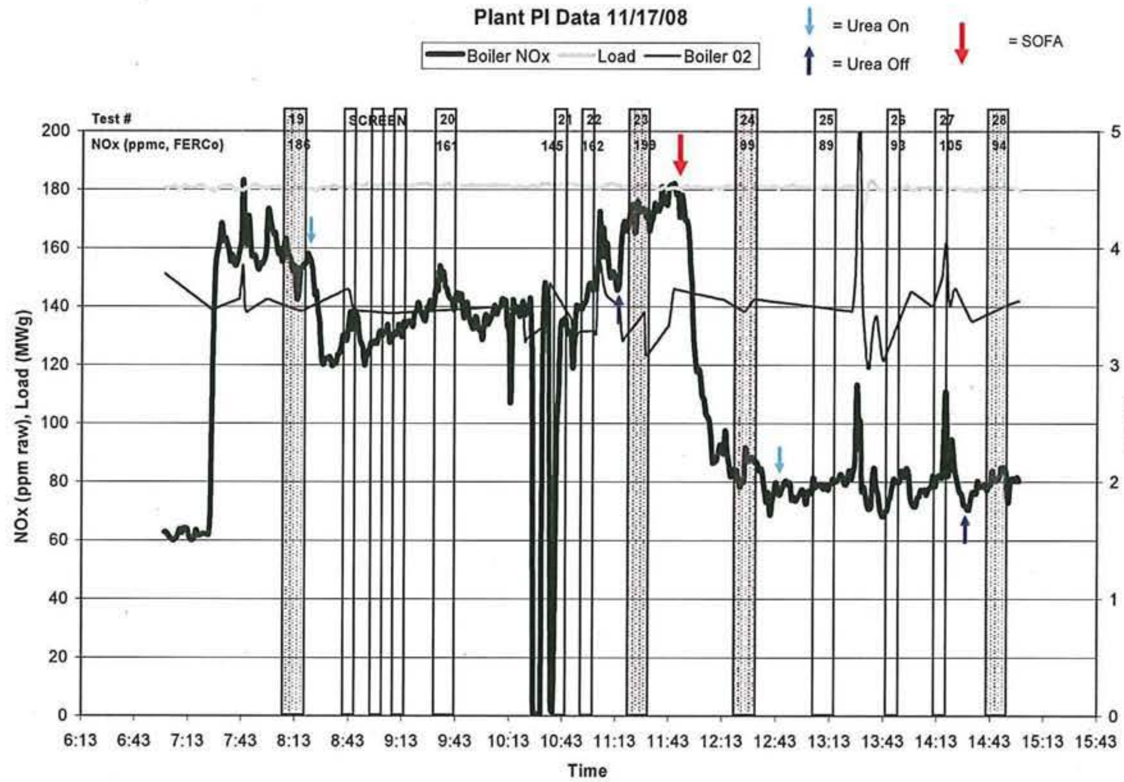


Figure 3-10
Day 3 Unit Load, NO_x, and O_2 Data with Test Numbers and Times

These tests demonstrated typical SNCR NO_x reduction capabilities on the order of 25% at the higher baseline NO_x levels. Contour plots consistently showed better removals on the south side of the boiler (see Appendix E). This could be attributable to either the cooler flue gas temperatures present, or due to inconsistent nozzle performance. The results also demonstrated that reducing the NO_x baseline yields diminished SNCR performance.

Day 4 (11-18-08)

Day 4 testing was performed at full load and normal OFA conditions (Figure 3-11). It was noted that aux air damper positions ABS-DES were more variable, floating between 15 to 20% open. Baseline NO_x levels were 70 ppmc, and O_2 levels remained fairly steady at 3.9%. The higher capacity nozzles had arrived earlier in the day and tests were performed using two different sets (3 gpm (11.4 lpm)/50° fan and 1.5 gpm (5.7 lpm)/30° fan). A smaller third set was also tested (0.5 gpm (1.9 lpm)/30° fan).

Nozzle pressure was varied between 10 psig to 40 psig, which varied the urea solution concentration from 28 to 3%, depending on the nozzle flow capacity curve. Nozzle orientation was also varied (vertical fan spray vs. horizontal fan spray), which exhibited no impact. NO_x

removals for all tests were less than 5% at an NSR of 1.5, with ammonia slip levels using a tunable diode laser monitor measured below 10 ppm.

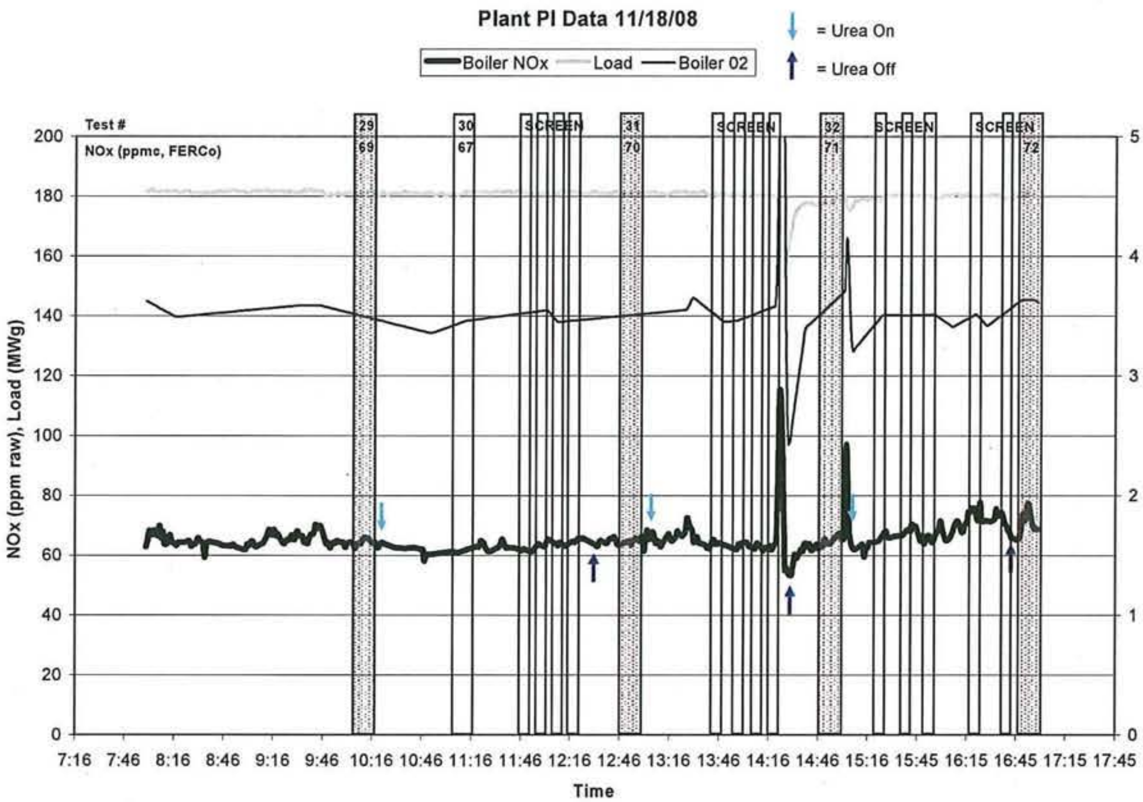


Figure 3-11
Day 4 Unit Load, NO_x, and O_2 Data with Test Numbers and Times

Tests with the higher capacity nozzles yielded NO_x removals of less than 5%. The smaller 0.5 gpm nozzles actually increased NO_x, which could be attributed to the smaller droplets and faster evaporation under unfavorable flue gas temperatures. It was decided to do more testing at higher baseline NO_x levels to determine an optimized set-up, and to test the effect of varying the CO level.

Day 5 (11-19-08)

Day 5 testing was done at full load at an intermediate OFA condition, which provided a baseline NO_x of 155 ppmc, and a 3.8% O_2 level (see Figure 3-12). The auxiliary air dampers ABS-DES were not steady, ranging from 40 to 85% open. As a result, the baseline NO_x varied continuously throughout the day, diminishing the consistency of the results. During this series of tests all eight reagent injectors were utilized, with the outside injectors using the smaller 25-08 nozzles (aligned vertically to avoid wall impingement), and 1.5 gpm (5.7 lpm)/30° fan nozzles for the middle six injectors.

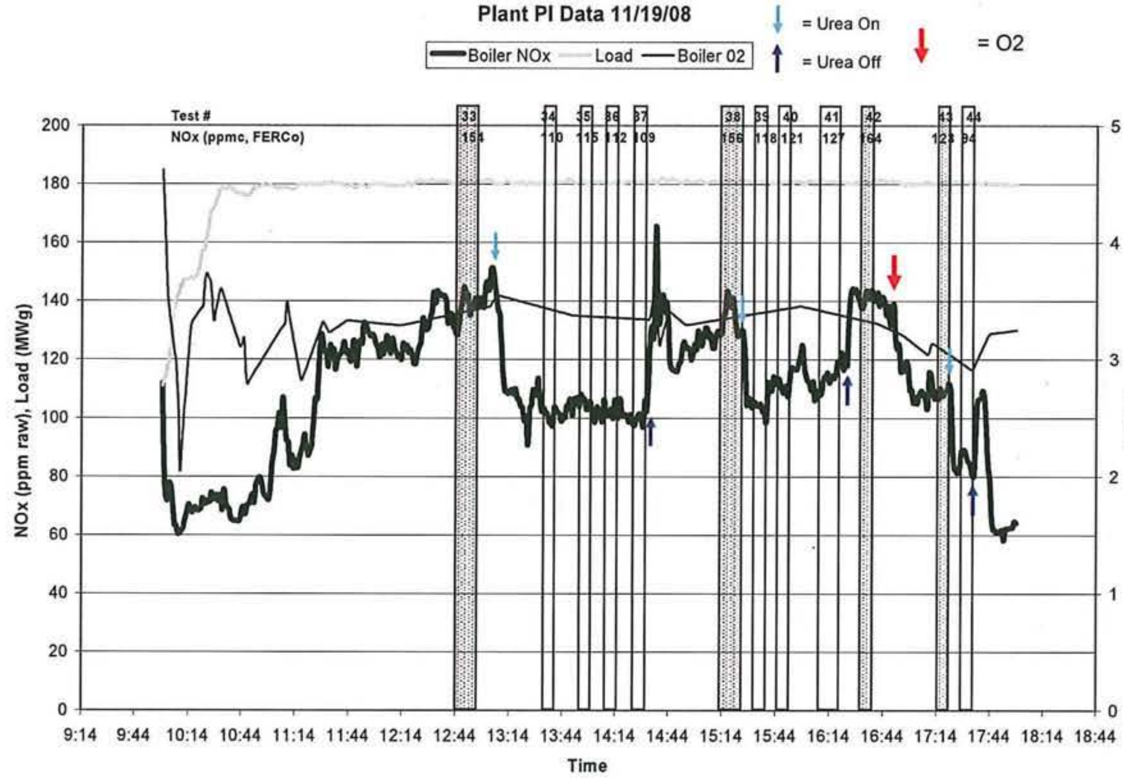


Figure 3-12
Day 5 Unit Load, NO_x, and O_2 Data with Test Numbers and Times

Nozzle pressure was varied from 20 psig (1.4 atmospheres) to 35 psig (2.4 atmospheres), while keeping the NSR constant at 1.0. Injector biasing was also tested by shutting off flow to individual lances, but this had little impact. NO_x removals ranged from 25 to 30%, while ammonia slip levels measured with the ammonia monitor on the south duct were below 10 ppm.

Excess O_2 was then lowered to increase CO levels. Baseline gaseous values for this condition were 123 ppmc for NO_x, and 3.4% O_2. The baseline CO level, as measured at the economizer outlet, was increased from 60 ppm to 400 ppm. Utilizing the same injection configuration at an NSR of 1.2 resulted in 24% NO_x removal, with ammonia slip values below 5 ppm.

Increasing the NO_x baseline and utilizing higher capacity nozzles yielded SNCR performance at the upper ranges (25-30%), with a slight trend of increasing removals with larger drop sizes. The increase in CO did not appear to significantly impact SNCR performance (Figure 3-13), with differences in NO_x reduction performance with the overall range in variability.

In sum, SNCR results demonstrated that typical SNCR NO_x reductions were achievable at higher baseline NO_x levels (e.g., greater than 120 ppm). Thus, results obtained at low baseline NO_x levels were not constrained by the reagent injectors or injector configuration that was implemented.

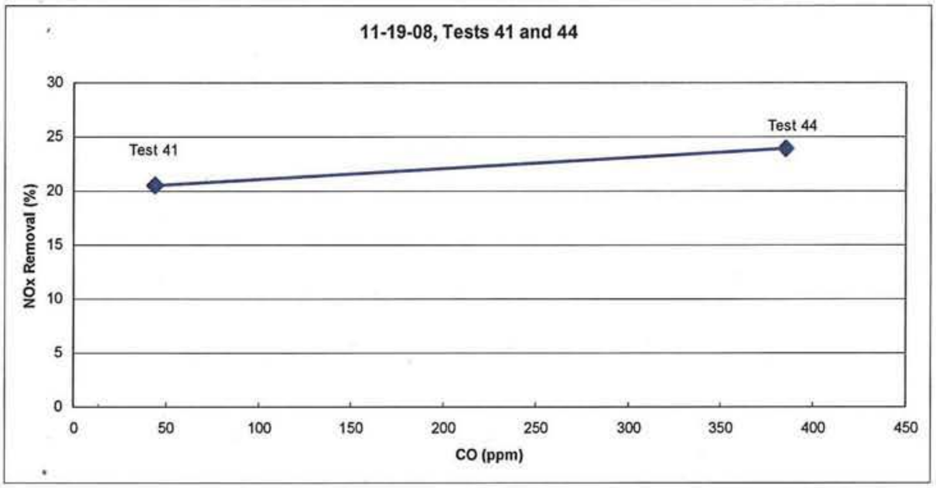


Figure 3-13
Effect of CO Level on SNCR Performance

Day 6 (11-20-08)

Day 6 testing was performed at full load and normal OFA conditions (see Figure 3-14). The dampers for auxiliary air ABS-DES were unsteady, ranging from 18 to 35%. Throughout the day the unit was experiencing mill problems, which lead to inconsistent baseline readings. Baseline NO_x values ranged from 74 to 88 ppmc, while O_2 levels were relatively consistent at 3.9 to 4.1%. These tests were designed to provide an extended operational performance assessment with the same injection configuration as Day 5.

Tests were run at NSR values of 2.0, 2.5, and 3.0, which gave NO_x removals of 8%, 11% and 14%, respectively. Again, movement of the NO_x baseline affected the calculated percent NO_x reduction removal results. Wet chemical ammonia slip values from this day varied from 19 to 24 ppm, while ammonia monitor slip values ranged from 8 to 19 ppm. The ammonia slip ppm levels during these tests were greater than the reduced NO_x levels.

During the final Day 6 test (NSR = 2.5), plant personnel collected a fly ash sample using a CEGRIT Sampler at the ESP inlet. Fly ash baseline samples were also collected prior to the test program on November 5 and 11. Analysis of the baseline samples showed nominally 5 ppm ammonia on the ash (weight basis). Analysis of the Day 6 sample showed 9 ppm ammonia (weight basis). This result indicates very little ammonia adsorption on the ash, possibly the result of the high alkalinity of the PRB ash.

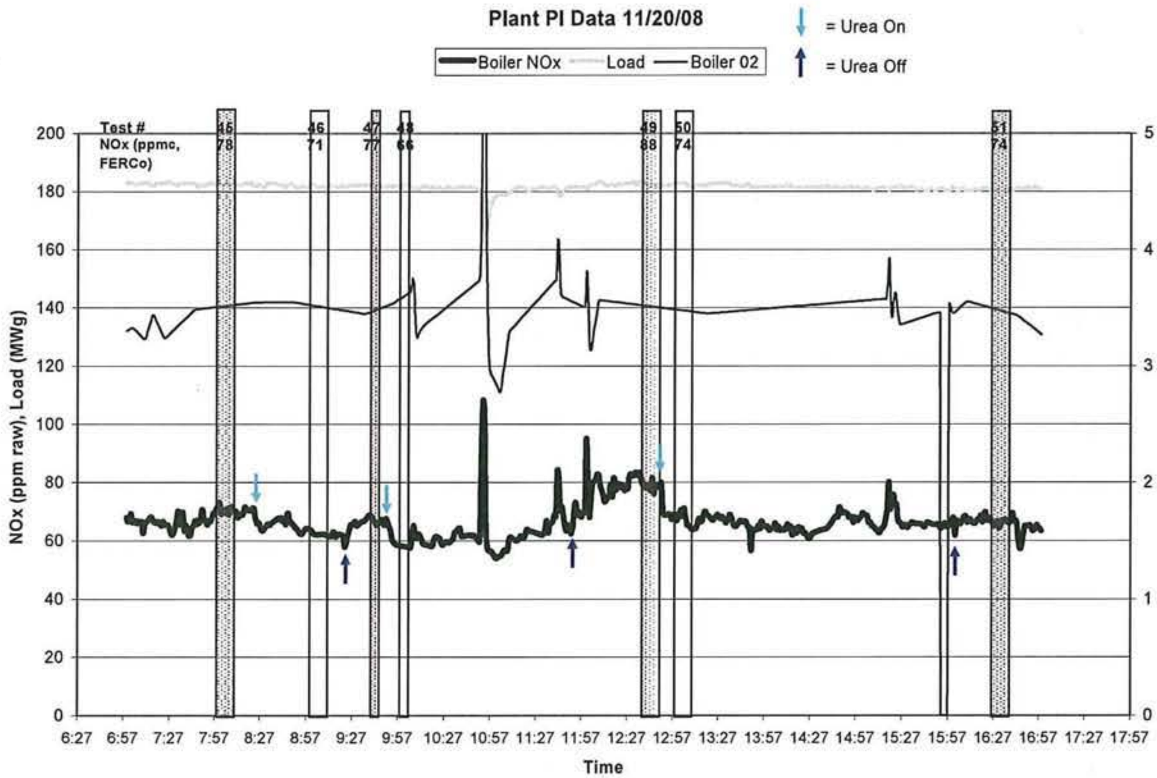


Figure 3-14
Day 6 Unit Load, NO_x, and O_2 Data with Test Numbers and Times

Higher NSR values improved NO_x reduction but also lead to higher NH_3 slip values. Although the baseline NO_x was inconsistent, SNCR reductions showed 8 to 15% reduction over the range of NSRs from 2.0 to 3.0. Further SNCR optimization may be possible, but improvement would likely only be second order at these low baseline NO_x levels. Estimates of optimized NO_x reduction at slip levels below 10 ppm would be 8 to 12%.

Baseline NO_x Level Impacts

Lower baseline NO_x levels limited SNCR performance during the test program. This is illustrated Figure 3-14 using all of the data at full load. Figure 3-15 isolates data for a specific nozzle type (1.5 gpm (5.7 lpm)/30°).

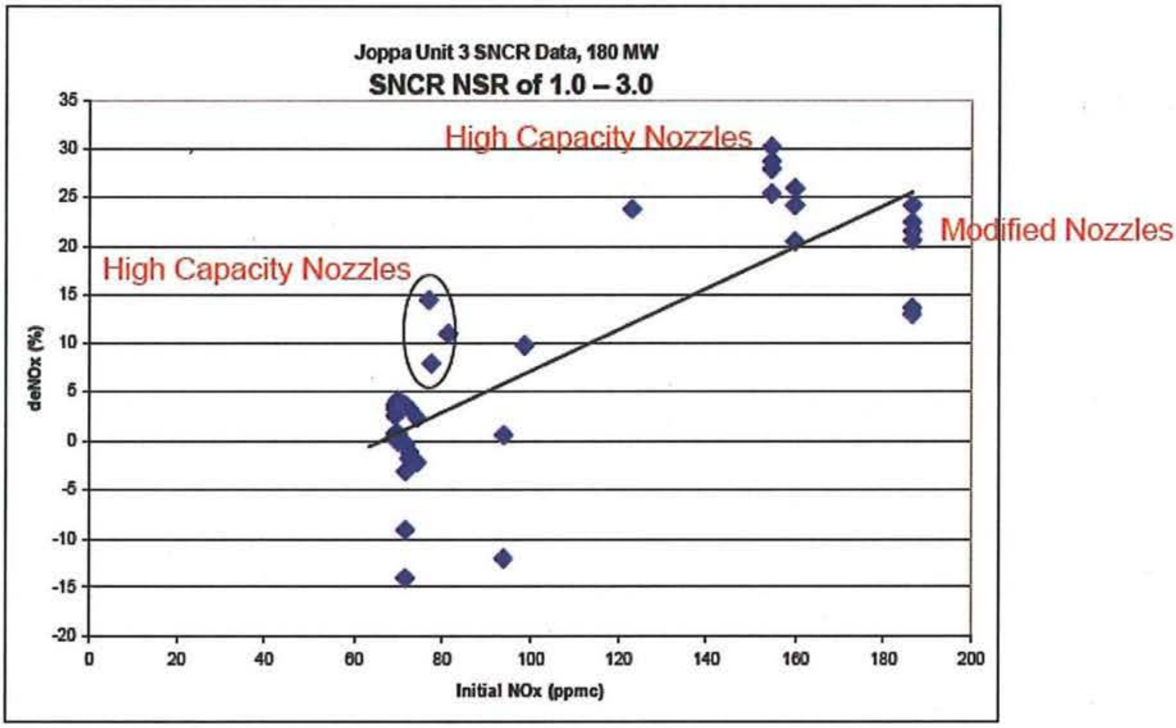


Figure 3-15
Full Load NO_x Reduction Plotted with Initial NO_x

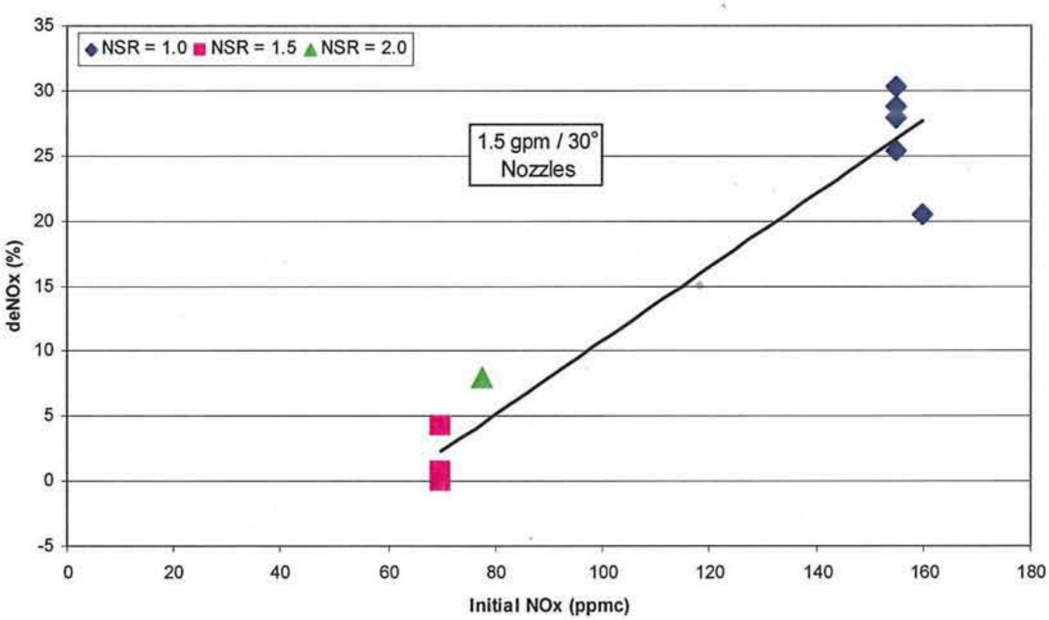


Figure 3-16
Full Load NO_x Reduction Plotted with Initial NO_x (1.5 gpm/ 30º Nozzles)

4
ECONOMIC ASSESSMENT

In order to assess the cost effectiveness of a SNCR system applied to a low baseline NO_x unit, a capital cost estimate was generated from a previously described approach (1004727, December 2004) and reproduced in Table 4-1. The approach estimates a capital cost of nominally \$2.5 million, which yields an annualized levelized cost of \$436,000 with a capital cost recovery factor of 17.5%. On a relative basis, SNCR is a variable cost oriented technology, with the urea solution being the principle variable cost component. For a 180 MW unit with a baseline NO_x level of 0.115 lb/MBtu, the hourly consumption of 50% urea solution at an average NSR of 1.2 is less than 0.6 gpm (2.3 lpm). Assuming an 80% capacity factor, and a delivered 50% urea reagent cost of \$1.40 per gallon, annual reagent costs are on the order \$334,000. As shown in Table 4-2, with an average SNCR performance of 10% NO_x reductions, nominally 73 tons of NO_x would be reduced each year. With annualized capital costs of \$436,000 and reagent costs of \$334,000 for a total of \$770,000, the cost effectiveness per ton of NO_x removed is \$10,620. The variable operating cost for 50% urea reagent alone is \$4,600 per ton NO_x removed. Increasing the NO_x reduction performance to 15% would reduce the overall cost effectiveness to \$7,080 per ton NO_x removed with operating costs for urea reagent being reduced to \$3,070 per ton NO_x removed due to the increased reagent utilization.

Table 4-1
SNCR Capital Cost Estimate

SNCR Trim Capital Cost Estimate

			SNCR
Boiler Capacity (MW)			180
Boiler Width (ft)			40
Baseline NOx (lb/MBtu)			0.115
HVT Testing / Modeling			$80,000
Startup & Testing			$150,000
Storage Requirements (30 days)		24,517 gallons	
Storage Requirements (14 days)		11,441 gallons	
Reagent Storage			$200,000
Injection System		#Inj	
	MNL Lances	0	$0
	Upper Level Inj	8	$330,000
	Mid Level Inj	0	
	Lower Level Inj w/Retracts	0	
Compressors			$200,000
Continuous Ammonia Monitor (4 path)		2	$175,000
Continuous FEGT Monitor		6	$100,000
Installation			$438,000
Total Process Capital (TPC)			$1,673,000
Taxes		6%	$100,380
Engineering & Procurement		10%	$167,300
Field Supervision & Indirects		8%	$133,840
Project Contingency		10%	$167,300
Vendor Markups		15%	$250,950
Total Estimated Capital			$2,492,770
$/kW			13.85

Table 4-2
Low Baseline NO_x Cost Effectiveness

Unit Capacity	180	
Capacity Factor	80%	
Baseline Nox (lb/Mbtu)	0.115	0.104
Heat Input (Mbtu/hr)	1,800	
NOx Removal		10%
Tons NOx Removed		
Annual (tons Nox)	725	73
Capital Cost Recovery Factor	17.5%	
Capital Cost		$2,492,770
Annual Levelized Capital Cost		$436,235
Urea Reagent Cost		$334,088
Annual Cost Estimate		$770,323
Annual SNCR Levelized Costs	$/ton NOx	$10,620
Urea Operating Costs	$/ton NOx	$4,606
Urea Cost ($gal)	$ 1.40	

It should be noted that there are a number of factors that would impact the cost estimates generated herein. Among these factors is the scope of the retrofit, process control system implemented, and the cost of urea solution, which is proportional to the price of its natural gas feedstock. However, the cost estimates do place into context the elevated cost per ton NO_x removed. This elevated cost is attributable to both the low baseline NO_x levels, and relatively low number of tons NO_x removed on an annual basis, as well as the reduced SNCR operational efficiencies at low NO_x levels.

5 CONCLUSIONS

While several SNCR demonstrations have been conducted through EPRI over the previous decade to document the achievable NO_x reduction performance with a single level of reagent injectors, they have all been performed on units with full load baseline NO_x levels ranging between 0.17 lb/MBtu – 0.35 lb/MBtu. As each demonstration used existing boiler access, typically provided by observation doors, there was a range of injector spacing used at each demonstration site. Figure 5-1 provides a first level assessment of the impact of injector spacing and unit size on SNCR NO_x reduction performance. As noted in Figure 5-1, each of these demonstration projects achieved short term SNCR NO_x reduction performance between 20-30%. Injector spacing appears to have a first order impact on SNCR performance while unit capacity appeared to exhibit a lesser impact on SNCR performance that was more pronounced for units greater than 500 MW in capacity.

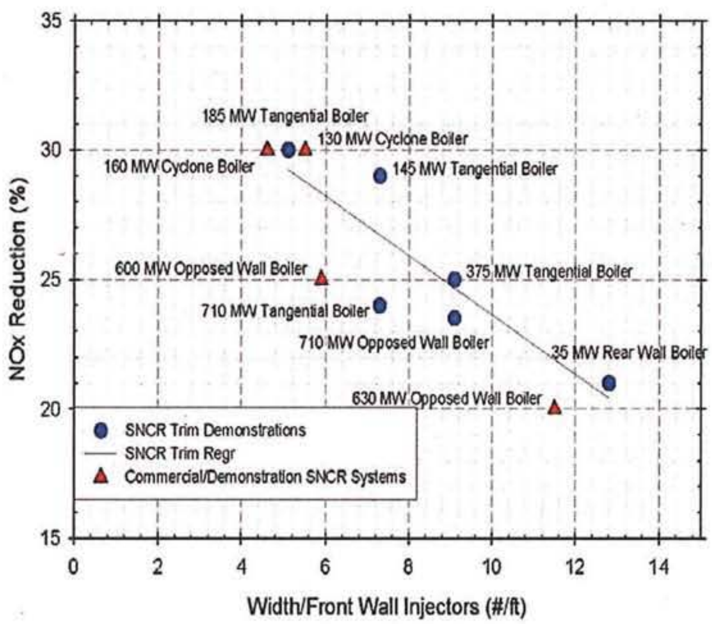


Figure 5-1
Full Load SNCR Trim Demonstration Performance at NSR = 1 and Baseline NO_x Levels Greater Than 0.15 lb/MBtu

As shown in Figure 1-4, however, CFD modeling has shown that SNCR performance can degrade significantly at baseline NO_x levels of 100 ppm and below. While the current project only required modest NO_x reductions from SNCR, it was not known what actual level of SNCR performance might be anticipated. Toward this end, a comprehensive program was conducted at Joppa Unit 3 to evaluate SNCR performance at baseline NO_x levels of nominally 0.10 lb/MBtu (70 ppm) using a single-level, urea-based SNCR system. The project included O_2, CO, NO_x and ammonia slip measurements at the air heater inlet, and temperature measurements at the furnace exit. Testing was performed at loads ranging from 150 to 180 MWg over a six-day period. Several parameters were varied, including NSR, atomizer type, baseline NO_x levels, and baseline CO levels.

While initial assessments of furnace exit gas temperatures (FEGT) suggested smaller drops might be required to minimize ammonia slip levels, the limited heat transfer surface area in the upper furnace actually necessitated larger droplets and a more dilute urea solution. With reagent injectors along the front wall, injected urea droplets needed to traverse the boiler depth prior to reaching the convective pass entrance where the flue gas was begun to be cooled down toward the SNCR process temperature of 1,850ºF (1,010ºC). As a result, droplets generated from the injectors had insufficient residence time prior to their evaporation and yielded minimal NO_x reduction levels (i.e., <5%). While larger capacity nozzles were ordered, reduced load testing on the second day supported these preliminary conclusions. Lower FEGT and increased residence times at comparable baseline NO_x levels yielded improved SNCR NO_x reduction performance that ranged between 5 – 10%, depending upon the injection conditions. Nozzles modified to provide larger droplets and flow rate increased the overall SNCR NO_x reduction performance between 8 – 12% at a NSR of 1.5 while maintaining ammonia slip levels as measured on the south duct at 10 ppm. A plot of the NO_x reduction performance as a function of atomization pressure (Figure 3-8) demonstrated the effect of evaporation rate, with larger droplets (lower atomization pressure) yielding higher NO_x reduction levels.

As overall SNCR NO_x reduction performance at this stage of the demonstration project was less than 15%, however, there were questions regarding the impact of the baseline NO_x level as well as the reagent injection location and resultant mixing and reagent release. To address this important question, tests on the third day destaged the unit to create a higher baseline NO_x level that was on the order of 190 ppm. While using modified injectors which created distribution gradients within the boiler, overall NO_x reduction levels improved to 20 – 24%. These results suggested that the reagent injection location was not constraining the overall SNCR performance, and that the low baseline NO_x levels represented a significant factor that was potentially limiting SNCR performance.

These results were supported further on the fifth day of testing when larger capacity commercial pressure atomizers were tested at increased baseline NO_x levels of around 155 ppm. These tests yielded a range of NO_x reduction performance between 25 – 30% at a NSR of 1.0. Further tests that altered the excess oxygen level in order to reduce CO levels, indicated a limited effect by CO on observed SNCR performance.

To minimize the impact of reducing both the NO_x and urea within the boiler by keeping a constant NSR, tests on the sixth day set up the boiler with a typical baseline NO_x level that ranged from 74 – 88 ppm over the course of the day. Instead of maintaining a NSR of 1.0, the same amount of urea was injected into the boiler as on Day 5 so as to minimize any mixing impacts on SNCR performance (e.g. similar urea distribution/concentrations across the flue gas). Overall NO_x reduction levels, however, were diminished to levels just under 10%. Increasing the

NSR further to values of 2.5 and 3.0 increased the SNCR NO_x reduction performance to 11% and 14% respectively, but ammonia slip levels also increased to levels on the order of 20 ppm.

In sum, SNCR performance appears to be significantly degraded at baseline NO_x emission levels less than 100 ppm. The increased ammonia slip levels experienced during the testing on Day 6 indicates that there was reagent present at the optimum SNCR temperature window. The overall performance is likely constrained due to imperfect mixing that is achieved within the boiler with the low energy reagent injectors. As the NSR was increased from 2.0 – 3.0 on Day 6, the overall NO_x reduction performance also increased (Table 5-1). The increased NO_x reductions with increasing urea flow rate is supportive of the overall SNCR results at Joppa 3 being mixing constrained at low baseline NO_x levels. While the results on Day 6 experienced unacceptable ammonia slip values between 15 – 20 ppm, air atomized injectors may provide finer droplet size distribution 'tuning capability' at a constant liquid flow rate than that achievable with the mechanically atomized injectors used during this project. Overall SNCR performance capabilities at baseline NO_x emission levels of 75 ppm, however, will likely be constrained within a NOx reduction range of 8 – 12%. It should be noted that at the baseline NOx levels cited, this range in SNCR performance represents a difference of 3 ppmv.

Table 5-1
SNCR NOx Reduction Performance on Day 6 as a Function of NSR

NSR	ΔNO_x
2.0	8.0%
2.8	11.0%
3.0	14.5%

A
PARAMETRIC TEST METHODS

Continuous Gas Monitoring

Gaseous species concentrations of NO, CO, O_2, and CO_2 were measured using an extractive continuous emissions monitoring (CEM) package contained in a mobile emissions laboratory. A schematic of the sample handling system is presented in Figure A-1. The system is comprised of three basic subsystems, including: 1) sample acquisition and conditioning system, 2) calibration gas system, and 3) analyzers. Each of these subsystems is described in the following paragraphs.

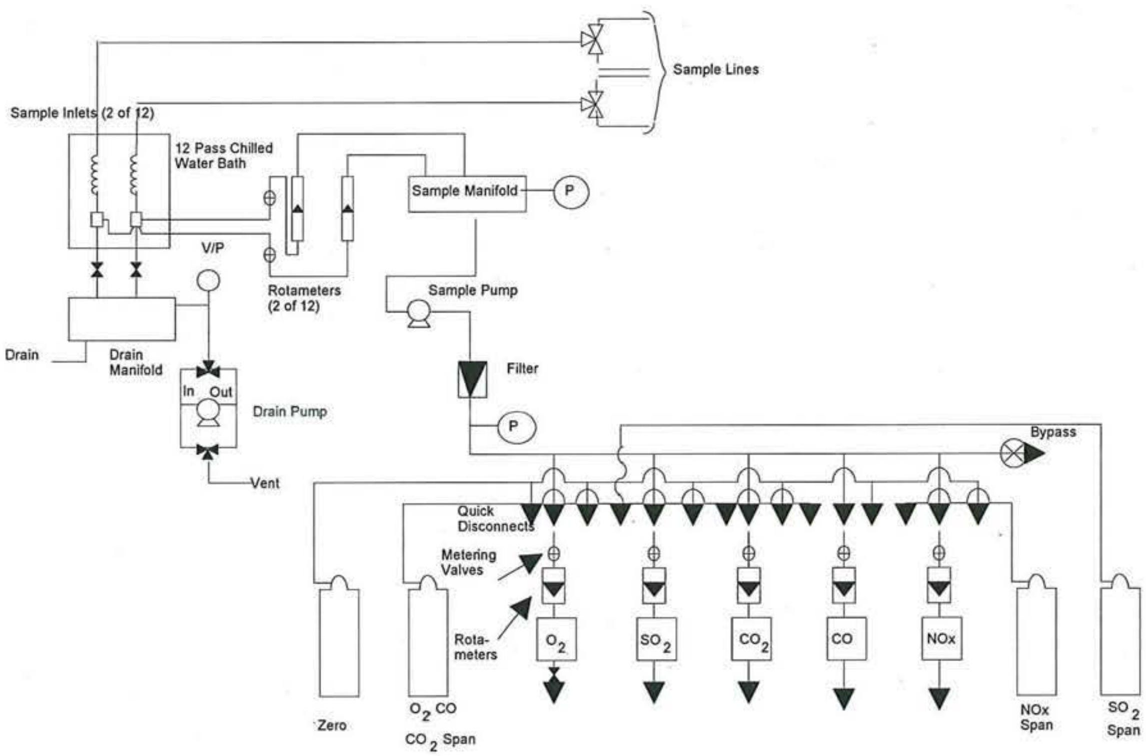


Figure A-1
Gas Sample Handling System

The sample acquisition and conditioning system contains components to extract a representative gas sample, transport the sample to the analyzers, and remove moisture and particulate material from the sample. In addition to performing these tasks, the system preserves the measured species and delivers them intact for analysis. For the program, the economizer exit ducts were fitted with a grid of 16 gas sample probes. The economizer exit consists of two separate ducts. Each duct contained a four wide by two deep probe array, 8 probes in each duct for a total of 16 probes. Figure A-2 shows the arrangement of the probe grid and the locations of the continuous NH_3 analyzer. The overall duct dimensions at this sample location are 45 feet (13.7m) wide by 8.5 feet (2.6m) deep.

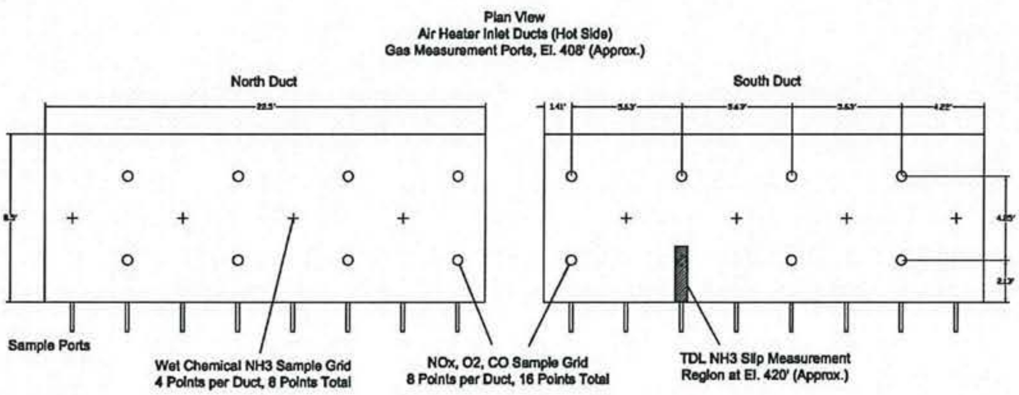


Figure A-2
Economizer Exit Probe Locations

Gaseous samples were extracted through stainless steel probes; external filters were used at the outlet of each probe to reduce particulate loading. The samples were then drawn through inert polyethylene sample lines into a refrigerated (38°F, 3°C) dryer for moisture removal. The sample then entered the dual head, diaphragm pump. All sample-wetted components of the pump are stainless steel or Teflon. The pressurized sample leaving the pump flows to the analyzers. Excess sample is vented through a back-pressure regulator, maintaining a constant pressure of 5 to 6 psig to the analyzers.

The analyzers were calibrated with gases certified to ±1% calibration by the manufacturer to comply with reference method requirements. The cylinders are equipped with pressure regulators which supply the calibration gas to the analyzers at the same pressure and flow rate as the sample. The selection of zero, span, or sample gas directed to each analyzer is accomplished by operation of the sample/calibration selector valves.

Table A-1 lists the analyzers used for this test program.

Table A-1
Continuous Gas Analyzers

Species	Analyzers	Measurement Principle
NO/NO_x	TECO 10A	Chemiluminescent
O_2	Siemens Oxymat 5E	Paramagnetic
CO	ZRH	NDIR
CO_2	ZRH	NDIR

NO/O_2/CO Profiles

An important aspect of SNCR optimization is the assessment of chemical distribution and the resulting stratification of NO_x removal and NH_3 slip. The NO_x removal and NH_3 slip will vary not only due to non-uniform chemical distribution, but also with temperature variations at the injection plane. To assess local NO_x reductions and slip, point-by-point measurements need to be made at the exit of the economizer (i.e., it is possible that one localized low temperature region, or small region with excess chemical, can be contributing a majority of the measured NH_3 slip).

To simplify these point-by-point measurements, FERCo has developed an NO/O_2/CO monitoring system that is capable of simultaneously monitoring the NO, O_2, and CO levels for up to twelve separate sample points in the economizer exit duct. This analyzer system allows the duct emissions profiles to be characterized in a matter of minutes, as opposed to hours for traditional duct emission traverse techniques. Data from twelve sample lines are taken every ten seconds and a contour plot of O_2, NO and CO is shown in "real time" on the computer screen. Figure A-3 shows a general arrangement of this system.

Wet Chemical NH_3 Slip Measurements

Ammonia slip measurements were made using a batch wet chemical technique. This method involves sampling a measured portion of the flue gas and collecting the condensed ammonia vapors in a wet chemical sampling train. The ammonia content of the samples was then determined using an ammonia ion-specific electrode. This method allows same-day turnaround of ammonia samples while in the field.

The ammonia sample was taken from ports located at the air heater inlet. Four ports were sampled from, and combined to get an average number for each duct. The sample was withdrawn using a low flow rate sample pump (e.g., 15-20 scfh [0.4-0.6 m^3/hr]). The flue gas sample was then passed through three impingers. The first two impingers contained 0.02 N sulfuric acid (H_2SO_4) and the final impinger was dry. Nominally two cubic feet of flue gas are passed through the impinger train during each test at a rate of about 0.2 ft^3 per minute [0.3 m^3 per hour].

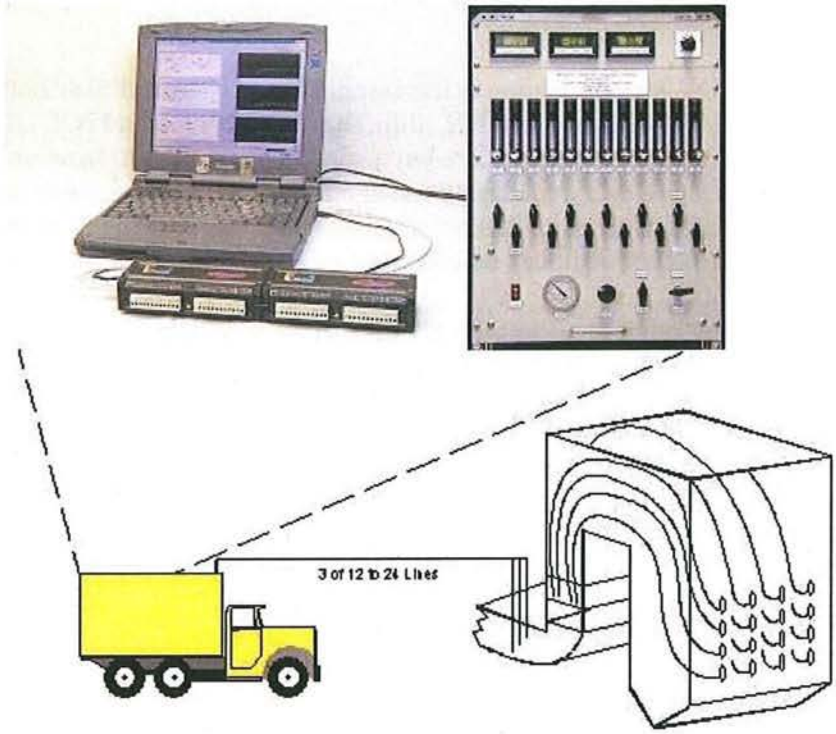


Figure A-3
Multipoint Multigas Combustion Diagnostic Analyzer

Following each sample run, the sample probe, Teflon line and sampling train glassware were washed with dilute H_2SO_4 into the bottle containing the impinger solution. Figure A-4 shows the sample train schematic.

The samples were analyzed using an ammonia ion-specific electrode. The electrode is gas sensitive, and uses a hydrophobic, gas permeable membrane to separate the sample solution from the electrode internal solution. Dissolved ammonia in the sample diffuses through the membrane until the partial pressure of ammonia is equal on both sides of the membrane. In any sample, the partial pressure of the ammonia is proportional to its concentration. The ion-specific electrode was calibrated daily with NH4Cl solutions of known concentration.

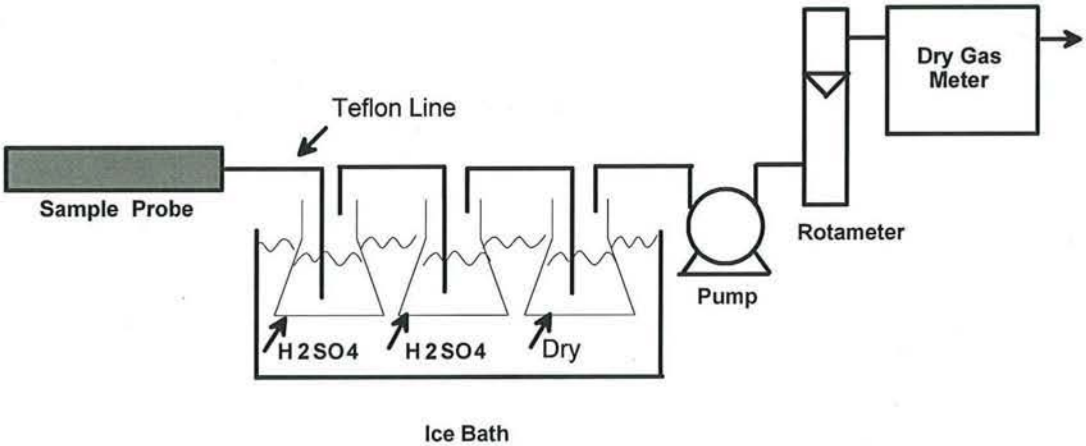


Figure A-4
Ammonia Sampling Train Schematic

Continuous Ammonia Monitor

For this test program, EPRI made available an *in situ* continuous ammonia monitor that was installed in the air heater inlet duct. This instrument utilizes a tunable diode laser which is mounted on a thermoelectric cooler to maintain a stable temperature environment. The laser is coupled to a fiber-optic cable, which is in turn coupled to a fiber-optic beam splitter where the beam is divided into a number of equal outputs when in the 'multiplexer' mode of operation.

For the current system, three outputs using an optical multiplexer from the fiber-optic beam splitter are sent to the back of the analyzer where they provide the laser emission for the signal measurements for each of the measurement targets. One output from the beam splitter provides the laser emission for the reference channel. The laser emission on the reference channel passes through a small reference cell containing a high concentration of NH_3 that is used to lock the laser wavelength onto the absorption feature, as well as to serve as a secondary calibration standard.

Calibrations are done to the instrument by way of introducing a known amount of ammonia into a small audit cell inside the LasIR analyzer. The audit cell is located just above the reference cell. This configuration, in principle, is exactly the same as having a known amount of NH_3 blowing through the probe, as it does not matter where the molecules of ammonia are so long as they are somewhere directly in the light path. The net result is a convenient calibration procedure which obviates the need for cylinders of calibration gases at the site since the ammonia concentration in the audit cell is relatively stable.

Furnace Temperature Monitors

The project utilized two furnace temperature monitors. Both the SpectraTemp® and InfraView® instruments incorporate optical pyrometry techniques to measure temperature in real time. The technique is based on Planck's blackbody, which is an ideal surface that acts as a perfect radiation emitter and absorber.

In a commercial SNCR system, the optical temperature measurements can be either integrated into the SNCR control system, or used by the operators to control soot blowing in order to maintain near constant temperatures in the upper furnace. For the current project, the instrument was used solely to monitor the upper furnace temperature.

The InfraView® measures infrared emissions from CO_2 within the gas, while the SpectraTemp® measures emissions within the visible spectrum from ash particles entrained in the combustion gas. Both instruments are prone to inference from wall infrared emissions, however, calculations show that within certain bandwidths it may not be significant. These instruments are fine-tuned to measure wavelengths from the appropriate sources, only installation and monitoring of the devices was necessary during the test program.

B
PARAMETRIC TEST RESULTS

Parametric Test Results

Test	Date	Time	Description * = A-B Comp	Load MW	OFA Condition	Heat Rate Btu/KW-hr
1	15-Nov	8:40	Baseline	180	Normal OFA	10000
2	15-Nov	10:40	15055 Injectors, Outsides Off, NSR = 1.5	180	Normal OFA	10000
3	15-Nov	11:45	2508 Injector with NSR = 1.5	180	Normal OFA	10000
4	15-Nov	12:14	Baseline	180	Normal OFA	10000
5	15-Nov	13:15	2508 Injector, 20 psi, NSR = 1.5	180	Normal OFA	10000
6	15-Nov	14:03	2508 Injector, 80 psi, NSR = 1.5	180	Normal OFA	10000
7	15-Nov	15:16	2508 Injector, 10 psi, NSR = 1.5	180	Normal OFA	10000
8	15-Nov	15:41	Baseline	180	Normal OFA	10000
9	16-Nov	8:45	Baseline	180	Normal OFA	10000
10	16-Nov	9:47	2508, 10 psi North, 20 psi South, NSR=1.5	180	Normal OFA	10000
11	16-Nov	10:15	2508, 15 psi North, 25 psi South, NSR=1.5	180	Normal OFA	10000
12	16-Nov	10:40	Baseline	180	Normal OFA	10000
13	16-Nov	12:06	Baseline, Low Load	150	Normal OFA	10000
14	16-Nov	12:33	Low Load, 2508, 40 psi uniform, NSR = 1.5	150	Normal OFA	10000
SCREEN	16-Nov	12:54	Low Load, 2508, 35 psi uniform, NSR = 1.5*	150	Normal OFA	10000
SCREEN	16-Nov	13:06	Low Load, 2508, 30 psi uniform, NSR = 1.5*	150	Normal OFA	10000
SCREEN	16-Nov	13:17	Low Load, 2508, 25 psi uniform, NSR = 1.5*	150	Normal OFA	10000
SCREEN	16-Nov	13:29	Low Load, 2508, 20 psi uniform, NSR = 1.5*	150	Normal OFA	10000
SCREEN	16-Nov	13:41	Low Load, 2508, 15 psi uniform, NSR = 1.5*	150	Normal OFA	10000
15	16-Nov	14:12	Baseline, Low Load	150	Normal OFA	10000
16	16-Nov	14:45	Low Load, 2508, 20 psi uniform, NSR = 1.5	150	Normal OFA	10000
SCREEN	16-Nov	15:23	Low Load, J5/64, 20 psi uniform, NSR = 1.5*	150	Normal OFA	10000
SCREEN	16-Nov	15:36	Low Load, J5/64, 25 psi uniform, NSR = 1.5*	150	Normal OFA	10000
SCREEN	16-Nov	15:54	Low Load, J5/64, max pressure, NSR = 1.5*	150	Normal OFA	10000
17	16-Nov	16:23	Baseline	150	Normal OFA	10000
18	16-Nov	16:52	Low Load, J5/64, 25 psi uniform, NSR = 1.5	150	Normal OFA	10000
19	17-Nov	8:04	Baseline, High NOx	180	OFA Off	10000
SCREEN	17-Nov	8:40	High NOx, J5/64, 25 psi uniform, NSR = 1*	180	OFA Off	10000
SCREEN	17-Nov	8:53	High NOx, J5/64, 20 psi uniform, NSR = 1*	180	OFA Off	10000
SCREEN	17-Nov	9:06	High NOx, J5/64, 30 psi uniform, NSR = 1*	180	OFA Off	10000
20	17-Nov	9:28	High NOx, J5/64, 20 psi uniform, NSR = 1	180	OFA Off	10000
21	17-Nov	10:35	High NOx, J5/64, 20 psi uniform, NSR = 1.4*	180	OFA Off	10000
22	17-Nov	10:53	High NOx, J5/64, 20 psi uniform, NSR = 0.5*	180	OFA Off	10000
23	17-Nov	11:23	Baseline, High NOx	180	OFA Off	10000
24	17-Nov	12:22	Baseline, Mid OFA	180	Middle OFA	10000
25	17-Nov	13:02	Mid OFA, J5/64, 20 psi uniform, NSR = 1	180	Middle OFA	10000
26	17-Nov	13:48	Mid OFA, J5/64, 20 psi uniform, NSR = 1.5*	180	Middle OFA	10000
27	17-Nov	14:12	Mid OFA, J5/64, 20 psi uniform, NSR = 0.5*	180	Middle OFA	10000
28	17-Nov	14:41	Baseline, Mid OFA	180	Middle OFA	10000
29	18-Nov	10:05	Baseline, Full Load	180	Normal OFA	10000
30	18-Nov	11:02	3/50 Vert Orientation, 30 psi uniform, NSR = 1.5	180	Normal OFA	10000
SCREEN	18-Nov	11:45	3/50, 30 psi uniform, NSR = 1.5*	180	Normal OFA	10000
SCREEN	18-Nov	11:55	3/50, 35 psi uniform, NSR = 1.5*	180	Normal OFA	10000
SCREEN	18-Nov	12:05	3/50, 40 psi uniform, NSR = 1.5*	180	Normal OFA	10000
SCREEN	18-Nov	12:15	3/50, 20 psi uniform, NSR = 1.5*	180	Normal OFA	10000
31	18-Nov	12:47	Baseline	180	Normal OFA	10000
SCREEN	18-Nov	13:40	1.5/30, 40 psi uniform, NSR = 1.5*	180	Normal OFA	10000
SCREEN	18-Nov	13:54	1.5/30, 35 psi uniform, NSR = 1.5*	180	Normal OFA	10000
SCREEN	18-Nov	14:06	1.5/30, 30 psi uniform, NSR = 1.5*	180	Normal OFA	10000
SCREEN	18-Nov	14:18	1.5/30, 25 psi uniform, NSR = 1.5*	180	Normal OFA	10000
32	18-Nov	14:48	Baseline	180	Normal OFA	10000
SCREEN	18-Nov	15:20	1.5/30, 25 psi uniform, NSR = 1.5*	180	Normal OFA	10000
SCREEN	18-Nov	15:37	1.5/30, 20 psi uniform, NSR = 1.5*	180	Normal OFA	10000
SCREEN	18-Nov	15:50	1.5/30, 10 psi uniform, NSR = 1.5*	180	Normal OFA	10000
SCREEN	18-Nov	16:20	0.5/30, 10 psi uniform, NSR = 1.5*	180	Normal OFA	10000
SCREEN	18-Nov	16:32	0.5/30, 40 psi uniform, NSR = 1.5*	180	Normal OFA	10000
SCREEN	18-Nov	16:45	Baseline	180	Normal OFA	10000
33	19-Nov	12:43	Baseline, Mid OFA (20%/0%), All 8 Injection Ports in Service	180	Middle OFA	10000
34	19-Nov	13:35	Mid OFA, Outside 2508 @ 20 psi, Middle 1.5/30 @ 30 psi, NSR = 1.0*	180	Middle OFA	10000
35	19-Nov	13:55	Mid OFA, Outside 2508 @ 20 psi, Middle 1.5/30 @ 35 psi, NSR = 1.0*	180	Middle OFA	10000
36	19-Nov	14:10	Mid OFA, Outside 2508 @ 20 psi, Middle 1.5/30 @ 25 psi, NSR = 1.0*	180	Middle OFA	10000
37	19-Nov	14:25	Mid OFA, Outside 2508 @ 20 psi, Middle 1.5/30 @ 20 psi, NSR = 1.0*	180	Middle OFA	10000
38	19-Nov	15:13	Baseline, Mid OFA	180	Middle OFA	10000
39	19-Nov	15:30	Mid OFA, Outside 2508 @ 20 psi, Middle 1.5/30 @ 30 psi (4, 5 OFF), NSR = 1.0*	180	Middle OFA	10000
40	19-Nov	15:45	Mid OFA, Outside 2508 OFF, Middle 1.5/30 @ 30 psi, NSR = 1.0*	180	Middle OFA	10000
41	19-Nov	16:09	Mid OFA, Outside 2508 @ 20 psi, Middle 1.5/30 @ 30 psi, NSR = 1.0	180	Middle OFA	10000
42	19-Nov	16:35	Baseline, Mid OFA*	180	Middle OFA	10000
43	19-Nov	17:15	Baseline, O2 Adj*	180	Middle OFA	10000
44	19-Nov	17:30	O2 Adj, Outside 2508 @ 20 psi, Middle 1.5/30 @ 30 psi, NSR = 1.25*	180	Middle OFA	10000
45	20-Nov	7:57	Baseline, Full Load	180	Normal OFA	10000
46	20-Nov	9:00	Outside 2508 @ 20 psi, Middle 1.5/30 @ 30 psi, NSR = 2.0	180	Normal OFA	10000
47	20-Nov	9:40	Baseline*	180	Normal OFA	10000
48	20-Nov	10:00	Outside 2508 @ 20 psi, Middle 1.5/30 @ 30 psi, NSR = 3.0	180	Normal OFA	10000
49	20-Nov	12:37	Baseline	180	Normal OFA	10000
50	20-Nov	13:00	Outside 2508 @ 20 psi, Middle 1.5/30 @ 30 psi, NSR = 2.5	180	Normal OFA	10000
51	20-Nov	16:27	Baseline	180	Normal OFA	10000

Test	Water Flow gpm	Urea Flow gpm	Metering Pump Setting	Water+Urea gpm	[Urea] %
1	4	0	Off	-	-
2	3.99	0.81	33	4.8	7.4
3	3.99	0.81	33	4.8	7.4
4	4	0	Off	-	-
5	2.19	0.81	33	3	11.6
6	5.89	0.81	33	6.7	5.3
7	0.99	0.81	33	1.8	19.0
8	1	0	Off	-	-
9	1.6	0	Off	-	-
10	1.59	0.81	33	2.4	14.4
11	2.19	0.81	33	3	11.6
12	2.2	0	Off	-	-
13	2.2	0	Off	-	-
14	4.18	0.62	26	4.8	5.7
SCREEN	3.58	0.62	26	4.2	6.4
SCREEN	3.18	0.62	26	3.8	7.1
SCREEN	2.78	0.62	26	3.4	7.9
SCREEN	2.38	0.62	26	3	9.0
SCREEN	1.88	0.62	26	2.5	10.7
15	1.9	0	Off	-	-
16	2.38	0.62	26	3	9.0
SCREEN	6.08	0.62	26	6.7	4.1
SCREEN	7.08	0.62	26	7.7	3.5
SCREEN	8.38	0.62	26	9	3.0
17	8.4	0	Off	-	-
18	6.88	0.62	26	7.5	3.6
19	6.9	0	Off	-	-
SCREEN	6	1.4	55	7.4	8.2
SCREEN	5.1	1.4	55	6.5	9.3
SCREEN	7.1	1.4	55	8.5	7.2
20	5.1	1.4	55	6.5	9.3
21	4.65	1.85	72	6.5	12.3
22	5.8	0.7	29	6.5	4.7
23	5.8	0	Off	-	-
24	5.8	0	Off	-	-
25	5.8	0.7	29	6.5	4.7
26	5.43	1.07	43	6.5	7.2
27	6.14	0.36	16	6.5	2.4
28	6.1	0	Off	-	-
29	6.1	0	Off	-	-
30	Overscale	0.74	30	Overscale	-
SCREEN	Overscale	0.74	30	Overscale	-
SCREEN	Overscale	0.74	30	Overscale	-
SCREEN	Overscale	0.74	30	Overscale	-
SCREEN	Overscale	0.74	30	Overscale	-
31	7.8	0	Off	-	-
SCREEN	7.76	0.74	30	8.5	3.8
SCREEN	6.76	0.74	30	7.5	4.3
SCREEN	6.26	0.74	30	7	4.6
SCREEN	5.26	0.74	30	6	5.4
32	5.3	0	Off	-	-
SCREEN	5.26	0.74	30	6	5.4
SCREEN	4.76	0.74	30	5.5	5.9
SCREEN	2.56	0.74	30	3.3	9.7
SCREEN	0.36	0.74	30	1.1	27.8
SCREEN	2.26	0.74	30	3	10.7
SCREEN	2.3	0	Off	-	-
33	6.9	0	Off	-	-
34	6.9	1.1	44	8	6.0
35	7.6	1.1	44	8.7	5.5
36	6.4	1.1	44	7.5	6.4
37	5.4	1.1	44	6.5	7.4
38	5.4	0	Off	-	-
39	4.7	1.1	44	5.8	8.2
40	5.8	1.1	44	6.9	7.0
41	6.7	1.1	44	7.8	6.2
42	6.7	0	Off	-	-
43	6.7	0	Off	-	-
44	6.7	1.1	44	7.8	6.2
45	6.7	0	Off	-	-
46	6.9	1.1	44	8	6.0
47	6.9	0	Off	-	-
48	6.55	1.65	65	8.2	8.7
49	6.6	0	Off	-	-
50	6.6	1.65	65	8.2	8.7
51	6.6	0	Off	-	-

Parametric Test Results

Test	Inj #1	Inj #2	Inj #3	Inj #4	Inj #5	Inj #6	Inj #7	Inj #8
1	15055 V	15055 H	15055 H	15055 H	15055 H	15055 H	15055 H	15055V
2	Off	15055H	15055 H	15055 H	15055 H	15055 H	15055 H	Off
3	Off	2508H	2508H	2508H	2508H	2508H	2508H	Off
4	Off	2508H	2508H	2508H	2508H	2508H	2508H	Off
5	Off	2508H	2508H	2508H	2508H	2508H	2508H	Off
6	Off	2508H	2508H	2508H	2508H	2508H	2508H	Off
7	Off	2508H	2508H	2508H	2508H	2508H	2508H	Off
8	Off	2508H	2508H	2508H	2508H	2508H	2508H	Off
9	Off	2508H	2508H	2508H	2508H	2508H	2508H	Off
10	Off	2508H	2508H	2508H	2508H	2508H	2508H	Off
11	Off	2508H	2508H	2508H	2508H	2508H	2508H	Off
12	Off	2508H	2508H	2508H	2508H	2508H	2508H	Off
13	Off	2508H	2508H	2508H	2508H	2508H	2508H	Off
14	Off	2508H	2508H	2508H	2508H	2508H	2508H	Off
SCREEN	Off	2508H	2508H	2508H	2508H	2508H	2508H	Off
SCREEN	Off	2508H	2508H	2508H	2508H	2508H	2508H	Off
SCREEN	Off	2508H	2508H	2508H	2508H	2508H	2508H	Off
SCREEN	Off	2508H	2508H	2508H	2508H	2508H	2508H	Off
SCREEN	Off	2508H	2508H	2508H	2508H	2508H	2508H	Off
15	Off	2508H	2508H	2508H	2508H	2508H	2508H	Off
16	Off	2508H	2508H	2508H	2508H	2508H	2508H	Off
SCREEN	Off	J 5/64	J 5/64	J 5/64	J 5/64	J 5/64	J 5/64	Off
SCREEN	Off	J 5/64	J 5/64	J 5/64	J 5/64	J 5/64	J 5/64	Off
SCREEN	Off	J 5/64	J 5/64	J 5/64	J 5/64	J 5/64	J 5/64	Off
17	Off	J 5/64	J 5/64	J 5/64	J 5/64	J 5/64	J 5/64	Off
18	Off	J 5/64	J 5/64	J 5/64	J 5/64	J 5/64	J 5/64	Off
19	Off	J 5/64	J 5/64	J 5/64	J 5/64	J 5/64	J 5/64	Off
SCREEN	Off	J 5/64	J 5/64	J 5/64	J 5/64	J 5/64	J 5/64	Off
SCREEN	Off	J 5/64	J 5/64	J 5/64	J 5/64	J 5/64	J 5/64	Off
SCREEN	Off	J 5/64	J 5/64	J 5/64	J 5/64	J 5/64	J 5/64	Off
20	Off	J 5/64	J 5/64	J 5/64	J 5/64	J 5/64	J 5/64	Off
21	Off	J 5/64	J 5/64	J 5/64	J 5/64	J 5/64	J 5/64	Off
22	Off	J 5/64	J 5/64	J 5/64	J 5/64	J 5/64	J 5/64	Off
23	Off	J 5/64	J 5/64	J 5/64	J 5/64	J 5/64	J 5/64	Off
24	Off	J 5/64	J 5/64	J 5/64	J 5/64	J 5/64	J 5/64	Off
25	Off	J 5/64	J 5/64	J 5/64	J 5/64	J 5/64	J 5/64	Off
26	Off	J 5/64	J 5/64	J 5/64	J 5/64	J 5/64	J 5/64	Off
27	Off	J 5/64	J 5/64	J 5/64	J 5/64	J 5/64	J 5/64	Off
28	Off	J 5/64	J 5/64	J 5/64	J 5/64	J 5/64	J 5/64	Off
29	Off	3 gpm/ 50	3 gpm/ 50	3 gpm/ 50	3 gpm/ 50	3 gpm/ 50	3 gpm/ 50	Off
30	Off	3 gpm/ 50V	3 gpm/ 50V	3 gpm/ 50V	3 gpm/ 50V	3 gpm/ 50V	3 gpm/ 50V	Off
SCREEN	Off	3 gpm/ 50	3 gpm/ 50	3 gpm/ 50	3 gpm/ 50	3 gpm/ 50	3 gpm/ 50	Off
SCREEN	Off	3 gpm/ 50	3 gpm/ 50	3 gpm/ 50	3 gpm/ 50	3 gpm/ 50	3 gpm/ 50	Off
SCREEN	Off	3 gpm/ 50	3 gpm/ 50	3 gpm/ 50	3 gpm/ 50	3 gpm/ 50	3 gpm/ 50	Off
SCREEN	Off	3 gpm/ 50	3 gpm/ 50	3 gpm/ 50	3 gpm/ 50	3 gpm/ 50	3 gpm/ 50	Off
31	Off	3 gpm/ 50	3 gpm/ 50	3 gpm/ 50	3 gpm/ 50	3 gpm/ 50	3 gpm/ 50	Off
SCREEN	Off	1.5 gpm/ 30	1.5 gpm/ 30	1.5 gpm/ 30	1.5 gpm/ 30	1.5 gpm/ 30	1.5 gpm/ 30	Off
SCREEN	Off	1.5 gpm/ 30	1.5 gpm/ 30	1.5 gpm/ 30	1.5 gpm/ 30	1.5 gpm/ 30	1.5 gpm/ 30	Off
SCREEN	Off	1.5 gpm/ 30	1.5 gpm/ 30	1.5 gpm/ 30	1.5 gpm/ 30	1.5 gpm/ 30	1.5 gpm/ 30	Off
SCREEN	Off	1.5 gpm/ 30	1.5 gpm/ 30	1.5 gpm/ 30	1.5 gpm/ 30	1.5 gpm/ 30	1.5 gpm/ 30	Off
32	Off	1.5 gpm/ 30	1.5 gpm/ 30	1.5 gpm/ 30	1.5 gpm/ 30	1.5 gpm/ 30	1.5 gpm/ 30	Off
SCREEN	Off	1.5 gpm/ 30	1.5 gpm/ 30	1.5 gpm/ 30	1.5 gpm/ 30	1.5 gpm/ 30	1.5 gpm/ 30	Off
SCREEN	Off	1.5 gpm/ 30	1.5 gpm/ 30	1.5 gpm/ 30	1.5 gpm/ 30	1.5 gpm/ 30	1.5 gpm/ 30	Off
SCREEN	Off	1.5 gpm/ 30	1.5 gpm/ 30	1.5 gpm/ 30	1.5 gpm/ 30	1.5 gpm/ 30	1.5 gpm/ 30	Off
SCREEN	Off	0.5 gpm/ 30	0.5 gpm/ 30	0.5 gpm/ 30	0.5 gpm/ 30	0.5 gpm/ 30	0.5 gpm/ 30	Off
SCREEN	Off	0.5 gpm/ 30	0.5 gpm/ 30	0.5 gpm/ 30	0.5 gpm/ 30	0.5 gpm/ 30	0.5 gpm/ 30	Off
SCREEN	Off	0.5 gpm/ 30	0.5 gpm/ 30	0.5 gpm/ 30	0.5 gpm/ 30	0.5 gpm/ 30	0.5 gpm/ 30	Off
33	2805V	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	2805V
34	2805V	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	2805V
35	2805V	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	2805V
36	2805V	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	2805V
37	2805V	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	2805V
38	2805V	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	2805V
39	2805V	1.5 gpm/30	1.5 gpm/30	Off	Off	1.5 gpm/30	1.5 gpm/30	2805V
40	Off	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	Off
41	2805V	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	2805V
42	2805V	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	2805V
43	2805V	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	2805V
44	2805V	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	2805V
45	2805V	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	2805V
46	2805V	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	2805V
47	2805V	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	2805V
48	2805V	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	2805V
49	2805V	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	2805V
50	2805V	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	2805V
51	2805V	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	1.5 gpm/30	2805V

Test	Inj #1 gph	Inj #2 gph	Inj #3 gph	Inj #4 gph	Inj #5 gph	Inj #6 gph	Inj #7 gph	Inj #8 gph
1	35	35	35	35	35	35	35	35
2	Off	48	48	47	48	48	48	Off
3	Off	48	48	48	48	48	48	Off
4	Off	44	44	44	44	44	44	Off
5	Off	32	32	32	32	32	32	Off
6	Off	76	76	76	76	76	76	Off
7	Off	20	20	20	20	20	18	Off
8	Off	20	20	20	20	20	20	Off
9	Off	20	20	20	20	20	20	Off
10	Off	20	20	20	33	33	33	Off
11	Off	29	29	29	38	38	38	Off
12	Off	29	29	29	38	38	38	Off
13	Off	47	47	47	47	47	47	Off
14	Off	47	47	47	47	47	47	Off
SCREEN	Off	42	42	42	42	42	42	Off
SCREEN	Off	39	39	39	39	39	39	Off
SCREEN	Off	35	35	35	35	35	35	Off
SCREEN	Off	32	32	32	32	32	32	Off
SCREEN	Off	27	27	27	27	27	27	Off
15	Off	27	27	27	27	27	27	Off
16	Off	32	32	32	32	32	32	Off
SCREEN	Off	76	72	50	64	62	74	Off
SCREEN	Off	86	81	55	72	69	81	Off
SCREEN	Off	90	90	87	90	90	90	Off
17	Off	90	90	87	90	90	90	Off
18	Off	88	82	55	69	69	81	Off
19	Off	88	82	55	69	69	81	Off
SCREEN	Off	88	70	55	70	66	84	Off
SCREEN	Off	76	60	46	60	58	72	Off
SCREEN	Off	95	78	60	80	74	92	Off
20	Off	76	60	47	61	58	71	Off
21	Off	76	60	47	61	58	71	Off
22	Off	76	60	47	61	58	71	Off
23	Off	76	60	47	61	58	71	Off
24	Off	76	60	47	61	58	71	Off
25	Off	76	60	47	61	58	71	Off
26	Off	76	60	47	61	58	71	Off
27	Off	76	60	47	61	58	71	Off
28	Off	76	60	47	61	58	71	Off
29	Off	76	60	47	61	58	71	Off
30	Off	Overscale	Overscale	Overscale	Overscale	Overscale	Overscale	Off
SCREEN	Off	Overscale	Overscale	Overscale	Overscale	Overscale	Overscale	Off
SCREEN	Off	Overscale	Overscale	Overscale	Overscale	Overscale	Overscale	Off
SCREEN	Off	Overscale	Overscale	Overscale	Overscale	Overscale	Overscale	Off
SCREEN	Off	Overscale	Overscale	Overscale	Overscale	Overscale	Overscale	Off
31	Off	Overscale	Overscale	Overscale	Overscale	Overscale	Overscale	Off
SCREEN	Off	82	82	82	82	82	82	Off
SCREEN	Off	75	75	75	75	75	75	Off
SCREEN	Off	68	68	68	68	68	68	Off
SCREEN	Off	62	62	62	62	62	62	Off
32	Off	62	62	62	62	62	62	Off
SCREEN	Off	62	62	62	62	62	62	Off
SCREEN	Off	54	54	54	54	54	54	Off
SCREEN	Off	33	33	33	33	33	33	Off
SCREEN	Off	11	11	11	11	11	11	Off
SCREEN	Off	30	30	30	30	30	30	Off
SCREEN	Off	30	30	30	30	30	30	Off
33	31	68	68	68	68	68	68	31
34	31	68	68	68	68	68	68	31
35	32	76	76	76	76	76	76	32
36	32	62	62	62	62	62	62	32
37	32	57	57	57	57	57	57	32
38	32	57	57	57	57	57	57	32
39	31	69	69	Off	Off	69	69	31
40	Off	69	69	69	69	69	69	Off
41	31	69	69	69	69	69	69	31
42	31	69	69	69	69	69	69	31
43	31	69	69	69	69	69	69	31
44	31	69	69	69	69	69	69	31
45	31	69	69	69	69	69	69	31
46	31	69	69	69	69	69	69	31
47	31	69	69	69	69	69	69	31
48	31	69	69	69	69	69	69	31
49	31	69	69	69	69	69	69	31
50	31	69	69	69	69	69	69	31
51	31	69	69	69	69	69	69	31

Parametric Test Results

Test	Inj #1	Inj #2	Inj #3	Inj #4	Inj #5	Inj #6	Inj #7	Inj #8
	psi	psi	psi	psi	psi	psi	psi	psi
1	46	46	46	46	46	46	46	46
2	Off	86	87	86	86	87	85	Off
3	Off	44	44	44	44	44	44	Off
4	Off	38	38	38	38	38	38	Off
5	Off	20	20	20	20	20	20	Off
6	Off	80	80	80	80	80	80	Off
7	Off	10	10	10	10	10	10	Off
8	Off	10	10	10	10	10	10	Off
9	Off	10	10	10	10	10	10	Off
10	Off	10	10	10	20	20	20	Off
11	Off	15	15	15	25	25	25	Off
12	Off	15	15	15	25	25	25	Off
13	Off	40	40	40	40	40	40	Off
14	Off	42	42	42	42	42	42	Off
SCREEN	Off	35	35	35	35	35	35	Off
SCREEN	Off	30	30	30	30	30	30	Off
SCREEN	Off	25	25	25	25	25	25	Off
SCREEN	Off	20	20	20	20	20	20	Off
SCREEN	Off	15	15	15	15	15	15	Off
15	Off	15	15	15	15	15	15	Off
16	Off	20	20	20	20	20	20	Off
SCREEN	Off	20	20	20	20	20	20	Off
SCREEN	Off	25	25	25	25	25	25	Off
SCREEN	Off	28	30	55	37	38	30	Off
17	Off	28	30	55	37	38	30	Off
18	Off	25	25	25	25	25	25	Off
19	Off	25	25	25	25	25	25	Off
SCREEN	Off	25	25	25	25	25	25	Off
SCREEN	Off	20	20	20	20	20	20	Off
SCREEN	Off	30	30	30	30	30	30	Off
20	Off	20	20	20	20	20	20	Off
21	Off	20	20	20	20	20	20	Off
22	Off	20	20	20	20	20	20	Off
23	Off	20	20	20	20	20	20	Off
24	Off	20	20	20	20	20	20	Off
25	Off	20	20	20	20	20	20	Off
26	Off	20	20	20	20	20	20	Off
27	Off	20	20	20	20	20	20	Off
28	Off	20	20	20	20	20	20	Off
29	Off	20	20	20	20	20	20	Off
30	Off	30	30	30	30	30	30	Off
SCREEN	Off	30	30	30	30	30	30	Off
SCREEN	Off	35	35	35	35	35	35	Off
SCREEN	Off	40	40	40	40	40	40	Off
SCREEN	Off	45	45	45	45	45	45	Off
31	Off	45	45	45	45	45	45	Off
SCREEN	Off	40	40	40	40	40	40	Off
SCREEN	Off	35	35	35	35	35	35	Off
SCREEN	Off	30	30	30	30	30	30	Off
SCREEN	Off	25	25	25	25	25	25	Off
32	Off	25	25	25	25	25	25	Off
SCREEN	Off	25	25	25	25	25	25	Off
SCREEN	Off	20	20	20	20	20	20	Off
SCREEN	Off	10	10	10	10	10	10	Off
SCREEN	Off	10	10	10	10	10	10	Off
SCREEN	Off	40	40	40	40	40	40	Off
SCREEN	Off	40	40	40	40	40	40	Off
33	20	30	30	30	30	30	30	20
34	20	30	30	30	30	30	30	20
35	20	35	35	35	35	35	35	20
36	20	25	25	25	25	25	25	20
37	20	20	20	20	20	20	20	20
38	20	20	20	20	20	20	20	20
39	20	30	30	Off	Off	30	30	20
40	Off	30	30	30	30	30	30	Off
41	20	30	30	30	30	30	30	20
42	20	30	30	30	30	30	30	20
43	20	30	30	30	30	30	30	20
44	20	30	30	30	30	30	30	20
45	20	30	30	30	30	30	30	20
46	20	30	30	30	30	30	30	20
47	20	30	30	30	30	30	30	20
48	20	30	30	30	30	30	30	20
49	20	30	30	30	30	30	30	20
50	20	30	30	30	30	30	30	20
51	20	30	30	30	30	30	30	20

Test	NSR	O2 % dry	O2 % wet	CO ppm	NOx ppm	NOxc ppmc	NOx-Baseline ppmc	NOx lb/MMBtu	NOx-Baseline lb/MMBtu	dNOx %
1	-	3.90	3.43	317	71.0	74.8		0.102		-
2	1.5	3.88	3.41	455	72.0	75.7	74.1	0.103	0.101	-2.1
3	1.5	3.83	3.37	345	69.0	72.4	74.1	0.099	0.101	2.4
4	-	3.86	3.40	434	70.0	73.5		0.101		-
5	1.5	4.02	3.54	299	66.0	70.0	72.4	0.096	0.099	3.3
6	1.5	4.02	3.54	387	69.0	73.2	72.4	0.100	0.099	-1.1
7	1.5	4.12	3.63	197	69.0	73.6	72.4	0.101	0.099	-1.7
8	-	3.55	3.12	590	69.0	71.2		0.097		-
9	-	3.88	3.41	342	73.0	76.8		0.105		-
10	1.5	3.94	3.47	116	70.0	73.9	76.4	0.101	0.104	3.2
11	1.5	3.95	3.48	289	71.0	75.0	76.4	0.102	0.104	1.8
12	-	3.93	3.46	307	72.0	75.9		0.104		-
13	-	3.96	3.48	312	66.0	69.7		0.095		-
14	1.5	4.23	3.72	181	62.0	66.6	68.3	0.091	0.093	2.6
SCREEN	1.5	4.01	3.53		60.2	63.8	68.3	0.087	0.093	6.6
SCREEN	1.5	3.99	3.51		60.8	64.4	68.3	0.088	0.093	5.8
SCREEN	1.5	4.00	3.52		59.8	63.3	68.3	0.087	0.093	7.3
SCREEN	1.5	3.99	3.51		57.8	61.2	68.3	0.084	0.093	10.5
SCREEN	1.5	4.10	3.61		57.7	61.5	68.3	0.084	0.093	10.0
15	-	4.05	3.56	220	63.0	66.9		0.091		-
16	1.6	4.08	3.59	244	57.0	60.7	65.1	0.083	0.089	6.8
SCREEN	1.6	3.91	3.44		56.1	59.1	65.1	0.081	0.089	9.2
SCREEN	1.6	3.69	3.25		54.7	56.9	65.1	0.078	0.089	12.6
SCREEN	1.6	4.35	3.83		55.0	59.5	65.1	0.081	0.089	8.6
17	-	3.91	3.44	358	60.0	63.2		0.086		-
18	1.6	4.02	3.54	279	56.0	59.4	63.2	0.081	0.086	6.1
19	-	4.00	3.52	15	176.0	186.4		0.255		-
SCREEN	1.0	3.80	3.34	15	141.3	147.9	186.4	0.202	0.255	20.7
SCREEN	1.0	3.68	3.24	18.9	135.8	141.2	186.4	0.193	0.255	24.3
SCREEN	1.0	3.74	3.29	18.3	140.1	146.1	186.4	0.200	0.255	21.6
20	1.0	4.00	3.52	15	152.0	161.0	186.4	0.220	0.255	13.6
21	1.4	3.69	3.25	35	139.0	144.6	186.4	0.198	0.255	22.4
22	0.5	3.55	3.12	35	157.0	162.0	186.4	0.221	0.255	13.1
23	-	3.93	3.46	66	189.0	199.4		0.272		-
24	-	4.21	3.70	105	92.0	98.7		0.135		-
25	1.0	3.99	3.51	168	84.0	88.9	98.7	0.122	0.135	9.9
26	1.6	4.01	3.53	123	88.0	93.3	93.9	0.127	0.128	0.7
27	0.5	4.22	3.71	88	98.0	105.2	93.9	0.144	0.128	-12.0
28	-	4.12	3.63	118	88.0	93.9		0.128		-
29	-	3.93	3.46	378	65.0	68.6		0.094		-
30	1.5	3.98	3.50	407	63.0	66.6	69.2	0.091	0.095	3.7
SCREEN	1.5	3.81	3.35	290	64.3	67.3	69.2	0.092	0.095	2.7
SCREEN	1.5	3.72	3.27	334	64.2	66.9	69.2	0.091	0.095	3.4
SCREEN	1.5	3.78	3.33	354	65.9	68.9	69.2	0.094	0.095	0.4
SCREEN	1.5	3.83	3.37	425	65.5	68.7	69.2	0.094	0.095	0.8
31	-	3.99	3.51	396	66.0	69.9		0.095		-
SCREEN	1.5	3.81	3.35	441	66.7	69.9	69.9	0.095	0.095	0.0
SCREEN	1.5	3.89	3.42	314	66.2	69.7	69.9	0.095	0.095	0.3
SCREEN	1.5	3.90	3.43	408	65.8	69.3	69.9	0.095	0.095	0.8
SCREEN	1.5	3.71	3.26	371	64.2	66.9	69.9	0.091	0.095	4.3
32	-	4.10	3.61	269	67.0	71.4		0.098		-
SCREEN	1.4	3.74	3.29	340	66.0	68.8	71.5	0.094	0.098	3.7
SCREEN	1.4	3.71	3.26	317	68.8	71.6	71.5	0.098	0.098	-0.2
SCREEN	1.4	3.79	3.34	241	70.4	73.7	71.5	0.101	0.098	-3.0
SCREEN	1.4	3.85	3.39	239	77.6	81.5	71.5	0.111	0.098	-14.0
SCREEN	1.4	3.71	3.26	282	74.9	78.0	71.5	0.107	0.098	-9.1
SCREEN	-	3.74	3.29	242	68.6	71.6		0.098		-
33	-	3.89	3.42	62	147.0	154.7		0.211		-
34	1.0	3.67	3.23	81	106.0	110.1	154.7	0.151	0.211	28.8
35	1.0	3.69	3.25	67	111.0	115.5	154.7	0.158	0.211	25.4
36	1.0	3.73	3.28	56	107.0	111.5	154.7	0.152	0.211	27.9
37	1.0	3.64	3.20	81	104.0	107.9	154.7	0.147	0.211	30.3
38	-	4.08	3.59	31	146.0	155.4		0.212		-
39	1.0	3.66	3.22	58	114.0	118.4	159.8	0.162	0.218	25.9
40	1.0	3.59	3.16	50	117.0	121.0	159.8	0.165	0.218	24.3
41	1.0	3.85	3.39	44	121.0	127.0	159.8	0.174	0.218	20.5
42	-	3.45	3.04	43	160.0	164.1		0.224		-
43	-	3.42	3.01	422	120.0	122.9		0.168		-
44	1.2	3.49	3.07	385	91.0	93.6	122.9	0.128	0.168	23.9
45	-	3.90	3.43	330	74.0	77.9		0.106		-
46	2.0	4.06	3.57	361	67.0	71.2	77.4	0.097	0.106	8.0
47	-	4.13	3.63	308	72.0	76.9		0.105		-
48	3.0	4.00	3.52	380	62.0	65.7	76.9	0.090	0.105	14.6
49	-	4.06	3.57	162	83.0	88.2		0.121		-
50	2.8	3.95	3.48	212	68.5	72.3	81.3	0.099	0.111	11.0
51	-	4.04	3.56	249	70.0	74.3		0.102		-

Parametric Test Results

Test	North InfraView °F	SpectraTemp °F	South InfraView °F	South Duct, Int. TDL Ammonia Slip ppmc	Wet Chem. Ammonia Slip (ppmc) North	South
1	2045	2155	1700			
2	2050	2186	1770			
3	2060	2177	1760			
4	2030	2175	1720			
5	2070	2166	1740			
6	2050	2177	1710			
7	2070	2180	1800			
8	2060	2200	1700			
9				0.7		
10	2090	2205	1690	4.8		
11	2090	2200	1750	6.3		
12				0.5		
13	1980	2140	1580	0.7		
14	1950	2150	1625	2.5		
SCREEN						
SCREEN						
SCREEN						
SCREEN						
SCREEN						
15						
16	1960	2145	1600			
SCREEN						
SCREEN						
SCREEN	2010	2160	1580			
17						
18	2020	2160	1590			9.5
19						
SCREEN	1950	2295	1600			
SCREEN	1950	2305	1660			
SCREEN	1980	2320	1660			
20	1940	2315	1660		4.8	9.8
21	1920	2305	1640			
22	1940	2305	1650			
23						
24						
25	2040	2245	1680		3.4	5.2
26						
27	1990	2215	1740			
28						
29				0.6		
30	2100	2200	1680	6.1		
SCREEN				3.8		
SCREEN				3.5		
SCREEN	2125	2193	1680	2.8		
SCREEN				1.8		
31				0.8		
SCREEN	2100	2220	1600	2.3		
SCREEN				1.8		
SCREEN				2.3		
SCREEN				1.1		
32				0.3		
SCREEN						
SCREEN	2130	2194	1760			
SCREEN						
SCREEN	2120	2190	1750			
SCREEN						
SCREEN						
33				0.8		
34	1860	2255	1560	2.8		
35	1858	2265	1585	5.4		
36	1875	2266	1540	5.1		
37	1890	2267	1585	2.1		
38				0.8		
39	1900	2276	1590	1.8		
40	1910	2276	1630	2.8		
41	1900	2275	1580	2.7		
42				0.4		
43				0.8		
44	1920	2271	1620	2.1		
45				0.5		
46	2060	2194		2.3		
47				0.3		
48	2010	2180		19.1	24.4	19.9
49				0.8		
50	2070	2205		7.8	18.5	22.4
51				0.7		

C
COAL ANALYSIS

SGS

January 02, 2009

Fossil Energy Research
23342 C South Pointe
Laguna Hills, CA 92653
USA

Client Sample ID:	11-20-08-B32-2101	**P. O. #:**	08-578-2101
Date Received:	12/23/2008	**Sample Type:**	-8 Mesh Moist
Matrix:	Coal		
Net Sample Weight:	1230.50		

SGS Sample ID: 072-36941-001

		As Received	Dry	MAF
% Moisture, Total	[ASTM D 3302]	29.13		
% Ash	[ASTM D 3174/5142]	5.12	7.22	
% Volatile Matter	[ASTM D 5142]	30.39	42.89	46.23
% Fixed Carbon	[ASTM D 3172]	35.36	49.89	53.77
Gross Calorific Value (Btu/lb)	[ASTM D 5865]	8488	11978	12910
% Sulfur	[ASTM D 4239]	0.27	0.38	
% Carbon	[ASTM D 5373]	49.23	69.47	
% Hydrogen	[ASTM D 5373]	3.17	4.47	
% Nitrogen	[ASTM D 5373]	0.70	0.99	
% Oxygen (Calc)	[ASTM D 3176]	12.38	17.47	

Analyte	Result	Method
Pounds of Ash/mm Btu	6.03 lb	ASTM D 5865
Pounds of Sulfur/mm Btu	0.32 lb	ASTM D 5865
Pounds of SO2/mm Btu	0.64 lb	ASTM D 5865

Respectfully submitted,
SGS NORTH AMERICA INC.

Denver Laboratory

Page 1 of 1

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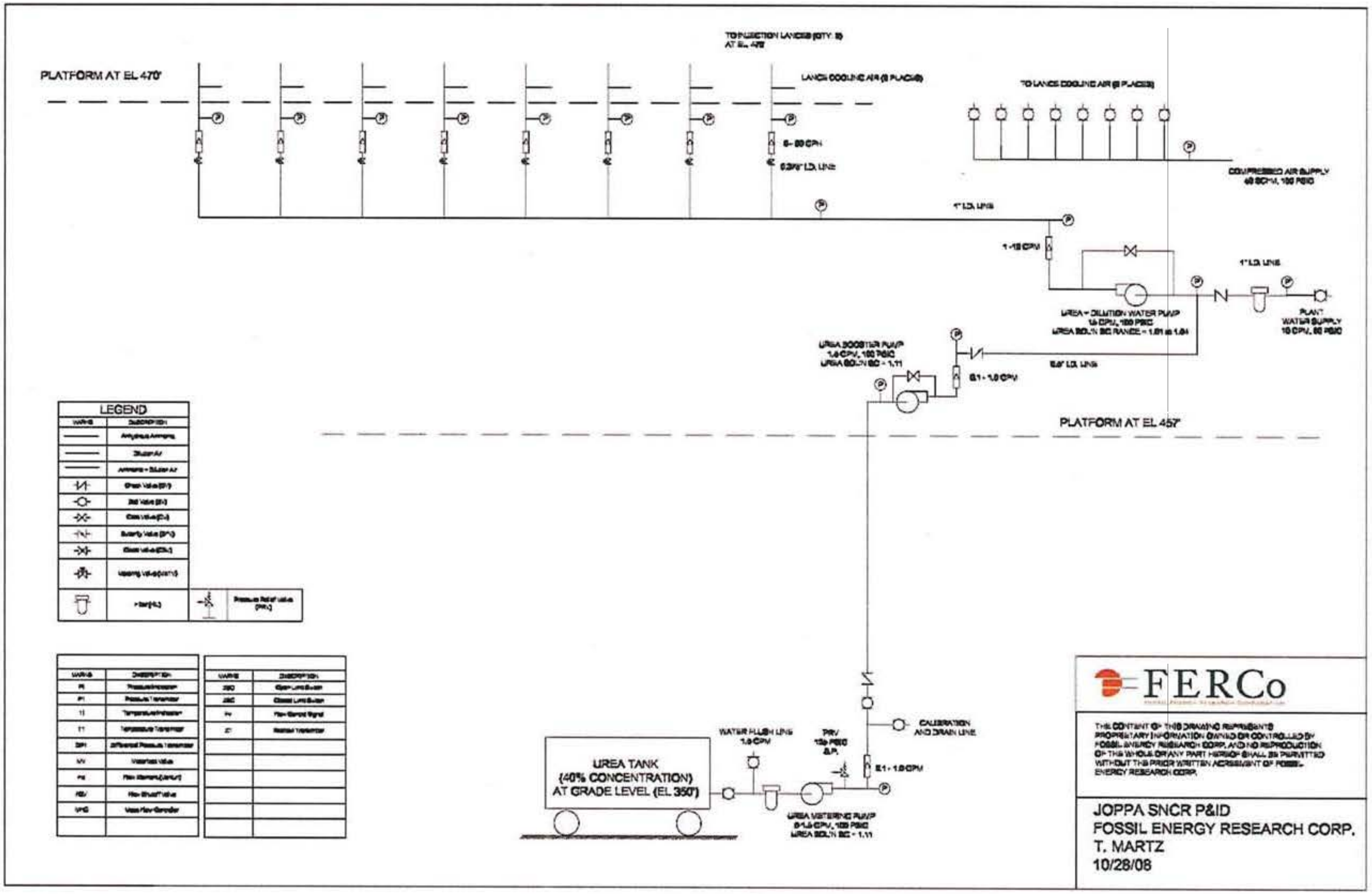
Member of the SGS Group

GENERAL CONDITIONS OF SERVICE ON REVERSE

D
SNCR P&ID


PLATFORM AT EL 470'
PLATFORM AT EL 457'
LEGEND
UREA TANK
(40% CONCENTRATION)
AT GRADE LEVEL (EL 350')
CALIBRATION
AND DRAIN LINE
FERCo
JOPPA SNCR P&ID
FOSSIL ENERGY RESEARCH CORP.
T. MARTZ
10/28/08

E
CONTOUR PLOTS

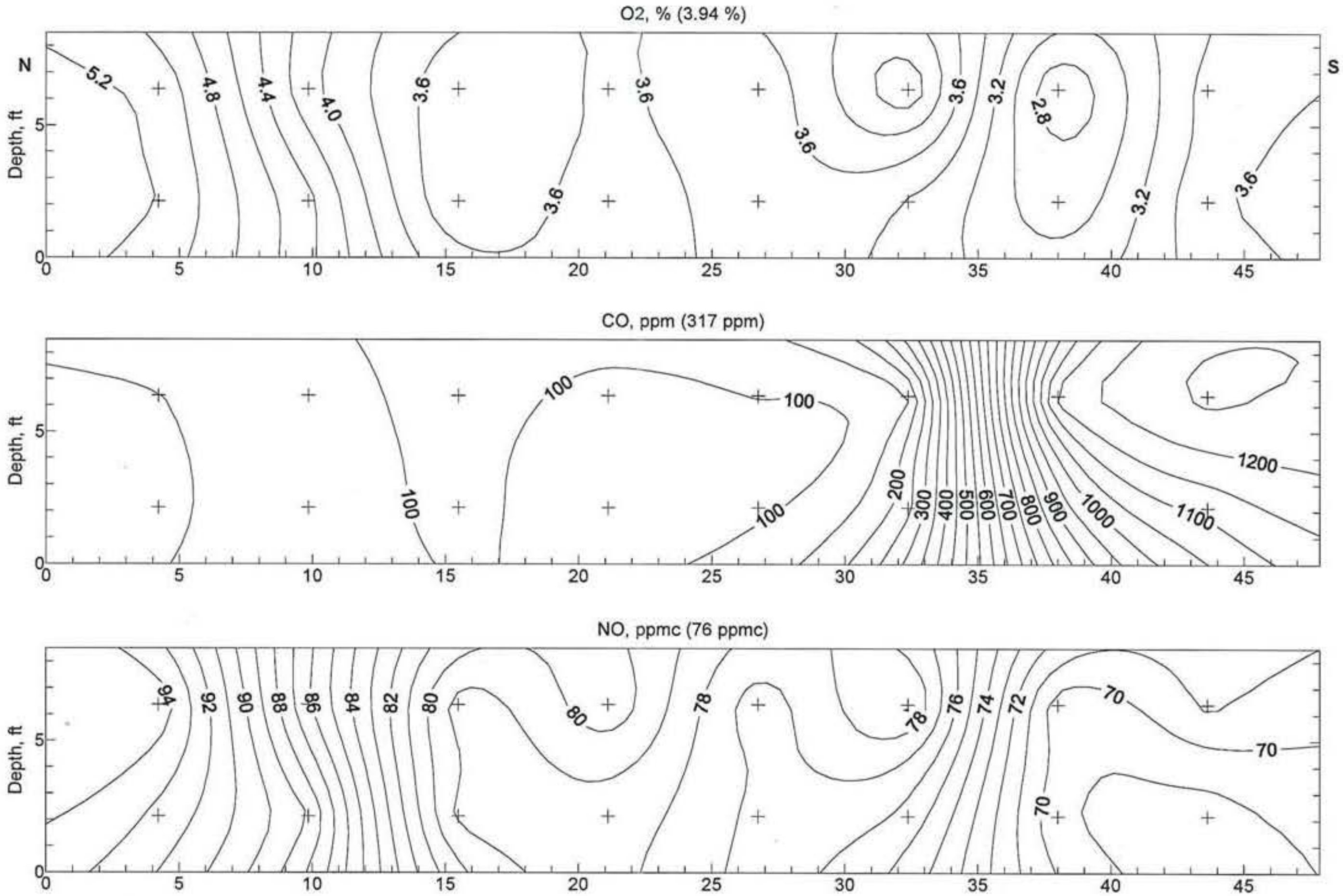


Figure E-1
Test 1, Full Load Baseline, Day 1 (11/15/08)

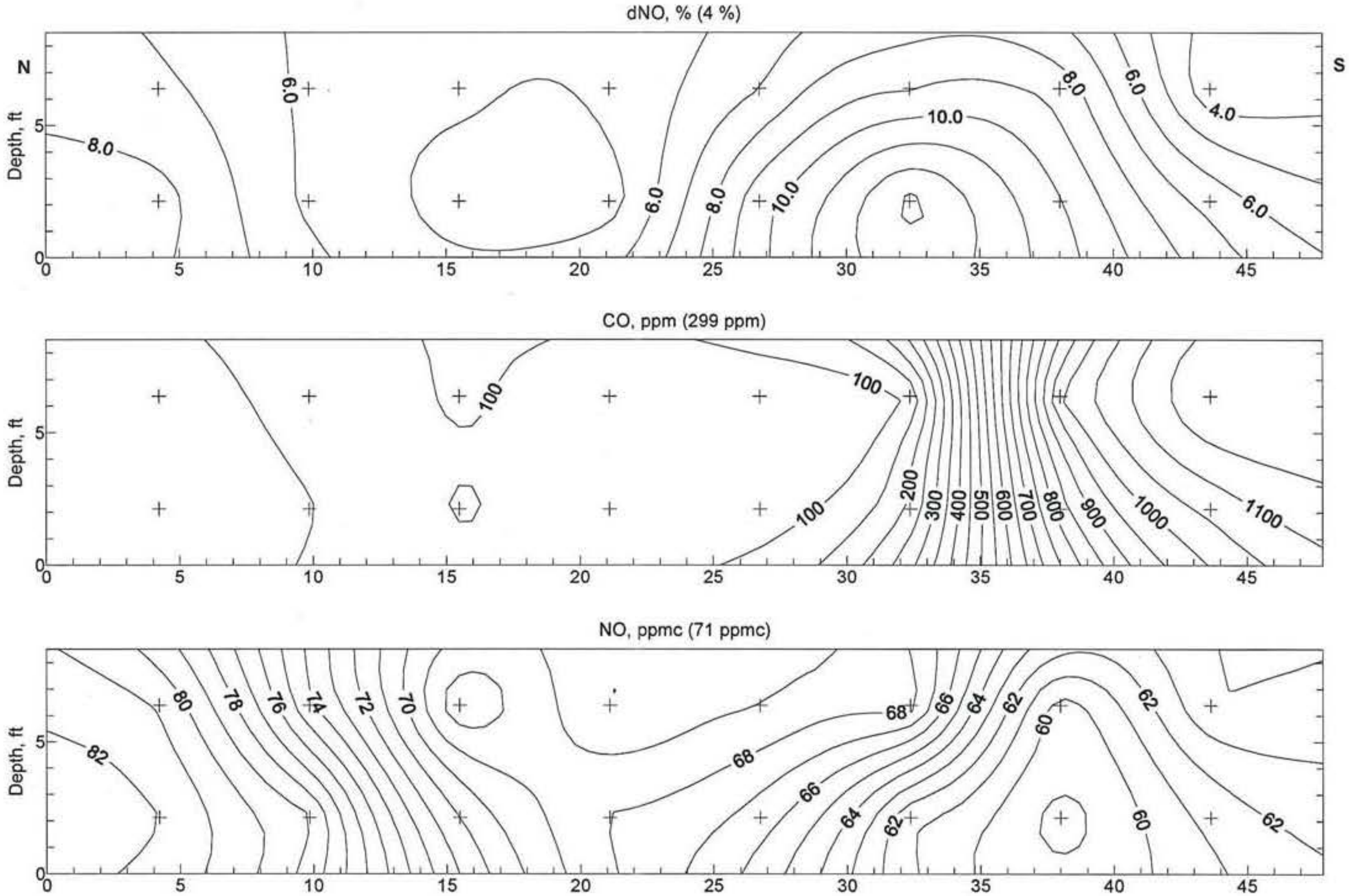


Figure E-2
Test 5, SNCR Injection Test, Day 1 (11/15/08)

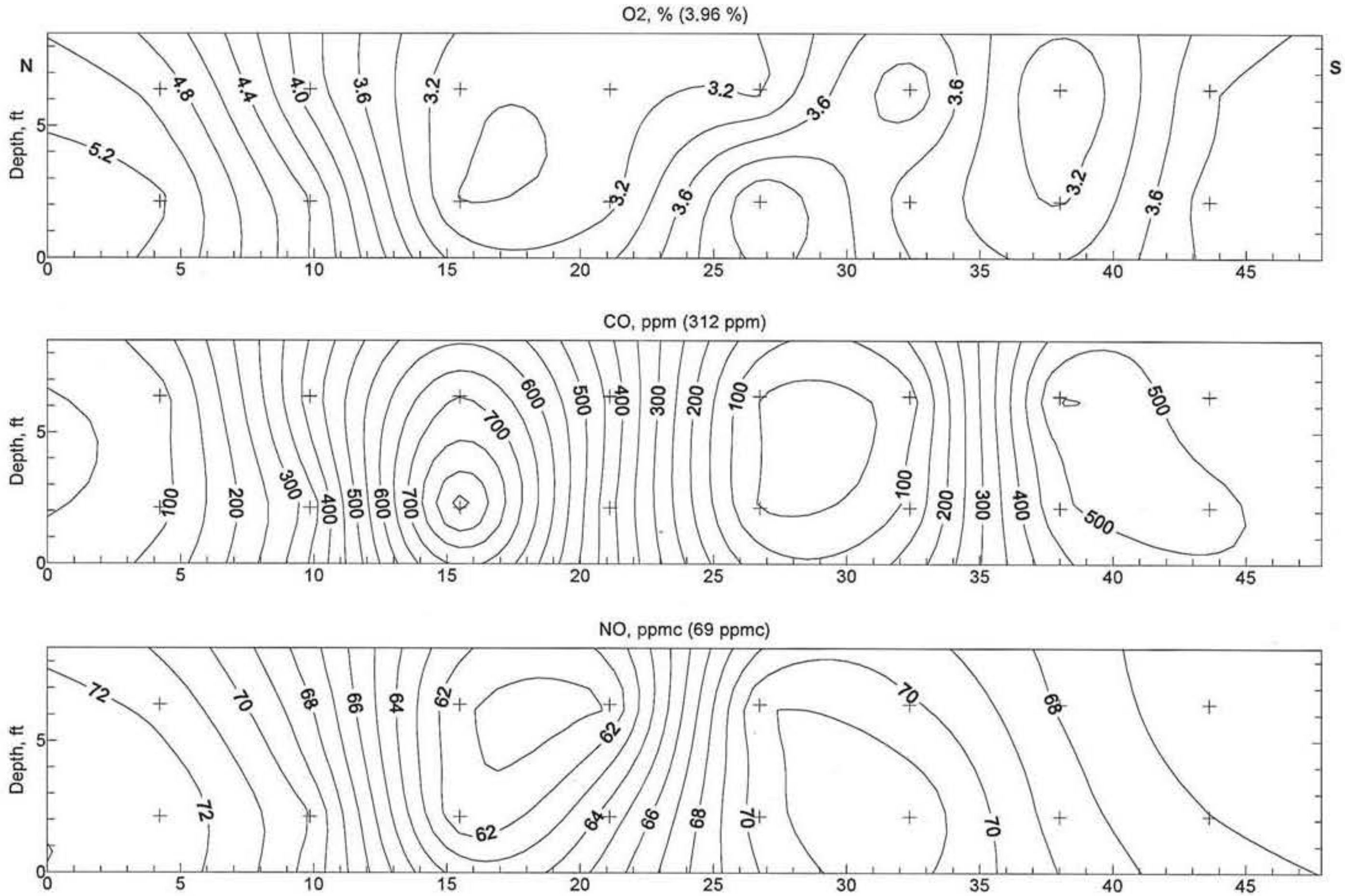


Figure E-3
Test 13, 150 MWg Baseline, Day 2 (11/16/08)

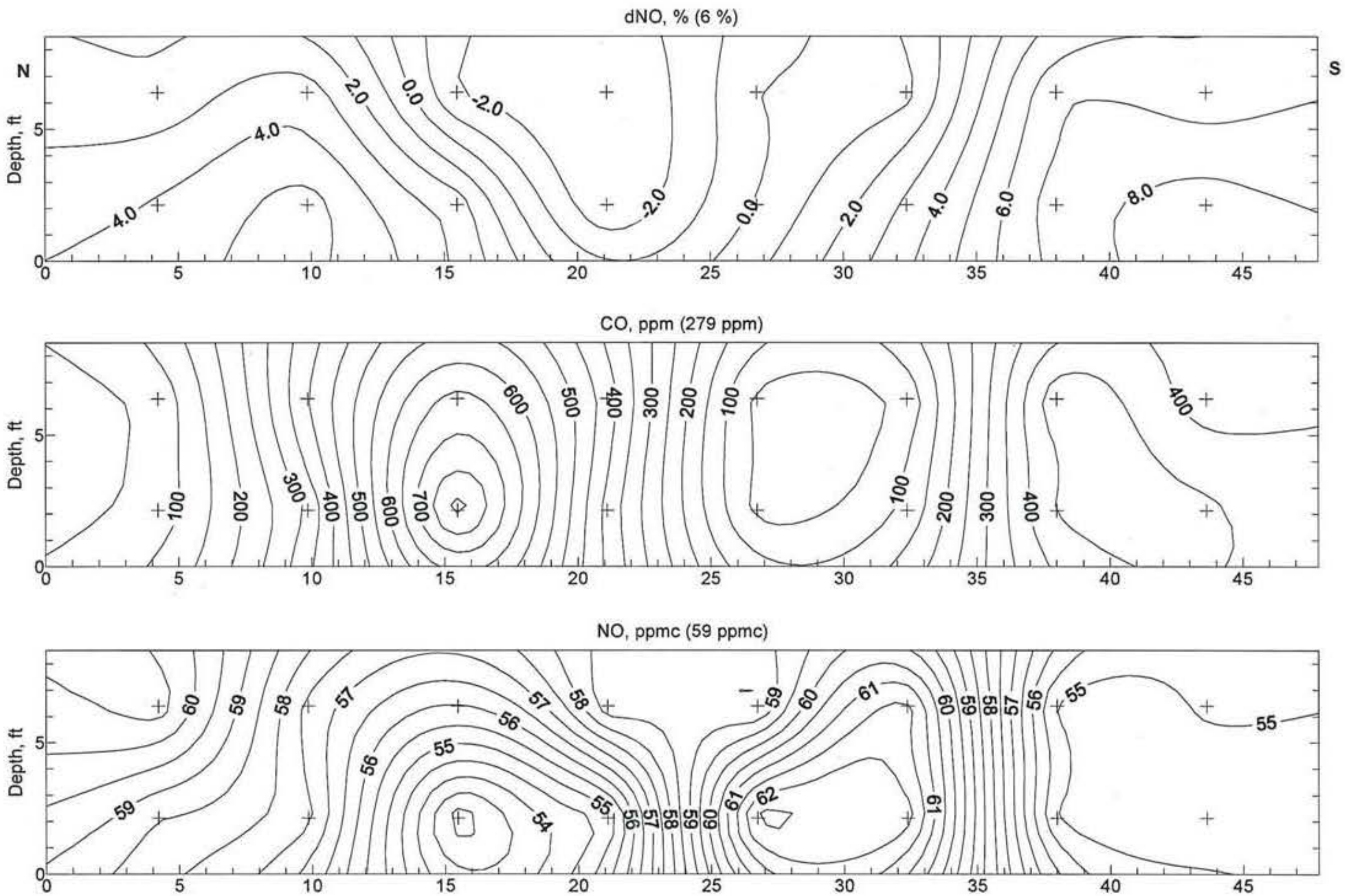


Figure E-4
Test 18, SNCR Injection Test, Day 2 (11/16/08)

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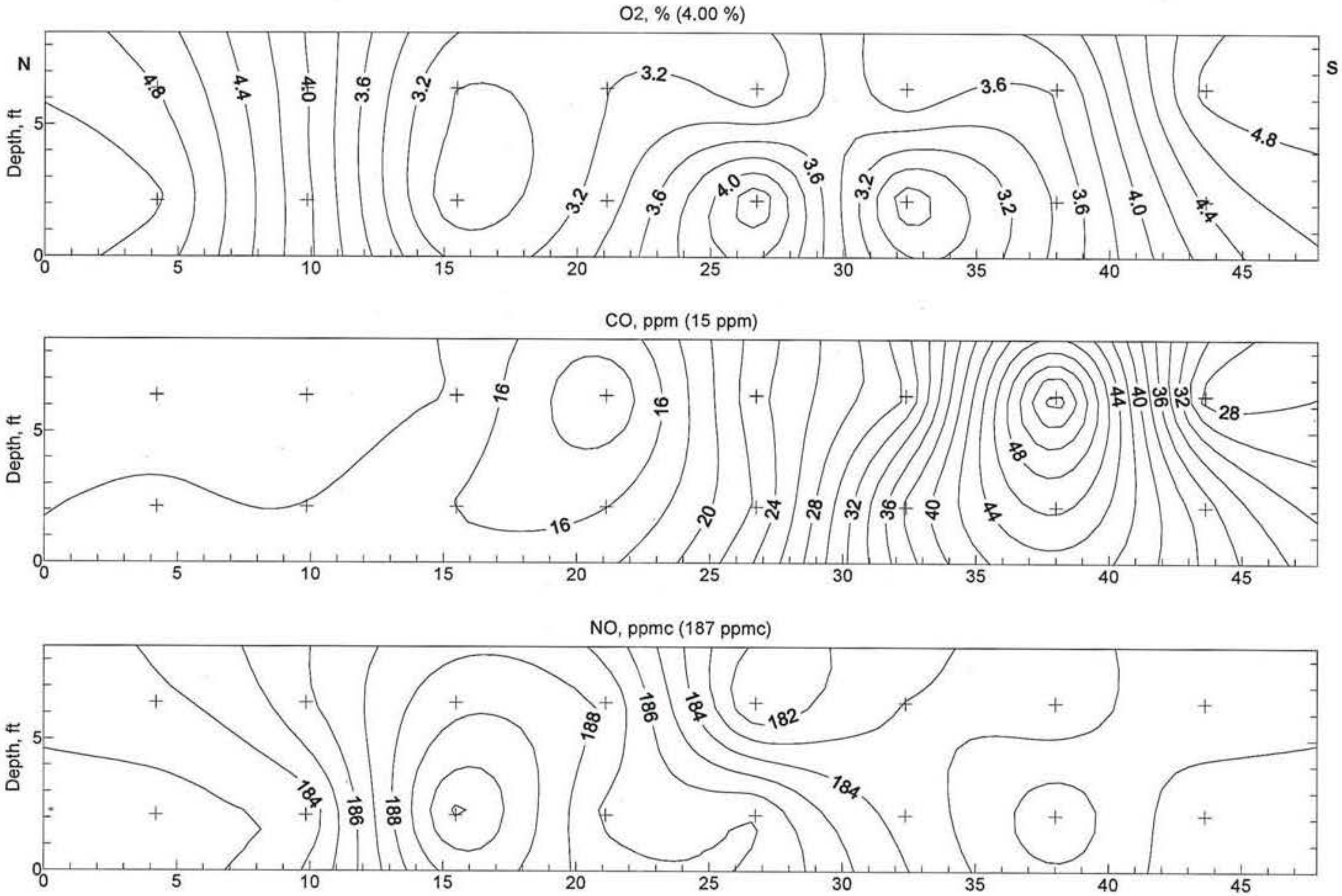

Figure E-5
Test 19, SOFA Off Baseline, Day 3 (11/17/08)

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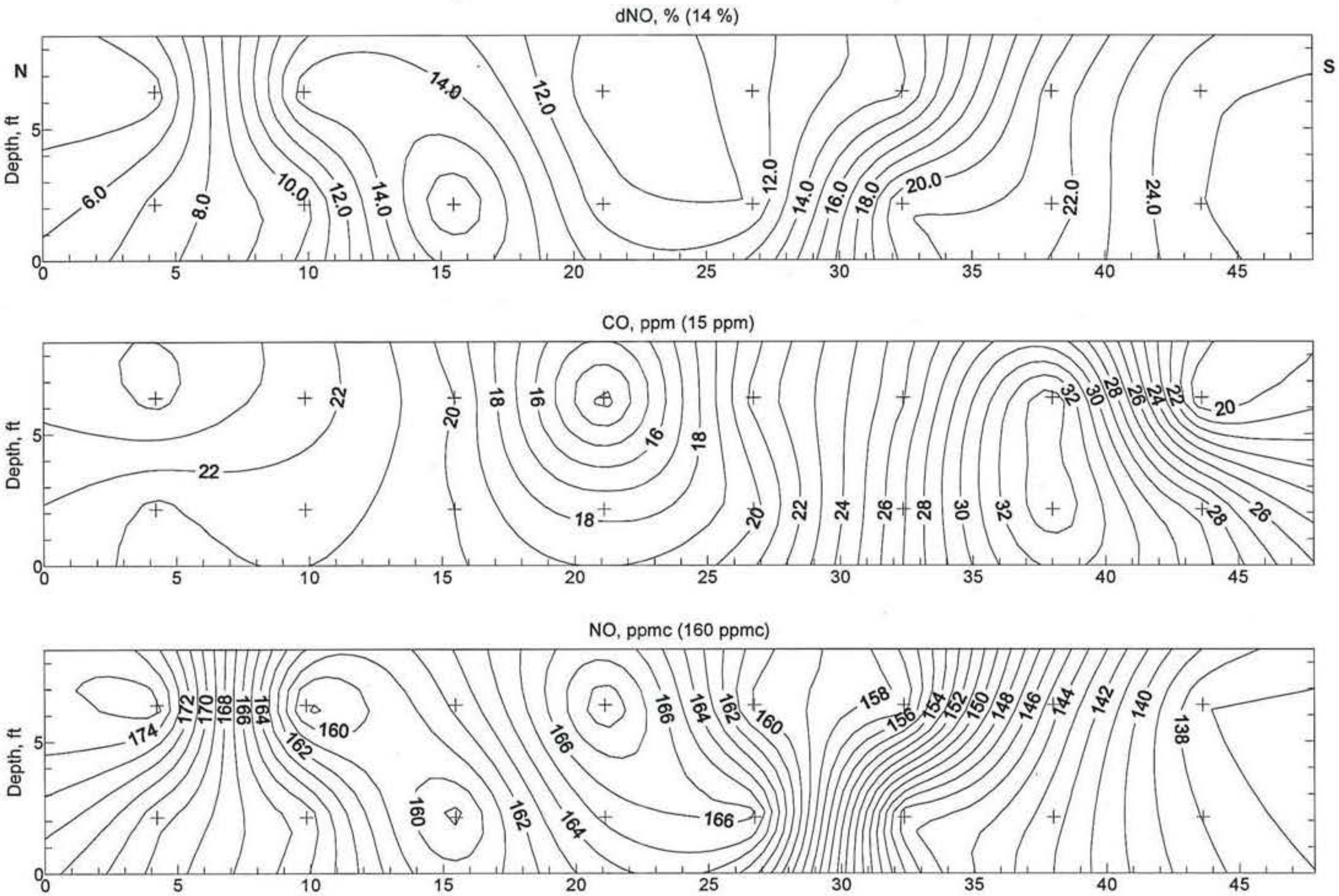

Figure E-6
Test 20, SNCR Injection Test, Day 3 (11/17/08)

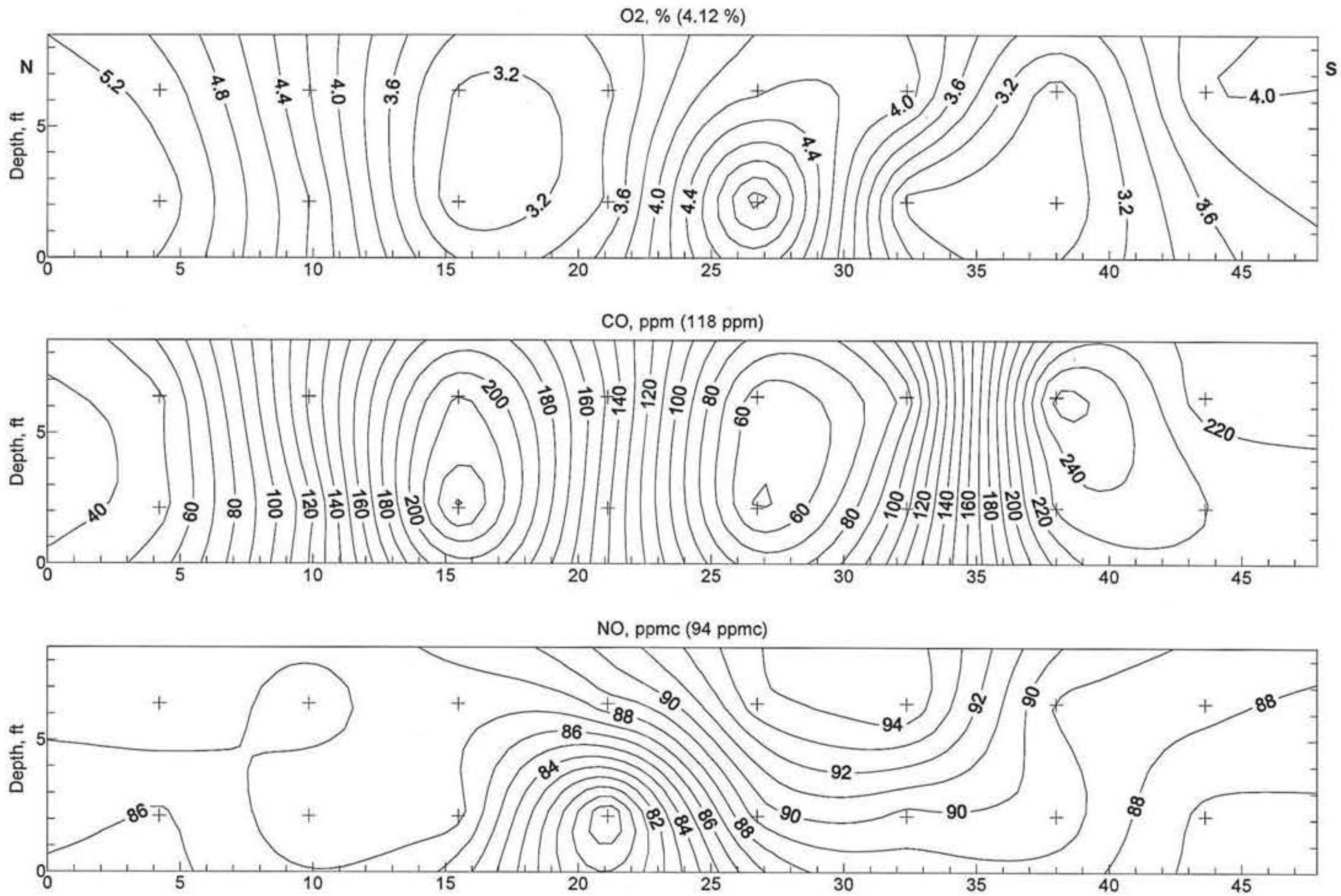

Figure E-7
Test 28, Middle SOFA Baseline, Day 3 (11/17/08)

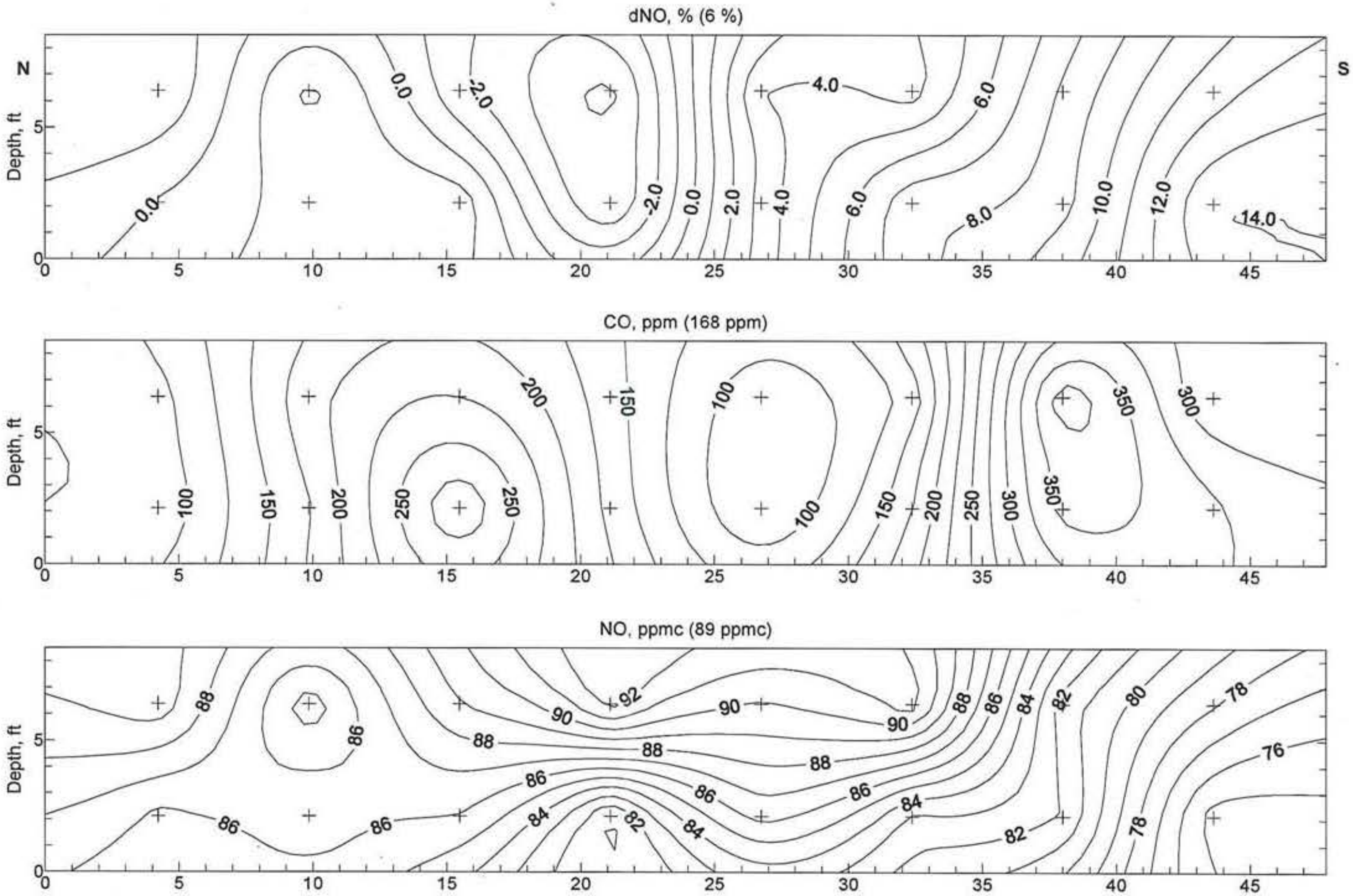

Figure E-8
Test 25, SNCR Injection Test, Day 3 (11/17/08)

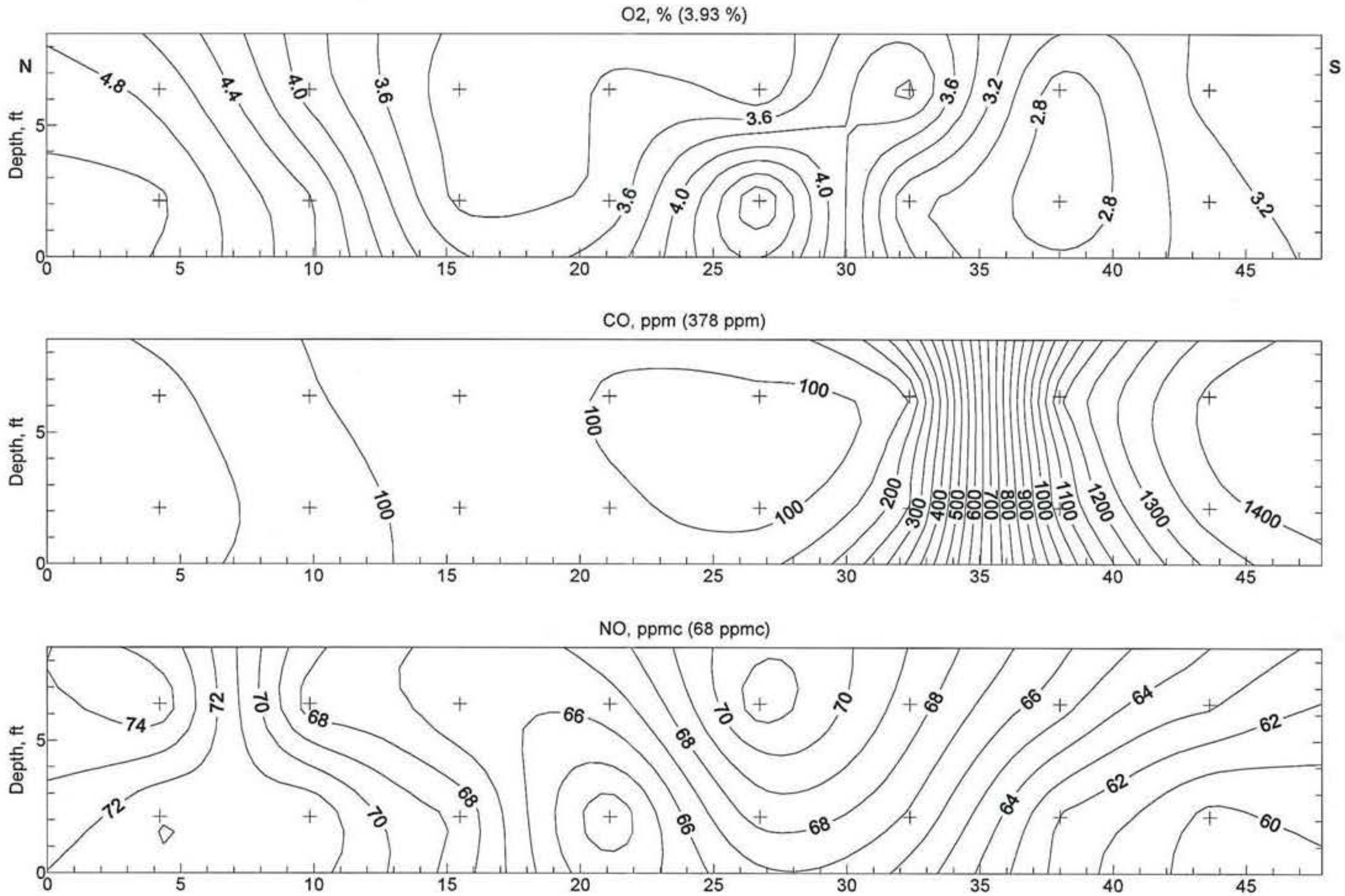

Figure E-9
Test 29, Full Load Baseline, Day 4 (11/18/08)

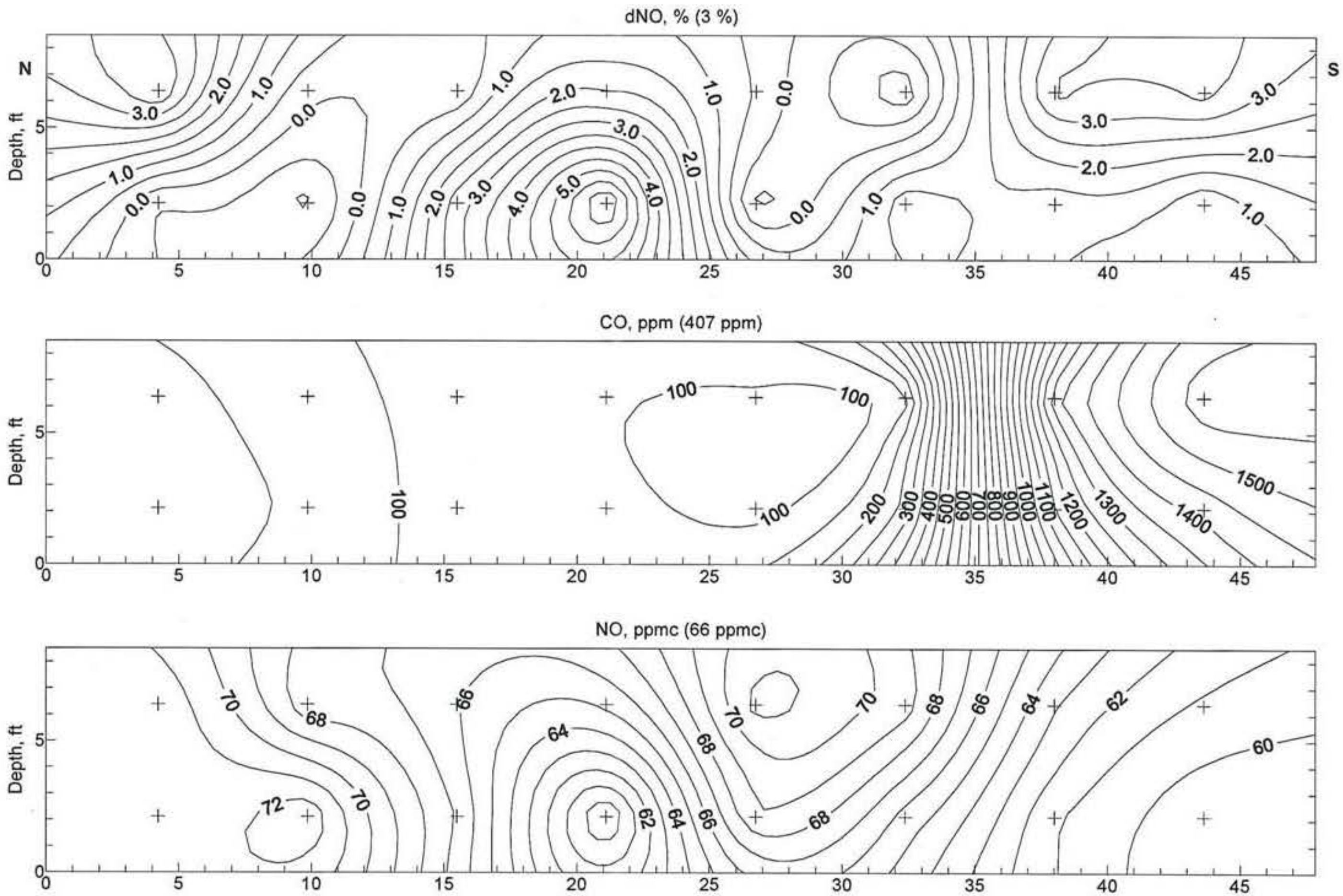

Figure E-10
Test 30, SNCR Injection Test, Day 4 (11/18/08)

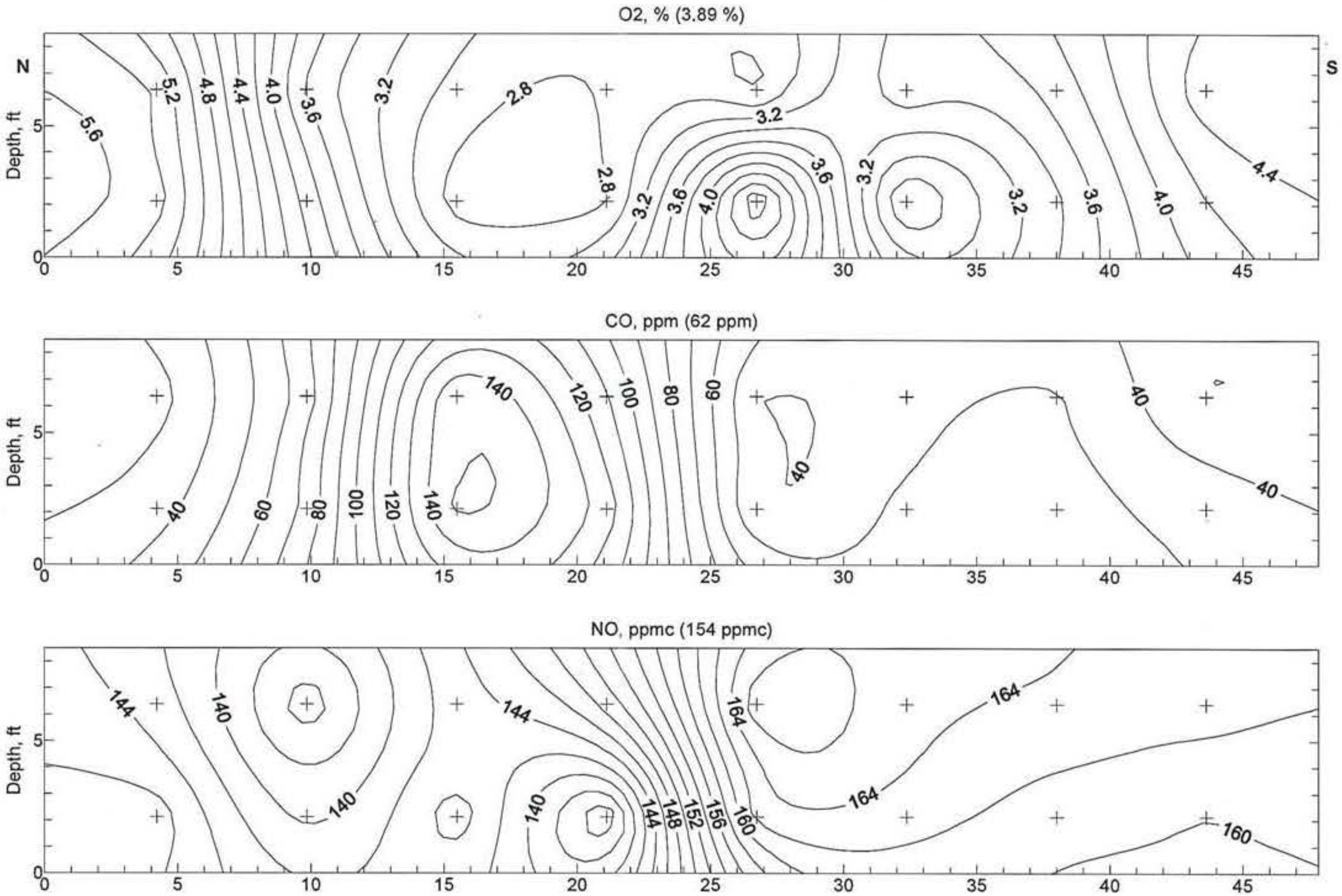

Figure E-11
Test 33, Middle SOFA Baseline, Day 5 (11/19/08)

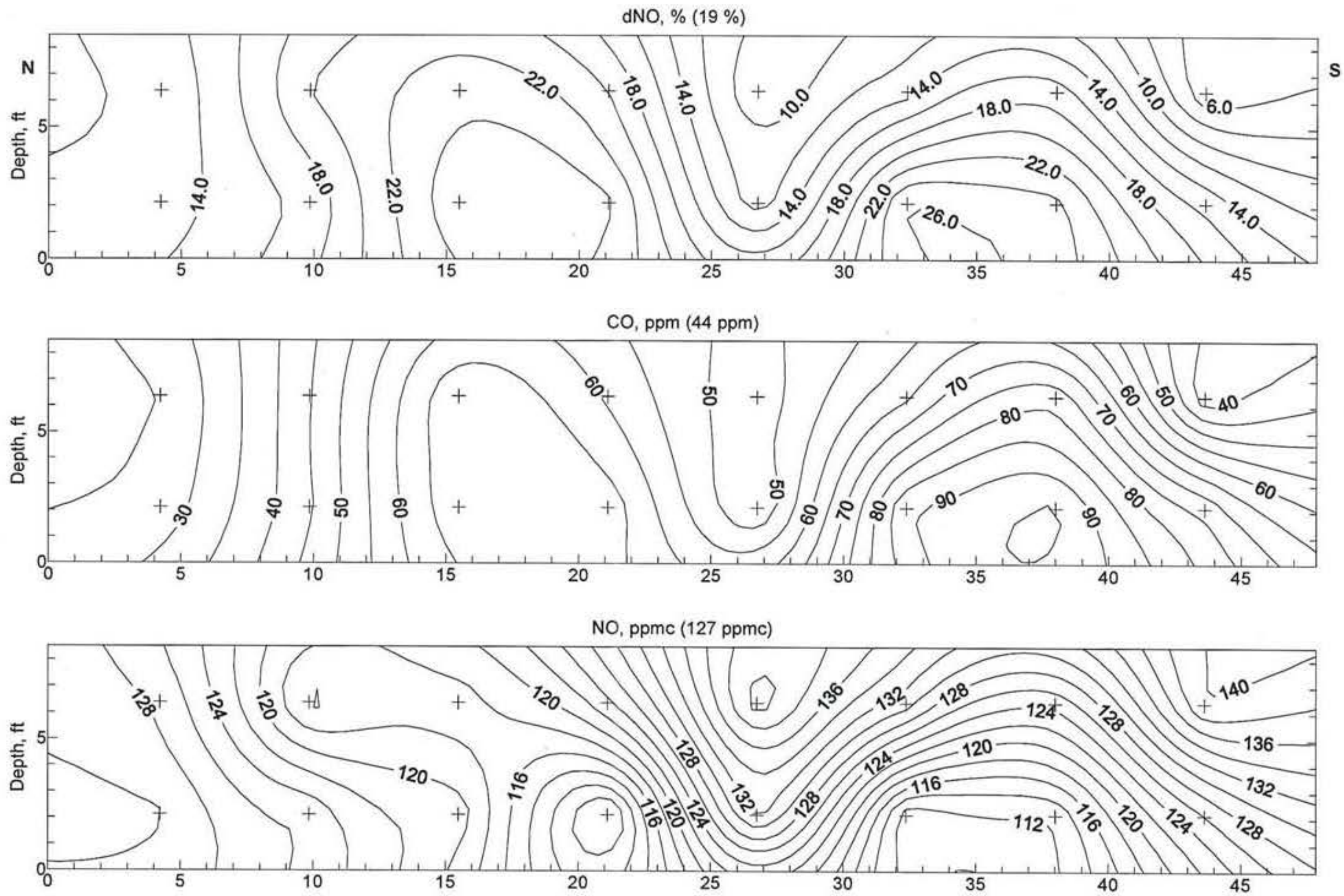

Figure E-12
Test 41, SNCR Injection Test, Day 5 (11/19/08)

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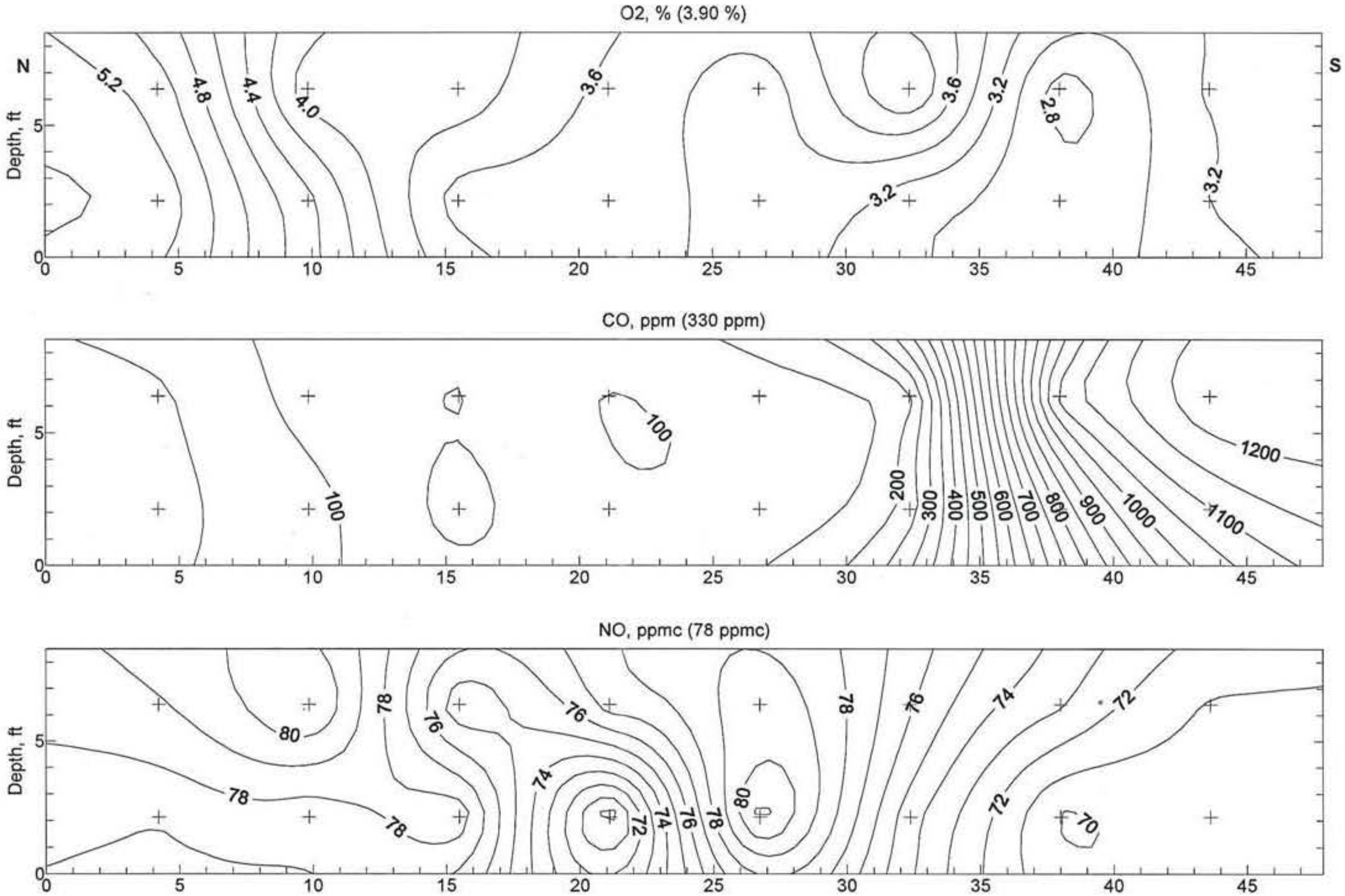

Figure E-13
Test 45, Full Load Baseline, Day 6 (11/20/08)

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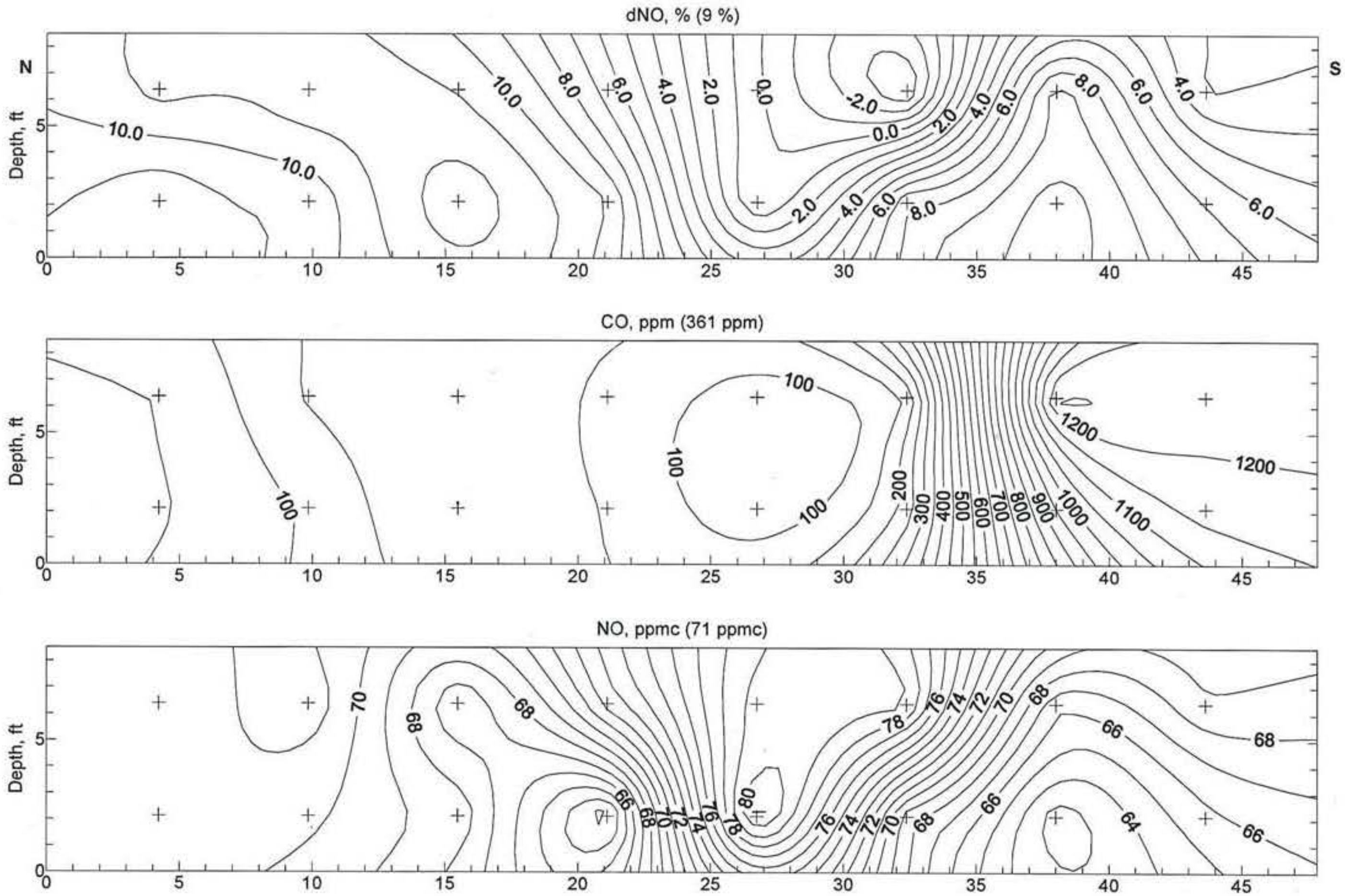

Figure E-14
Test 46, SNCR Injection Test, Day 6 (11/20/08)

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Memorandum

To: William Bumpers, Baker Botts L.L.P.
From: Andrew Skoglund
Subject: CALPUFF Visibility Impact Variations
Date: 4/4/2012
Project: 34280013.01
c: Mary Jo Roth, Debra Nelson - GRE; Joel Trinkle, Laura Brennan - Barr

CALPUFF is the USEPA's preferred model for assessing visibility impacts at Class I Areas resulting from long range (50 – 300 km) plume transport. CALPUFF is a multi-source model which accounts for plume advection and atmospheric chemical reactions to estimate the concentrations of primary chemical species (ammonium nitrate, ammonium sulfate, elemental carbon, organic carbon, fine particulate and soil) known to cause haze (i.e., visibility impairment). Plumes in CALPUFF are transported using sophisticated meteorological data and plume transformations from atmospheric chemical reactions occur due to interactions of plume pollutants, background atmospheric pollutants (ozone and ammonia) and meteorological variables – most importantly water vapor as represented by relative humidity.

Visibility impairment is calculated as a function of the light scattering properties of atmospheric particles and gases. An increase in light scattering particles decreases the visual range as measured in deciviews. The EPA estimates that a sensitive observer may be able to detect a variation of 0.5 deciviews, with 1.0 deciviews being a more accepted threshold for distinguishable difference in visual impairment. Modeled visibility impacts of 0.1 deciviews are therefore indistinguishable to the human eye.

Calpuff modeled visibility impacts are reported in the model output files to thousandths of deciviews. However, this level of sensitivity overstates the potential accuracy of the model when compared to real-world observations. Assessments of the CALPUFF modeling suite versus real-world monitoring data demonstrate the potential for significant differences between modeled and actual concentrations. There are many model inputs which play a role in impact variability, ranging from background chemistry data to emissions data entered into the model.

Visibility calculations are directly affected by the background chemistry input to the model. While ozone is input to the model based on hourly observations from available monitoring locations within the modeling domain, ammonia inputs are calculated monthly average values. The use of monthly ammonia background concentrations in the model, allows for consistency between modeling runs, but is a simplification of the actual conditions and impacts to visibility. Variation in ammonia background can have a measurable effect on the chemical transformations in the model, and in turn on modeled visibility impacts. The background values for visibility impairing pollutants (ammonium nitrate, ammonium sulfate, elemental carbon, organic carbon, fine particulate, and soil.) are based on projected values of pristine or natural conditions. These also are input as monthly average background levels. Variability in actual backgrounds, while demonstrating definite seasonal changes, is not limited to changing by calendar month.

Additionally, the fixed nature of the modeled emissions utilized in BART analyses does not reflect actual operations of a facility. Few facilities will operate at their maximum 24-hour rate 365 days per year. The emission rates and parameters for the potential modeled scenarios use assumed emissions and fixed stack parameters (e.g. exhaust temperature, airflow) for scenarios not already in operation at a facility. Final design may yield variations in these parameters, an additional source of impact variability. There is the possibility for considerable variation in actual emissions versus the modeled maximum rates used for BART analysis. It could be expected that small changes to the source parameter assumptions would result in small changes to the model results. Therefore, if the assumed stack flow rate or temperature for the EPA BART controls were misrepresented by 10 - 20% from potential as-built values, it could be possible that the deciview difference would be on the order of 0.1 deciviews – i.e., within the sensitivity of the model.

Inasmuch as the BART modeling analysis methodology is proscriptive (e.g., model each facility individually, use background monthly ammonia values, etc…), the CALPUFF results from one model run to the next can be useful in a relative sense and not in an absolute sense (i.e., the CALPUFF model results are not expected to reflect observed values). However, the difference in results from any two modeling runs needs to be understood in context of the parameter estimated. For the BART analysis, the parameter of interest is deciviews and the human perceptibility threshold is 0.5 deciviews. On this basis, differences in model run results of less than 0.5 deciviews are not significant.

For the CCS modeling analysis, the model run differences are 1) baseline – current controls compared to 2) baseline – EPA BART controls. In both cases, the relative model results (baseline – controls) show a fairly large difference (up to 2 deciviews), giving some confidence in the modeling results that controls would result in perceptible improvements to visibility. However, the EPA's contention that the 0.1 deciview difference between 1) and 2) is actionable based on modeling, ignores the fact that 0.1 is the difference between two large numbers.

Given the many sources of variability of input to CALPUFF's visibility analysis versus actual impacts, a difference of 0.1 deciviews between options may reflect no real difference at all.

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TRANSMITTAL LETTER

To:	Mary Jo Roth (GRE)	**Date:**	April 5, 2012
c:	Deb Nelson (GRE), Diane Stockdill (GRE), Joel Trinkle (Barr)		
Project #:	34280013.01	**Re:**	GRE CCS Supplemental NOx Analysis
Sent by:	Laura Brennan	**Phone:**	952.832.2615

We are sending you:

	Correspondence	X	Reports		Plans
	Copy of Letter		Specifications		Other:

These are transmitted as checked below:

	For approval	X	As requested		Other:
	For your use		For review and comment:		

Description:

This report is a revised version of the original November 2011 report titled "Best Available Retrofit Technology Refined Analysis for NOx Emissions" submitted by GRE to the NDDH. The report reflects the collaborative effort of Barr and GRE with assistance from other technical consultants to develop an appropriate control strategy for Coal Creek's Units 1 and 2. Barr assisted with the development and update of cost estimates for various control scenarios, incorporating GRE's work with URS and Golder into the technical discussion at GRE's direction.

The Refined NOx Analysis is prepared in response to comments from the NDDH provided in letters dated January 19, 2012 and February 28, 2012. The conclusions and text of the analysis are not markedly changed in responding to NDDH's comments. The changes in this report primarily focus on updated modeling results and clarifications to cost calculations, as described below.

In response to an anomaly identified in Appendix D of GRE's submittal, GRE has revised the visibility tables that were presented in that submittal. A review of the modeling output files for the year 2000 SNCR run in question concluded that the values presented in the original table were consistent with the output files. The original modeling runs had been conducted in 2006 and 2007 for the initial BART evaluation, and the intermediate data files were no longer available to identify whether the apparent error was the result of an incomplete annual model run or some other contributing factor. In order to be responsive to NDDH's request for clarification of the data, the model was re-run. The modeling files had not previously been reopened for the NOx refined analysis efforts in 2011 and 2012. Accordingly, GRE also took the opportunity to more closely

realign the NOx emission rates and stack-related modeling input parameters with the scenarios described in the report for all scenarios in all years as opposed to the approximations from previously modeled scenarios shown in the November 2011 tables.

The new results more closely align with the expected reductions for each control scenario and follow the trend originally illustrated in the year 2001 and 2002 tables for the February 10, 2012 submittal. The revised modeling runs support the conclusions presented in the GRE NOx analysis, and have only resulted in minor revisions to Table 3.3.1 and Appendix D.

In this revised report, NDDH also provides several comments with respect to alignment of calculations and clarity of documentation provided in the Appendix A cost calculations. Footnotes and documentation are appropriately updated. Additionally, the calculation alignment is clarified through the inclusion of additional significant digits. Neither of these updates result in changes to the final cost tables included within the report text.

Should you have any questions regarding this transmittal or the revisions herein, please contact Laura Brennan at 952.832.2615.

GREAT RIVER ENERGY®

A Touchstone Energy® Cooperative

Coal Creek Station Units 1 and 2

Supplemental Best Available Retrofit Technology Refined Analysis for NOx Emissions

November 2011; Updated April 5, 2012

Coal Creek Station Supplemental BART Refined Analysis for NOx Emissions

November 2011; Updated April 5, 2012

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1.0 Introduction

In December 2007, GRE submitted its final Best Available Retrofit Technology (BART) evaluation for Regional Haze controls to the North Dakota Department of Health (NDDH). The NDDH incorporated the proposed emission limitations for Coal Creek Station (CCS) Units 1 and 2 into their proposed State Implementation Plan (SIP), and issued a draft Permit-to-Construct (PTC) for these BART limits. As part of their review on North Dakota's draft and final SIP, EPA requested supplemental data and documentation on Coal Creek's BART controls. These requests started in February 2010, and continued through June 2011 and July 2011. GRE provided the requested information.

On September 21, 2011, EPA proposed a Federal Implementation Plan (FIP), which would override certain NDDH determinations, particularly with respect to required NOx controls for certain coal-fired utility units. On November 3, 2011, NDDH requested that GRE provide a supplemental BART analysis that is focused on NOx control options at Coal Creek Station. In particular, GRE has performed more refined analyses on selective non-catalytic reduction (SNCR) cost assumptions, achievable control levels and the overall impacts to ash re-use on Coal Creek's Units 1 and 2. This supplemental analysis is being provided to address questions from the NDDH per its letters of January 19, 2012 and February 28, 2012.

Based on the supplemental analyses, Great River Energy still asserts that use of its state-of-the-art coal drying technology, DryFining™, in conjunction with second generation combustion control low NOx burners with separated overfire air (LNC3+), meets EPA's presumptive BART NOx limit of 0.17 lb/MMBtu, and is consistent with cost effective thresholds as set by North Dakota and ultimately approved by EPA through their partial approval of the North Dakota SIP. When all factors are adequately considered, including ammoniated ash impacts, SNCR is not considered cost effective for Coal Creek and would not result in perceptible visibility improvements in the affected Class I areas.

This supplemental analysis summarizes updated SNCR cost and emission assessments and supplemental information provided by URS Energy and Construction (URS). It also provides an updated ash implication assessment and supplemental information as provided by Golder Associates (Golder). (see Appendices F and G, respectively) The updated ash implications are then integrated with the updated SNCR cost and emission estimates to more accurately demonstrate that SNCR is not cost effective, by either EPA established thresholds or NDDH established thresholds.

1.1 Initial BART Analysis and EPA Guidance

In preparing the initial BART analysis and subsequent revisions, Great River Energy developed a combination of detailed engineering and screening level analyses, which were ultimately used by NDDH to make their BART determinations. From the BART preamble, EPA sets presumptive levels based on their cost effective assessments and deciview reductions, and essentially rule out post combustion NOx controls for electric generating units greater than 750MW, subject to the state's determination. Great River Energy's screening level analyses on SNCR and ash impacts initially supported EPA's presumptive determination. Great River Energy continues to concur with EPA's establishment of a presumptive NOx emission limit at 0.17 lb/MMBtu.

Specifically, in its final rule publication of 40 CFR Part 51, Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations, EPA establishes presumptive NOx levels based on combustion controls, and not SNCR:

> *In today's action, EPA is setting presumptive NOx limits for EGUs larger than 750 MW. EPA's analysis indicates that the large majority of the units can meet these presumptive limits at relatively low costs. Because of differences in individual boilers, however, there may be situations where the use of such controls would not be technically feasible and/or cost-effective. For example, certain boilers may lack adequate space between the burners and before the furnace exit to allow for the installation of over-fire air controls. Our presumption accordingly may not be appropriate for all sources. As noted, the NOx limits set forth here today are presumptions only in making a BART determination, <u>States have the ability to consider the specific characteristics of the source at issue and to find that the presumptive limits would not be appropriate for that source.</u>* (emphasis added)

> *For all types of boilers other than cyclone units, the limits in Table 2 are based on the use of current combustion control technology. Current combustion control technology is generally, but not always, more cost-effective than post-combustion controls such as SCRs. For cyclone boilers, SCRs were found to be more cost-effective than current combustion control technology; thus the NOx limits for cyclone units are set based on using SCRs. SNCRs are generally not cost-effective except in very limited applications and therefore were not included in EPA's analysis. The types of current combustion control technology options assumed include low NOx burners, over-fire air, and coal reburning.*

We are establishing presumptive NOx limits in the guidelines that we have determined are cost-effective for most units for the different categories of units below, based on our analysis of the expected costs and performance of controls on BART-eligible units greater than 200 MW. We assumed that coal-fired EGUs would have space available to install separated over-fire air. Based on the large number of units of various boiler designs that have installed separated over-fire air, we believe this assumption to be reasonable. It is possible, however, that some EGUs may not have adequate space available. In such cases, other NOx combustion control technologies could be considered such as Rotating Opposed Fire Air (''ROFA''). The limits provided were chosen at levels that approximately 75 percent of the units could achieve with current combustion control technology. The costs of such controls in most cases range from just over $100 to $1000 per ton. Based on our analysis, however, we concluded that approximately 25 percent of the units could not meet these limits with current combustion control technology. However, our analysis indicates that all but a very few of these units could meet the presumptive limits using advanced combustion controls such as rotating opposed fire air (''ROFA''), which has already been demonstrated on a variety of coal-fired units. Based on the data before us, the costs of such controls in most cases are less than $1500 per ton. (emphasis added)

The advanced combustion control technology we used in our analysis, ROFA, is recently available and has been demonstrated on a variety of unit types. It can achieve significantly lower NOx emission rates than conventional over-fire air and has been installed on a variety of coal-fired units including T-fired and wall-fired units. We expect that not only will sources have gained experience with and improved the performance of the ROFA technology by the time units are required to comply with any BART requirements, but that more refinements in combustion control technologies will likely have been developed by that time. As a result, we believe our analysis and conclusions regarding NOx limits are conservative. For those units that cannot meet the presumptive limits using current combustion control technology, States should carefully consider the use of advanced combustion controls such as ROFA in their BART determination (emphasis added).[1]

There are several key concepts from EPA's preamble. First, Coal Creek is unique in that it has installed DryFining™ as a novel multi-pollutant control technology. This is important because it enhances the effectiveness of the NOx combustion controls. Second, Coal Creek re-uses the vast

[1] Federal Register / Vol. 70, No. 128 / Wednesday, July 6, 2005 / Page 39134-39135.

majority of its fly ash rather than disposing of it. Any negative impacts to fly ash, such as adding ammonia, will have both operational risks and cost implications for Great River Energy that must be included in any cost-effectiveness determination. Third, EPA has made its cost-effectiveness determination in setting presumptive BART NOx levels and has given states the authority to determine if more stringent requirements are needed based on their review.

In reviewing EPA's preamble discussion, it was clear to GRE that the EPA did not expect BART control scenarios for tangentially-fired units, such as Coal Creek Station's Units 1 and 2, to include post combustion add-on controls such as selective catalytic reduction (SCR) and SNCR. As such, in the initial BART evaluation, GRE focused on supporting this determination through the use of screening level cost data, and comparing those screening costs to cost effectiveness thresholds.

Based on the direction provided in the BART preamble and guidance, along with an analysis of cost effectiveness thresholds implemented in other EPA regulatory programs,[2] GRE proposed a cost effectiveness range of $1,300 to $1,800 (2006$) per ton of NOx removed. Guidance provided by NDDH presented higher cost per ton thresholds than EPA's in setting the presumptive level.

GRE's BART NOx determination for CCS Units 1 and 2 was consistent with EPA's preamble and confirmed that advanced combustion controls and an emission limit of 0.17 lb/MMBtu represented BART. SNCR was found to be cost <u>in</u>effective based on screening level analysis, and presented additional operational and non-environmental impacts that were not exhaustively discussed in the December 2007 BART analysis but are provided herein.

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[2] http://www.ndhealth.gov/AQ/RegionalHaze/Regional%20Haze%20Link%20Documents/Appendix%20C/Coal%20Creek/Coal%20Creek%20BART%20Analysis.pdf (Appendix B).

2.0 Refined NOx Control Evaluation at CCS

This section will first establish that Coal Creek is unique, such that site specific evaluations are more appropriate than relying on general screening level assumptions to determine emission reductions and associated costs. It will then summarize the evaluation of site specific SNCR NOx reductions by URS, as well as ash impacts from the ammonia associated with this control.

2.1 Unique Aspects of Unit 1 and 2 NOx Controls

As discussed in the following sections, Coal Creek Station is neither average nor typical. EPA Guidelines, provided to States in identifying appropriate Regional Haze control requirements and provided in EPA's Pollution Control Cost Manual (2002), are developed in order to assist State authorities in making regulatory determinations. These guidelines are not to be viewed as regulatory requirements. They are best suited for evaluating average or typical installations. Units 1 and 2 are uniquely designed and employ a state-of-the-art lignite fuel enhancement technology, or DryFining™. This means that any accurate analysis of add-on NOx controls must be site specific and not rely upon general guidelines, which might apply to a normal facility.

2.1.1 DryFining™ Technology

GRE has a long track record of being innovative and going beyond minimum environmental requirements. DryFining™ is a $270 million, multi-pollutant technology. It reduces coal moisture and impurities while increasing the heat content of Fort Union lignite, which has the highest moisture of any coal in the US. The operation of DryFining™ has afforded CCS Units 1 and 2 significant reductions across the spectrum of emissions. Sulfur dioxide and mercury emissions have been reduced by more than 40%. Carbon dioxide emissions have been reduced by 4%. NOx emissions – the subject of the EPA FIP and this evaluation – have been reduced by more than 20%.

GRE expected that some additional NOx reductions would result from the implementation of DryFining™. It was estimated that the reduction in coal moisture, and corresponding increase in coal heat content, would result in less coal into the furnace, and more air available elsewhere in the furnace, which can be utilized to reduce NOx emissions. However, this NOx reduction benefit was not quantified in the original BART analysis. At the time of the final BART analysis (December 2007), DryFining™ had not yet operated, and the exact degree of control was unknown for this innovative strategy. Because DryFining™ has been in place for nearly two years, NOx emissions are

reduced. Consequently, current (baseline) NOx emissions that are used in Section 3.1 have been updated to reflect the URS control cost analysis and are inclusive of DryFining™, with low NOx burner technology as applicable.

2.1.2 NOx Combustion Control Considerations

GRE's proposed BART NOx control strategy includes the use of DryFining™ along with advanced combustion controls. As a result of the installation of the proposed advanced combustion controls on Unit 2, GRE has gained a better understanding of anticipated NOx control levels and costs.

The size and arrangement of the furnace box on CCS Units 1 and 2 is unique. It is literally a one-of-a-kind furnace box, sized specifically for the high moisture Fort Union lignite. Given a larger firebox, relative to other lower-moisture, higher-heat-content coal-fired units, there is a correspondingly higher complexity and higher cost to NOx combustion controls. There is a greater distance across the furnace through which the air must penetrate, thus increasing the size and type of wall nozzles, along with increased nozzle staging complexity throughout the wall sections. When an advanced combustion air system is added to a larger firebox, it requires additional wall openings, and redesign to wall water tubes, further increasing costs.

Since the time of the initial BART submittal, GRE has gained direct operational experience on the performance of these advanced combustion controls and DryFining™. Prior to the installation of DryFining™, most of the available primary air was needed to convey, grind, and dry the coal in the pulverizers due to the high moisture in the coal. Consequently, the maximum performance for the LNC3+ control installed on Unit 2 could not be fully realized upon initial installation. The Unit 2 LNC3+ installation includes larger registers to increase available primary air. Since a significant amount of that primary air was used to dry and pulverize the "unrefined" high moisture coal, there was not sufficient air available for the larger registers to act as a form of overfire air. With DryFining™, there is additional air available to be routed to the larger registers, which reduces NOx emissions. As a result, Units 1 and 2 currently operate with annual average NOx emissions of 0.200 and 0.153 lb/MMBtu, respectively. Unit 2's lower annual average NOx emission rate is directly attributable to the larger registers, which are tentatively anticipated for Unit 1 in 2014.

2.1.3 Site Specific SNCR Expected Control Levels

Portions of Coal Creek Station's December 2007 submittal of the NOx BART analysis were based on screening level data presented in the EPA Pollution Control Cost Manual (2002). Since EPA has proposed to reject North Dakota's SIP largely on their assessment of SNCR's screening level, cost

effectiveness, it is imperative to more accurately portray SNCR costs. With respect to SNCR specifically, EPA acknowledges in its cost manual:

> *SNCR system design is a proprietary technology. Extensive details of the theory and correlations that can be used to estimate design parameters such as the required [normal stoichiometric ratio] NSR are not published in the technical literature. Furthermore, <u>the design is highly site-specific.</u> <u>In light of these complexities, SNCR system design is generally undertaken by providing all of the plant- and boiler-specific data to the SNCR system supplier, who specifies the required NSR and other design parameters based on prior experience</u> and computational fluid dynamics and chemical kinetic modeling.*[3](emphasis added)

As discussed above, GRE has established that Coal Creek is unique due to its boiler size, DryFining™, and existing NOx combustion controls. Therefore, only a site specific evaluation, by a competent engineering and construction company (URS) familiar with SNCR engineering and installation costs, should be used to estimate emission reductions and associated costs. URS is a leading engineering consultant, with significant experience in installing SNCR technology, having managed the design and installation of several dozen SNCR pollution control systems throughout the world. This experience qualifies URS to make site-specific recommendations on SNCR design.

URS completed a site inspection, evaluated the unique aspects of Coal Creek, and provided their refined analysis (see Appendix B).

URS has determined that the removal efficiency for Coal Creek Unit 1 with an inlet NOx concentration of 0.22 lb/MMBtu would not be 50% as anticipated from the EPA Pollution Control Cost Manual (2002), and as used in GRE's original BART analysis. Rather, URS estimates a removal rate of approximately 30% removal for Unit 1. With respect to Unit 2, and an inlet concentration of 0.15 to 0.16 lb/MMBtu, URS estimates the removal efficiency would be approximately 20%.

EPA has raised concerns with respect to utilizing a new baseline period in determining the removal efficiencies for SNCR vs. DryFining™ with LNC3+. At the time of the 2007 BART analysis, GRE had no experience with the DryFining™ technology and was unable to determine the removal efficiencies possible with the LNC3+ and DryFining™ projects combined relative to NOx emissions.

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[3] EPA Pollution Control Cost Manual (2002); Section 4.2 Chapter 1.3.

In an effort to evaluate existing installed technologies, GRE incorporated actual DryFining™ operating experience and performance subsequent to the 2007 analysis. This information must be considered in the revised analysis in order to capture the actual realized removal efficiencies of the DryFining™ and LNC3+ technologies as existing installed pollution control technologies. GRE notes that since the submittal of the 2007 BART analysis, GRE has lowered its Unit 2 NOx emissions from the baseline level of 0.22 lb/MMBtu to 0.153 lb/MMBtu on an annual average basis. This equates to an emissions reduction of 30.5% from the previously utilized 2007 baseline.

In addition to GRE's experience operating CCS with LNC3+ in combination with the DryFining™ technology, resulting in lower NOx emission levels, a relatively new study has been completed for a facility with low-baseline NOx emissions[4] (Appendix E). This EPRI study addressed applicability of and anticipated removal efficiencies for SNCR for units with low-baseline NOx emissions. The study's findings suggest that SNCR performance is significantly decreased at baseline NOx emission levels less than 100 ppm[5]. The demonstrated low removal efficiencies (~10% reduction) are much lower than GRE's suggested removal efficiency for the SNCR technology (20%) applied in this analysis. Similarly, the low removal efficiencies are also much lower that the removal efficiency of 25%+ suggested in EPA's proposed FIP.

The study concludes that for low-baseline NOx applications, at levels around 75 ppm4, anticipated removal efficiency for SNCR is in the range of 8%-12%. If GRE takes into account the data from this study in place of the removal efficiency recommended by URS, the cost effectiveness would be well outside the range deemed cost effective. GRE's anticipated SNCR removal efficiency of 20% is likely higher than the technology will be able to achieve starting from a baseline of 0.153 lb NOx/MMBtu or 88 ppm (DryFining™ with LNC3+ installed). GRE continues to use a removal efficiency of 20% in its analysis based on the SNCR technology evaluation conducted by URS, but notes that this value may in fact be conservatively optimistic.

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[4] *Low-Baseline NOx Selective Non-Catalytic Reduction Demonstration*: *Joppa Unit 3*. EPRI, Palo Alto, CA: 2009, 1018665. GRE asserts a business confidentiality claim and asserts this report is confidential business information subject to the protections set forth in Air Pollution Control Rules for the State of North Dakota at 33-15-01-16 and 40 CFR Part 2.

[5] Current NOx concentrations for CCS Unit 1 and Unit 2 are 110 ppm and 88 ppm, respectively (determined on a 12-month rolling average basis).

Given these lower projected emission rates, and the lower "baseline" emission rates from installed controls, the cost evaluation has been revised, accordingly, in Section 3.1.

Rather than relying on the original screening level analyses, GRE finds it imperative to provide this updated information to North Dakota to make their well-informed cost effectiveness determinations.

2.2 Revision of Baseline NOx Emissions

The BART Guidelines (40 CFR 51, Appendix Y) state "The baseline emissions rate should represent a realistic depiction of anticipated annual emissions for the source. In general, for the existing sources subject to BART, you will estimate the anticipated annual emissions based upon actual emissions from a baseline period." To accurately depict the anticipated annual emissions for the units at CCS a new baseline must be established taking into consideration the DryFining™ technology and installed combustion controls in Unit 2 (LNC3+). The DryFining™ process is designed to remove moisture and segregate dense material from the coal prior to introduction of the coal into the final stage of grinding and conveyance into the boiler. DryFining™ having been funded under a DOE collaborative agreement (DE-FC26-04NT41763) was required to conduct performance tests which demonstrated a heat input reduction of approx. 2-3%. Having removed the moisture prior to the introduction into the pulverizers lends to less primary air required to "dry" and convey the coal through the pulverizers, making air available for staging (Over-fired air NOx control) in other areas in the boiler. This drier coal will not require the same amount of heat input into the boiler because wet coal expends some of its heat input to vaporize the moisture in the coal and its heating value has increased per pound so fewer pounds are needed. Thus a drier coal will not require that additional coal typically lost to vaporizing the moisture and reduced heating value. DryFining™ is currently obtaining a moisture reduction in the coal of approximately 8%. Future tuning is continuing and will meet a required reduction of 12% by 2016, which is needed for the SO_2 BART analysis to achieve full scrubbing.

In order to make its cost effectiveness determination, North Dakota must not only have site specific control cost, but also accurate emission reduction estimates. Clearly, with the installation of both LNC3, LNC3+, and DryFining™, Coal Creek's NOx emissions are greatly reduced with respect to "baseline" values previously provided. In this section, in light of recently refined analysis, GRE will update baseline emissions to be used in making the cost effectiveness determination.

Based on the timing of the original analysis, the initial BART evaluation used baseline emission rates for approximately the same time period that was used to determine the visibility baseline, which was

a 5-year period of emission inventory data from 2000 to 2004. It is necessary to update the baseline emissions for Units 1 and 2 for this technology evaluation in order to reflect current conditions and unit performance. Both units utilize "low NOx coal-and-air nozzles with close-coupled and separated overfire air," which is referred to as LNC3. Since the time of the initial evaluation, NOx controls in the form of larger registers,[6] advancing the LNC3 controls (LNC3+),[7] have been added to Unit 2, which means that the two units have different baselines for the purpose of estimating future emission reductions. For Unit 1, the revised baseline is 0.200 lb/MMBtu, as an annual average. For Unit 2, the revised baseline is 0.153 lb/MMBtu, as an annual average, as also described in Section 2.1.2. These new "baseline" emission rates are lower than the initial BART baseline of 0.22 lb/MMBtu.

2.2.1 Circumferential Cracking in Boiler Tubes

Following the installation of LNC3+ technology at Unit 2, CCS has determined that an emission rate of 0.15 lb/MMBtu for LNC3+ is not a sustainable 30-day rolling average control level due to circumferential cracking. In other words, the 0.15 lb/MMBtu on a 30-day rolling basis is at the edge of this technology's capabilities. While GRE may intermittently achieve this rate on a monthly or perhaps more easily as an annual average, it is not the basis for a 30-day rolling limit.

As background, in 2008 GRE lowered NOx emissions from Unit 2 by expanding the OFA registers. This diverted more of the combustion air from the burners of the boiler to an area about 30 feet higher in the boiler. In doing so, the flame temperatures were lowered, which reduced the production of NOx generated by the combination of oxygen and nitrogen gas burned under high temperatures. NOx emissions were lowered, but there was an unexpected side effect. This low NOx emission rate caused circumferential cracks in the boiler tubes between the burner front and the over-fired air registers.

The phenomenon of circumferential cracking has several interrelated contributing factors including high surface temperatures (>900°F bare tubes, >1100°F weld overlays) (which exposes the boiler tubes to high wall temperatures and high temperature fluctuations, which produces numerous thermal fatigue cracks in the boiler walls), frequent and severe thermal spikes (>100°F), and corrosive

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[6] Larger registers allow for a greater ability to tune combustion staging and thus control NOx emissions.

[7] LNC3 is the acronym used by EPA to describe a specific type of restrictive combustion control. To differentiate between the controls installed on Unit 1 and the additional controls installed on Unit 2 (both are versions of LNC3), the acronyms LNC3 and LNC3+ are used for each unit, respectively.

conditions/deposits. Low NOx burner systems with overfire air ports produce longer flames and increase the chance of flame impingement and local overheating of the boiler walls.

In 2009, Coal Creek Station began to experience unscheduled outages on Unit 2 due to failures from the circumferential cracking described above. To understand and correct this problem, Great River Energy engaged the Electric Power Research Institute (EPRI) to assist in evaluating the causes and potential remedies for this problem. To date, corrective actions have included detailed examinations of the boiler tubes to detect the extent of the cracking, the installations of additional temperature monitors to determine boiler wall temperatures, the replacement of damaged boiler tubes, and continued tuning of the boiler to minimize the circumferential cracking in the zone of concern. While not eliminating the problem, these efforts have greatly reduced the problem of unscheduled outages caused by circumferential cracking. Based on our analysis, it is not clear how to completely and consistently eliminate this problem, while operating at or near 0.15 lb/MMBtu on a 30-day rolling basis. Efforts continue to further reduce this circumferential cracking problem while balancing our desire to operate at lower NOx emission levels.

The only examples of tangentially-fired units with emissions lower than the 0.17 lb/MMBtu NOx presumptive level are facilities with post combustion NOx controls, such as SNCR. Further, a majority of these SNCR controlled sources operate well above the 0.17 lb/MMBtu, as annual averages, as detailed in the Cross State Air Pollution Rule and illustrated in Figure 2.2. Consequently, GRE presumes it cannot safely and consistently operate below 0.17 lb/MMBtu as a 30-day rolling limit, without installing SNCR.

2.2.2 Load Variability

In addition to circumferential cracking, this assessment must also consider load variability and its impacts on NOx emissions. The NOx emission limits proposed in the original BART evaluation for Units 1 and 2 did not consider that Coal Creek's units would experience significant load variability. GRE has historically operated as a baseload unit, without much load swinging. In May 2011, Midwest Independent Transmission System Operator (MISO) began cycling CCS in the real-time market. In September 2011, GRE greatly increased the cycling range of CCS in response to current market prices in the MISO market. This is important because load swinging significantly impacts expected NOx control performance. While base load NOx emissions can be tuned due to relatively stable load, the swinging load cannot be finely tuned but must still be accounted for when assessing compliance with emission limits.

Table 2.1 illustrates the variability experienced during recent load swinging. It is different on Units 1 and 2, due to different NOx controls. Based on changing market conditions, load variability is expected to continue as an operational scenario for Units 1 and 2 for the foreseeable future. As such, any emission limit must account for this additional variability in emissions. It is clear from Table 2.1 that the BART NOx presumptive emission rate of 0.17 lb/MMBtu is achievable, including load variability, and also reflecting the maximum NOx emission reductions from LNC3+ and DryFining™, as demonstrated through Unit 2.

Table 2.1 Coal Creek Station NOx Emission Rates During Load Variability

Scenario Description		NOx Emissions (lb/MMBtu)			
		Unit 1		Unit 2	
		Min	Max	Min	Max
Overall - Nov. 2010 to Nov. 2011	30-day Rolling	0.179	0.219	0.14	0.169
Load Variability – May – November 2011	30-day Rolling	0.186	0.219	0.146	0.166
	Hourly Average	0.206		0.16	
Load Variability – September – November 2011	30-day Rolling	**0.207**	**0.219**	**0.163**	**0.166**
	Hourly Average	0.218		0.17	

In addition, GRE provides a chart (Figure 2.1) showing Unit 2's 30-day rolling average NOx emission rate, with notes on tuning emphasis and load variability, as further support of the 0.17 lb/MMBtu emission limit.

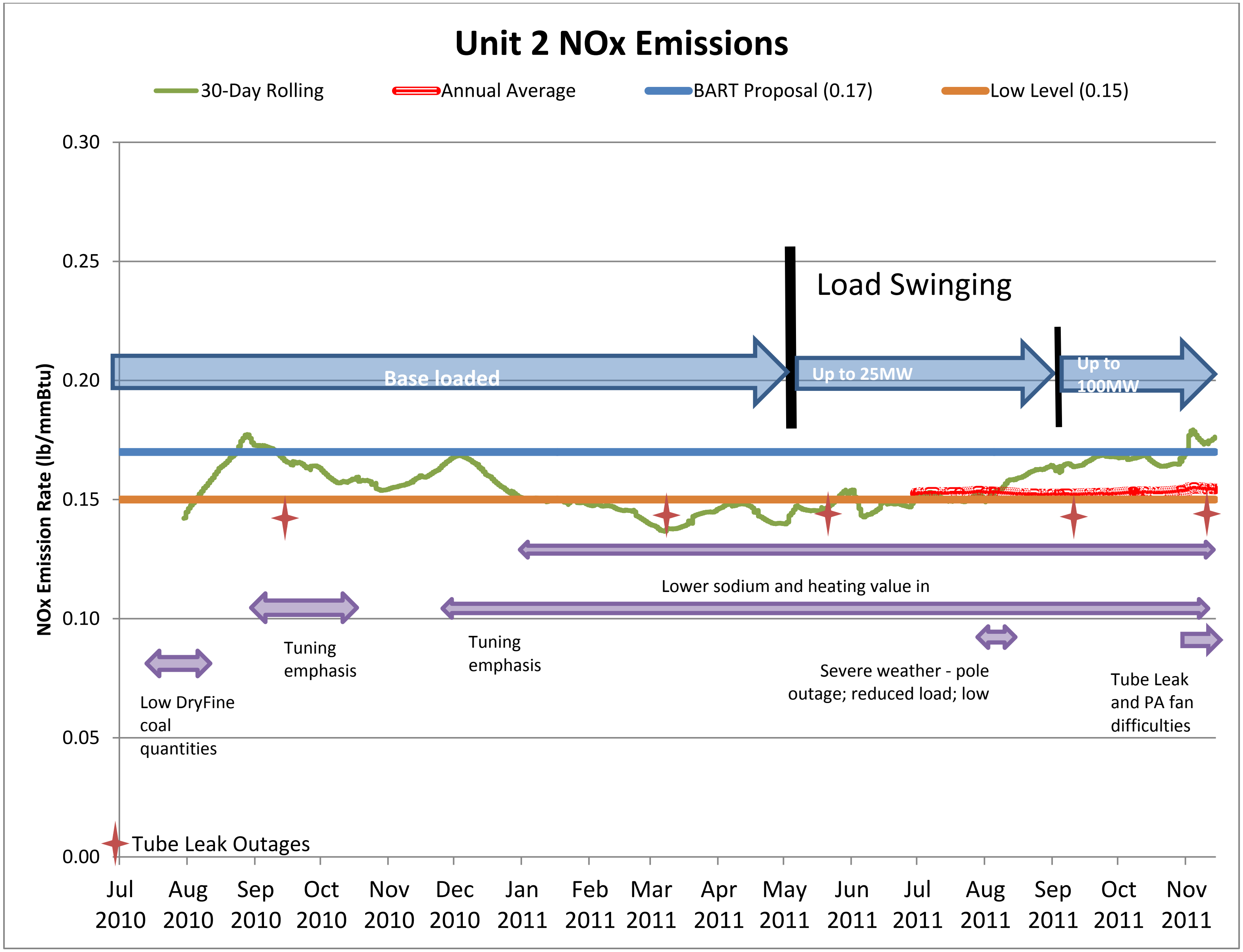

Figure 2.1 Unit 2 30-Day Rolling NOx Emission Averages

2.2.3 Evaluation of SNCR Effectiveness in CSAPR

Interestingly, the Coal Creek presumptive NOx BART emission rates are consistent with annual average emissions as modeled by EPA in CSAPR. By reviewing existing units of similar design, data from the docket for the proposed Cross State Air Pollution Rule (Docket ID EPA-HQ-OAR-2009-0491) illustrates that there are currently no tangentially-fired utility electricity generating units with LNC3 combustion controls and SNCR post combustion controls that operate at or below the presumptive BART limit of 0.17 lb/MMBtu for NOx (Figure 2.2), as annual averages. If the data set is expanded to include LNC3 ("low NOx coal-and-air nozzles with separated overfire air (LNC2[8])") and "low NOx burners and overfire air (OFA)" as illustrated in Figure 2.3, only four supercritical[9] emission units operate below the presumptive NOx limit of 0.17 lb/MMBtu. None of the facilities included in the CSAPR database operate at or below the proposed FIP limit of 0.12 lb/MMBtu. All of the facilities analyzed use SNCR to effectively achieve the Coal Creek presumptive NOx emission limit of 0.17 lb/MMBtu. To state it differently, Coal Creek effectively achieves presumptive BART with DryFining™ rather than SNCR.

[8] LNC2 and LNC3 are various types of low NOx burner design.

LNC2 = Low NOx burner with separated OFA

LNC3 = Low NOx burner with close-coupled and separated OFA

[9] For a subcritical boiler (standard operational design consistent with CCS Units 1 and 2), steam to power the turbine is derived by heating liquid water to its saturation point and then isothermally heating of the system causing the phase change from liquid water to steam (boiling). In contrast, a supercritical steam generating unit operates at such a high pressure that liquid water does not boil and is instead converted to a supercritical fluid, an intermediate fluid having properties of both liquid water and steam. Operation of supercritical units is typically more thermally efficient than operation of subcritical units, resulting in less fuel combusted for the same energy output and, consequently, lower emissions.

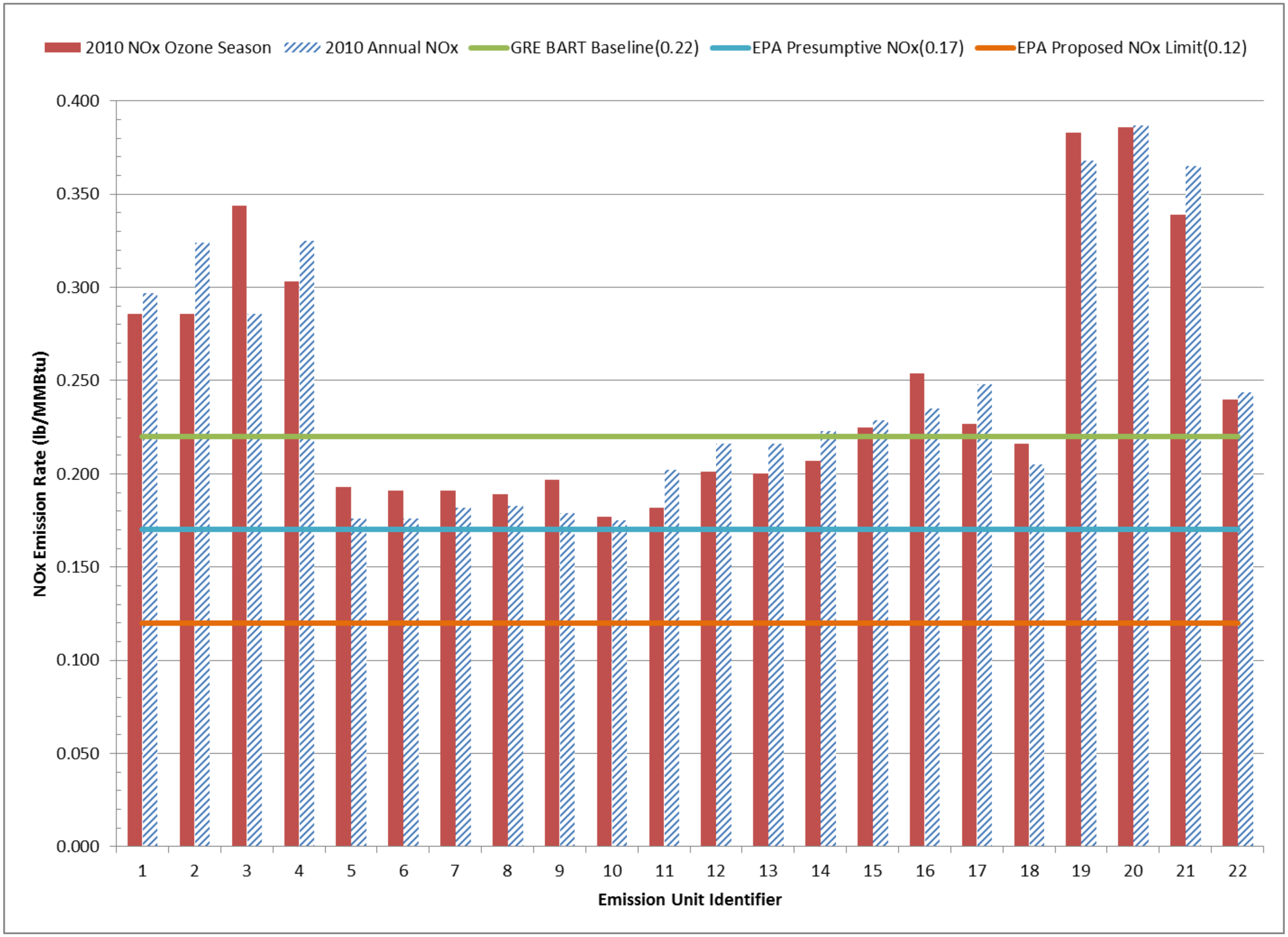

Figure 2.2 2010 NOx Emission Rates from CSAPR Rule Data for Units with SNCR and LNC3/OFA NOx Control

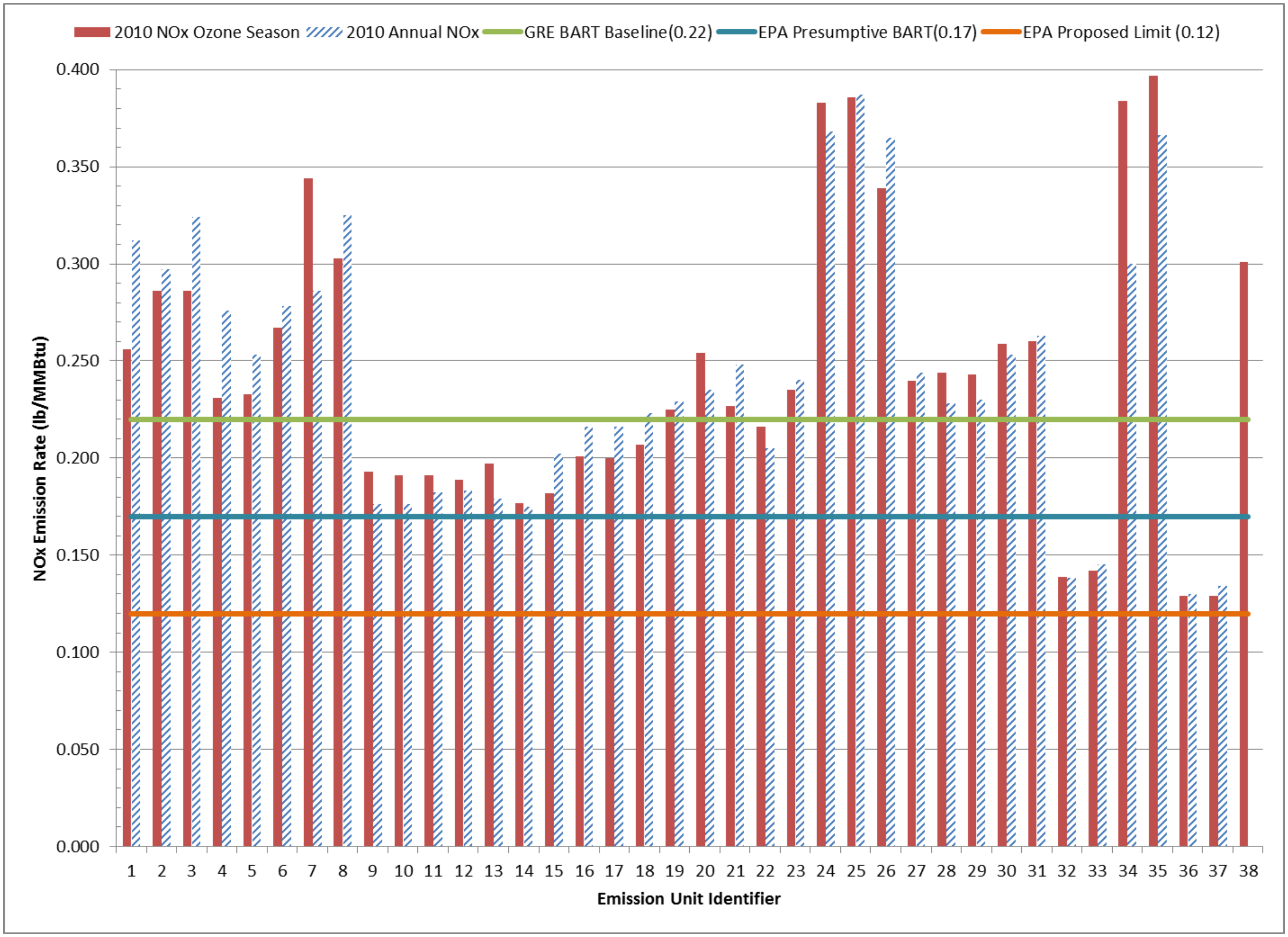

Figure 2.3 2010 NOx Emission Rates from CSAPR Rule Data for Units with SNCR and LNC2/LNC3/OFA NOx Control

2.2.4 Ash Cost Considerations

The EPA indicated in its proposed FIP that GRE fly ash sales and disposal values provided in previous submittals were in error and, when corrected, resulted in SNCR being cost effective. Great River Energy had previously submitted two estimates: $5/ton and $36/ton (2006$). Contrary to our Summer 2011 submittal, these values were not necessarily in error, but instead represented different assumptions on economic impacts of lost ash sales and associated disposal costs. Therefore, rather than rely upon these screening level values as previously submitted, GRE contracted with Golder Associates to provide a more refined analysis of ash impacts associated with the installation of SNCR. The following discussion and attached "Fly Ash Storage and Ammonia Slip Mitigation Technology Evaluation" (Appendix C) provides a more comprehensive assessment of ash implications associated with SNCR installation.

To provide some additional background on the previously submitted values, the $36/ton value represented the total freight on board (FOB) Coal Creek Station price that was paid by the end user. The $5/ton dollar per ton figure represented what GRE received as a portion of the FOB price prior to December 1, 2011.

Both of the values ($5/ton and $36/ton) attempted to capture lost revenue from decreased ash sales. In each case, an additional $5/ton cost was added as GRE's cost to dispose of the unsalable ash. This additional $5/ton disposal value was the result of a screening level analysis and had not taken into account all of the internal costs associated with ash disposal. This disposal value also had not accounted for anticipated cost increases based on changing ash disposal regulations, nor did it take into account various ash disposal levels as could be anticipated due to lost fly ash sales.

GRE and Headwaters Resources, Inc (HRI), GRE's strategic partner in the sales and distribution of fly ash, have invested heavily into fly ash sales infrastructure including terminals and storage facilities, conveying equipment, scales and train car shuttles. HRI financed GRE's portion of the infrastructure through a per ton payment on fly ash sales. The current ash sales contract requires payments to GRE that total 30% of the $41 (2011$) FOB price or $12.30 per ton (2011$) of ash that is delivered.

Considerable effort has been taken to clarify the impacts that SNCR installation will have on GRE's ash management methods, overall disposal costs and reduction in ash sales revenues. In short, Great River Energy firmly believes, and EPA acknowledges in its proposed FIP, that SNCR may have a detrimental impact to ash sales. The Golder analysis represents these risk ranging from a worst case

100% lost fly ash sales, to an optimistic 30% lost sales, as shown in their Scenarios B and C, respectively. For the sole purpose of defining a baseline, a hypothetical Scenario A "No Ash Impacts," has also been included as a reference point.

2.2.5 SNCR's Impact on Ash Management Options

Fly ash from CCS is used throughout the Upper Midwest to replace a portion of Portland cement in concrete production, making the concrete more durable and longer lasting. Ash generated at Coal Creek Station has chemical and physical properties that make it an extremely desirable ash in the concrete market. Coal Creek Station currently generates approximately 525,000 tons of fly ash per year. Approximately 415,000 tons of that ash is sold as a Portland cement replacement. Coal Creek fly ash has been used in many large-scale projects such as construction of the new Interstate-35W Bridge after its collapse.

The beneficial use of fly ash also has a strong positive economic benefit to Great River Energy, and the regional economy. We started selling fly ash nearly three decades ago. In that time, we have grown this activity into a sizable annual revenue stream. The addition of SNCR will have a negative impact on the marketability, value and perception of Coal Creek Station's fly ash. The addition of ammonia into the combustion process leaves an ammonia residue on the ash that can cause aesthetic and worker safety issues during the use of the ash. The residual ammonia in the ash eventually off-gases and creates odors which are offensive, are potentially dangerous to human health, and can even pose an explosion risk. Section 1-2 of EPA's Pollution Control Cost Manual recognizes this fact and states the following:

> *Ammonia sulfates also deposit on the fly ash that is collected by particulate removal equipment. The ammonia sulfates are stable until introduced into an aqueous environment with an elevated pH levels. Under these conditions, ammonia gas can release into the atmosphere. These results in an odor problem or, in extreme instances, a health and safety concern. Plants that burn alkali coal or mix the fly ash with alkali materials can have fly ash with high pH. In general, fly ash is either disposed of as waste or sold as a byproduct for use in processes such as concrete admixture. <u>Ammonia content in the fly ash greater than 5 ppm can result in off-gassing which would impact the</u>*

salability of the ash as a byproduct and the storage and disposal of the ash by landfill.[10](emphasis added)

The range of residual ammonia left with the fly ash can vary with each installation of SNCR. Ammonia slip of only 5 ppm, generally accepted as the minimum that can be achieved with SNCR, can render fly ash unmarketable. (URS, Appendix B) Even in those systems where residual ammonia is generally low, there will be times of increased ammonia slip based on plant operations. As the plant output varies due to market demand or startup/shutdown activity, varying levels of ammonia will be used to control NOx and, consequently, the levels in the ash will change. Variable ammonia levels in the ash create additional complexity to both sales and/or treatment, and will result in increased disposal.

2.2.6 Ammonia Mitigation Technology

Great River Energy is committed to ash re-use due to its economic and environmental benefits. Therefore, we anticipate additional capital and operating costs to treat the ash in order to ideally preserve a percentage of ash sales. With respect to ammoniated ash treatment, Ammonia Slip Mitigation (ASM) technology refers to a variety of technologies that have been designed to improve the marketability of ammoniated ash. These technologies fall into two rough categories, combustion or carbon burn out (CBO) and chemical treatment. CBO is the process of running the ash through an additional combustion unit that would combust and burn out the residual carbon and ammonia that is with the ash. This is a capital intensive technology that also has high operating costs. The second category of ASM technology is generally referred to as chemical treatment. These treatment technologies involve creating a chemical or physical reaction that results in the off-gassing of the residual ammonia. These treatment technologies are generally less costly than CBO. For purposes of this more refined analysis, GRE contracted with Golder Associates to provide a detailed cost estimate of one particular chemical treatment technology as a potentially cost effective option. The detailed cost estimate can be found in Appendix C.

Even with a cost effective ASM technology installed, there will be times when the residual ammonia levels in the ash are too high to treat. Ammonia injection rates will vary during periods of startup and shutdown, in addition to variable load operation, in order to maintain compliance with the BART limits. Variable ammonia injection rates and associated changes in ash concentrations will result in

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frequent testing and periodic rejection of ash for on-site disposal. Further, variable ammoniated ash levels will put GRE's generated ash in a very vulnerable position with respect to competitors in the fly ash marketplace, reducing ash sales and increasing on-site disposal.

2.2.7 Ash Disposal Scenario Cost Summaries

Appendix C contains a technical assessment and cost analysis of ammonia slip mitigation technology and ash disposal under RCRA Subtitle D design standards. To address the uncertainty regarding costs associated with ammoniated ash management and disposal, a range of costs is presented. These costs are based on three scenarios described below. Table 2.2 shows the volumes of ash produced, sold and disposed of in each scenario. For a more detailed description please see Appendix C.

Scenario A (current ash sales levels) – This scenario is the base case with fly ash sales equal to the average sales over the past few years. The scenario assumes that fly ash will be disposed of in a new landfill with a design based on RCRA Subtitle D practices, and has a 20-year disposal capacity. No post processing of the fly ash is required to maintain 100% marketability. (Golder 2011) This hypothetical scenario is not considered to be a possible option for future ash management costs but serves as a point of reference for understanding future impacts.

Scenario B (No ash sales) – This "worst case" scenario assumes that the ammonia slip impact of SNCR makes fly ash at CCS completely unsalable. The scenario also assumes that fly ash will be disposed of in a new landfill with a design based on RCRA Subtitle D practices, and has a 20-year disposal capacity. (Golder 2011)

***Scenario C* (30% sales reduction, ASM costs)** – This "realistic" scenario assumes that Headwater's ASM technology will be viable for ammonia-impacted fly ash at CCS. However, sales will be reduced from current sales levels due to load swing impacts on ammonia slip, market conditions, and other factors previously identified. The scenario also assumes that fly ash will be disposed of in a new landfill with a design based on RCRA Subtitle D practices, and has a 20-year disposal capacity. (Golder 2011)

Table 2.2 Fly Ash Sales and Disposal Tons

	Scenario A (Current Sales)	Scenario B (No Sales)	Scenario C (Reduced Sales, ASM)
Fly Ash Produced (ton/yr)	525,000	525,000	525,000
Fly Ash Sold (ton/yr)	415,000	0	290,500
Fly Ash Disposed (ton/yr)	110,000	525,000	234,500

It is clear in EPA's proposed FIP that the installation of SNCR may negatively impact ash sales[11].

Our knowledge of the ash marketplace, SNCR systems, and treatment technologies confirm that the installation of SNCR will have a detrimental impact on the salability of fly ash. GRE believes that Scenario A, which represents no impact to ash sales, is extremely unlikely. Nevertheless, we present it as a point of reference for better quantifying the ash impacts from SNCR installation.

GRE believes that scenario B (zero ash sales) is a likely outcome, but we hope that through investment in ASM technology we will be able to preserve some of the ash sales. To model partial ash sales, we created Scenario C. Scenario C assumes an investment in ASM technology and a reduction of ash sales by 30%.

It is not possible to determine exactly what percent of ash sales would be lost based on the installation of the SNCR and ammonia mitigation technologies at Coal Creek Station. There are no plants in the country with both of these technologies operating together on a lignite-fired unit. In fact, the vendor responsible for the ammonia mitigation technology will not guarantee the technology's performance at Coal Creek Station.

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[11] Federal Register / Vol. 76, No. 183 / Wednesday, September 21, 2011 / Page 58620.

"Regarding this value for fly ash sales, North Dakota concluded that SCR and SNCR use at Coal Creek would likely result in NH_3 in the fly ash due to NH_3 slip which would negatively affect fly ash salability. According to Great River Energy and North Dakota, fly ash that is currently beneficially used in the production of concrete would, instead, be landfilled. While we have opted to agree that fly ash will not be saleable for the SNCR and SCR options for purposes of our cost analyses, we are seeking comment on this issue, particularly related to the levels of NH_3 that fly ash marketers deem problematic, and the availability, applicability, and cost of applying NH_3 mitigation techniques to fly ash derived from lignite coal."

Across the country there are examples of plants that have SCR or SNCR and sell most of their ash, however, there are also others that sell none of their ash. It is a very site-specific scenario and depends on the type of coal, type of combustion, type of ash collection, plant operation (cycling % load), type of ammonia mitigation technology (if any), and how the SNCR or SCR system has been designed, installed and implemented. Each and every site is very different.

For the sake of modeling the costs related to lost ash sales we determined it was important to model a middle ground between 0% lost ash sales and 100% lost ash sales. There is a strong possibility that all ash sales will be lost and a zero chance that 100% ash sales will be maintained; some middle option needed to be considered. We looked across the industry to determine the best scenario for a moderate outcome. The 30% lost ash sales figure reflects a reasonable and optimistic (i.e., conservative) outcome that can be justified based on our understanding of plant operations and the ash markets in which we compete for sales.

The only plant (Eastlake) in the U.S. operating with the discussed ammonia mitigation technology operates under a very different scenario. This plant mixes the ammoniated ash with a non-ammoniated ash prior to sales. Thus, Eastlake is able to sell up to approximately 85% of its ash. However, Coal Creek Station is unlike the Eastlake plant. Increased load variation at CCS, adjusting plant output to match the MISO market in which we operate, can lead to upsets in the SNCR system and higher levels of ammonia in the ash.

The addition of ammonia mitigation technology and additional handling and processing steps will also increase the cost of ash to the end users. As our price point in the market increases, we will face increased competition and will lose some sales to competing ash sources.

In addition, consistency is a prized trait for a fly ash that is marketed to the cement industry. The addition of SNCR will have a detrimental impact on the consistency of the market product. Decreased consistency will lead to lower demand for the ash and will result in some lost sales to competing ash sources.

Predicting exactly what impact all of these factors will have on our ash sales is not possible. Based on our investigation and knowledge, and that of the experts we consulted, we concluded it is very likely that we will lose 50% or more of our ash sales. We chose to model 30% loss in sales as a conservative scenario that likely underestimates the real impact of this technology on ash sales.

Furthermore, in our modeling scenarios, we assumed that the future regulation of coal ash would not be subject to RCRA Subtitle C requirements. Consistent with our comments to EPA's docket during its Coal Combustion Residuals rulemaking, we believe Subtitle C regulation of coal ash is unwarranted and unnecessary. Nevertheless, EPA has proposed it as one option for a final rule. Subtitle C regulation of coal ash would significantly increase our cost to handle and dispose of our ash. Subtitle C regulation has not been included in our scenarios.

In summary, we consider a 30% scenario to be a very optimistic view of the future that relies on the successful implementation of a technology that cannot currently be guaranteed by the vendor and has never been installed on lignite-fired units. This scenario also quantifies increased disposal costs, in addition to some GRE-specific economic benefit from preserved ash sales. None of the scenarios attempt to capture economic impacts to GRE's strategic partners or other regional entities, but these impacts are mentioned in Section 3.2 and should also be taken into consideration when making a final BART determination.

2.2.8 Ash Management Costs

There are three major cost categories to be considered in each of these scenarios;

- Fly ash disposal cost estimates,
- Ammonia slip mitigation costs, and
- Lost fly ash sales revenue

Each cost area is summarized below. For a more detailed assessment, see Appendix C.

2.2.9 Fly Ash Disposal Cost Estimates

Given significant uncertainty with pending regulatory requirements such as RCRA Subtitles C and D, with ammonia slip treatment technologies, and with market reactions to ammoniated ash, Great River Energy has developed essentially three scenarios that attempt to capture a range of possibilities associated with SNCR installation. For all three scenarios, a 20-year disposal capacity and a RCRA Subtitle D design is assumed. It is also assumed that the landfill will be built on property not currently owned by GRE, as GRE does not currently have a suitable location for siting a Subtitle D landfill. For this cost estimate, it is assumed that property just west of the plant property would be purchased for the new facility. Landfill size is based on a 20-year fly ash disposal capacity. For the three scenarios, this varies between 2.2 million and 10.5 million tons of capacity. For each scenario, Golder developed a simplified landfill footprint that would provide the 20-year fly ash disposal capacity.

The cost estimate includes costs for the life of the disposal facility including engineering, design, and permitting; construction; and operations and maintenance, including closure and post-closure care. Golder used actual costs from similar projects at CCS, local contractor rates, RS Means manuals (RS Means 2010), and professional judgment to develop this cost estimate. Sources and assumptions are documented. Some general assumptions for the cost estimate include:

- All costs are estimated in 2011 dollars.
- Capital costs are annualized based on a 20-year life and 5.5% interest rate.
- Existing fly ash processing equipment (silos, unloaders, etc.) is not included. Disposal costs begin once the haul trucks are loaded with fly ash.
- Existing fly ash sales infrastructure (silos, scales, rail facilities) and operations and maintenance are not included.
- Disposal costs only include fly ash disposal and not facility airspace or operations and maintenance for other coal combustion products produced at CCS. (Golder 2011)

Table 2.3 Disposal Cost Summary (2011$)

	Scenario A (Current Sales)	Scenario B (No Sales)	Scenario C (Reduced Sales, ASM)
Fly Ash Disposed (ton/yr)	110,000	525,000	234,500
Total Disposal Cost ($/ton)	$18.06	$11.18	$13.91
Annual Disposal Cost ($/yr)	$1,987,000	$5,870,000	$3,262,000
Annual Increase in Disposal Cost Compared to Scenario A ($/yr)	-	$3,883,000	$1,275,000
Incremental Increase in Disposal Cost Compared to Scenario A ($/ton) *	-	$7.40	$5.44

*These values are used in the BART analysis as they represent the only the incremental costs above the baseline costs which would be incurred with or without the installation of SNCR.

2.2.10 Ammonia Slip Mitigation Costs

Post-processing of ammonia slip impacted fly ash by Headwater's ASM technology is proposed as an option to maintain fly ash sales. This post-processing is only being applied to the sold fly ash tonnage in Scenario C. Depending upon the plant power profile and how the fly ash distribution system is setup, it is likely that additional tons of fly ash will be treated and disposed, but these potential cost impacts are not included. The cost impact for ASM post-processing is shown in Table 2.4. (Golder 2011)

Table 2.4 ASM Post-Processing Costs (Golder 2011)

	Scenario A (Current Sales)	Scenario B (No Sales)	Scenario C (Reduced Sales, ASM)
ASM Unit Rate Capital and O&M ($/ton sold)	$0.00	$0.00	$5.61
ASM Annual Capital and O&M ($/yr)	$0	$0	$1,629,000

2.2.11 Lost Fly Ash Sales Revenue

The current fly ash sales are supported by a large investment in capital infrastructure as well as a large operations and maintenance contingency. Changes to the quantity of fly ash marketed and sold will have a direct impact on fly ash management costs, as the revenue currently used to offset fly ash management will be lost. The lost fly ash sales revenue is based on the 2010 average price per ton FOB of $41.00; with 30% of the sale price going to GRE as revenue. The cost impact of the potential loss in fly ash sales in shown in Table 2.5. (Golder 2011)

Table 2.5 Lost Fly Ash Sales (Golder 2011)

	Scenario A (Current Sales)	Scenario B (No Sales)	Scenario C (Reduced Sales, ASM)
Lost Fly Ash Sales Revenue ($/ton lost sales)	$12.30	$12.30	$12.30
Annual Lost Fly Ash Sales Revenue ($/yr)	$0	$5,105,000	$1,531,000

2.2.12 Total Fly Ash Management Costs

The combination of the ASM post-processing, fly ash disposal, and lost fly ash sales revenue is shown in Table 2.6. This table represents the total economic impact of SNCR installation on GRE's fly ash management in two likely scenarios; a total loss of ash sales and a 30% reduction in ash sales.

Table 2.6 Total Fly Ash Management Costs (Golder 2011)

	Scenario A (Current Sales)	Scenario B (No Sales)	Scenario C (Reduced Sales, ASM)
Total (Disposal + Post Processing + Lost Sales)			
Annual Cost ($/yr)	$1,987,000	$10,975,000	$6,422,000
Unit Cost ($/ton produced)	$3.79	$20.91	$12.23
Additional Cost (Scenario B/C - Scenario A)			
Fly Ash Management Cost ($/yr)	-	$8,988,000	$4,435,000
Fly Ash Management Cost ($/ton produced)	-	$17.12	$8.45

2.2.13 BART Analysis Ash Disposal Cost Summary[12]

While the exact impacts to Coal Creek Station's ash are unknown, mandating SNCR will leave GRE in a vulnerable position where we would expect to incur significantly higher costs from lost ash sales and increased landfilling. Based on the detailed technical review discussed above and included as Appendix C, GRE proposes a range of ash disposal costs and lost ash sales revenue figures in the BART analysis. None of the scenarios consider the significant cost impact of potential RCRA Subtitle C regulation in the future.

Scenario B represents the highest cost scenario with a total annual additional cost of $8,988,000. The total cost includes lost ash sales revenue of $5,105,000 (Table 2.5) and an additional annual ash disposal cost of $3,883,000 or $7.40 per ton disposed (Table 2.3).

Scenario C represents an optimistically low cost scenario with a total annual additional cost of $4,435,000. The total cost includes lost ash sales revenue of $1,531,000 (Table 2.5) and an additional annual ash disposal cost of $1,275,000 or $5.44 per ton disposed (Table 2.3). Scenario C also includes a Ammonia Slip Mitigation cost of $5.61 per ton of ash reused for an additional annual cost of $1,629,000 (Table 2.4).

[12] All costs within this section are presented in 2011$.

3.0 Integrated NOx Control and Ash Impact Impacts Analyses

This section will integrate the revised baseline emissions, the refined URS SNCR Analysis and the Golder Ash Impact Analysis. It will then provide a summary table with associated cost per ton and incremental cost per ton values.

3.1 SNCR Control Cost Analysis

As discussed in Section 2.1.3, baseline NOx emissions are adjusted to reflect existing controls. Based on the updated baseline, Table 3.1 summarizes the anticipated control costs for additional NOx controls. It includes more refined SNCR costs for CCS Units 1 and 2 (See URS Report Appendix B). It also includes cost scenarios from the Golder Associates Fly Ash Storage and Ammonia Slip Mitigation Technology Evaluation (See Appendix C). It should be noted that the controlled NOx emission concentrations and mass rates have been evaluated on an annual average basis and are not representative of anticipated operation on a shorter scale averaging period (30-day rolling or 24-hour rolling), consistent with BART guidance that costs be normalized to the expected annual emissions reduction. The 30-day rolling limits are intended to be inclusive of unit startup and shutdown as well as variability in load. Consequently, associated BART limits must be higher than stated annual averages used for estimating cost effectiveness (e.g., LNC3+ is evaluated at 0.153 lb NOx/MMBtu on an annual average basis with an anticipated 30-day rolling limit of 0.17 lb NOx/MMBtu). Costs are valued on a present (2011) dollars basis.

Considerable effort has been taken to clarify the impacts that SNCR installation will have on GRE's ash management methods, overall disposal costs and reduction in ash sales revenues. In short, Great River Energy firmly believes, and EPA acknowledges in its proposed FIP, that SNCR may have a detrimental impact to ash sales. The Golder analysis represents these risk ranging from a worst case 100% lost fly ash sales, to an optimistic 30% lost sales, as shown in their Scenarios B and C, respectively. For the sole purpose of defining a baseline, a hypothetical Scenario A "No Ash Impacts," has also been included as a reference point.

Table 3.1 Control Cost Summary (2011$)

Unit ID	Control Description	NOx Emissions (lb/MMBtu)	Control Eff. From Baseline (%)	Emission Reduction from Baseline (T/yr)	Installed Capital Cost ($MM)	Annualized Operating Cost ($MM)	Pollution Control Cost ($/ton)	Incremental Cost $/ton
Unit 1	SNCR, LNC3+, 100% Lost Ash Sales (Scenario B)	0.122	33%	1,525.2	$17.873	$8.878	$5,821	$19,125
	SNCR, LNC3+, 30% Lost Ash Sales (Scenario C)					$6.602	$4,329	$13,762
	SNCR, LNC3+, No Ash Impacts (Scenario A)					*$4.384*	*$2,875*	*$8,534*
	SNCR, 100% Lost Ash Sales (Scenario B)	0.150	25%	1,152.8	$12.176	$8.795	$7,629	NA – Inferior Control
	SNCR, 30% Lost Ash Sales (Scenario C)					$6.519	$5,655	
	SNCR, No Ash Impacts (Scenario A)					*$4.301*	*$3,731*	
	LNC3+	0.153	24%	1,100.9	$6.079	$0.763	$693	$693
	Baseline (LNC3)	0.200	NA-Base	NA-Base	NA-Base	NA-Base	NA-Base	NA-Base
Unit 2	SNCR, 100% Lost Ash Sales (Scenario B)	0.122	20%	772.5	$11.794	$8.115	$10,505	$10,505
	SNCR, 30% Lost Ash Sales (Scenario C)					$5.839	$7,559	$7,559
	SNCR, No Ash Impacts (Scenario A)					*$3.621*	*$4,688*	*$4,688*
	Baseline – LNC3+	0.153	NA-Base	NA-Base	NA-Base	NA-Base	NA-Base	NA-Base

Scenario A (No Ash Impacts) is provided for reference only and does not represent a feasible control option.

Below is provided the least cost envelope illustrated graphically. Only dominant controls falling within the least cost envelope were further analyzed for incremental feasibility. Inferior technologies are deemed not cost effective.

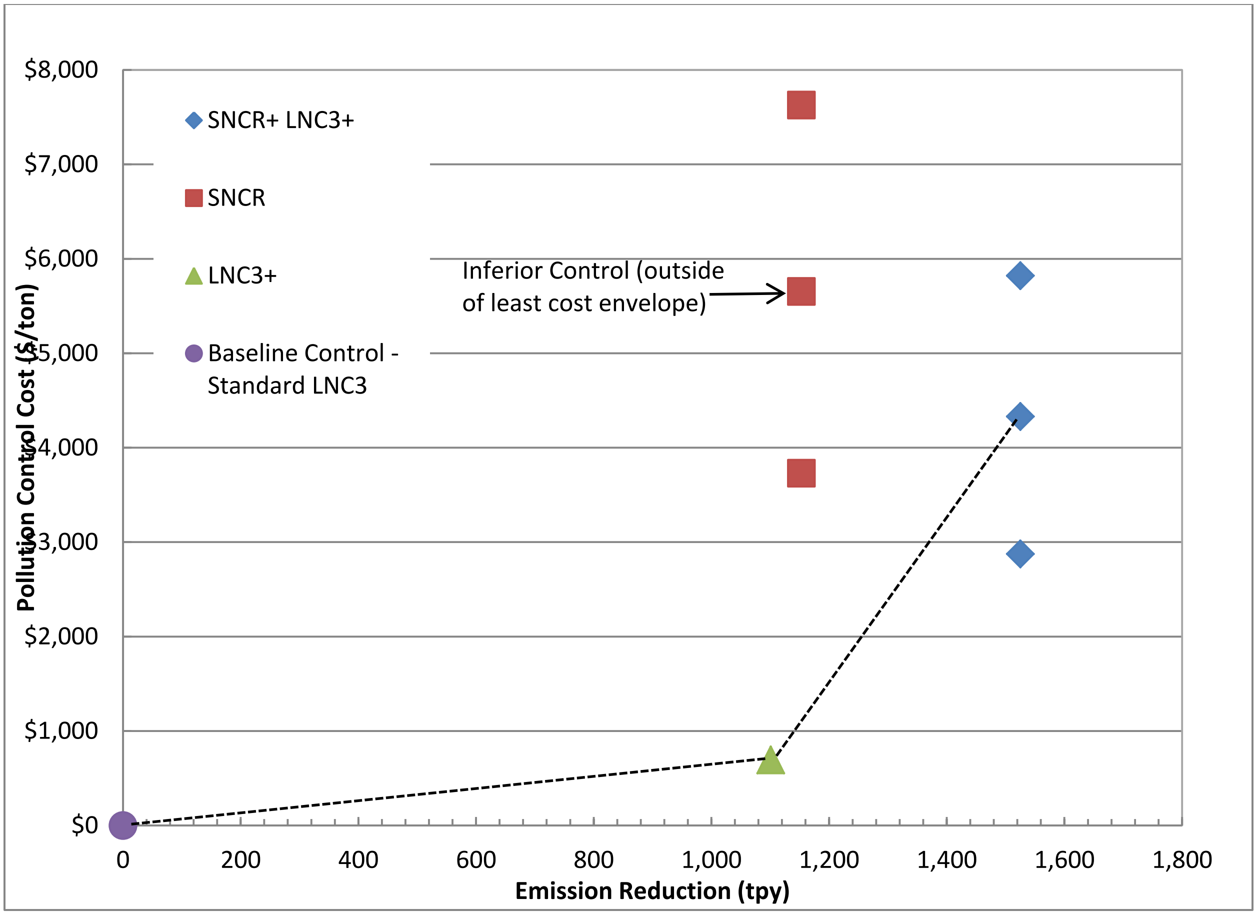

Figure 3.1 **Incremental NOx Analysis**

The remaining feasible technologies are illustrated on the basis of annualized emission reduction in tons per year and total annualized cost in millions of dollars per year.

This refined economic impacts analysis confirms GRE's original conclusion that SNCR is not a cost effective NOx control option. From Table 3.1, it would appear as if Unit 1 SNCR – No Ash Impacts would be cost effect on a dollar per ton basis according to the State of ND thresholds, but in understanding that this scenario is considered hypothetical since some level of ash impacts are expected, and the incremental cost per ton is an order of magnitude higher than anything deemed cost effective. The disparity in the incremental costs occurs due to the fact that the DryFining™ with LNC3+ technology could achieve the associated emissions reduction indicated for the SNCR technology. As highlighted, the "most realistic" or optimistic scenario is 30% lost ash sales, with cost exceeding $4,000 (2011$) per ton of NOx controlled. This value is higher than EPA's determination of economic infeasibility for SCR for CCS at around $4,000/ton (2011$) of NOx removed stated in the FIP.

Although not directly incorporated into GRE's capital and operating control costs presented above, NDDH must also consider additional impacts, such as indirect and stranded cost components discussed in Section 3.2 and Section 3.3.

3.2 Additional Impacts

GRE provides these additional impact considerations not found in the original BART analysis as important to North Dakota in making its final BART determination.

1. The use of DryFining™ technology that has already been implemented for use at both units at a cost of $270 million. GRE has made a significant investment to achieve multi-pollutant emission reductions and visibility improvements in the region.

2. At the time of this submittal, GRE has already installed LNC3+ combustion controls at Unit 2. In 2011 dollars, this was at a cost of over $6 million and has already resulted in NOx reductions. The same system is currently tentatively scheduled to be installed on Unit 1 during the 2014 outage.

3. Ash infrastructure investments of over $31 million have been made to date for management and sale of Coal Creek Station's ash. Over $7 million of the total investment have been made by GRE, directly.

4. The DryFining™ technology provides a dual emission improvement for the total BART analysis. In order to achieve 100% scrubbing for the SO_2 analysis GRE must reduce the moisture, related air flow and therefore the total mass of flue gas travelling through the absorbers in the scrubber. DryFining™ will be implemented to its fullest extent by the BART compliance deadline.

3.2.1 Regional Impact from Ash Sales Revenue

The BART analysis does not take into account additional regional economic impacts resulting from the reduction or elimination of CCS ash sales. In order to estimate these regional impacts, one can use the freight on board (FOB) price of the ash at $41 (2011$), and subtract GRE's share of that revenue at $12.30 (2011$). Therefore, SNCR installation would reduce or eliminate ash sales, eliminating an additional $28.70/ton (2011$) from the local and regional economy. This could result in a loss of as much as $11,910,500 (2011$) per year from the local and regional economy. In addition to these regional economic impacts, there are other impacts that must also be considered.

3.2.2 Fly Ash is Important to the National Economy

Fly ash is an important part of the regional and national economy. The National Association of Manufacturers reported in 2010 that Coal Combustion Residuals (CCRs) contribute $6-11 billion annually to the U.S. economy through revenues from sales for beneficial use, avoided cost of disposal, and savings from use as a sustainable building material.[13] The beneficial use of fly ash and other CCRs are directly responsible for a large number of jobs throughout the country. A 2011 report by Veritas found that "Approximately 10.6 million tons of coal combustion residuals were used in concrete-related products during 2009. Those products provided employment for 240,100 manufacturing workers, 78,480 foundation, structure, and building exterior workers and many of the 102,350 nonresidential building construction workers during 2010." (Veritas 2011[14])

3.2.3 Fly Ash is Important to Regional and National Infrastructure

The American Road and Transportation Builders Association[15] completed a report in 2011 that highlighted the importance of fly ash as a component of road and bridge construction across the country. Their research found that the elimination of fly ash as a construction material would increase the average annual cost of building roads, runways and bridges in the United States by nearly $5.23 billion. This total includes $2.5 billion in materials price increases, $930 million in additional repair work and $1.8 billion in bridge work. The additional costs would total $104.6 billion over 20 years.

3.2.4 Environmental Benefits of Ash Reuse

The use of fly ash as a replacement for cement has many environmental benefits. As a result of the increased use of fly ash, less land is disturbed for quarrying raw materials, less land is taken out of production for landfills, and less carbon dioxide (CO_2) is emitted into the atmosphere to make cement. Using one ton of fly ash instead of Portland cement reduces up to one ton of greenhouse gas emissions. Inversely, by contaminating the ash with ammonia, and increasing ash disposal, there will be a corresponding 1-to-1 ton increase in CO_2 emissions from using more Portland cement. These CO_2 emissions are not trivial.

[13] Report available at: http://www.regulations.gov/#!documentDetail;D=EPA-HQ-RCRA-2009-0640-6992.

[14] Available at: http://www.recyclingfirst.org/pdfs/101.pdf.

[15] Available at: http://www.artba.org/mediafiles/study2011flyash.pdf.

3.2.5 Additional Ash Management Cost Considerations

The ash management costs detailed in this report are considered to be conservative figures from reasonable assumptions that most likely underestimate GRE's future expenditures on ash management.

The ash analysis envisions that all future disposal facilities will be designed and constructed to RCRA subtitle D standards. EPA is currently proceeding with an ash disposal rulemaking that will create uniform national disposal standards under RCRA subtitle D, the far more stringent Subtitle C (Hazardous Waste), or some hybrid approach that takes some requirements from each Subtitle D and C. The cost of complying with a Subtitle C rule would vastly exceed the amounts discussed in this report. This analysis reasonably assumes Subtitle D.

The ash disposal costs discussed above are portrayed as three scenario costs: a baseline which represents current ash sales figures; a scenario where all ash must be disposed of; and a scenario where ash sales are reduced by 30% from the baseline. There is significant uncertainty regarding specific impacts to beneficial reuse if SNCR were installed. The zero ash sales scenario (Scenario B) is very possible and is an outcome that we hope to avoid. Scenario C captures a "hybrid" estimate of the future where some ash is beneficially used and some additional ash must be disposed. For the hybrid scenario, we chose a 30% reduction in sales. This 30% estimate is an optimistic figure of preserved ash sales at 70%. It is quite possible that the amount of ash requiring disposal could easily represent a 50%, 70% or larger reduction in fly ash sales. For this reason, Scenario C is likely to produce ash management costs that are lower than will actually be encountered.

As discussed above, there are a variety of different Ammonia Slip Mitigation (ASM) technologies available. Most of these technologies have only been installed at a small number of generating units and, to GRE's knowledge, no lignite-fired unit is currently operating SNCR and ASM technology.[16] Of all ASM technologies that were investigated, the Headwaters technology was the least expensive. If the Headwaters ASM technology fails to function properly on lignite, it is likely that we would incur significantly larger costs to preserve the beneficial reuse of some portion of our fly ash.

[16] It is important to note that Headwaters ASM technical staff have stated that this technology has not been tested on a lignite unit and they would not guarantee any level of performance if installed at CCS.

The EPA Pollution Control Cost Manual (2002) does not allow GRE to include in our BART analysis the value of previously purchased assets that would be rendered useless by the elimination or reduction of fly ash sales. GRE and its strategic partner, Headwaters Resources, have invested $31 million on ash storage, transportation and distribution infrastructure.

3.3 SNCR Visibility Impacts

It is known that NOx contributes to ammonium nitrate formation, which is predominantly a winter "haze" contributor. For purposes of valuing the welfare effects of recreational visibility, it is important to consider that the North Dakota national parks are generally not in high use during the winter season. If required to install SNCR, GRE will pay an extreme price per deciview resulting in imperceptible improvements for a time of year when the parks are generally not used.

To satisfy EPA's proposed Federal Implementation Plan, Coal Creek Station would need to install SNCR technology to reach a NOx emissions level that is 29% lower than EPA's presumptive BART. Yet, the extensive modeling performed as part of the BART analysis concludes that the installation of SNCR, at an emission rate of 0.12 lb/mmBtu, will have an imperceptible improvement in visibility, ranging from 0.05 deciview (dV) to 0.18 dV in the Class I areas near the facility. This is far less than one-half of what EPA has determined to be perceptible to the human eye (0.50 dV)[17]. As such, it is not justifiable for GRE to incur the added cost of SNCR without any appreciable improvement in visibility.

It is worth noting that SNCR will result in ammonia emissions to the atmosphere. Ammonia is a listed state toxic in North Dakota, and is viewed as a contributor to regional haze because it can bond with sulfur dioxide and nitrogen oxides to form ammonium sulfate and ammonium nitrate aerosols Consequently, GRE does not believe that SNCR is a cost effective technology for improving visibility.

3.3.1 CCS Modeled Visibility Impacts

Under EPA's modeling guidelines, it is necessary to develop a 24-hour maximum anticipated emission rate for each control technology in order to assess visibility impacts. GRE assumes that on a 30-day rolling basis, combustion and post-combustion NOx controls can experience emissions that

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[17] Federal Register / Vol. 76, No. 183 / Wednesday, September 21, 2011.

FR discusses State's ability to consider potential impacts for VOC and ammonia although full analyses may not be required.

are approximately 10% higher than their annual design basis. Similarly, for assessing a 24-hour maximum emission rate, GRE assumes emissions will be up to 20% higher than the annual design rate for a given control.

GRE presented a full evaluation of anticipated cost per unit visibility impairment (Δ-dV) in its final BART analysis (Dec 2007). Pollutant interaction has an impact on modeled visibility impairment and, as such, GRE believes that modeling changes to NOx emission rates alone will not provide visibility modeling results that are representative of actual emission controls. This may overstate visibility improvement as compared to modeling NOx, SO_2 and fine PM together. However, for the purpose of illustrating the relative visibility impacts of SNCR and LNC3+, an analysis of the difference in modeled impacts is presented in Table 3.2.

An incremental cost per deciview analysis is also included in Table 3.2. This comparison relies on the annualized operating costs presented in Table 3.1, and represents the difference in annualized capital costs between the two controls compared to the change in average visibility impairment for the 98th percentile over the three modeled years for the same controls.

Table 3.2 Difference in Impairment and Incremental Cost for LNC3+ with Tuning and SNCR with LNC3+

Unit ID	2000 (dV)	2001 (dV)	2002 (dV)	Average (dV)	Incremental Cost per dV (MM$/dV)[1]
Unit 1	0.031	0.044	0.093	0.056	$103.81
Unit 1 & 2	0.062	0.083	0.172	0.106	$110.26

[1] Incremental cost comparison (2011$) of LNC3+ with SNCR with LNC3+ at 30% lost ash sales.

The visibility analysis demonstrates that SNCR will not result in actual improvement to visibility in North Dakota's affected Class I areas, and potential modeled improvements will come at a prohibitive incremental cost exceeding $100 million (2011$) per deciview. Utilities in North Dakota only contribute ~6% to total NOx emissions in the State. Consequently, any additional utility NOx reductions will not have an appreciable effect on visibility improvement. Additional details regarding modeling inputs and visibility impairment is presented in Appendix D.

4.0 Conclusions

Great River Energy provided BART Determinations utilizing the 5 step process in 2007. Until now, Great River Energy has provided screening level analyses and assumptions with respect to SNCR installation. Due to EPA's proposed FIP, and its assertion that SNCR is cost effective for Coal Creek Station, Great River Energy responds with more refined analyses in three primary areas. This refined analysis reevaluates the last two steps of the BART Determination process for LNC3+ and SNCR technology at Coal Creek Station.

First, URS provides a site specific evaluation of SNCR effectiveness at Coal Creek Station, which results in lower projected emissions reductions from this control. These emission estimates clearly change the basis for any cost effective determination. Consideration for startup and shutdown emissions, circumferential cracking and load variations should also factor into this determination as discussed in Section 2.2.

Second, URS reviewed and updated both capital and operating costs for SNCR, based on their expertise and site specific investigation. These values were relatively consistent with values presented to EPA in June and July 2011, but are somewhat higher than the screening values presented in the original BART analysis.

Third, Golder Associates conducted a detail ash impact analysis associated with a range of costs from contaminating the fly ash with ammonia from SNCR. While the exact impacts to Coal Creek Station's ash management and sales are unknown, mandating SNCR will leave GRE in a vulnerable position where we would expect to incur significantly higher costs from lost ash sales and increased landfilling. Based on a detailed technical review GRE would expect to incur additional ash annual costs somewhere between $4,435,000 and $8,988,000 (2011$).

The final two steps of the BART Determination include Step 4 - "Evaluate Impacts and Document Results" and Step 5 – "Evaluate Visibility Impacts". In evaluating the impacts of Unit 1's technologies it was concluded that installation of SNCR alone (without LNC3+) is an economic inferior technology and therefore is not further evaluated incrementally. When the SNCR and LNC3+ technologies were evaluated together for Unit 1 and Unit 2 they were deemed not cost effective on an incremental basis and therefore not an appropriate BART technology. GRE included the visibility tables for the associated LNC3+, and SNCR cases presented in Table 3.1. The final conclusion for the visibility impacts is that based on our refined analysis the state Class I areas would not see any

perceptible improvement in visibility by requiring a level of NOx control above LNC3+ for CCS, and additional reductions would be cost prohibitive on a dollar per deciview basis (Table 3.2).

When the three refined analyses of the final two steps of the BART Determination process are combined and evaluated, it clearly demonstrates that the presumptive NOx limit of 0.17 lb/mmBtu is both cost effective and results in significant visibility improvements in North Dakota's Class I areas.

On strictly a cost effective basis, SNCR can be ruled not cost effective for Unit 2, especially when the GRE specific risks and costs associated with this technology are included. On an incremental cost effectiveness basis, SNCR can be ruled not cost effective for Unit 1, also considering the GRE specific risks and costs associated with this technology. As noted, there are additional economic and visibility impacts associated with SNCR that further preclude it from consideration.

Appendix A

Pollution Control Cost Evaluations

Great River Energy Coal Creek Station
BART Supplement - NOx Emission Control Cost Analysis

Table A-1: Cost Summary

NO_x Control Cost Summary - Unit 1

Case	Control Technology [1]	Annual Designed Emissions lb/MMBtu	Control Eff % from Baseline [3]	Controlled Emissions T/yr	Emission Reduction T/yr	Installed Capital Cost MM$	Annualized Control Cost MM$/yr	Pollution Control Cost $/ton	Annual Incremental Cost $/ton [4]	See Table XX for additional information
	SNCR + LNC3+ - 100% Lost Ash Sales						$8.878	$5,821	$19,125	A-4, A-10
3 [2]	SNCR + LNC3+ - 30% Lost Ash Sales	0.122	33%	3,086.2	1,525.2	$17.873	$6.602	$4,329	$13,762	A-4, A-9
	SNCR + LNC3+ - No Ash Impacts						*$4.384*	*$2,875*	*$8,534*	*A-4, A-8*
	SNCR - 100% Lost Ash Sales						$8.795	$7,629	NA - Inferior Control	A-7
2	SNCR - 30% Lost Ash Sales	0.150	25%	3,458.5	1,152.8	$12.176	$6.519	$5,655	NA - Inferior Control	A-6
	SNCR - No Ash Impacts						*$4.301*	*$3,731*	*NA - Inferior Control*	*A-5*
1	LNC3+	0.153	24%	3,510.5	1,100.9	$6.079	$0.763	$693	$693	A-4
0	Baseline Control - Standard LNC3	0.200	NA-Base	4,611.4	NA-Base	NA-Base	NA-Base	NA-Base	NA-Base	A-3

NO_x Control Cost Summary - Unit 2

Case	Control Technology [1]	Annual Designed Emissions lb/MMBtu	Control Eff % from Baseline [3]	Controlled Emissions T/yr	Emission Reduction T/yr	Installed Capital Cost MM$	Annualized Control Cost MM$/yr	Pollution Control Cost $/ton	Annual Incremental Cost $/ton [4]	See Table XX for additional information
	SNCR - 100% Lost Ash Sales					$11.794	$8.115	$10,505	$10,505	A-10
1	SNCR - 30% Lost Ash Sales	0.122	20%	3,089.8	772.5	$11.794	$5.839	$7,559	$7,559	A-9
	SNCR - No Ash Impacts					*$11.794*	*$3.621*	*$4,688*	*$4,688*	*A-8*
0	Baseline Control - LNC3+	0.153	NA-Base	3,862.3	NA-Base	NA-Base	NA-Base	NA-Base	NA-Base	A-3

[1] Ash impact scenarios align with November 2011 Golder report.
No Ash Impacts - Golder Scenario A; *Scenario provided for reference only and does not represent a feasible outcome*
30% Lost Ash Sales - Golder Scenario C
100% Lost Ash Sales - Golder Scenario B

[2] Capital costs for combined control scenario on Unit 1 are calculated using LNC3+ costs for Unit 1 (scenario 1) and SNCR costs for Unit 2, as unit 2 presently has LNC3+ installed.

[3] Calculated on a mass basis.

[4] Incremental costs calculated as the difference in annualized operating cost divided by the difference in emission reduction for the next lowest level of dominant control.

Great River Energy Coal Creek Station

BART Supplement - NOx Emission Control Cost Analysis

Table A-2: Emission Inventory Data / Baseline Emission Rate for BART Control Cost Analysis

Equipment Information: GRE Coal Creek Unit I				6015	MMBtu/hr
Year (12-Month Avg. Period)	Jul 2010 - Jun 2011	Aug 2010 - Jul 2011	Sep 2010 - Aug 2011	Oct 2010 - Sep 2011	Nov 2010 -Oct 2011
Hours of Operation	7,700	7,700	7,635	7,599	7,629
Fuels Used:					
Quanity of Lignite - Tons	3,356,248	3,352,605	3,296,938	3,268,966	3,282,270
Percent Sulfur in Coal (Average)	0.64%	0.65%	0.65%	0.66%	0.61%
BTU per Unit of Coal (Average)	6,415	6,448	6,482	6,517	6,003
Heat Input	4.410E+07	4.422E+07	4.356E+07	4.320E+07	4.346E+07
MMBtu/hr	5,727	5,743	5,705	5,685	5,697
% of Capacity	95.2%	95.5%	94.8%	94.5%	94.7%
NOx lb/MMBtu	0.200	0.200	0.199	0.200	0.203
Total Stack Emissions:					
NOx Emitted Tons Per Year:	4,416.3	4,412.0	4,333.1	4,330.2	4,402.3
NOx Emitted Lb Per Hour:	1,204.8	1,200.3	1,196.7	1,205.8	1,218.5
Stack Emissions --- Lignite:					
NOX CEM Annual Average lb/MMBtu	0.201	0.200	0.200	0.201	0.203

Baseline Emis	
Unit 1	**Unit 2**
7,653	8,410
3,311,405	3,688,805
0.64%	0.64%
6,373	6,373
43,708,554	47,761,077
5,712	5,679
95.0%	94.3%
0.200	0.153
4,378.8	3,642.5
1205.2	918.5
0.201	0.153

Equipment Information: GRE Coal Creek Unit II				6022	MMBtu/hr
Year	Jul 2010 - Jun 2011	Aug 2010 - Jul 2011	Sep 2010 - Aug 2011	Oct 2010 - Sep 2011	Nov 2010 -Oct 2011
Hours of Operation	8,430	8,430	8,397	8,401	8,390
Fuels Used:					
Quanity of Lignite - Tons	3,730,674	3,718,253	3,676,481	3,672,436	3,646,178
Percent Sulfur in Coal (Average)	0.64%	0.65%	0.65%	0.66%	0.61%
BTU per Unit of Coal (Average)	6,415	6,448	6,482	6,517	6,003
Heat Input	4.810E+07	4.799E+07	4.757E+07	4.764E+07	4.751E+07
MMBtu/hr	5,706	5,692	5,665	5,671	5,662
% of Capacity	94.9%	94.6%	94.2%	94.3%	94.1%
NOx lb/MMBtu	0.152	0.153	0.152	0.152	0.153
Total Stack Emissions:					
NOx Emitted Tons Per Year:	3,662.4	3,666.8	3,610.4	3,626.8	3,646.1
Stack Emissions --- Lignite:					
NOX CEM Annual Average lb/MMBtu	0.152	0.153	0.152	0.153	0.154

Great River Energy Coal Creek Station

BART Supplement - NOx Emission Control Cost Analysis

Table A-3: Summary of Utility, Chemical and Supply Costs

Operating Unit: Unit 1 or 2 **Study Year** 2011

From Golder Report

Item	Unit Cost	Units	Reference Cost	Year	Data Source	Notes
Operating Labor	37.00	$/hr	25.86	2002	Stone & Webster 2002 Cost Estimate; confirmed by GRE	
Maintenance Labor	37.00	$/hr	26.25	2002	Stone & Webster 2002 Cost Estimate; confirmed by GRE	
Electricity	0.0604	$/kwh	0.049	2004	DOE Average Retail Price of Industrial Electricity, 2004	http://www.eia.doe.gov/emeu/aer/txt/ptb0810.html
Water	0.31	$/kgal	0.79	2002	Stone & Webster 2002 Cost Estimate; confirmed by GRE	
Cooling Water	0.32	$kgal	0.23	1999	EPA Air Pollution Control Cost Manual, 6th ed. Section 3.1 Ch 1	Ch 1 Carbon Adsorbers, 1999 $0.15 - $0.30 Avg of 22.5 and 7 yrs and 3% inflation
Compressed Air	0.37	$/kscf	0.25	1998	EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1	Example problem; Dried & Filtered, Ch 1.6 '98 cost adjusted for 3% inflation
Wastewater Disposal Neutralization	1.96	$/kgal	1.50	2002	EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 2 Chapter 2.5.5.5	Section 2 lists $1- $2/1000 gal. Cost adjusted for 3% inflation Sec 6 Ch 3 lists $1.30 - $2.15/1,000 gal
Wastewater Disposal Bio-Treat	4.96	$/kgal	3.80	2002	EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 5.2 Chapter 1	Ch 1 lists $1.00 - $6.00 for municipal treatment, $3.80 is average. Cost adjusted for 3% inflation
Solid Waste Disposal - No Impact	0.000	$/ton	0.00	2011	Assume no chang in GRE landfill cost for ash	Fly ash disposal of 0 net tons
Solid Waste Disposal - 30% Lost	5.438	$/ton	5.438	2011	Golder Fly Ash Management Evaluation - Nov. 2011	Cost per ton of $13.91/ ton for 234,500 tons less existing cost of $18.06/tons for 110,000 tons
Solid Waste Disposal - 100% Lost	7.396	$/ton	7.396	2011	Golder Fly Ash Management Evaluation - Nov. 2011	Cost per ton of $11.18/ ton for 525,000 tons less existing cost of $18.06/tons for 110,000 tons
Hazardous Waste Disposal	326.19	$/ton	250.00	2002	EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 2 Chapter 2.5.5.5	Section 2 lists $200 - $300/ton Used $250/ton. Cost adjusted for 3% inflation
Waste Transport	0.65	$/ton-mi	0.500	2002	EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 3	Example problem. Cost adjusted for 3% inflation
Ash Sales	12.300	$/ton	12.300	2011	Golder Fly Ash Management Evaluation - Nov. 2011	$/ton received for sale of ash; this amount is lost if ash cannot be sold
Ammonia Mitigation	5.610	$/ton	5.610	2011	Golder Fly Ash Management Evaluation - Nov. 2011	
Chemicals & Supplies						
Lime	90.00	$/ton	72.19	2005	GRE per Diane Stockdill 12/6/05 email	Cost adjusted for 3% inflation
Caustic	364	$/ton	305.21	2005	GRE per Diane Stockdill 12/6/05 email	Cost adjusted for 3% inflation
Urea	500	$/ton	500	2011	URS SNCR Report - November 2011	
Oxygen	17.91	kscf	15.00	2005	Get cost from Air Prod Website	Cost adjusted for 3% inflation
EPA Urea	179.1	$/ton				
Ammonia	1	$/lb	0.92	2005	GRE per Diane Stockdill	Cost adjusted for 3% inflation
Other						
Sales Tax	0	%			GRE per Diane Stockdill 12/6/05 email	
Interest Rate	5.50%	%			GRE per Diane Stockdill 12/6/05 email	Estimated prime rate plus 3%

Please note, for units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal

Future Operating Scenario for BART Cost Analysis

Operating Information	Unit 1	Unit 2			Data Source	Notes
Annual Op. Hrs	7,652.6	8,409.6	Hours		July 2010 to October 2011 Coal Creek Emission Data	
Utilization Rate	100.0%	100.0%			GRE per Diane Stockdill 12/6/05 email	
Equipment Life	20	20	yrs			Engineering Estimate
Coal Ash	11.70	11.70	wt % ash		2010 Coal Creek Emission Inventory	
Coal Sulfur	0.64	0.64	% Coal Sulfur Content		July 2010 to October 2011 Coal Creek Emission Data	
Coal Heating Value	6,373	6,373	Btu/lb of coal		July 2010 to October 2011 Coal Creek Emission Data	
Design Capacity	6,015	6,022	MMBtu/hr			
ID Fan Flow Rates	Assumes coal drying with DryFining™					
Standardized Flow Rate	866293.7	866293.7	scfm @ 32º F			
Temperature	330.0	330.0	Deg F		GRE per G. Riveland 4/5/06 email	
Moisture Content	13.3%	13.3%			GRE per G. Riveland 4/5/06 email	
Actual Flow Rate	2,234,300	2,234,300	acfm		GRE per G. Riveland 4/5/06 email	
Standardized Flow Rate	1,391,000	1,391,000	scfm @ 330º F		GRE per G. Riveland 4/5/06 email	
Dry Std Flow Rate	1,205,997	1,205,997	dscfm @ 330º F			
NOx Pollutant Data						
Max Emis (lb/hr)	1,205.2	918.5			July 2010 to October 2011 Coal Creek Emission Data	
Max Emis (tpy)	4,611.4	3,862.3				
Baseline Emiss (lb/MMBtu)	0.200	0.153				

Great River Energy Coal Creek Station

BART Supplement - NOx Emission Control Cost Analysis

Table A-4: Unit 1 NOx Control - Foster Wheeler LNC3+

Operating Unit: **Unit 1**

Emission Unit Number	EU-1		Stack/Vent Number	SV-1		CEPCI	
Desgin Capacity	6,015	MMBtu/hr	Standardized Flow Rate	866,294	scfm @ 32º F	2005	468.2
Expected Utiliztion Rate	100%		Temperature	330	Deg F	2011	588.9
Expected Annual Hours of Operation	7,652.6	Hours	Moisture Content	13.3%		Inflation Factor	1.26
Annual Interest Rate	5.5%		Actual Flow Rate	2,234,300	acfm		
Expected Equipment Life	20	yrs	Standardized Flow Rate	1,391,000	scfm @ 330º F		
Baseline NOx	0.200	lb/MMBtu	Dry Std Flow Rate	1,205,997	dscfm @ 330º F		

CONTROL EQUIPMENT COSTS

Capital Costs		
Direct Capital Costs		
Purchased Equipment (A)		1,257,796
Purchased Equipment Total (B)		**1,958,057**
Installation - Standard Costs		1,958,057
Installation - Site Specific Costs		NA
Installation Total		3,729,632
Total Direct Capital Cost, DC		5,687,689
Total Indirect Capital Costs, IC		391,611
Total Capital Investment (TCI) = DC + IC		**6,079,300**
Operating Costs		
Total Annual Direct Operating Costs	Labor, supervision, materials, replacement parts, utilities, etc.	7,079
Total Annual Indirect Operating Costs	Sum indirect oper costs + capital recovery cost	756,131
Total Annual Cost (Annualized Capital Cost + Operating Cost)		**763,210**

Emission Control Cost Calculation

Pollutant	**Max Emis Lb/Hr**	**Pre-control Annual T/Yr**	**Cont Eff %**	**Exit Conc**	**Conc Units**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
Nitrogen Oxides (NOx)	1,205.2	4,611.4	24%			3510.5	1,100.9	693

Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 2 (Used PM Scrubber which has lowest installed cost multiplier)

Notes & Assumptions

1. Sept 2005 Cost Estimate from Foster Wheeler, Option 2, inflated to 2011 dollars. Ratio based on actual cost for Unit 2 instalaltion.
2. Total capital investment reflects actual installed costs for Unit 2 installation, infllated to 2011 dollars.
3. Assumed 0.1 hr/shift operatior and maintenance labor for LNB
4. Process, emissions and cost data listed above is for one unit.
5. For units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal

Great River Energy Coal Creek Station
BART Supplement - NOx Emission Control Cost Analysis
Table A-4: Unit 1 NOx Control - Foster Wheeler LNC3+

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) (1)			**1,257,796**
Instrumentation			
Sales Taxes			
Freight			
Purchased Equipment Total (B)			**1,958,057**
Installation			
Foundations & supports			
Handling & erection			
Electrical			
Piping			
Insulation			
Painting			
Installation Subtotal Standard Expenses (1)			**1,958,057**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Site Specific - Other		Site Specific	NA
Total Site Specific Costs			NA
Installation Total			**3,729,632**
Total Direct Capital Cost, DC			**5,687,689**
Indirect Capital Costs			
Engineering, supervision	5%	of purchased equip cost (B)	97,903
Construction & field expenses	10%	of purchased equip cost (B)	195,806
Contractor fees	0%	of purchased equip cost (B)	0
Start-up	1%	of purchased equip cost (B)	19,581
Performance test	1%	of purchased equip cost (B)	19,581
Model Studies	NA	of purchased equip cost (B)	NA
Contingencies	3%	of purchased equip cost (B)	58,742
Total Indirect Capital Costs, IC	20%	of purchased equip cost (B)	**391,611**
Ozone Generator, Installed Cost			**0**
Total Capital Investment (TCI) = DC + IC (2)			**6,079,300**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**6,079,300**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	NA		-
Supervisor	NA		-
Maintenance			
Maintenance Labor	37.00	$/Hr, 0.1 hr/8 hr shift, 7652.6 hr/yr	3,539
Maintenance Materials	100%	of maintenance labor costs	3,539
Utilities, Supplies, Replacements & Waste Management			
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
Total Annual Direct Operating Costs			**7,079**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	4,247
Administration (2% total capital costs)	2%	of total capital costs (TCI)	121,586
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	60,793
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	60,793
Capital Recovery	0.0837	for a 20- year equipment life and a 5.5% interest rate	508,712
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**756,131**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**763,210**

Great River Energy Coal Creek Station
BART Supplement - NOx Emission Control Cost Analysis
Table A-4: Unit 1 NOx Control - Foster Wheeler LNC3+

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Parts & Equipment:		
Equipment Life	5	years
CRF	0.0000	
Rep part cost per unit	0	$/ft^3
Amount Required	0	ft^3
Packing Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:			
Equipment Life	3		
CRF	0.3707		
Rep part cost per unit	0	$ each	
Amount Required	0	Number	
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax	
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr	OAQPS list replacement times from 5 - 20 min per bag.
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	
Annualized Cost	**0**		

Electrical Use							
	Flow acfm		Δ P ft H2O	**Efficiency**	**Hp**	**kW**	
Blower, Scrubber	2,234,300		0	0.7	-	0.0	EPA Cost Cont Manual 6th ed Section 5.2 Chapter 1 Eq 1.48
	Flow	Liquid SPGR	Δ P ft H2O	**Efficiency**	**Hp**	**kW**	
Circ Pump	000 gpm	1	0	0.7	-	0.0	EPA Cost Cont Manual 6th ed Section 5.2 Chapter 1 Eq 1.49
H2O WW Disch	0 gpm	1	0	0.7	-	0.0	EPA Cost Cont Manual 6th ed Section 5.2 Chapter 1 Eq 1.49
			lb/hr O_3				
LTO Electric Use	4.5 kW/lb O_3					0	
Other							
Total						0.0	

Reagent Use & Other Operating Costs						
Ozone Needed	1.8	lb O3/lb NOx	-	lb/hr O3		
Oxygen Needed	10%	wt O2 to O3 conversion		0 lb/hr O2		0 scfh O2
LTO Cooling Water	150	gal/lb O3	0 gpm			
Liquid/Gas ratio	0.0	* L/G = Gal/1,000 acf				
Circulating Water Rate	0	gpm				
Water Makeup Rate/WW Disch =		20% of circulating water rate =	0 gpm			
Scrubber Cost	10	$/scfm Gas	$0		Incremental cost per BOC. Need to increase vessel size over standard absorber.	
Ozone Generator	$350	lb O3/day	$0	Installed	Installed cost factor per BOC.	

Direct Operating Cost Calculations — **Annual hours of operation:** **7,652.6**; **Utilization Rate:** **100%**

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Operating Labor							
Op Labor	0	$/Hr	0.1	hr/8 hr shift	96	0	$/Hr, 0.1 hr/8 hr shift, 7652.6 hr/yr
Supervisor	15%	of Op.			NA	-	15% of Operator Costs
Maintenance							
Maint Labor	37.00	$/Hr	0.1	hr/8 hr shift	96	3,539	$/Hr, 0.1 hr/8 hr shift, 7652.6 hr/yr
Maint Mtls	100	% of Maintenance Labor			NA	3,539	100% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.0604	$/kwh	0.0	kW-hr	0	0	$/kwh, 0 kW-hr, 7652.6 hr/yr, 100% utilization
Water	0.3100	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 7652.6 hr/yr, 100% utilization
Cooling Water	0.3208	$kgal	0.0	gpm	0	0	$kgal, 0 gpm, 7652.6 hr/yr, 100% utilization
Comp Air	0.3671	$/kscf	0	kscfm	0	0	$/kscf, 0 kscfm, 7652.6 hr/yr, 100% utilization
WW Treat Neutralization	1.9572	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 7652.6 hr/yr, 100% utilization
WW Treat Biotreatement	4.9581	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 7652.6 hr/yr, 100% utilization
SW Disposal	0.0000	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 7652.6 hr/yr, 100% utilization
Haz W Disp	326.1933	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 7652.6 hr/yr, 100% utilization
Ammonia Mitigation	5.6100	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 7652.6 hr/yr, 100% utilization
Lost Ash Sales	12.3000	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 7652.6 hr/yr, 100% utilization
Lime	90.0000	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 7652.6 hr/yr, 100% utilization
Caustic	364.4367	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 7652.6 hr/yr, 100% utilization
Oxygen	17.9108	kscf	0.0	kscf/hr	0	0	kscf, 0 kscf/hr, 7652.6 hr/yr, 100% utilization

*annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

Great River Energy Coal Creek Station

BART Supplement - NOx Emission Control Cost Analysis

Table A-5: Unit 1 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (Maintain Ash Sales)

Operating Unit: **Unit 1**

Emission Unit Number	EU-1		Stack/Vent Number	SV-1	
Desgin Capacity	6,015	MMBtu/hr	Standardized Flow Rate	866,294	scfm @ 32º F
Expected Utiliztion Rate	100%		Temperature	330	Deg F
Expected Annual Hours of Operation	7,652.6	Hours	Moisture Content	13.3%	
Annual Interest Rate	5.5%		Actual Flow Rate	2,234,300	acfm
Expected Equipment Life	20	yrs	Standardized Flow Rate	1,391,000	scfm @ 330º F
Baseline NOx	0.200	lb/MMBtu	Dry Std Flow Rate	1,205,997	dscfm @ 330º F

CONTROL EQUIPMENT COSTS

Capital Costs								
Direct Capital Costs								
Purchased Equipment (A)								3,700,000
Purchased Equipment Total (B)								**8,465,600**
Installation - Standard Costs								1,270,000
Installation - Site Specific Costs								1,036,000
Installation Total								1,758,000
Total Capital Investment (TCI) = DC + IC								**12,176,084**
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.						3,282,068
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost						1,018,887
Total Annual Cost (Annualized Capital Cost + Operating Cost)								**4,300,954**

Emission Control Cost Calculation

Pollutant	**Max Emis Lb/Hr**	**Pre-control Annual T/Yr**	**Cont Eff %**	**Exit Conc**	**Conc Units**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
Nitrogen Oxides (NOx)	1,205.2	4,611.4	25.0%			3458.5	1,152.8	3,731

Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1

Notes & Assumptions

1 November 2011 SNCR Evaluation from URS
2 SNCR Maintenance Costs EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.21
3 Process, emissions and cost data listed above is for one unit.
4 For units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal
5 Retrofit factor of 60% used by URS based on site visit to Coal Creek Station.
6 SW disposal and fly ash sales data from Nov. 2011 Golder Fly Ash Evaluation, Appendix B2
7 One-time cost for Technology Licensing Fee for the SNCR process is ~0.5% of the Process Capital.

Great River Energy Coal Creek Station
BART Supplement - NOx Emission Control Cost Analysis
Table A-5: Unit 1 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (Maintain Ash Sales)

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment			**3,700,000**
Purchased Equipment Costs			
Instrumentation	10%	of purchased equipment cost	370,000
Site Specific and Prime Contractor Markup	28%	of purchased equipment cost	1,036,000
Freight	5%	of purchased equipment cost	185,000
Purchased Equipment Total	43%		5,291,000
Purchased Equipment Total+ Retrofit Factor (A)			**8,465,600**
Indirect Installation			
General Facilities		See Notes & Assumptions 1 on pg. 1 of Table	420,000
Engineering & Home Office		See Notes & Assumptions 1 on pg. 1 of Table	850,000
Process Contingency		See Notes & Assumptions 1 on pg. 1 of Table	488,000
Total Indirect Installation Costs (B)		See Notes & Assumptions 1 on pg. 1 of Table	**1,758,000**
Project Contingeny (C)		See Notes & Assumptions 1 on pg. 1 of Table	**1,540,000**
Total Plant Cost (D)		A + B + C	**11,763,600**
Allowance for Funds During Construction (E)		0 for SNCR	**0**
Prepaid Royalties (F)		See Notes & Assumptionss 1 and 7 on pg. 1 of Table	**42,000**
Pre Production Costs (G)		See Notes & Assumptions 1 on pg. 1 of Table	**236,000**
Inventory Capital (H)		Reagent Vol * $/gal	**134,484**
Intial Catalyst and Chemicals (I)		0 for SNCR	**0**
Total Capital Investment (TCI) = DC + IC		D + E + F + G +H + I	**12,176,084**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**12,176,084**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	NA		-
Supervisor	NA		-
Maintenance			
Maintenance Total	1.50	% of Total Capital Investment	182,641
Maintenance Materials	NA	% of Maintenance Labor	-
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.060	See Direct Operating Cost Calculations on last pg.	28,218
Water	0.310	See Direct Operating Cost Calculations on last pg.	8,256
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
Urea	500.00	See Direct Operating Cost Calculations on last pg.	3,062,953
NA	NA		-
Total Annual Direct Operating Costs			**3,282,068**
Indirect Operating Costs			
Overhead	NA	of total labor and material costs	NA
Administration (2% total capital costs)	NA	of total capital costs (TCI)	NA
Property tax (1% total capital costs)	NA	of total capital costs (TCI)	NA
Insurance (1% total capital costs)	NA	of total capital costs (TCI)	NA
Capital Recovery	0.08368	for a 20- year equipment life and a 5.5% interest rate	1,018,887
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**1,018,887**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**4,300,954**

See Summary page for notes and assumptions

Great River Energy Coal Creek Station
BART Supplement - NOx Emission Control Cost Analysis
Table A-5: Unit 1 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (Maintain Ash Sales)

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.08368	

Replacement Catayst			<- Enter Equipment Name to Get Cost
Equipment Life	5	years	
CRF	0.2342		
Rep part cost per unit	0	$/ft^3	
Amount Required	12	ft^3	
Packing Cost	0	Cost adjusted for freight & sales tax	
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)	
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	
Annualized Cost	**0**		

Replacement Parts & Equipment:			<- Enter Equipment Name to Get Cost
Equipment Life	2	years	
CRF	0.0000		
Rep part cost per unit	0	$/ft^3	
Amount Required	0	Cages	
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax	See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs
Installation Labor	0	10 min per bag, Labor + Overhead (68% = $29.65/hr)	
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	EPA CCM list replacement times from 5 - 20 min per bag.
Annualized Cost	**0**		

Electrical Use			
NOx in	0.20	lb/MMBtu	kW
NSR	0.60		
Power			61.0
Total			61.0

Reagent Use & Other Operating Costs					
NOx in	0.20	lb/MMBtu	Urea Use	1601	lb/hr
Efficiency	25%		Volume 14 day inventory	269	ton
Duty	6,015	MMBtu/hr	Inventory Cost	$134,484	
Water Use	3480	gal/hr			

Direct Operating Cost Calculations — **Annual hours of operation: 7,652.6** — **Utilization Rate: 100%**

Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
Operating Labor							
Op Labor	37	$/Hr	0.0	hr/8 hr shift	0	0	$/Hr, 0.0 hr/8 hr shift, 7652.6 hr/yr
Supervisor	15%	of Op.			NA	-	15% of Operator Costs
Maintenance							
Maintenance Total	1.5	% of Total Capital Investment				182,641.26	% of Total Capital Investment
Maint Mtls	0	% of Maintenance Labor			NA	0	0% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.06045	$/kwh	61.00000	kW-hr	466,808.60	28,217.79	$/kwh, 61.0 kW-hr, 7652.6 hr/yr, 100% utilization
Water	0.31000	$/kgal	3480.00000	gph	26,631.05	8,255.62	0.31 $/kgal X 3,480.0 gph/1000 X 7652.6 hr/yr X 100% utilization
Cooling Water	0.32080	$kgal	0.00000	gpm	0	0	$kgal, 0 gpm, 7652.6 hr/yr, 100% utilization
Comp Air	0.36713	$/kscf	0.00000	scfm/kacfm**	0	0	$/kscf, 0.0 scfm/kacfm**, 7652.6 hr/yr, 100% utilization
WW Treat Neutralization	1.95716	$/kgal	0.00000	gpm	0	0	$/kgal, 0.0 gpm, 7652.6 hr/yr, 100% utilization
WW Treat Biotreatement	4.95814	$/kgal	0.00000	gpm	0	0	$/kgal, 0.0 gpm, 7652.6 hr/yr, 100% utilization
SW Disposal	0.00000	$/ton	7.18710	ton/hr	55,000	0	$/ton, 7.2 ton/hr, 7652.6 hr/yr, 100% utilization
Haz W Disp	326.19330	$/ton	0.00000	ton/hr	0	0	$/ton, 0.0 ton/hr, 7652.6 hr/yr, 100% utilization
Ammonia Mitigation	5.61	$/ton	0.00000	ton/hr	0	0	$/ton, 0.0 ton/hr, 7652.6 hr/yr, 100% utilization
Lost Ash Sales	12.3	$/ton	0.00000	ton/hr	0	0	$/ton, 0.0 ton/hr, 7652.6 hr/yr, 100% utilization
Lime	90.0	$/ton	0.00000	lb/hr	0	0	$/ton, 0.0 lb/hr, 7652.6 hr/yr, 100% utilization
Urea	500.0	$/ton	0.80050	ton/hr	6,125.91	3,062,953.15	500 $/ton X 0.8005 ton/hr X 7652.6 hr/yr X 100% utilization
Oxygen	17.91078	kscf	0.00000	kscf/hr	0	0	kscf, 0.0 kscf/hr, 7652.6 hr/yr, 100% utilization

** Std Air use is 2 scfm/kacfm

*annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

Great River Energy Coal Creek Station

BART Supplement - NOx Emission Control Cost Analysis

Table A-6: Unit 1 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (30% Lost Ash Sales)

Operating Unit: **Unit 1**

Emission Unit Number	EU-1		Stack/Vent Number	SV-1	
Desgin Capacity	6,015	MMBtu/hr	Standardized Flow Rate	866,294	scfm @ 32º F
Expected Utiliztion Rate	100%		Temperature	330	Deg F
Expected Annual Hours of Operation	7,652.6	Hours	Moisture Content	13.3%	
Annual Interest Rate	5.5%		Actual Flow Rate	2,234,300	acfm
Expected Equipment Life	20	yrs	Standardized Flow Rate	1,391,000	scfm @ 330º F
Baseline NOx	0.200	lb/MMBtu	Dry Std Flow Rate	1,205,997	dscfm @ 330º F

CONTROL EQUIPMENT COSTS

Capital Costs	
Direct Capital Costs	
Purchased Equipment (A)	3,700,000
Purchased Equipment Total (B)	**8,465,600**
Installation - Standard Costs	1,270,000
Installation - Site Specific Costs	1,036,000
Installation Total	1,758,000
Total Capital Investment (TCI) = DC + IC	**12,176,084**
Operating Costs	
Total Annual Direct Operating Costs — Labor, supervision, materials, replacement parts, utilities, etc.	5,500,243
Total Annual Indirect Operating Costs — Sum indirect oper costs + capital recovery cost	1,018,887
Total Annual Cost (Annualized Capital Cost + Operating Cost)	**6,519,129**

Emission Control Cost Calculation

Pollutant	**Max Emis Lb/Hr**	**Pre-control Annual T/Yr**	**Cont Eff %**	**Exit Conc**	**Conc Units**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
Nitrogen Oxides (NOx)	1,205.2	4,611.4	25.0%			3458.5	1,152.8	5,655

Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1

Notes & Assumptions

1. November 2011 SNCR Evaluation from URS
2. SNCR Maintenance Costs EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.21
3. Process, emissions and cost data listed above is for one unit.
4. For units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal
5. Retrofit factor of 60% used by URS based on site visit to Coal Creek Station.
6. SW disposal and fly ash sales data from Nov. 2011 Golder Fly Ash Evaluation, Appendix B2
7. One-time cost for Technology Licensing Fee for the SNCR process is ~0.5% of the Process Capital.

Great River Energy Coal Creek Station
BART Supplement - NOx Emission Control Cost Analysis
Table A-6: Unit 1 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (30% Lost Ash Sales)

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment			**3,700,000**
Purchased Equipment Costs			
Instrumentation	10.00%	of purchased equipment cost	370,000
Site Specific and Prime Contractor Markup	28.00%	of purchased equipment cost	1,036,000
Freight	5.00%	of purchased equipment cost	185,000
Purchased Equipment Total	43.00%		5,291,000
Purchased Equipment Total+ Retrofit Factor (A)			**8,465,600**
Indirect Installation			
General Facilities		See Notes & Assumptions 1 on pg. 1 of Table	420,000
Engineering & Home Office		See Notes & Assumptions 1 on pg. 1 of Table	850,000
Process Contingency		See Notes & Assumptions 1 on pg. 1 of Table	488,000
Total Indirect Installation Costs (B)		See Notes & Assumptions 1 on pg. 1 of Table	**1,758,000**
Project Contingeny (C)		See Notes & Assumptions 1 on pg. 1 of Table	**1,540,000**
Total Plant Cost (D)		A + B + C	**11,763,600**
Allowance for Funds During Construction (E)		0 for SNCR	**0**
Prepaid Royalties (F)		See Notes & Assumptionss 1 and 7 on pg. 1 of Table	**42,000**
Pre Production Costs (G)		See Notes & Assumptions 1 on pg. 1 of Table	**236,000**
Inventory Capital (H)		Reagent Vol * $/gal	**134,484**
Intial Catalyst and Chemicals (I)		0 for SNCR	**0**
Total Capital Investment (TCI) = DC + IC		D + E + F + G +H + I	**12,176,084**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**12,176,084**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	NA		-
Supervisor	NA		-
Maintenance			
Maintenance Total	1.50	% of Total Capital Investment	182,641
Maintenance Materials	NA	% of Maintenance Labor	-
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.060	See Direct Operating Cost Calculations on last pg.	28,218
Water	0.310	See Direct Operating Cost Calculations on last pg.	8,256
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
SW Disposal	5.44	See Direct Operating Cost Calculations on last pg.	637,648
NA	NA		-
Ammonia Mitigation	5.61	See Direct Operating Cost Calculations on last pg.	814,853
Lost Ash Sales	12.30	See Direct Operating Cost Calculations on last pg.	765,675
NA	NA		-
Urea	500.00	See Direct Operating Cost Calculations on last pg.	3,062,953
NA	NA		-
Total Annual Direct Operating Costs			**5,500,243**
Indirect Operating Costs			
Overhead	NA	of total labor and material costs	NA
Administration (2% total capital costs)	NA	of total capital costs (TCI)	NA
Property tax (1% total capital costs)	NA	of total capital costs (TCI)	NA
Insurance (1% total capital costs)	NA	of total capital costs (TCI)	NA
Capital Recovery	0.08368	for a 20- year equipment life and a 5.5% interest rate	1,018,887
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**1,018,887**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**6,519,129**

See Summary page for notes and assumptions

Great River Energy Coal Creek Station

BART Supplement - NOx Emission Control Cost Analysis

Table A-6: Unit 1 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (30% Lost Ash Sales)

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.08368	

Replacement Catayst		<- Enter Equipment Name to Get Cost
Equipment Life	5	years
CRF	0.2342	
Rep part cost per unit	0	$/ft^3
Amount Required	12	ft^3
Packing Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:		<- Enter Equipment Name to Get Cost	
Equipment Life	2	years	
CRF	0.0000		
Rep part cost per unit	0	$/ft^3	
Amount Required	0	Cages	
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax	See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs
Installation Labor	0	10 min per bag, Labor + Overhead (68% = $29.65/hr)	
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	EPA CCM list replacement times from 5 - 20 min per bag.
Annualized Cost	**0**		

Electrical Use			
NOx in	0.20	lb/MMBtu	kW
NSR	0.60		
Power			61.0
Total			61.0

Reagent Use & Other Operating Costs					
NOx in	0.20	lb/MMBtu	Urea Use	1601	lb/hr
Efficiency	25%		Volume 14 day inventory	269	ton
Duty	6,015	MMBtu/hr	Inventory Cost	$134,484	
Water Use	3480	gal/hr			

Direct Operating Cost Calculations — **Annual hours of operation: 7,652.6** — **Utilization Rate: 100%**

Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
Operating Labor							
Op Labor	37	$/Hr	0.0	hr/8 hr shift	0	0	$/Hr, 0.0 hr/8 hr shift, 7652.6 hr/yr
Supervisor	15%	of Op.			NA	-	15% of Operator Costs
Maintenance							
Maintenance Total	1.5	% of Total Capital Investment				182,641.26	% of Total Capital Investment
Maint Mtls	0	% of Maintenance Labor			NA	0	0% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.06045	$/kwh	61.00000	kW-hr	466,808.60	28,217.79	0.0604 $/kwh X 61.0 kW-hr X 7652.6 hr/yr X 100% utilization
Water	0.31000	$/kgal	3480.00000	gph	26,631.05	8,255.62	0.3100 $/kgal X 3,480.0 gph/1000 X 7652.6 hr/yr X 100% utilization
Cooling Water	0.32080	$kgal	0.00000	gpm	0	0	$kgal, 0 gpm, 7652.6 hr/yr, 100% utilization
Comp Air	0.36713	$/kscf	0.00000	scfm/kacfm**	0	0	$/kscf, 0.0 scfm/kacfm**, 7652.6 hr/yr, 100% utilization
WW Treat Neutralization	1.95716	$/kgal	0.00000	gpm	0	0	$/kgal, 0.0 gpm, 7652.6 hr/yr, 100% utilization
WW Treat Biotreatement	4.95814	$/kgal	0.00000	gpm	0	0	$/kgal, 0.0 gpm, 7652.6 hr/yr, 100% utilization
SW Disposal	5.43836	$/ton	15.32159	ton/hr	117,250	637,648	5.4384 $/ton X 15.3216 ton/hr X 7652.6 hr/yr X 100% utilization
Haz W Disp	326.19330	$/ton	0.00000	ton/hr	0	0	$/ton, 0.0 ton/hr, 7652.6 hr/yr, 100% utilization
Ammonia Mitigation	5.61	$/ton	18.98048	ton/hr	145,250	814,853	5.61 $/ton X 18.9805 ton/hr X 7652.6 hr/yr X 100% utilization
Lost Ash Sales	12.3	$/ton	8.13449	ton/hr	62,250.0	765,675	12.3 $/ton X 8.1345 ton/hr X 7652.6 hr/yr X 100% utilization
Lime	90.0	$/ton	0.00000	lb/hr	0	0	$/ton, 0.0 lb/hr, 7652.6 hr/yr, 100% utilization
Urea	500.0	$/ton	0.80050	ton/hr	6,125.91	3,062,953.15	500 $/ton X 0.8005 ton/hr X 7652.6 hr/yr X 100% utilization
Oxygen	17.91078	kscf	0.00000	kscf/hr	0	0	kscf, 0.0 kscf/hr, 7652.6 hr/yr, 100% utilization

** Std Air use is 2 scfm/kacfm

*annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

Great River Energy Coal Creek Station
BART Supplement - NOx Emission Control Cost Analysis
Table A-7: Unit 1 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (100% Lost Ash Sales)

Operating Unit: **Unit 1**

Emission Unit Number	EU-1		Stack/Vent Number	SV-1	
Desgin Capacity	6,015	MMBtu/hr	Standardized Flow Rate	866,294	scfm @ 32º F
Expected Utiliztion Rate	100%		Temperature	330	Deg F
Expected Annual Hours of Operation	7,652.6	Hours	Moisture Content	13.3%	
Annual Interest Rate	5.5%		Actual Flow Rate	2,234,300	acfm
Expected Equipment Life	20	yrs	Standardized Flow Rate	1,391,000	scfm @ 330º F
Baseline NOx	0.200	lb/MMBtu	Dry Std Flow Rate	1,205,997	dscfm @ 330º F

CONTROL EQUIPMENT COSTS

Capital Costs		
Direct Capital Costs		
Purchased Equipment (A)		3,700,000
Purchased Equipment Total (B)		**8,465,600**
Installation - Standard Costs		1,270,000
Installation - Site Specific Costs		1,036,000
Installation Total		1,758,000
Total Capital Investment (TCI) = DC + IC		**12,176,084**
Operating Costs		
Total Annual Direct Operating Costs	Labor, supervision, materials, replacement parts, utilities, etc.	7,775,768
Total Annual Indirect Operating Costs	Sum indirect oper costs + capital recovery cost	1,018,887
Total Annual Cost (Annualized Capital Cost + Operating Cost)		**8,794,654**

Emission Control Cost Calculation

Pollutant	**Max Emis Lb/Hr**	**Pre-control Annual T/Yr**	**Cont Eff %**	**Exit Conc**	**Conc Units**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
Nitrogen Oxides (NOx)	1,205.2	4,611.4	25.0%			3458.5	1,152.8	7,629

Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1

Notes & Assumptions

1. November 2011 SNCR Evaluation from URS
2. SNCR Maintenance Costs EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.21
3. Process, emissions and cost data listed above is for one unit.
4. For units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal
5. Retrofit factor of 60% used by URS based on site visit to Coal Creek Station.
6. SW disposal and fly ash sales data from Nov. 2011 Golder Fly Ash Evaluation, Appendix B2
7. One-time cost for Technology Licensing Fee for the SNCR process is ~0.5% of the Process Capital.

Great River Energy Coal Creek Station
BART Supplement - NOx Emission Control Cost Analysis
Table A-7: Unit 1 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (100% Lost Ash Sales)

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment			**3,700,000**
Purchased Equipment Costs			
Instrumentation	10.00%	of purchased equipment cost	370,000
Site Specific and Prime Contractor Markup	28.00%	of purchased equipment cost	1,036,000
Freight	5.00%	of purchased equipment cost	185,000
Purchased Equipment Total	43.00%		5,291,000
Purchased Equipment Total+ Retrofit Factor (A)			**8,465,600**
Indirect Installation			
General Facilities		See Notes & Assumptions 1 on pg. 1 of Table	420,000
Engineering & Home Office		See Notes & Assumptions 1 on pg. 1 of Table	850,000
Process Contingency		See Notes & Assumptions 1 on pg. 1 of Table	488,000
Total Indirect Installation Costs (B)		See Notes & Assumptions 1 on pg. 1 of Table	**1,758,000**
Project Contingeny (C)		See Notes & Assumptions 1 on pg. 1 of Table	**1,540,000**
Total Plant Cost (D)		A + B + C	**11,763,600**
Allowance for Funds During Construction (E)		0 for SNCR	**0**
Prepaid Royalties (F)		See Notes & Assumptionss 1 and 7 on pg. 1 of Table	**42,000**
Pre Production Costs (G)		See Notes & Assumptions 1 on pg. 1 of Table	**236,000**
Inventory Capital (H)		Reagent Vol * $/gal	**134,484**
Intial Catalyst and Chemicals (I)		0 for SNCR	**0**
Total Capital Investment (TCI) = DC + IC		D + E + F + G +H + I	**12,176,084**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**12,176,084**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	NA		-
Supervisor	NA		-
Maintenance			
Maintenance Total	1.50	% of Total Capital Investment	182,641
Maintenance Materials	NA	% of Maintenance Labor	-
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.060	See Direct Operating Cost Calculations on last pg.	28,218
Water	0.310	See Direct Operating Cost Calculations on last pg.	8,256
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
SW Disposal	7.40	See Direct Operating Cost Calculations on last pg.	1,941,450
NA	NA		-
NA	NA		-
Lost Ash Sales	12.30	See Direct Operating Cost Calculations on last pg.	2,552,250
NA	NA		-
Urea	500.00	See Direct Operating Cost Calculations on last pg.	3,062,953
NA	NA		-
Total Annual Direct Operating Costs			**7,775,768**
Indirect Operating Costs			
Overhead	NA	of total labor and material costs	NA
Administration (2% total capital costs)	NA	of total capital costs (TCI)	NA
Property tax (1% total capital costs)	NA	of total capital costs (TCI)	NA
Insurance (1% total capital costs)	NA	of total capital costs (TCI)	NA
Capital Recovery	0.08368	for a 20- year equipment life and a 5.5% interest rate	1,018,887
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**1,018,887**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**8,794,654**

See Summary page for notes and assumptions

Great River Energy Coal Creek Station

BART Supplement - NOx Emission Control Cost Analysis

Table A-7: Unit 1 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (100% Lost Ash Sales)

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.08368	

Replacement Catayst		<- Enter Equipment Name to Get Cost
Equipment Life	5	years
CRF	0.2342	
Rep part cost per unit	0	$/ft^3
Amount Required	12	ft^3
Packing Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:		<- Enter Equipment Name to Get Cost	
Equipment Life	2	years	
CRF	0.0000		
Rep part cost per unit	0	$/ft^3	
Amount Required	0	Cages	
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax	See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs
Installation Labor	0	10 min per bag, Labor + Overhead (68% = $29.65/hr)	
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	EPA CCM list replacement times from 5 - 20 min per bag.
Annualized Cost	**0**		

Electrical Use			
NOx in	0.20	lb/MMBtu	kW
NSR	0.60		
Power			61.0
Total			61.0

Reagent Use & Other Operating Costs					
NOx in	0.20	lb/MMBtu	Urea Use	1601	lb/hr
Efficiency	25%		Volume 14 day inventory	269	ton
Duty	6,015	MMBtu/hr	Inventory Cost	$134,484	
Water Use	3480	gal/hr			

Direct Operating Cost Calculations — **Annual hours of operation:** **7,652.6** — **Utilization Rate:** **100%**

Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
Operating Labor							
Op Labor	37	$/Hr	0.0	hr/8 hr shift	0	0	$/Hr, 0.0 hr/8 hr shift, 7652.6 hr/yr
Supervisor	15%	of Op.			NA	-	15% of Operator Costs
Maintenance							
Maintenance Total	1.5	% of Total Capital Investment				182,641.26	% of Total Capital Investment
Maint Mtls	0	% of Maintenance Labor			NA	0	0% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.06045	$/kwh	61.00000	kW-hr	466,808.60	28,217.79	0.0604 $/kwh X 61.0 kW-hr X 7652.6 hr/yr X 100% utilization
Water	0.31000	$/kgal	3480.00000	gph	26,631.05	8,255.62	0.3100 $/kgal X 3,480.0 gph/1000 X 7652.6 hr/yr X 100% utilization
Cooling Water	0.32080	$kgal	0.00000	gpm	0	0	$kgal, 0 gpm, 7652.6 hr/yr, 100% utilization
Comp Air	0.36713	$/kscf	0.00000	scfm/kacfm**	0	0	$/kscf, 0.0 scfm/kacfm**, 7652.6 hr/yr, 100% utilization
WW Treat Neutralization	1.95716	$/kgal	0.00000	gpm	0	0	$/kgal, 0.0 gpm, 7652.6 hr/yr, 100% utilization
WW Treat Biotreatement	4.95814	$/kgal	0.00000	gpm	0	0	$/kgal, 0.0 gpm, 7652.6 hr/yr, 100% utilization
SW Disposal	7.39600	$/ton	34.30207	ton/hr	262,500	1,941,450	7.3960 $/ton X 34.3021 ton/hr X 7652.6 hr/yr X 100% utilization
Haz W Disp	326.19330	$/ton	0.00000	ton/hr	0	0	$/ton, 0.0 ton/hr, 7652.6 hr/yr, 100% utilization
Ammonia Mitigation	5.61	$/ton	0.00000	ton/hr	0	0	$/ton, 0.0 ton/hr, 7652.6 hr/yr, 100% utilization
Lost Ash Sales	12.3	$/ton	27.11497	ton/hr	207,500	2,552,250	12.3 $/ton X 27.1150 ton/hr X 7652.6 hr/yr X 100% utilization
Lime	90.0	$/ton	0.00000	lb/hr	0	0	$/ton, 0.0 lb/hr, 7652.6 hr/yr, 100% utilization
Urea	500.0	$/ton	0.80050	ton/hr	6,125.91	3,062,953.15	500.0 $/ton X 0.8005 ton/hr X 7652.6 hr/yr X 100% utilization
Oxygen	17.91078	kscf	0.00000	kscf/hr	0	0	kscf, 0.0 kscf/hr, 7652.6 hr/yr, 100% utilization

** Std Air use is 2 scfm/kacfm

*annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

Great River Energy Coal Creek Station

BART Supplement - NOx Emission Control Cost Analysis

Table A-8: Unit 2 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (Maintain Ash Sales)

Operating Unit: **Unit 2**

Emission Unit Number	EU-2		Stack/Vent Number	SV-2	
Desgin Capacity	6,022	MMBtu/hr	Standardized Flow Rate	866,294	scfm @ 32º F
Expected Utiliztion Rate	100%		Temperature	330	Deg F
Expected Annual Hours of Operation	8,409.6	Hours	Moisture Content	13.3%	
Annual Interest Rate	5.5%		Actual Flow Rate	2,234,300	acfm
Expected Equipment Life	20	yrs	Standardized Flow Rate	1,391,000	scfm @ 330º F
Baseline NOx	0.153	lb/MMBtu	Dry Std Flow Rate	1,205,997	dscfm @ 330º F

CONTROL EQUIPMENT COSTS

Capital Costs								
Direct Capital Costs								
Purchased Equipment (A)								3,600,000
Purchased Equipment Total (B)								**8,236,800**
Installation - Standard Costs								1,230,000
Installation - Site Specific Costs								1,008,000
Installation Total								1,702,000
Total Capital Investment (TCI) = DC + IC								**11,793,820**
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.						2,634,116
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost						986,899
Total Annual Cost (Annualized Capital Cost + Operating Cost)								**3,621,015**

Emission Control Cost Calculation

Pollutant	**Max Emis Lb/Hr**	**Pre-control Annual T/Yr**	**Cont Eff %**	**Exit Conc**	**Conc Units**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
Nitrogen Oxides (NOx)	918.5	3,862.3	20.0%			3089.8	772.5	4,688

Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1

Notes & Assumptions

1. November 2011 SNCR Evaluation from URS
2. SNCR Maintenance Costs EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.21
3. Process, emissions and cost data listed above is for one unit.
4. For units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal
5. Retrofit factor of 60% used by URS based on site visit to Coal Creek Station.
6. SW disposal and fly ash sales data from Nov. 2011 Golder Fly Ash Evaluation, Appendix B2
7. One-time cost for Technology Licensing Fee for the SNCR process is ~0.5% of the Process Capital.

Great River Energy Coal Creek Station

BART Supplement - NOx Emission Control Cost Analysis

Table A-8: Unit 2 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (Maintain Ash Sales)

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment			**3,600,000**
Purchased Equipment Costs			
Instrumentation	10.00%	of purchased equipment cost	360,000
Site Specific and Prime Contractor Markup	28.00%	of purchased equipment cost	1,008,000
Freight	5.00%	of purchased equipment cost	180,000
Purchased Equipment Total	43.00%		5,148,000
Purchased Equipment Total+ Retrofit Factor (A)			**8,236,800**
Indirect Installation			
General Facilities		See Notes & Assumptions 1 on pg. 1 of Table	410,000
Engineering & Home Office		See Notes & Assumptions 1 on pg. 1 of Table	820,000
Process Contingency		See Notes & Assumptions 1 on pg. 1 of Table	472,000
Total Indirect Installation Costs (B)		See Notes & Assumptions 1 on pg. 1 of Table	**1,702,000**
Project Contingeny (C)		See Notes & Assumptions 1 on pg. 1 of Table	**1,490,000**
Total Plant Cost (D)		A + B + C	**11,428,800**
Allowance for Funds During Construction (E)		0 for SNCR	**0**
Prepaid Royalties (F)		See Notes & Assumptionss 1 and 7 on pg. 1 of Table	**41,000**
Pre Production Costs (G)		See Notes & Assumptions 1 on pg. 1 of Table	**227,000**
Inventory Capital (H)		Reagent Vol * $/gal	**97,020**
Intial Catalyst and Chemicals (I)		0 for SNCR	**0**
Total Capital Investment (TCI) = DC + IC		D + E + F + G +H + I	**11,793,820**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**11,793,820**

OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	NA		-
Supervisor	NA		-
Maintenance			
Maintenance Total	1.50	% of Total Capital Investment	176,907
Maintenance Materials	NA	% of Maintenance Labor	-
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.060	See Direct Operating Cost Calculations on last pg.	22,367
Water	0.310	See Direct Operating Cost Calculations on last pg.	6,570
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
Urea	500.00	See Direct Operating Cost Calculations on last pg.	2,428,272
NA	NA		-
Total Annual Direct Operating Costs			**2,634,116**
Indirect Operating Costs			
Overhead	NA	of total labor and material costs	NA
Administration (2% total capital costs)	NA	of total capital costs (TCI)	NA
Property tax (1% total capital costs)	NA	of total capital costs (TCI)	NA
Insurance (1% total capital costs)	NA	of total capital costs (TCI)	NA
Capital Recovery	0.08368	for a 20- year equipment life and a 5.5% interest rate	986,899
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**986,899**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**3,621,015**

See Summary page for notes and assumptions

Great River Energy Coal Creek Station

BART Supplement - NOx Emission Control Cost Analysis

Table A-8: Unit 2 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (Maintain Ash Sales)

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.08368	

Replacement Catayst		<- Enter Equipment Name to Get Cost	
Equipment Life	5	years	
CRF	0.2342		
Rep part cost per unit	0	$/ft^3	
Amount Required	12	ft^3	
Packing Cost	0	Cost adjusted for freight & sales tax	
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)	
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	
Annualized Cost	**0**		

Replacement Parts & Equipment:		<- Enter Equipment Name to Get Cost	
Equipment Life	2	years	
CRF	0.0000		
Rep part cost per unit	0	$/ft^3	
Amount Required	0	Cages	
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax	See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs
Installation Labor	0	10 min per bag, Labor + Overhead (68% = $29.65/hr)	
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	EPA CCM list replacement times from 5 - 20 min per bag.
Annualized Cost	**0**		

Electrical Use			
NOx in	0.15	lb/MMBtu	kW
NSR	0.44		
Power			44.0
Total			44.0

Reagent Use & Other Operating Costs					
NOx in	0.15	lb/MMBtu	Urea Use	1155	lb/hr
Efficiency	20%		Volume 14 day inventory	194	ton
Duty	6,022	MMBtu/hr	Inventory Cost	$97,020	
Water Use	2520	gal/hr			

Direct Operating Cost Calculations — **Annual hours of operation:** **8,409.6** — **Utilization Rate:** **100%**

Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
Operating Labor							
Op Labor	37	$/Hr	0.0	hr/8 hr shift	0	0	$/Hr, 0.0 hr/8 hr shift, 8409.6 hr/yr
Supervisor	15%	of Op.			NA	-	15% of Operator Costs
Maintenance							
Maintenance Total	1.5	% of Total Capital Investment				176,907.30	% of Total Capital Investment
Maint Mtls	0	% of Maintenance Labor			NA	0	0% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.06045	$/kwh	44.00000	kW-hr	370,022.40	22,367.23	0.0604 $/kwh X 44.0 kW-hr X 8409.6 hr/yr X 100% utilization
Water	0.31000	$/kgal	2520.00000	gph	21,192.19	6,569.58	0.3100 $/kgal X 2,520.0 gph/1000 X 8409.6 hr/yr X 100% utilization
Cooling Water	0.32080	$kgal	0.00000	gpm	0	0	$kgal, 0 gpm, 8409.6 hr/yr, 100% utilization
Comp Air	0.36713	$/kscf	0.00000	scfm/kacfm**	0	0	$/kscf, 0.0 scfm/kacfm**, 8409.6 hr/yr, 100% utilization
WW Treat Neutralization	1.95716	$/kgal	0.00000	gpm	0	0	$/kgal, 0.0 gpm, 8409.6 hr/yr, 100% utilization
WW Treat Biotreatement	4.95814	$/kgal	0.00000	gpm	0	0	$/kgal, 0.0 gpm, 8409.6 hr/yr, 100% utilization
SW Disposal	0.00000	$/ton	6.54014	ton/hr	55,000	0	$/ton, 6.5 ton/hr, 8409.6 hr/yr, 100% utilization
Haz W Disp	326.19330	$/ton	0.00000	ton/hr	0	0	$/ton, 0.0 ton/hr, 8409.6 hr/yr, 100% utilization
Ammonia Mitigation	5.61	$/ton	0.00000	ton/hr	0	0	$/ton, 0.0 ton/hr, 8409.6 hr/yr, 100% utilization
Lost Ash Sales	12.3	$/ton	0.00000	ton/hr	0	0	$/ton, 0.0 ton/hr, 8409.6 hr/yr, 100% utilization
Lime	90.0	$/ton	0.00000	lb/hr	0	0	$/ton, 0.0 lb/hr, 8409.6 hr/yr, 100% utilization
Urea	500.0	$/ton	0.57750	ton/hr	4,856.54	2,428,272.00	500.0 $/ton X 0.5775 ton/hr X 8409.6 hr/yr X 100% utilization
Oxygen	17.91078	kscf	0.00000	kscf/hr	0	0	kscf, 0.0 kscf/hr, 8409.6 hr/yr, 100% utilization

** Std Air use is 2 scfm/kacfm

*annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

Great River Energy Coal Creek Station

BART Supplement - NOx Emission Control Cost Analysis

Table A-9: Unit 2 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (30% Lost Ash Sales)

Operating Unit: **Unit 2**

Emission Unit Number	EU-2		Stack/Vent Number	SV-2	
Desgin Capacity	6,022	MMBtu/hr	Standardized Flow Rate	866,294	scfm @ 32º F
Expected Utiliztion Rate	100%		Temperature	330	Deg F
Expected Annual Hours of Operation	8,409.6	Hours	Moisture Content	13.3%	
Annual Interest Rate	5.5%		Actual Flow Rate	2,234,300	acfm
Expected Equipment Life	20	yrs	Standardized Flow Rate	1,391,000	scfm @ 330º F
Baseline NOx	0.153	lb/MMBtu	Dry Std Flow Rate	1,205,997	dscfm @ 330º F

CONTROL EQUIPMENT COSTS

Capital Costs								
Direct Capital Costs								
Purchased Equipment (A)								3,600,000
Purchased Equipment Total (B)								**8,236,800**
Installation - Standard Costs								1,230,000
Installation - Site Specific Costs								1,008,000
Installation Total								1,702,000
Total Capital Investment (TCI) = DC + IC								**11,793,820**
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.						4,852,291
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost						986,899
Total Annual Cost (Annualized Capital Cost + Operating Cost)								**5,839,190**

Emission Control Cost Calculation

Pollutant	**Max Emis Lb/Hr**	**Pre-control Annual T/Yr**	**Cont Eff %**	**Exit Conc**	**Conc Units**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
Nitrogen Oxides (NOx)	918.5	3,862.3	20.0%			3089.8	772.5	7,559

Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1

Notes & Assumptions

1. November 2011 SNCR Evaluation from URS
2. SNCR Maintenance Costs EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.21
3. Process, emissions and cost data listed above is for one unit.
4. For units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal
5. Retrofit factor of 60% used by URS based on site visit to Coal Creek Station.
6. SW disposal and fly ash sales data from Nov. 2011 Golder Fly Ash Evaluation, Appendix B2
7. One-time cost for Technology Licensing Fee for the SNCR process is ~0.5% of the Process Capital.

Great River Energy Coal Creek Station
BART Supplement - NOx Emission Control Cost Analysis
Table A-9: Unit 2 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (30% Lost Ash Sales)

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment			**3,600,000**
Purchased Equipment Costs			
Instrumentation	10.00%	of purchased equipment cost	360,000
Site Specific and Prime Contractor Markup	28.00%	of purchased equipment cost	1,008,000
Freight	5.00%	of purchased equipment cost	180,000
Purchased Equipment Total	43.00%		5,148,000
Purchased Equipment Total+ Retrofit Factor (A)			**8,236,800**
Indirect Installation			
General Facilities		See Notes & Assumptions 1 on pg. 1 of Table	410,000
Engineering & Home Office		See Notes & Assumptions 1 on pg. 1 of Table	820,000
Process Contingency		See Notes & Assumptions 1 on pg. 1 of Table	472,000
Total Indirect Installation Costs (B)		See Notes & Assumptions 1 on pg. 1 of Table	**1,702,000**
Project Contingeny (C)		See Notes & Assumptions 1 on pg. 1 of Table	**1,490,000**
Total Plant Cost (D)		A + B + C	**11,428,800**
Allowance for Funds During Construction (E)		0 for SNCR	**0**
Prepaid Royalties (F)		See Notes & Assumptionss 1 and 7 on pg. 1 of Table	**41,000**
Pre Production Costs (G)		See Notes & Assumptions 1 on pg. 1 of Table	**227,000**
Inventory Capital (H)		Reagent Vol * $/gal	**97,020**
Intial Catalyst and Chemicals (I)		0 for SNCR	**0**
Total Capital Investment (TCI) = DC + IC		D + E + F + G +H + I	**11,793,820**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**11,793,820**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	NA		-
Supervisor	NA		-
Maintenance			
Maintenance Total	1.50	% of Total Capital Investment	176,907
Maintenance Materials	NA	% of Maintenance Labor	-
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.060	See Direct Operating Cost Calculations on last pg.	22,367
Water	0.310	See Direct Operating Cost Calculations on last pg.	6,570
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
SW Disposal	5.44	See Direct Operating Cost Calculations on last pg.	637,648
NA	NA		-
Ammonia Mitigation	5.61	See Direct Operating Cost Calculations on last pg.	814,853
Lost Ash Sales	12.30	See Direct Operating Cost Calculations on last pg.	765,675
NA	NA		-
Urea	500.00	See Direct Operating Cost Calculations on last pg.	2,428,272
NA	NA		-
Total Annual Direct Operating Costs			**4,852,291**
Indirect Operating Costs			
Overhead	NA	of total labor and material costs	NA
Administration (2% total capital costs)	NA	of total capital costs (TCI)	NA
Property tax (1% total capital costs)	NA	of total capital costs (TCI)	NA
Insurance (1% total capital costs)	NA	of total capital costs (TCI)	NA
Capital Recovery	0.08368	for a 20- year equipment life and a 5.5% interest rate	986,899
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**986,899**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**5,839,190**

See Summary page for notes and assumptions

Great River Energy Coal Creek Station

BART Supplement - NOx Emission Control Cost Analysis

Table A-9: Unit 2 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (30% Lost Ash Sales)

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.08368	

Replacement Catayst		<- Enter Equipment Name to Get Cost
Equipment Life	5	years
CRF	0.2342	
Rep part cost per unit	0	$/ft^3
Amount Required	12	ft^3
Packing Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:		<- Enter Equipment Name to Get Cost	
Equipment Life	2	years	
CRF	0.0000		
Rep part cost per unit	0	$/ft^3	
Amount Required	0	Cages	
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax	See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs
Installation Labor	0	10 min per bag, Labor + Overhead (68% = $29.65/hr)	
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	EPA CCM list replacement times from 5 - 20 min per bag.
Annualized Cost	**0**		

Electrical Use			
NOx in	0.15	lb/MMBtu	kW
NSR	0.44		
Power			44.0
Total			44.0

Reagent Use & Other Operating Costs					
NOx in	0.15	lb/MMBtu	Urea Use	1155	lb/hr
Efficiency	20%		Volume 14 day inventory	194	ton
Duty	6,022	MMBtu/hr	Inventory Cost	$97,020	
Water Use	2520	gal/hr			

Direct Operating Cost Calculations — **Annual hours of operation: 8,409.6**; **Utilization Rate: 100%**

Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
Operating Labor							
Op Labor	37	$/Hr	0.0	hr/8 hr shift	0	0	$/Hr, 0.0 hr/8 hr shift, 8409.6 hr/yr
Supervisor	15%	of Op.			NA	-	15% of Operator Costs
Maintenance							
Maintenance Total	1.5	% of Total Capital Investment				176,907.30	% of Total Capital Investment
Maint Mtls	0	% of Maintenance Labor			NA	0	0% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.06045	$/kwh	44.00000	kW-hr	370,022.40	22,367.23	0.0604 $/kwh X 44.0 kW-hr X 8409.6 hr/yr X 100% utilization
Water	0.31000	$/kgal	2520.00000	gph	21,192.19	6,569.58	0.3100 $/kgal X 2,520.0 gph/1000 X 8409.6 hr/yr X 100% utilization
Cooling Water	0.32080	$kgal	0.00000	gpm	0	0	$kgal, 0 gpm, 8409.6 hr/yr, 100% utilization
Comp Air	0.36713	$/kscf	0.00000	scfm/kacfm**	0	0	$/kscf, 0.0 scfm/kacfm**, 8409.6 hr/yr, 100% utilization
WW Treat Neutralization	1.95716	$/kgal	0.00000	gpm	0	0	$/kgal, 0.0 gpm, 8409.6 hr/yr, 100% utilization
WW Treat Biotreatement	4.95814	$/kgal	0.00000	gpm	0	0	$/kgal, 0.0 gpm, 8409.6 hr/yr, 100% utilization
SW Disposal	5.43836	$/ton	13.94240	ton/hr	117,250	637,648	5.4384 $/ton X 13.9 ton/hr X 8409.6 hr/yr X 100% utilization
Haz W Disp	326.19330	$/ton	0.00000	ton/hr	0	0	$/ton, 0.0 ton/hr, 8409.6 hr/yr, 100% utilization
Ammonia Mitigation	5.61	$/ton	17.27193	ton/hr	145,250	814,853	5.6 $/ton X 17.2719 ton/hr X 8409.6 hr/yr X 100% utilization
Lost Ash Sales	12.3	$/ton	7.40225	ton/hr	62,250	765,675	12.3 $/ton X 7.4023 ton/hr X 8409.6 hr/yr X 100% utilization
Lime	90.0	$/ton	0.00000	lb/hr	0	0	$/ton, 0.0 lb/hr, 8409.6 hr/yr, 100% utilization
Urea	500.0	$/ton	0.57750	ton/hr	4,856.54	2,428,272.00	500.0 $/ton X 0.5775 ton/hr X 8409.6 hr/yr X 100% utilization
Oxygen	17.91078	kscf	0.00000	kscf/hr	0	0	kscf, 0.0 kscf/hr, 8409.6 hr/yr, 100% utilization

** Std Air use is 2 scfm/kacfm

*annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

Great River Energy Coal Creek Station
BART Supplement - NOx Emission Control Cost Analysis
Table A-10: Unit 2 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (100% Lost Ash Sales)

Operating Unit: **Unit 2**

Emission Unit Number	EU-2		Stack/Vent Number	SV-2	
Desgin Capacity	6,022	MMBtu/hr	Standardized Flow Rate	866,294	scfm @ 32º F
Expected Utiliztion Rate	100%		Temperature	330	Deg F
Expected Annual Hours of Operation	8,409.6	Hours	Moisture Content	13.3%	
Annual Interest Rate	5.5%		Actual Flow Rate	2,234,300	acfm
Expected Equipment Life	20	yrs	Standardized Flow Rate	1,391,000	scfm @ 330º F
Baseline NOx	0.153	lb/MMBtu	Dry Std Flow Rate	1,205,997	dscfm @ 330º F

CONTROL EQUIPMENT COSTS

Capital Costs								
Direct Capital Costs								
Purchased Equipment (A)								3,600,000
Purchased Equipment Total (B)								**8,236,800**
Installation - Standard Costs								1,230,000
Installation - Site Specific Costs								1,008,000
Installation Total								1,702,000
Total Capital Investment (TCI) = DC + IC								**11,793,820**
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.						7,127,816
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost						986,899
Total Annual Cost (Annualized Capital Cost + Operating Cost)								**8,114,715**

Emission Control Cost Calculation

Pollutant	**Max Emis Lb/Hr**	**Pre-control Annual T/Yr**	**Cont Eff %**	**Exit Conc**	**Conc Units**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
Nitrogen Oxides (NOx)	918.5	3,862.3	20.0%			3089.8	772.5	10,505

Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1

Notes & Assumptions

1. November 2011 SNCR Evaluation from URS
2. SNCR Maintenance Costs EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.21
3. Process, emissions and cost data listed above is for one unit.
4. For units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal
5. Retrofit factor of 60% used by URS based on site visit to Coal Creek Station.
6. SW disposal and fly ash sales data from Nov. 2011 Golder Fly Ash Evaluation, Appendix B2
7. One-time cost for Technology Licensing Fee for the SNCR process is ~0.5% of the Process Capital.

Great River Energy Coal Creek Station

BART Supplement - NOx Emission Control Cost Analysis

Table A-10: Unit 2 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (100% Lost Ash Sales)

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment			**3,600,000**
Purchased Equipment Costs			
Instrumentation	10.00%	of purchased equipment cost	360,000
Site Specific and Prime Contractor Markup	28.00%	of purchased equipment cost	1,008,000
Freight	5.00%	of purchased equipment cost	180,000
Purchased Equipment Total	43.00%		5,148,000
Purchased Equipment Total+ Retrofit Factor (A)			**8,236,800**
Indirect Installation			
General Facilities		See footnote 1 on pg. 1 of Table	410,000
Engineering & Home Office		See footnote 1 on pg. 1 of Table	820,000
Process Contingency		See footnote 1 on pg. 1 of Table	472,000
Total Indirect Installation Costs (B)		See footnote 1 on pg. 1 of Table	**1,702,000**
Project Contingeny (C)		See footnote 1 on pg. 1 of Table	**1,490,000**
Total Plant Cost (D)		A + B + C	**11,428,800**
Allowance for Funds During Construction (E)		0 for SNCR	**0**
Prepaid Royalties (F)		See footnotes 1 and 7 on pg. 1 of Table	**41,000**
Pre Production Costs (G)		See footnote 1 on pg. 1 of Table	**227,000**
Inventory Capital (H)		Reagent Vol * $/gal	**97,020**
Intial Catalyst and Chemicals (I)		0 for SNCR	**0**
Total Capital Investment (TCI) = DC + IC		D + E + F + G +H + I	**11,793,820**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**11,793,820**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	NA		-
Supervisor	NA		-
Maintenance			
Maintenance Total	1.50	% of Total Capital Investment	176,907
Maintenance Materials	NA	% of Maintenance Labor	-
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.060	See Direct Operating Cost Calculations on last pg.	22,367
Water	0.310	See Direct Operating Cost Calculations on last pg.	6,570
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
SW Disposal	7.40	See Direct Operating Cost Calculations on last pg.	1,941,450
NA	NA		-
NA	NA		-
Lost Ash Sales	12.30	See Direct Operating Cost Calculations on last pg.	2,552,250
NA	NA		-
Urea	500.00	See Direct Operating Cost Calculations on last pg.	2,428,272
NA	NA		-
Total Annual Direct Operating Costs			**7,127,816**
Indirect Operating Costs			
Overhead	NA	of total labor and material costs	NA
Administration (2% total capital costs)	NA	of total capital costs (TCI)	NA
Property tax (1% total capital costs)	NA	of total capital costs (TCI)	NA
Insurance (1% total capital costs)	NA	of total capital costs (TCI)	NA
Capital Recovery	0.08368	for a 20- year equipment life and a 5.5% interest rate	986,899
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**986,899**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**8,114,715**

See Summary page for notes and assumptions

Great River Energy Coal Creek Station

BART Supplement - NOx Emission Control Cost Analysis

Table A-10: Unit 2 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (100% Lost Ash Sales)

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.08368	

Replacement Catayst		<- Enter Equipment Name to Get Cost
Equipment Life	5	years
CRF	0.2342	
Rep part cost per unit	0	$/ft^3
Amount Required	12	ft^3
Packing Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:		<- Enter Equipment Name to Get Cost	
Equipment Life	2	years	
CRF	0.0000		
Rep part cost per unit	0	$/ft^3	
Amount Required	0	Cages	
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax	See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs
Installation Labor	0	10 min per bag, Labor + Overhead (68% = $29.65/hr)	
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	EPA CCM list replacement times from 5 - 20 min per bag.
Annualized Cost	**0**		

Electrical Use			
NOx in	0.15	lb/MMBtu	kW
NSR	0.44		
Power			44.0
Total			44.0

Reagent Use & Other Operating Costs					
NOx in	0.15	lb/MMBtu	Urea Use	1155	lb/hr
Efficiency	20%		Volume 14 day inventory	194	ton
Duty	6,022	MMBtu/hr	Inventory Cost	$97,020	
Water Use	2520	gal/hr			

Direct Operating Cost Calculations — **Annual hours of operation:** **8,409.6**; **Utilization Rate:** **100%**

Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
Operating Labor							
Op Labor	37	$/Hr	0.0	hr/8 hr shift	0	0	$/Hr, 0.0 hr/8 hr shift, 8409.6 hr/yr
Supervisor	15%	of Op.			NA	-	15% of Operator Costs
Maintenance							
Maintenance Total	1.5	% of Total Capital Investment				176,907.30	% of Total Capital Investment
Maint Mtls	0	% of Maintenance Labor			NA	0	0% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.06045	$/kwh	44.00000	kW-hr	370,022.40	22,367.23	0.0604 $/kwh X 44.0 kW-hr X 8409.6 hr/yr X 100% utilization
Water	0.31000	$/kgal	2520.00000	gph	21,192.19	6,569.58	0.31 $/kgal X 2,520.0 gph/1000 X 8409.6 hr/yr X 100% utilization
Cooling Water	0.32080	$kgal	0.00000	gpm	0	0	$kgal, 0 gpm, 8409.6 hr/yr, 100% utilization
Comp Air	0.36713	$/kscf	0.00000	scfm/kacfm**	0	0	$/kscf, 0.0 scfm/kacfm**, 8409.6 hr/yr, 100% utilization
WW Treat Neutralization	1.95716	$/kgal	0.00000	gpm	0	0	$/kgal, 0.0 gpm, 8409.6 hr/yr, 100% utilization
WW Treat Biotreatement	4.95814	$/kgal	0.00000	gpm	0	0	$/kgal, 0.0 gpm, 8409.6 hr/yr, 100% utilization
SW Disposal	7.39600	$/ton	31.21433	ton/hr	262,500	1,941,450	7.3960 $/ton X 31.2 ton/hr X 8409.6 hr/yr X 100% utilization
Haz W Disp	326.19330	$/ton	0.00000	ton/hr	0	0	$/ton, 0.0 ton/hr, 8409.6 hr/yr, 100% utilization
Ammonia Mitigation	5.61	$/ton	0.00000	ton/hr	0	0	$/ton, 0.0 ton/hr, 8409.6 hr/yr, 100% utilization
Lost Ash Sales	12.3	$/ton	24.67418	ton/hr	207,500	2,552,250	12.3 $/ton X 24.6742 ton/hr X 8409.6 hr/yr X 100% utilization
Lime	90.0	$/ton	0.00000	lb/hr	0	0	$/ton, 0.0 lb/hr, 8409.6 hr/yr, 100% utilization
Urea	500.0	$/ton	0.57750	ton/hr	4,856.54	2,428,272.00	500.0 $/ton X 0.5775 ton/hr X 8409.6 hr/yr X 100% utilization
Oxygen	17.91078	kscf	0.00000	kscf/hr	0	0	kscf, 0.0 kscf/hr, 8409.6 hr/yr, 100% utilization

** Std Air use is 2 scfm/kacfm *annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

Appendix B

SNCR Evaluation for Coal Creek Station

COAL CREEK STATION
SELECTIVE NON-CATALYTIC REDUCTION (SNCR)
COST AND PERFORMANCE REVIEW

UNDERWOOD, MCLEAN COUNTY, NORTH DAKOTA

PROJECT NUMBER 28966-007

GREAT RIVER ENERGY

A Touchstone Energy Cooperative

URS ENERGY & CONSTRUCTION
7800 E. UNION AVE., SUITE 100
DENVER, CO 80237

Revision: 0 Status: Final

Introduction

Great River Energy (GRE) contracted URS Energy & Construction (URS) to conduct a review of the costs and performance capability of Selective Non-Catalytic Reduction (SNCR) at their Coal Creek Station (CCS) Units 1 & 2. This review was requested to provide; an estimate of the current capital cost for the installation of SNCR, operating and maintenance costs for SNCR, and the level of NOx reductions that can be achieved by SNCR.

The CCS units are identical 605 MW (gross - nominal) CE tangentially-fired furnaces burning North Dakota lignite. Each unit is equipped with Low NOx Burners (LNB) and Over-Fire Air (OFA). Unit 2's LNBs are 2nd generation technology while Unit 1's are the 1st generation installation. Unit 1 currently has a NOx emission rate of 0.20 lbs/MMBtu while Unit 2's NOx emission rate is 0.16 lbs/MMBtu.

The Final Best Achievable Retrofit Technology (BART) analysis submitted in 2007 was based on an inlet NOx concentration of 0.22 lbs/MMBtu and an SNCR removal efficiency of 50%. The current review uses the existing CCS NOx values presented in the previous paragraph and updated removal efficiencies. The following sections present data on SNCR capabilities and cost.

SNCR Capabilities

SNCR was originally developed in Japan in the 1970s for use on oil- and gas-fired units. Coal plant applications began in the late 1980s in Western Europe. Commercial U.S. installations on coal-fired utility boilers started in the early 1990s. More than 2 GW of capacity have been installed on coal-fired plants worldwide. SNCR requires injection of ammonia or urea into the proper temperature window within the back-pass of the furnace. The ammonia or urea reacts with NOx species to form nitrogen and water. Emission reduction capabilities range from 25% at 5-ppm ammonia slip to 30% at 10-ppm ammonia slip in most commercial installations.

An SNCR system will require the installation of reagent storage and transfer equipment, a multilevel injection grid and the necessary control instrumentation. Due to the elimination of the catalyst used in the SCR process, the SNCR consumption rates for ammonia or urea are typically 3-4 times the rates required for an SCR system on a per mole of NOx basis.

SNCR performance is dependent upon factors that are specific to each source. These factors are; flue gas temperature, flue gas residence time at temperatures within the reaction temperature range, reagent distribution, uncontrolled NOx levels, mixing between the injected reagent and the flue gas, and the CO and O2 concentrations in the flue gas stream. NOx reductions ranging from 25-75% have been reported with SNCR but the higher levels of reduction are only possible with high inlet NOx levels and

optimum temperatures and residence time. Typical SNCR performance for utility boilers is in the range of 20-35% NOx reductions.

The gas temperature at the point of injection is critical to the NOx reduction performance of an SNCR system. This window falls in a range of 1600-2000°F with an optimum temperature of approximately 1800°F. Above this temperature, ammonia begins to thermally decompose and below this temperature, the reaction rate for NOx reduction decreases, resulting in increased ammonia slip. The temperature profile in any given boiler changes with fluctuations in boiler load. Therefore, the optimum injection point will move during cycling operation and multiple injection points will be required. It should also be noted that the longer the ammonia or urea stays within the optimum temperature window, the higher the NOx reduction that is achieved. Residence times in excess of one second are desirable to achieve the maximum reduction efficiency. The minimum residence time is approximately 0.3 seconds for moderate performance. However, most large utility boilers have heat transfer surfaces (pendants and platens) positioned in this flue gas temperature zone. This reduces the effective use of the SNCR system, even when multiple injection levels are installed. In some cases, these internal obstructions will make the application of SNCR impractical.

Figure 1 shows SNCR NOx removal efficiency as a function of Inlet NOx concentration for 55 existing SNCR installations. The data shows the majority of the installations achieving 20-35% reductions in NOx and only a few installations achieving 50% or greater reductions. There is only one installation achieving 50% reduction at an inlet NOx concentration less than 0.4 lb/MMBtu. This single installation is a cyclone boiler burning a PRB/Illinois coal blend and is the only unit in the data set showing greater than 35% reduction for inlet NOx concentrations less than 0.4 lb/MMBtu.

This figure shows that there are no installations operating with Coal Creek's NOx levels that are achieving greater than 20-25% NOx reductions. The figure also shows that the majority of installations are achieving NOx reductions in the range of 20-30%. Based on the available data, from existing installations operating at the CCS inlet NOx levels used in the BART, the highest level of NOx reduction that could be expected is 30%. At the present CCS NOx levels, it is expected that the highest level of NOx reduction that could be expected is 20%.

Another factor to be considered in the application of SNCR is its effect upon fly ash sales. An ammonia slip of only 5 ppm, which is generally accepted as the minimum that can be achieved in an SNCR application, can render the fly ash produced by the unit unmarketable. CCS currently sells 400,000 tons/yr of fly ash. With SNCR, this fly ash will have to be disposed of in a landfill.

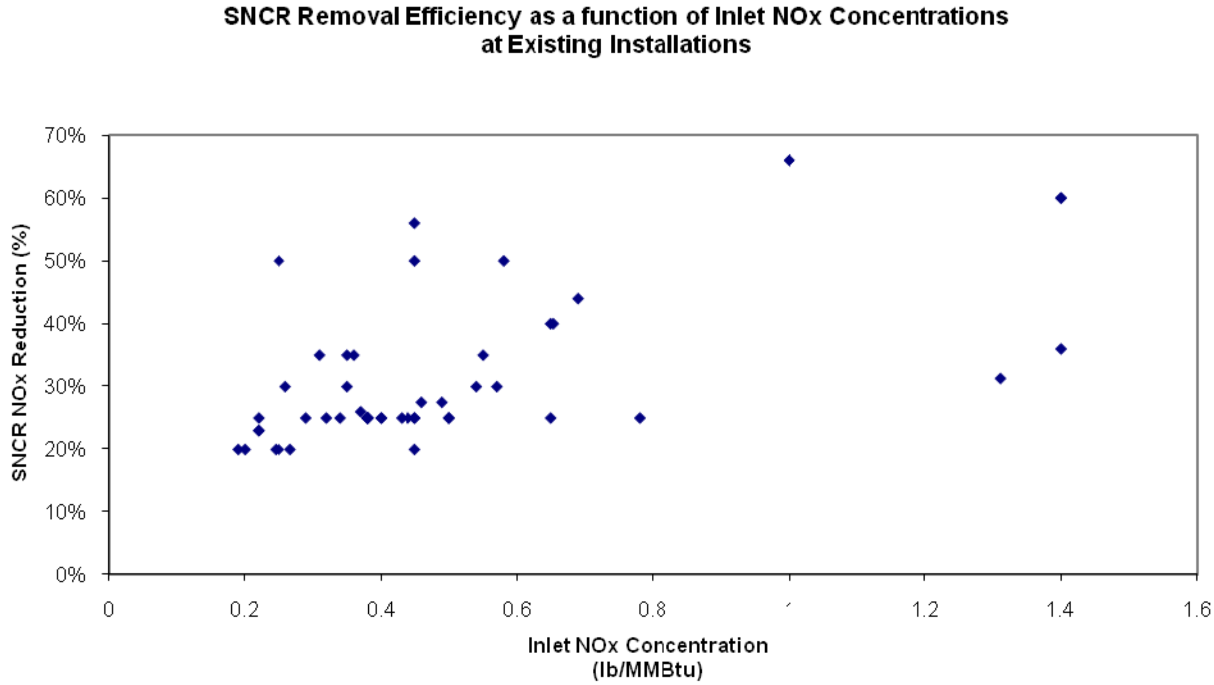

Figure 1 – SNCR Removal Efficiency

SNCR Costs

SNCR capital and operating costs were developed for five (5) different cases utilizing the Electric Power Research Institute's (EPRI) IECCOST model (Rev 3, Nov. 2010) with CCS site specific factors and cost components. The Integrated Emissions Control Cost Model (IECCOST) economic analysis workbook was first published by the Electric Power Research Institute in December 2004. IECCOST produces rough-order-of-magnitude (ROM) cost estimates (stated accuracy of ± 30%) of the installed capital and levelized annual operating costs for Integrated Emission Control (IEC) systems installed on coal-fired power plants. The IECCOST model allows comparison of cost information for conventional and developing SO_2, NOx, particulate, mercury, and integrated emissions control technologies. Costs for utility emission control systems are site-specific, and vary with technology, labor rates, construction conditions and material costs. The site-specific characteristics, operating conditions, process performance requirements and economic criteria serve as input to IECCOST.

IECCOST is able to calculate both new and retrofit plant costs. IECCOST calculates a retrofit factor for each cost area based on site congestion, existence of underground obstructions, soil conditions, seismic zone and state productivity. A series of combustion calculations are carried out based on the ultimate coal analysis provided by the utility and

the operating conditions specified for the boiler(s). The resulting flue gas composition serves as the basis for the calculation of a material balance for the control equipment. The material balance provides data for equipment sizing and calculation of the variable operating costs. The process-specific design criteria, including flue gas flow rate, pollutant removal rate, chemical consumption rate and waste production rate all are incorporated into the production of each process- and site-specific material balance.

The five (5) cases estimated for CCS are:

1. 0.22 lb/MMBtu inlet NOx with 30% reduction
2. 0.20 lb/MMBtu inlet NOx with 25% reduction
3. 0.16 lb/MMBtu inlet NOx with 20% reduction
4. 0.15 lb/MMBtu inlet NOx with 20% reduction
5. 0.22 lb/MMBtu inlet NOx with 50% reduction

These represent the initial BART assessment NOx rate of 0.22 lb/MMBtu with a commercially achievable reduction of 30% for case 1. Cases 2-4 are representative of CCS's existing NOx emission rates and commercially achievable reductions. The final case is the BART assessment case using 2011 dollars. The costs are for a urea-based SNCR system with 14 days of reagent storage. Urea pricing from a source local to CCS was obtained and the current cost of urea is $500/ton delivered to the site. The general plant input data and IECCOST outputs for SNCR capital and operation and maintenance costs are presented in the following section.

IECCOST DATA

Table 1 – Coal Creek Station Data

General Plant Technical Inputs

Total Gross Rating	MW	605
Gross Plant Heat Rate (GPHR)	Btu/KWhr	9,760
Total Net Rating (Less Auxiliary Power)	MW	572.0
Net Plant Heat Rate (NPHR, Without FGD)	Btu/KWhr	10,500
Plant Capacity Factor	%	90%
TECHNICAL INPUTS FOR BOILER:		
Boiler Heat Input	MMBtu/Hr	5,900
Boiler Heat Output	MMBtu/Hr	4,780
Total Air Downstream of Economizer	%	117.0%
Air Heater Leakage (% of econ. flue gas)	%	7.0%
Air Heater Outlet Gas Temp.	°F	300
Inlet Air Temp.	°F	80
Ambient Absolute Pressure	in. Hg	27.9
Pressure After Air Heater	in. H2O	-11
Moisture in Air	lb/lb dry air	0.013
Carbon Loss	%	0.5%
ASH SPLIT		
Fly Ash or Ash Overhead	%	76%
Bottom Ash	%	24%

Table 2 – SNCR Equipment Sizing

SNCR Equipment Sizing and Capacity Calcs			0.22 Inlet & 30% Reduction	0.20 Inlet & 25% Reduction	0.16 Inlet & 20% Reduction	0.15 Inlet & 20% Reduction	0.22 & 50% Reduction
Chosen Reagent			Urea	Urea	Urea	Urea	Urea
Required Reagent Injection	lb/hr		1991	1601	1188	1155	3318
Total Reagent Injection Flowrate	lb/hr		3982	3202	2375	2310	6636
NOx Removed	lb/hr		384	291	186	170	640
NOx Removed	tons/yr		1513	1147	734	670	2522
NOx Emissions	lb/hr		896	873	745	679	640
NOx Emissions	tons/yr		3531	3440	2935	2678	2522
Power Consumption	kW		75	61	45	44	126

Table 3 – Material Costs

SNCR Material Costs			0.22 Inlet & 30% Reduction	0.20 Inlet & 25% Reduction	0.16 Inlet & 20% Reduction	0.15 Inlet & 20% Reduction	0.22 & 50% Reduction
Cost Basis Year			2011	2011	2011	2011	2011
SNCR Equipment Cost	$		$3,800,000	$3,700,000	$3,600,000	$3,600,000	$4,200,000
Installation Factor			1.30	1.30	1.30	1.30	1.30
Installed Equipment Cost	$		$4,970,000	$4,800,000	$4,700,000	$4,700,000	$5,500,000
Prime Contractor's Markup	$		$497,000	$480,000	$470,000	$470,000	$550,000
Total Installed Cost	$		$5,500,000	$5,300,000	$5,100,000	$5,100,000	$6,000,000
Retrofit Factor			1.6	1.6	1.6	1.6	1.6
Total Equipment Cost	$		$8,750,000	$8,500,000	$8,200,000	$8,200,000	$9,600,000
General Facilities	$		$440,000	$420,000	$410,000	$410,000	$480,000
Engineering Fees	$		$875,000	$850,000	$820,000	$820,000	$960,000
Process Contingencies	$		$503,000	$488,000	$472,000	$472,000	$553,000
Project Contingencies	$		$1,580,000	$1,540,000	$1,490,000	$1,490,000	$1,740,000
Total Plant Cost (TPC)	$		$12,145,000	$11,790,000	$11,420,000	$11,400,000	$13,350,000
Total Cash Expended (TCE)	$		$12,145,000	$11,790,000	$11,420,000	$11,400,000	$13,350,000
Allowance for Funds During Constru	$		0	0	0	0	0
Total Plant Investment (TPI)	$		$12,145,000	$11,790,000	$11,420,000	$11,400,000	$13,350,000
Preproduction Costs	$		$243,000	$236,000	$228,000	$227,000	$267,000
Inventory Capital	$		$167,000	$134,000	$100,000	$98,000	$280,000
Initial Catalyst and Chemicals	$		$0	$0	$0	$0	$0
Prepaid Royalties	$		$44,000	$42,000	$41,000	$41,000	$48,000
Total Capital Requirement (TCR)	$		$12,600,000	$12,200,000	$11,800,000	$11,800,000	$13,900,000
Market Demand Escalation	$		$0	$0	$0	$0	$0
Power Outage Penalty	$		$0	$0	$0	$0	$0
Land Cost	$		$0	$0	$0	$0	$0
TCR w/ Market Dem., Power Outag	$		$12,600,000	$12,200,000	$11,800,000	$11,800,000	$13,900,000
	$/kW		21.80	21.10	20.40	20.40	24.00
	Mills/KWh		0.40	0.38	0.37	0.37	0.44

Table 4 – Operation & Maintenance Costs

SNCR O&M Costs			0.22 Inlet & 30% Reduction	0.20 Inlet & 25% Reduction	0.16 Inlet & 20% Reduction	0.15 Inlet & 20% Reduction	0.22 & 50% Reduction
Cost Basis Year			2011	2011	2011	2011	2011
Reagent Type			Urea	Urea	Urea	Urea	Urea
Reagent Consumption	lb/hr		1991	1601	1188	1155	3318
	tons/yr		7848	6310	4681	4553	13080
Water	gpm		72	58	43	42	119
Electricity	kW		75	61	45	44	126
NOx allowances generated	tons/yr		n/a	n/a	n/a	n/a	n/a
Reagent Cost	$/yr		$3,924,000	$3,155,000	$2,340,000	$2,280,000	$6,540,000
Water Cost	$/yr		$410,000	$330,000	$250,000	$240,000	$688,000
Additional Power Costs	$/yr		$24,000	$19,000	$142,000	$13,800	$40,000
NOx Credit	$/yr		$0	$0	$0	$0	$0
Total First Year Variable O&M Cost	$/yr		$4,360,000	$3,500,000	$2,600,000	$2,530,000	$7,270,000
Maintenance	$/yr		$189,000	$183,000	$177,000	$176,000	$210,000
Total First Year Fixed O&M Costs	$/yr		$189,000	$183,000	$177,000	$176,000	$210,000

Attachments

URS SNCR Experience
ICAC White Paper – SNCR for Controlling NOx Emissions – 2000
ICAC White Paper – SNCR for Controlling NOx Emissions – 2008 Update

ATTACHMENTS

The following table presents a listing a URS's SNCR experience. Additionally, a partial listing of the Integrated Emission Control (IEC) Technologies that URS has evaluated for the Electric Power Research Institute (EPRI) follows the SNCR experience list.

NO_X CONTROL EXPERIENCE – SNCR

Client	Project	Unit #	Location	Size (MW)	Fuel	PRB	Equipment Supplier	New (N) vs. Retrofit I	Completion Date	Scope
NRG Energy	5 Stations	14 Units	Various	2350	Coal		NA	R	Dec 02	FS, CE
Dayton Power & Light	Total System (6 plants)	15	Various	60-800	Coal		NA	R	1998	FS
Niagara Mohawk	Four Stations	1, 2, 3, 4	NY		Oil, Gas, Coal		NA	R	Dec 94	FS, CE
New York State Electric and Gas	System-wide	10 units	NY	Various	Coal			R	Dec 94	FS, CE
Duquesne Light and Power	System-wide		PA	Various	Coal		NA	R	Dec 93	FS, CE
Atlantic Electric	B. L. England Station			290	Coal		NA	R	Dec 93	FS, CE
Pennsylvania Power & Light	Brunner Island Station	3	PA	790	Coal		NA	R	Dec 93	FS, CE
PEPCO	Various	1, 2, 3, 4, 5, 6	Various	N/A	Coal, Oil, Gas		NA	R	Dec 93	FS, CE
Niagara Mohawk	Huntley Station	6, 7	Syracuse, NY	2 x 420	Coal		NA	R	Apr 93	FS, CE

NO_X CONTROL EXPERIENCE – SNCR

Client	Project	Unit #	Location	Size (MW)	Fuel	PRB	Equipment Supplier	New (N) vs. Retrofit I	Completion Date	Scope
Inland Steel and Nippon Steel (I/N Tek)	Furnaces and Aux. Boiler Continuous Galvanizing Line (9,000,000 tons/yr capacity)	N/A	IN	N/A	Gas		NA	N	Dec 92	FS, CE
Centerior Energy				72 thru 680	Coal			R	1992	FS, CE
Allegheny Energy Supply	Harrison Station	1, 2, 3	Shinnston, WV	3 x 685	Coal		NA	R	1992	E
San Diego Gas & Electric	System-Wide NO_X Compliance	13 Units	CA	Various	Various		NA	R	1991	PE
Entergy Services, Inc.	System-Wide NO_X Reduction Assessment	54 Units	Various	Various	Various		NA	R		FS
Chevron	El Segundo Refinery		CA		Refinery off-gas		NA	R		FS, CE
AES	Warrior Run	1	Cumberland, MD	180	Coal		NA	N	1998	E, P, C
PEPCO	Various	1, 2, 3, 4, 5, 6	Various	N/A	T-fired oil and coal Wall-fired oil and gas		NA	R	Dec 93	E
Tennessee Valley Authority	Johnsonville	6 units	Johnsonville, TN	6 x 100	Coal		NA	R	Dec 92	E
Los Angeles Dept. of Water & Power	Haynes	1, 2	Long Beach, CA	2 x 230	Gas/Oil		Ammonia injection	R	1992	E, C

NO_X CONTROL EXPERIENCE – SNCR

Client	Project	Unit #	Location	Size (MW)	Fuel	PRB	Equipment Supplier	New (N) vs. Retrofit I	Completion Date	Scope
Air Products	Stockton Cogeneration	1	Stockton, CA	50	Coal		NA	N	1988	D, E, CS
Chevron	El Segundo Refinery				Refinery off-gas		NA	R		FS
Texaco	Los Angeles Refinery		Los Angeles, CA	22	Refinery off-gas		NA	R		FS
Air Products	Cambria County	1	Pennsylvania		Waste Coal		NA	N		E, P

Legend:

BE	Bid Evaluation	D	Design	S	Startup
C	Construction	E	Engineering	STG	Steam Turbine Generator
CA	Construction Advisory	FS	Feasibility Study	T	Testing
CE	Cost Estimate	OE	Owner's Engineer	PRB	Powder River Basin Coal
CM	Construction Management	P	Procurement		

Integrated Emission Control Technologies evaluated for EPRI.

Gas Phase Oxidation Systems

Chem-Mod
ECO™
ECO2™
ISCA

Lextran SO2/NOx/Hg
LoTOx

Low-Temperature Multi-Pollutant Control System (MPCS)
THERMALONOx
Plasma/Electron Beam Systems
EBFGT
e-SCRUB™
Pioneer Industrial Technologies (PIT)
Pulsatech
WOWClean

Combustion Modification/Fuel Processing
Ashworth Combustor
Clean Combustion System (CCS)
Coal Tech
Emulsified Fuel Technology
Green Coal
High-Sodium Lignite-Derived Chars
K-Fuel
K-Lean
Lignite Cleaning System
The Mobotec System
N-Viro Fuel
Oxycombustion
Soot Free Catalyst
WRI Coal Processing

Wet Scrubbing Systems
Airborne

Aqueous Foam Air (AFA) Filter
CEFCO
Dry-Wet Hybrid Electrostatic Precipitator (ESP)
DynaWave
Eco Technologies
Envirolution/PureStream Gas-Liquid Contactor
FLU-ACE
Integrated Flue Gas Treatment
Integrated Advanced Tower
Ispra by SRT Group
LABSORB
Membrane Wet ESP
MercOx
PEA
Rapid Absorption Process (RAP)/Dry Absorption Process (DAP)
SkyMine

<u>Dry Technologies</u>
Argonne Spray Dryer
NOxOUT CASCADE / Turbosorp Technology (formerly CDS/SCR)
ClearGas Dry Scrubber
Copper Oxide
EMx (previously SCONOx/SCOSOx)
Indigo MAPS
Kuttner Luehr Filter Technology
Low Temperature Mercury Control (LTMC)
Novacon
PahlmanTM Process
ReACT Technology
SNOX

SOx-NOx-Rox Box (SNRB)
Trona Injection

Other Technologies
Argonne Hg/NOx Process
CANSOLV SO2/CO2 Process
GreenFuel
Integrated Pollutant Removal (IPR)
Low Temperature Sulfur Trioxide Removal System (LT-STRS) / Mitsubishi Mercury Treatment System (Mi-MeTS) (Previously MHI High Efficiency System / HCl Injection)
TIPS
Combined Plasma Scrubbing Technology (CPS)
Consummator
ECOBIK
Aqua Ammonia Process
BioDeNOx
Fungal Bioreactor
Plasma Enhanced ESP
ElectroCore

Appendix C

Fly Ash Storage and ASM Technology Evaluation

REPORT

FLY ASH STORAGE AND AMMONIA SLIP MITIGATION TECHNOLOGY EVALUATION

Great River Energy

Coal Creek Station

Submitted To: Great River Energy
Coal Creek Station
2875 Third Street SW
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Distribution: 4 Copies – Great River Energy
1 Copy – Golder Associates

November 15, 2011 **113-82161**

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Golder Associates

EXECUTIVE SUMMARY

Great River Energy (GRE) has requested that Golder Associates Inc. prepare a third-party review of potential ammonia slip mitigation (ASM) technology and cost comparisons for associated RCRA Subtitle D ash storage facility design for their Coal Creek Station (CCS) located in Underwood, North Dakota.

These evaluations are prepared in response to the United States Environmental Protection Agency's (EPA's) proposed Federal Implementation Plan (FIP) for the state of North Dakota. As part of the FIP process, the North Dakota Department of Health (NDDH) has requested that GRE prepare a Best Available Retrofit Technology (BART) analysis for nitrogen oxides (NOx) emissions, specifically evaluating the application of selective non-catalytic reduction (SNCR) emission control technology. Due to the potential for unreacted ammonia in the flue gas downstream of the SNCR (ammonia slip) reacting with sulfur compounds to form ammonia sulfates that deposit in the fly ash, there is concern over the significant impact on current fly ash sales. Therefore, GRE is evaluating an ASM technology at CCS as an option for treating ammonia slip impacted fly ash to allow continued beneficial use and sale of fly ash. This ASM technology is not proven for lignite derived fly ash and is presented as a potential option to reduce the impact of an SNCR on fly ash management. This evaluation includes an ASM technology cost estimation, fly ash disposal cost comparisons, and evaluation of the total cost impact of an SNCR on fly ash management at CCS.

Golder recently visited the Eastlake Station where Headwaters Energy Services' patented ASM technology is currently applied to manage ammonia levels in the fly ash. Based on this operation and Golder's knowledge of CCS and lignite coal-fired power plants, a cost estimate to apply ASM at CCS was prepared. The cost estimate includes costs for the ASM infrastructure including engineering and design, construction, and operations and maintenance. Costs are based on 2011 dollars and capital costs are annualized for a 20-year life and 5.5% interest rate. Existing fly ash sales infrastructure and operations and maintenance are not included in the cost estimate. ASM post-processing costs are estimated to be $5.61 per ton of fly ash treated.

Fly ash that cannot be marketed for beneficial use is disposed of in engineered and permitted facilities at CCS. Golder prepared a cost estimate for three potential operating scenarios: Scenario A – fly ash sales equal to the average sales over the past few years, Scenario B – ammonia slip impact of an SNCR makes fly ash at CCS unsalable, and Scenario C – ASM technology will be viable for ammonia impacted fly ash at CCS allowing a reduced amount of fly ash sales. A summary of the total estimated fly ash disposal costs is shown in the following table.

	Scenario A (Current Sales)	Scenario B (No Sales)	Scenario C (Reduced Sales, ASM)
Fly Ash Disposed (ton/yr)	110,000	525,000	234,500
Disposal Cost ($/ton)	$18.06	$11.18	$13.91
Annual Disposal Cost ($/yr)	$1,987,000	$5,870,000	$3,262,000
Annual Increase in Disposal Cost Compared to Scenario A ($/yr)	-	$3,883,000	$1,275,000

The landfill design included the specific size, location, infrastructure, liner, and cover relevant to each scenario. Costs for each scenario included the specific landfill design, engineering, and permitting costs, land acquisition, infrastructure development, liner construction, post-closure care, construction management and construction quality assurance (CQA), GRE internal costs, project contingencies, and operational costs. Based on the annual disposal cost estimate shown in the table above, the potential impact of an SNCR on the fly ash disposal costs at CCS may be an additional $3.9 million per year if fly ash is no longer marketable or an additional $1.3 million per year if the ASM technology proves successful.

The total cost impact of an SNCR on fly ash management at CCS includes ASM post-processing costs, fly ash disposal costs, and the loss in revenue generated from the sale of fly ash. Golder evaluated this total cost impact for each scenario, and is summarized in the table that follows. Based on this evaluation, the total additional cost impact to fly ash management as a result of an SNCR is between $4.4 and $9.0 million per year.

	Scenario A (Current Sales)	Scenario B (No Sales)	Scenario C (Reduced Sales, ASM)
Total (Disposal + Post Processing + Lost Sales)			
Annual Cost ($/yr)	$1,987,000	$10,975,000	$6,422,000
Unit Cost ($/ton produced)	$3.79	$20.91	$12.23
Additional Cost (Scenario B/C - Scenario A)			
Fly Ash Management Cost ($/yr)	-	$8,988,000	$4,435,000
Fly Ash Management Cost ($/ton produced)	-	$17.12	$8.45

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1.0 INTRODUCTION

Great River Energy (GRE) has requested that Golder prepare a third party review of ammonia slip mitigation technology, and cost comparisons for associated RCRA Subtitle D ash storage facility design for Coal Creek Station (CCS) located in Underwood, North Dakota. These evaluations are prepared in response to the United States Environmental Protection Agency's (EPA's) proposed Federal Implementation Plan (FIP) for the state of North Dakota. Based on the proposed FIP, GRE is evaluating selective non-catalytic reduction (SNCR) control technology to reduce nitrogen oxide (NO_x) emissions from CCS. If SNCR is installed at CCS, there is potential for unreacted ammonia in the flue gas downstream of the SNCR, called ammonia slip, and higher ammonia in fly ash. Due to the significant impact on current ash sales, GRE is evaluating a potential ammonia slip mitigation (ASM) technology patented by Headwaters Energy Services. In addition, GRE is evaluating three potential management scenarios for fly ash based on the potential impact of ammonia concentrations to the sale of fly ash.

Golder performed a third party review and estimated costs associated with implementation of Headwaters' ASM technology as applied to CCS. The review includes an estimate of the capital and operating and maintenance (O&M) costs for implementation of the ASM technology at CCS, with a focus on potential impacts to ash marketing and future sales to assist GRE in determining the feasibility of the ASM technology for operations at CCS. This evaluation is limited in scope given that "Headwaters has not conducted any field scale assessment on application of this technology to lignite derived fly ash. The limited current experience in commercial application and lack of field trials is not adequate for Headwaters to be able to provide any guarantee that the process can be successfully applied to treat lignite ash at the Coal Creek Station," per an email from Rafic Minkara (Headwaters) to John Weeda (GRE) on July 15, 2011.

Golder also prepared a cost comparison for three fly ash storage facility scenarios:

- Scenario 1: CCS's current fly ash sales rate (most fly ash sold);
- Scenario 2: No fly ash sales;
- Scenario 3: Application of ASM technology (allowing for some fly ash sales).

The cost evaluation includes a comparison of capital and O&M costs for each scenario assuming a new facility that meets EPA RCRA Subtitle D type regulations.

1.1 Qualifications

Golder Associates Corporation is an international employee-owned consulting engineering company specializing in the application of earth sciences and engineering to environmental, natural resources, and civil engineering projects. Operating since 1960, our company maintains a network of approximately

160 offices. Current worldwide employment exceeds 7,000 people. The United States operating company, Golder Associates Inc., employs approximately 1,200 people in 51 offices.

This project was conducted by a team based in our Denver, Colorado and Fort Collins, Colorado, offices. The project team was well-suited to perform the proposed services at CCS because of the experience of our technical staff on comparable projects, and our familiarity with the geotechnical and engineering properties of Subtitle D landfill designs. In addition, our team has a firm understanding of the engineering practice and regulatory environment surrounding coal-fired power plants, both in North Dakota and nationally, including ongoing rulemaking efforts by the EPA.

2.0 BACKGROUND

2.1 Regulatory Basis

In order to attain and maintain the National Ambient Air Quality Standards (NAAQS) within a state, state air quality agencies prepare State Implementation Plans (SIP) for EPA approval. If EPA disapproves of the SIP, either partially or fully, EPA will develop a Federal Implementation Plan (FIP) to address the deficiencies in the SIP.

On September 21, 2011, EPA proposed to partially disapprove the North Dakota SIP, specifically addressing regional haze and proposed a FIP to address the deficiency "concerning non-interference with programs to protect visibility in other states"[1]. As part of this process North Dakota Department of Health (NDDH) has requested a Best Available Retrofit Technology (BART) analysis for nitrogen oxides (NOx) emissions. This analysis was submitted by GRE in 2007 and additional evaluations and response to questions were submitted in 2010 and on July 15, 2011 to NDDH. NDDH is requesting additional analyses of selective non-catalytic reduction technology. This report does not include an SNCR evaluation, but provides a cost evaluation to address the potential impact the installation of SNCR would have on the existing GRE fly ash storage and sales.

2.2 SNCR and Ammonia Slip

Selective non-catalytic reduction (SNCR) technology is a post-combustion technology based on the chemical reduction of NOx into molecular nitrogen (N_2) and water vapor (H_2O). A nitrogen based reagent, such as urea, is injected into the post-combustion flue gas. The injection causes mixing of the reagent and flue gas while the heat in the flue gas provides energy for the reaction. The primary byproduct of the reaction is nitrous oxide (N_2O), which is a potent greenhouse gas (GHG).

Unreacted reagent in the flue gas downstream of the SNCR is called slip. This unreacted reagent will appear as ammonia, and reacts with sulfur compounds (from sulfur containing fuels) to form ammonia sulfates which deposit on the fly ash that is collected by the particulate emissions control equipment. The ammonia sulfates are stable in a dry state, but ammonia gas can release if the fly ash becomes wet. Ammonia content in the fly ash greater than 5 parts per million (ppm) (based on Headwaters' experience this level is 35 ppm) can result in release of ammonia gases which impact either the sale or storage and disposal of fly ash.

[1] Federal Register, EPA, 9/21/2011, www.federalregister.gov/articles/2011/9/21/2011-23372

3.0 AMMONIA SLIP MITIGATION

3.1 Background

Headwaters has developed an ammonia slip mitigation (ASM) technology to manage ammonia levels in the fly ash, so that a portion of the fly ash produced can be sold as a concrete additive. The Headwaters' ASM technology was initially developed in 2001 with the first US patent issued in 2004. The first commercial installation of ASM technology was installed at RG&E Russell Station in Rochester, New York in 2004. Russell Station used an SNCR and burned eastern bituminous coal.

The second commercial installation was installed at Eastlake Station in Ohio. Eastlake Station has a 600 megawatt (MW) unit that is fired with a 50/50 blend of Power River Basin (PRB) and eastern bituminous coal while generating approximately 100,000 TPY of fly ash. Headwaters is able to blend, treat, and market approximately 85% of the fly ash produced at Eastlake station. Fly ash is not treated during periods of highly variable ammonia concentrations, typically occurring during SNCR upset or plant load swings.

Currently, there are no commercial applications of ASM technology at a lignite-fired power plant, and Headwaters has not conducted any research on the application of the technology to lignite derived fly ash. Due to the lack of commercial experience with lignite derived fly ash, Headwaters will not provide a guarantee that the ASM technology can be successfully applied to lignite derived fly ash.

3.2 Process Description

The ASM technology mixes approximately 0.5-pound (lb) calcium hypochlorite (Cal-Hypo) with approximately 3,000-lb of fly ash in a hopper. The dose of cal-hypo, which is fed into the hopper using a rotary screw, is based on the ammonia concentration in the fly ash. Typical ammonia range for treatment is 50 to 150 ppm with a dosage of 0.2 to 1.3 lb of Cal-Hypo, resulting in ammonia concentrations after treatment of about 35 to 80 ppm.

Golder visited a current commercial application of ASM technology at the Eastlake Station (Figure 1). Fly ash from the electrostatic precipitator (ESP) is sent to one of two fly ash silos where the fly ash is tested daily to determine ammonia concentrations (Figure 2). If the ammonia concentrations are above 150 ppm, the fly ash is diverted for disposal. Fly ash with ammonia concentrations less than 150 ppm are sent to the third silo, after which it is "dosed" with Cal-Hypo and sent to the fourth silo (Figure 3 through Figure 5). The SNCR at Eastlake cannot keep the ammonia slip consistent, and often over-treats a portion of the fly ash stream. To increase the amount of treatable and marketable fly ash, fly ash with no ammonia from other sources is regularly blended into the Eastlake fly ash to keep the initial ammonia content below 150 ppm. Through the operation of the SNCR and by blending non-ammonia impacted fly ash with Eastlake's ammonia impacted fly ash, Eastlake is able to market approximately 85% of what

they produce because this fly ash is considered “treatable” (i.e., ammonia concentration levels are < 150 ppm). Diagrams of the East Lake Station system provided by Headwaters are shown in Appendix A. Subsequent to these diagrams, Headwaters has added a weigh hopper under the silo as shown in Figure 5.

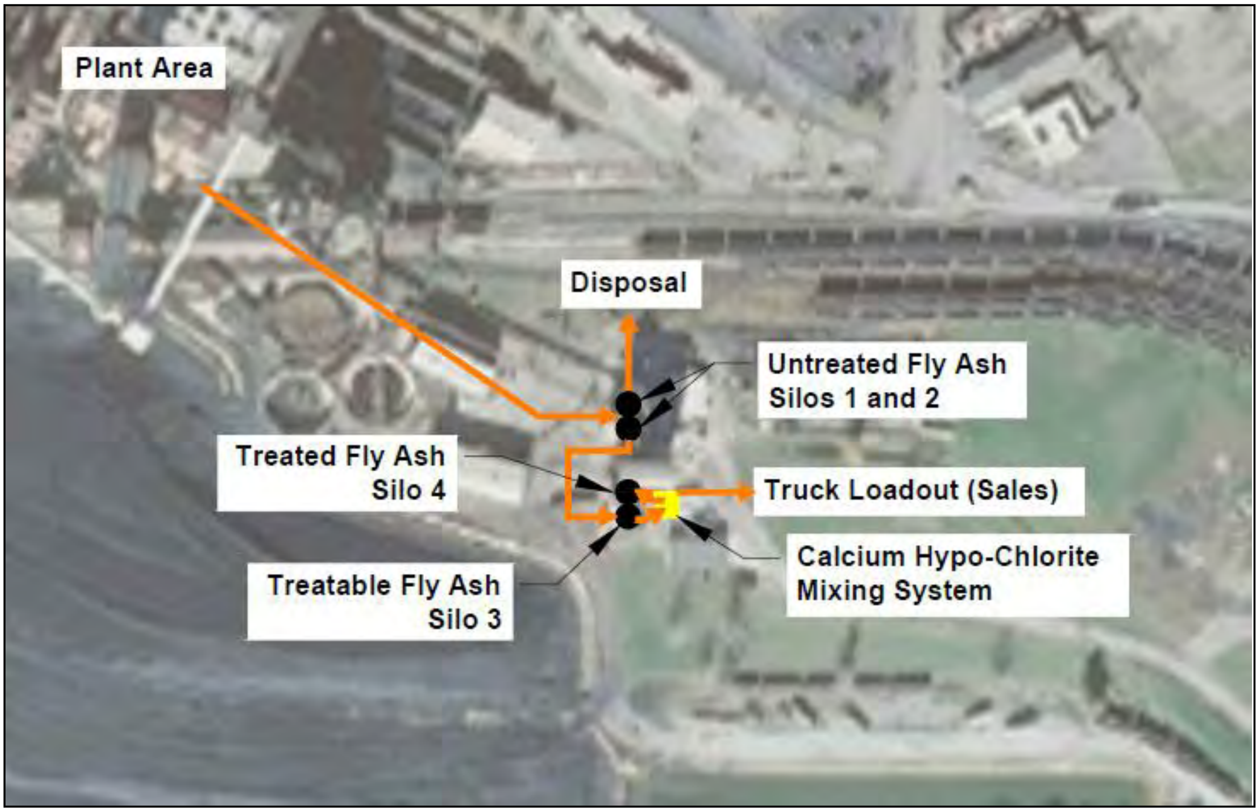


Figure 1: Eastlake Station ASM Schematic

Figure 2: Eastlake Station ASM Lab

Figure 3: Eastlake Station Silo 3, Silo 4, and ASM Setup

Figure 4: Eastlake Station ASM Control Panel

Figure 5: Eastlake Station ASM Mixing Hopper

3.3 Design and Limitations

Based on the Eastlake Station application, ASM is applied to fly ash with ammonia concentration levels less than 150 ppm. Ammonia levels can fluctuate based on plant load variations and SNCR operation. Ammonia concentrations are more consistent at base load conditions and dosing levels are typically based on this condition. Therefore, during load “swings,” it can be difficult to properly adjust the amount of ammonia injected into the flue gas resulting in varying concentrations of ammonia in the fly ash. If there is a plant upset condition, it may be several days until the ammonia concentrations in the fly ash being produced are at “treatable” levels again. The concern is two-fold. If the fly ash is not treated with enough Cal-Hypo, objectionable levels of ammonia will be released when the fly ash is mixed with water. Ammonia gas at low levels is an irritant but can be dangerous to life and health at high concentrations. If too much Cal-Hypo is added, chlorine gas will be released when the fly ash is mixed with water. Chlorine gas even at low concentrations is dangerous to life and health.

3.4 ASM Application at CCS

The application of ASM technology at CCS is being evaluated as an option for treating ammonia slip impacted fly ash to allow continued beneficial use and sale of fly ash.

3.4.1 Potential Design at CCS

For cost estimating, a potential layout for the application of ASM at CCS is shown in Figure 6. This potential layout utilizes the existing fly ash infrastructure including the truck load-out silos (91 and 92), the rail load-out silo (93), and the fly ash storage dome (94). To utilize ASM, the layout adds a new truck load-out silo south of Silos 91 and 92, and adds ASM Cal-Hypo feed systems at both the new truck load-out silo and the existing rail load-out silo (93). The general flow of material is treatable fly ash being routed to either the new truck load-out silo, the fly ash dome (94) or the rail load-out silo. From these silos, the fly ash is tested, and then mixed with Cal-Hypo as it is loaded into the trucks or rail cars. Additional testing of the resultant product would also be performed. Fly ash that is expected not to be treatable or saleable is routed to the exiting truck load-out silos (91 and 92) where it will be loaded into haul trucks and disposed at on-site disposal facilities.

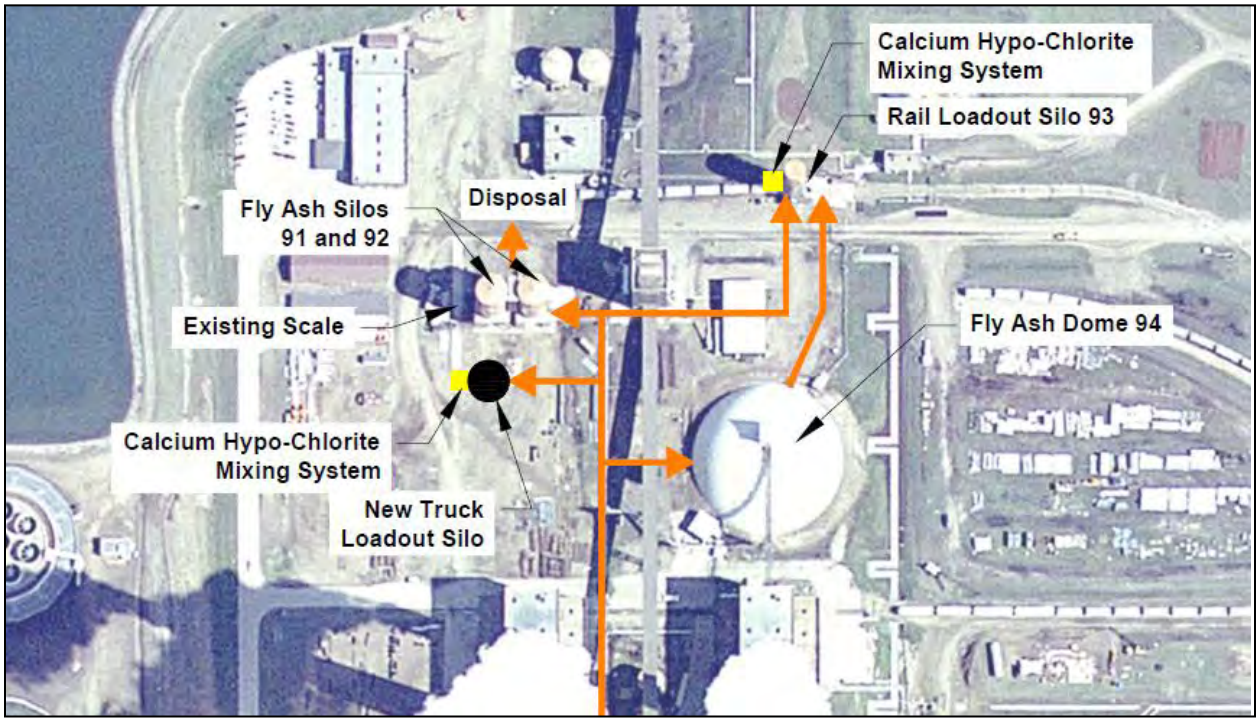


Figure 6: Coal Creek Station ASM Schematic

As discussed earlier, not all of the fly ash coming from the precipitators is expected to be within treatable levels of ammonia. In general, when the power generation units are operating at steady load and the SNCR ammonia injection system is operating properly, the fly ash produced should be treatable using the ASM system and will be collected in the rail load silo (93), the fly ash dome (94), or the new truck loadout silo (95). Conditions under which the ammonia content of the produced fly ash will be questionable include:

- Unit load swings causing variations in ash ammonia concentration (load swings may be due to regional wind penetration or variable load consistent with MISO);
- SNCR ammonia injection feed system problems; and
- Unit startup and shutdown which results in oily ash.

Golder expects that when any of these conditions occur, the fly ash produced will automatically be directed to the disposal silos (91 & 92). Fly ash will not be redirected to the sales silos (93, 94 or 95) until the upset is over and the fly ash collected in the first two rows of the electrostatic precipitator (ESP) has been tested and proven to have less than 150 ppm of ammonia in it.

Based on a review of the recent load profile at CCS, historic information on marketable fly ash at CCS, and an estimate of the reliability of the SNCR and ASM systems, approximately 30% of the fly ash now sent to the sales silos is assumed to have ammonia concentrations which will make it untreatable if an SNCR system is installed.

3.5 Cost Estimate

The cost estimate includes costs for the ASM infrastructure including engineering and design; construction; and operations and maintenance. Golder used actual costs from similar projects, and professional judgment to develop this cost estimate. Sources and assumptions are documented where appropriate. Some general assumptions for the cost estimate include:

- All costs are estimated in 2011 dollars.
- Capital costs are annualized based on a 20-year life and 5.5% interest rate.
- Existing fly ash sales infrastructure (silos, scales, rail facilities) and operations and maintenance are not included.

3.5.1 System Engineering and Design

This item is estimated as 10% of the total construction costs to develop the new facilities. Ten percent is based on Golder's professional judgment.

3.5.2 New Truck Load-Out Silo

The costs for the new truck load-out silo include site preparation, permit application, the silo and handling equipment, dust collection equipment, and feed piping. The costs for this construction are based on the construction of a similar fly ash sales terminal constructed for GRE in 2003. This silo had a 5,000-ton capacity and was used to transfer fly ash from rail cars to trucks (Figure 7). The total estimated cost for this item is $1.6 million and includes the following:

- Silo and truck scale similar to the Irondale, CO unit:
  - Silo slab on grade;
  - Starvrac reclaimer;
  - Truck scale beside the silo on grade;
  - Screw conveyor from discharge of the Starvrac reclaimer;
  - Bucket elevator to overhead;
  - Air slide ;
  - Building with the scale and ASM controls
- Additional items needed at CCS:
  - Feed piping and valves from each of the four fly ash conveying lines;
  - Higher capacity dust collectors to handle the high air flow from ESP.

Details for this cost estimate are included in Appendix B.

Figure 7: Typical Silo used in Cost Estimate

3.5.3 Cal-Hypo Feed System

The costs for the Cal-Hypo feed systems are estimated at $574,500 and include:

- Rail loadout silo (93):
  - Cal-Hypo storage and conveying building;
  - Day storage hopper for Cal-Hypo on the silo weigh bin floor;
  - Conveying system from the storage building to the day storage hopper;
  - Variable speed screw conveyor to feed Cal-Hypo into existing weigh hopper;
  - ASM system controls
- New truck loadout silo (95):
  - Weigh hopper above truck loadout spout;
  - Cal-Hypo storage and conveying building;
  - Day storage hopper for Cal-Hypo on the silo weigh bin floor;
  - Conveying system from the storage building to the day storage hopper;
  - Variable speed screw conveyor to feed Cal-Hypo into existing weigh hopper;
  - ASM system controls.

3.5.4 GRE Internal Costs

Internal costs for GRE to manage consultants, contractors, and in-house staff is estimated as 10% of the total costs (construction, engineering, permitting, CQA). Ten percent is based on GRE's experience with projects at CCS.

3.5.5 Project Contingency

Due to the order-of-magnitude scope of this cost estimate a contingency of 15% on the construction costs was added.

3.5.6 Operational and Maintenance Costs

ASM post-processing operations and maintenance costs are estimated as an annual cost. Operations costs include the cost of Cal-Hypo, fly ash sampling and testing costs, and labor to operate the system. Maintenance costs include labor and materials to maintain and repair the added equipment at the rail load-out silo (93) and the new truck load-out silo (95).

The estimated cost for this item, based on annual sale/processing of 290,500 tons, is approximately $1.4 million per year. Details for this cost estimate are included in Appendix B.

3.6 ASM Post-Processing Cost Summary

Using the quantities and the unit pricing described above, ASM post-processing costs are estimated as $5.61 per ton of fly ash treated.

4.0 FLY ASH DISPOSAL

Fly ash that cannot be marketed for beneficial use is disposed of in engineered and permitted facilities at CCS. Golder has prepared this order-of-magnitude cost estimate to compare costs between three scenarios defined to assess the potential impact of an SNCR on fly ash sales and disposal at CCS. Summary costs and key inputs are included in Table 1 through Table 3, and Figure 8 through Figure 10, with cost estimate details provided in Appendix B.

4.1 Fly Ash Disposal Scenarios

Three scenarios were evaluated to estimate the annual cost and the cost per ton to dispose of fly ash at CCS. These scenarios include:

- ***Scenario A*** – This scenario is the base case with fly ash sales equal to the average sales over the past few years. The scenario assumes that fly ash will be disposed of in a new landfill with a design based on RCRA Subtitle D practices, and has a 20-year disposal capacity. No post processing of the fly ash is required to make it marketable.
- ***Scenario B*** – This scenario assumes that the ammonia slip impact of an SNCR makes fly ash at CCS unsalable. The scenario also assumes that fly ash will be disposed of in a new landfill with a design based on RCRA Subtitle D practices, and has a 20-year disposal capacity.
- ***Scenario C*** – This scenario assumes that Headwater's ASM technology will be viable for ammonia impacted fly ash at CCS. However, sales will be reduced from current sales due to load swing impacts on ammonia slip, market conditions, and other factors previously identified. The scenario also assumes that fly ash will be disposed of in a new landfill with a design based on RCRA Subtitle D practices, and has a 20-year disposal capacity.

A summary of the fly ash production, sales, and disposal annual tonnages for these scenarios is provided in Table 1.

Table 1: Fly Ash Sales and Disposal Tons

	Scenario A (Current Sales)	Scenario B (No Sales)	Scenario C (Reduced Sales, ASM)
Fly Ash Produced (ton/yr)	525,000	525,000	525,000
Fly Ash Sold (ton/yr)	415,000	0	290,500
Fly Ash Disposed (ton/yr)	110,000	525,000	234,500

The total tonnage of fly ash produced is variable based on items such as plant load, plant efficiency, coal quality, and coal processing. Tonnage used in this analysis is meant to represent a typical or average amount of fly ash produced, sold, and disposed at CCS.

4.2 Landfill Design

For all three scenarios a 20-year disposal capacity and a RCRA Subtitle D design is assumed. It is also assumed that the landfill will be built on property not currently owned by GRE. For this cost estimate, it is assumed that property just west of the plant property would be purchased for the new facility. Figure 8 shows a potential location for these new facilities just west of the plant property and represents the approximate footprint required for Scenario A.

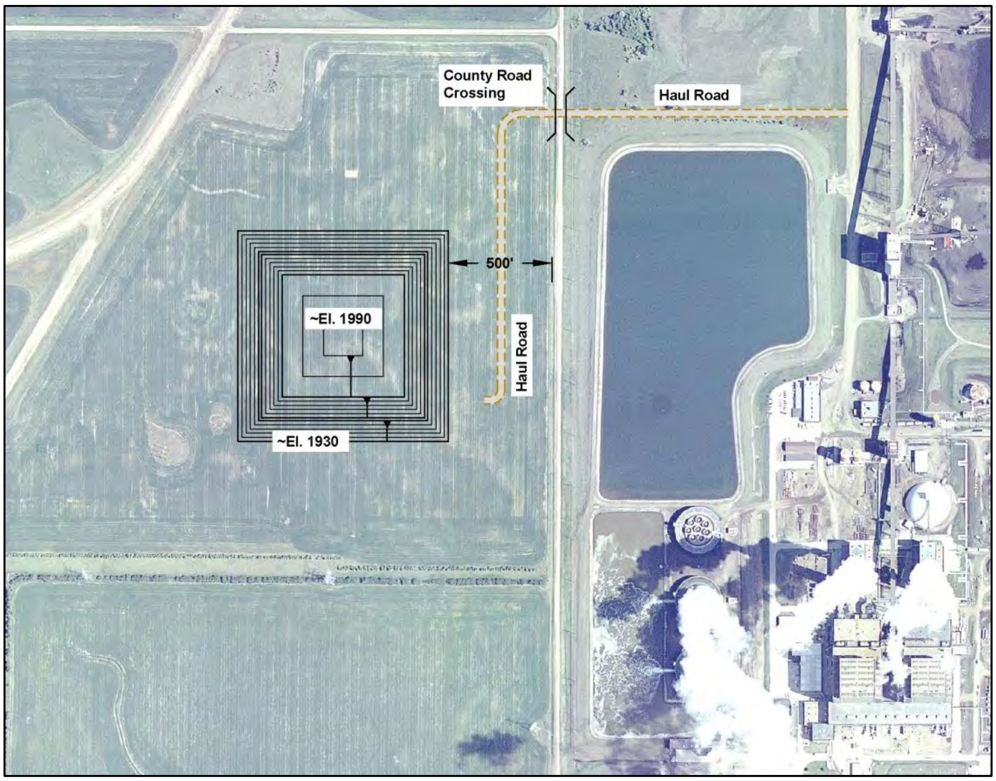


Figure 8: Potential Landfill Location (Scenario A)

4.2.1 Landfill Size

Landfill size is based on a 20-year fly ash disposal capacity. For the three scenarios this varies between 2.2 million and 10.5 million tons of capacity. For each Scenario, Golder developed a simplified landfill footprint that would provide the 20-year fly ash disposal capacity. The simplified landfill design assumes 10 feet of cut, 12-foot high soil berm, 3H:1V soil berm slopes, and 4H:1V fly ash slopes with a 5% crown. Based on preliminary engineering, the landfill capacity ranges between 75,000 and 118,000 cubic yards (cy) per lined acre due to the increased height capacity of a larger footprint facility. Figures showing the size of each Scenario are included in Appendix B.

The amount of cover area in relationship to the liner area has also been estimated based on preliminary engineering as 1.1 acres of cover for every 1 acre of liner.

The amount of land required is assumed to encompass at least a 500-foot buffer beyond this lined footprint to allow for access roads, fencing, support structures, and groundwater monitoring. For the land acquisition purchase estimate, the nearest whole or partial section of land to the required footprint was assumed.

Table 2 provides a summary of the estimated facility liner area, cover area, and site area for the three scenarios.

Table 2: Scenario Landfill Size

	Scenario A (Current Sales)	Scenario B (No Sales)	Scenario C (Reduced Sales, ASM)
Liner Acres (acres)	24.0	73.5	41.0
Cover Area (acres)	26.5	81.0	45.0
Site Area (acres)	160.0	240.0	160.0

4.2.2 Infrastructure Development

With the landfill constructed on a new property, considerable site development is required, which may include a haul truck access road, fencing and gates around the property, power to the new site, monitoring wells up- and down-gradient of the new facility, and a water return pipeline to allow the pumping of excess contact water from the site to the ash water tanks within the plant.

In addition, haul trucks will be required to cross a county road to deliver fly ash from the plant to the new facility. For safety and operational flexibility, a new country road bridge should be constructed to allow haul truck traffic under the county road. This bridge would include the bridge structure as well as the grading and embankment costs associated with the approach on the county road.

4.2.3 Liner

A liner design based on RCRA Subtitle D standards and historic practice at CCS was utilized. The assumed liner system is shown in Figure 9 and consists of (from bottom to top) a compacted clay layer ($1x10^{-7}$ cm/sec maximum permeability), a geomembrane liner, a leachate collection layer consisting of drainage material, piping and sumps, and a protective cover layer.

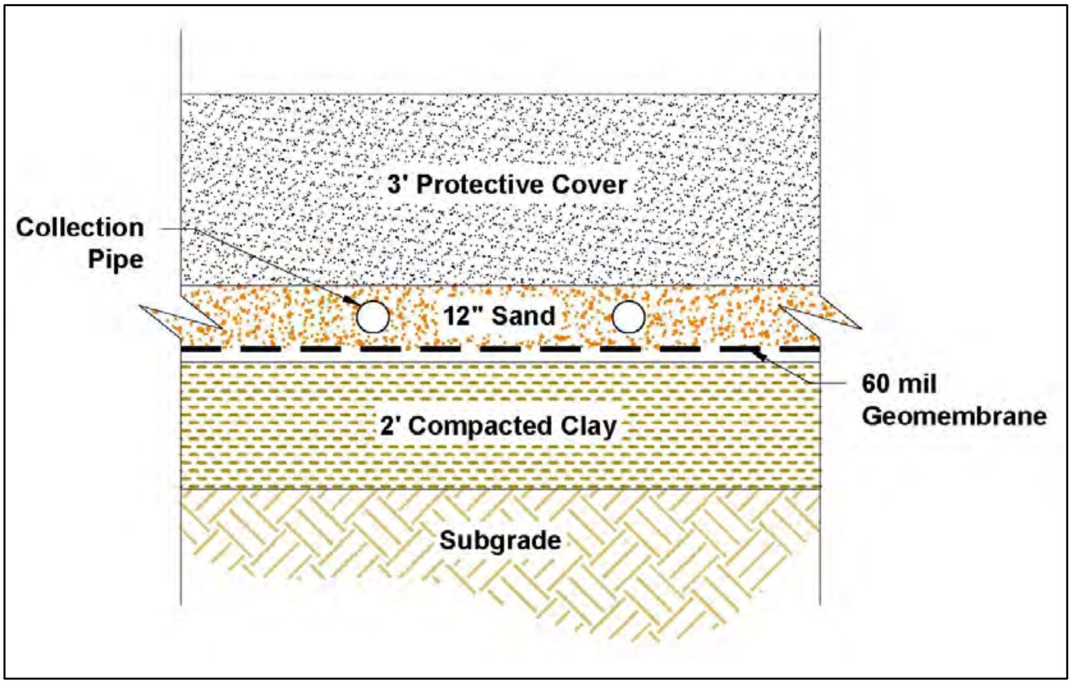


Figure 9: Composite Liner Detail

4.2.4 Cover

The final cover is also design based on RCRA Subtitle D standards and historic practice at CCS. The assumed cover system is shown in Figure 10 and consists of (from bottom to top) a compacted soil layer ($1x10^{-5}$ cm/sec maximum permeability), a textured geomembrane, a drainage layer consisting of drainage material and piping, and a vegetation layer. The drainage layer over the geomembrane is required to control the head on the liner and the resulting stability of growth medium. In addition, the cover will utilize terrace channels and armored down-chute channels to manage surface water runoff and reduce erosion.

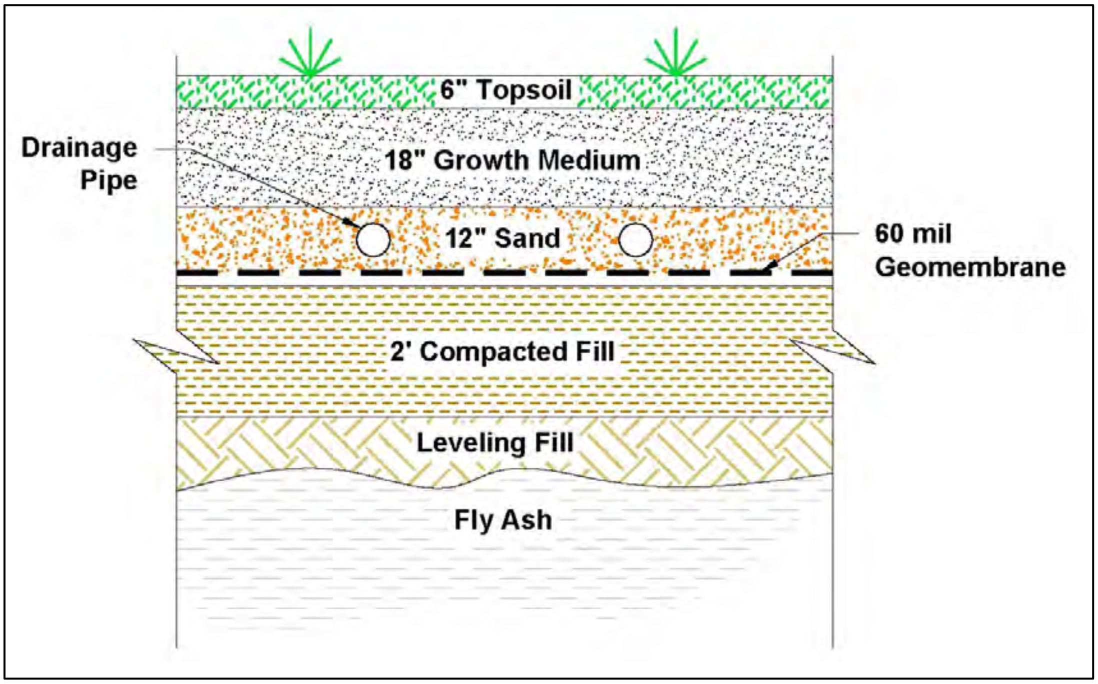


Figure 10: Composite Cover Detail

4.3 Cost Estimate

The cost estimate includes costs for the life of the disposal facility including engineering, design, and permitting; construction; and operations and maintenance, including closure and post-closure care. Golder used actual costs from similar projects at CCS, local contractor rates, RS Means manuals (RS Means 2010), and professional judgment to develop this cost estimate. Sources and assumptions are documented. Some general assumptions for the cost estimate include:

- All costs are estimated in 2011 dollars.
- Capital costs are annualized based on a 20-year life and 5.5% interest rate.
- Existing fly ash processing equipment (silos, unloaders, etc.) is not included. Disposal costs begin once the haul trucks are loaded with fly ash.
- Existing fly ash sales infrastructure (silos, scales, rail facilities) and operations and maintenance are not included.
- Disposal costs only include fly ash disposal and not facility airspace or operations and maintenance for other coal combustion products produced at CCS.

4.3.1 Engineering, Design, and Permitting

This item is estimated as 10% of the total construction costs to develop the facility. Ten percent is based on Golder's experience with coal combustion product facilities within the Midwest. The components included in this cost may include a facility siting evaluation, design of the facility, submittal of a solid waste landfill permit as well as permit renewals, submittal of air permits and NDPES permits, and creation of construction and bid packages for the facility.

The siting evaluation may include a hydrogeological characterization of the site, which includes drilling, soil testing, establishing groundwater baseline data, and preparing a hydrogeologic characterization report. Additional siting efforts may include a wetlands delineation, a site topographic survey, as well as other required evaluations.

Facility design includes both landfill design and infrastructure design. This includes grading plans, deposition plans, contact and surface water management plans, design of haul roads, and the design of the country bridge crossing.

Permitting may include the solid waste landfill permit, air permits, and an NPDES permit. This includes the development of operations plans for the facility, closure plans, post-closure care plans, groundwater sampling and analysis plans, a Stormwater Pollution Prevention (SWPP) plan, and other required submittals associated with the construction and operation of a new fly ash disposal facility.

4.3.2 Land Acquisition

Land acquisition of the property for the new facility includes site due diligence, and property purchase. Site due diligence may include survey, geotechnical characterization, environmental audit, and a landfill siting suitability evaluation. The property purchase may include legal fees as well as the purchase price. At this time, good crop land in the vicinity of CCS is selling for as much as $1,500 per acre. A unit cost of $2,000 per acre is used in the analysis to account for both the cost of the land and the site due diligence.

4.3.3 Infrastructure Development

The costs for the infrastructure development include fencing, monitoring well installation, power from the plant to landfill, facility access haul road, a return water pipeline, and a county road bridge crossing. The costs for this construction are estimated to be between $649,500 and $924,000 for the different scenarios. Details for the quantities and unit rates applied to this work are included in Appendix B.

4.3.4 Liner Construction

Liner construction includes several elements as described above including a compacted clay layer, a geomembrane liner, a leachate collection system, and protective cover. In addition, this construction effort will include clearing and grubbing, topsoil stripping and stockpiling, construction of temporary roads, soil excavation and stockpiling to be used for perimeter berms, compacted liner, and cover, and application of site controls such as erosion controls. The costs for this construction are estimated to be between $174,500 and $178,300 per acre for the different scenarios. Details for the quantities and unit rates applied to this work are included in Appendix B.

4.3.5 Final Cover Construction

Final cover construction includes leveling fill, compacted soil layer, a geomembrane liner, a drainage collection system, growth medium, topsoil, armored down-chute channels, and vegetation of the site. The costs for this construction are estimated to be between $132,400 and $143,000 per acre for the different scenarios. Details for the quantities and unit rates applied to this work are included in Appendix B.

4.3.6 Post-Closure Care

Post-closure care includes groundwater monitoring and reporting, annual site inspections, repair and maintenance of the final cover (soil, seeding, mowing, surface water structures), maintenance of the facility access roads and fencing, as well as permit required record keeping. Post closure care will occur for 30 years following the closure of the facility and is included in the capital/direct costs for this cost analysis. The costs for post closure care are estimated to be between $50,000 and $108,500 per year for the different scenarios. Details for the quantities and unit rates applied to this work are included in Appendix B.

4.3.7 Construction Management and Construction Quality Assurance

Throughout the construction effort, a construction manager will be on-site to communicate between the contractors and the design engineer. In addition to the construction manager, one or several construction quality assurance (CQA) monitors will be on-site during the construction. This item is estimated as 10% of the total construction costs to develop the facility. Ten percent is based on Golder's experience with coal combustion product facilities within the Midwest.

4.3.8 GRE Internal Costs

Internal costs for GRE to manage consultants, contractors, and in-house staff is estimated as 10% of the total costs (construction, engineering, permitting, CQA). Ten percent is based on GRE's experience with projects at CCS.

4.3.9 Project Contingency

Due to the order-of-magnitude scope of this cost estimate and the associated engineering and unit rate development, a contingency of 15% on the construction and land acquisition costs was added.

4.3.10 Operational Costs

Landfill operations and maintenance costs are estimated as an annual cost and include both engineering support and site operations. Engineering support includes design support; permit support, an annual inspection, groundwater monitoring, and an annual survey. Site operations include the ownership and operation of site haul and placement equipment, full-time site staff, and material expenses.

Estimated costs for this work are broken into haul costs, placement costs, and site management and maintenance costs.

Haul costs were estimated at $2.14 per ton based on haul distance, equipment capacity, operator costs, and equipment costs. Placement costs were estimated at $1.71 per ton based on dozer spreading with minimal compaction. Details on the haul and placement costs are included in Appendix B.

Site management and maintenance costs were estimated between $154,500 and $396,000 per year for the different scenarios. Details on the annual site management and maintenance costs are included in Appendix B.

4.4 Disposal Cost Summary

Using the quantities and the unit pricing described above, disposal costs were estimated for the three scenarios and are summarized in Table 3.

Table 3: Disposal Cost Summary

	Scenario A (Current Sales)	**Scenario B (No Sales)**	**Scenario C (Reduced Sales, ASM)**
Fly Ash Disposed (ton/yr)	110,000	525,000	234,500
Disposal Cost ($/ton)	$18.06	$11.18	$13.91
Annual Disposal Cost ($/yr)	$1,987,000	$5,870,000	$3,262,000
Annual Increase in Disposal Cost Compared to Scenario A ($/yr)	-	$3,883,000	$1,275,000

The disposal cost per ton is reduced with increased disposal quantity due to the efficiency of the landfill footprint (larger landfill can be built higher and has larger capacity), and the distribution of fixed costs (roads, bridge, fence) across a larger amount of disposed fly ash.

Based on the annual disposal cost estimate, the potential impact of an SNCR to the fly ash disposal costs at CCS may be an additional $3.9 million per year if fly ash is no longer marketable or an additional $1.3 million per year if the ASM technology proves successful.

5.0 COST IMPACT

The total cost impact of an SNCR on fly ash management at CCS requires the aggregation of the post-processing costs (ASM), the disposal costs, and the loss in revenue generated from the sale of fly ash. This total cost impact was evaluated for the three Scenarios discussed previously. As a basis for the cost comparison, Table 4 provides a summary of the annual tons of fly ash produced, sold, disposed, and the loss in fly ash sales in comparison to Scenario A (current sales).

Table 4: Fly Ash Sales and Disposal Tons

	Scenario A (Current Sales)	Scenario B (No Sales)	Scenario C (Reduced Sales, ASM)
Fly Ash Produced (ton/yr)	525,000	525,000	525,000
Fly Ash Sold (ton/yr)	415,000	0	290,500
Fly Ash Disposed (ton/yr)	110,000	525,000	234,500
Lost Fly Ash Sales (ton/yr)	0	415,000	124,500

5.1 Ammonia Slip Mitigation

Post-processing of ammonia slip impacted fly ash by Headwater's ASM technology is proposed as an option to maintain fly ash sales. This post-processing is only being applied to the sold fly ash tonnage in Scenario C. Depending upon the plant power profile and how the fly ash distribution system is setup, it is likely that additional tons of fly ash will be treated and disposed, but these potential costs impacts are not included. The cost impact for ASM post-processing is shown in Table 5.

Table 5: ASM Post-Processing Costs

	Scenario A (Current Sales)	Scenario B (No Sales)	Scenario C (Reduced Sales, ASM)
ASM Unit Rate Capital and O&M ($/ton sold)	$0.00	$0.00	$5.61
ASM Annual Capital and O&M ($/yr)	$0	$0	$1,629,000

5.2 Fly Ash Disposal

Disposal costs vary between the Scenarios with the per ton cost being reduced by disposal volume. The cost impact for fly ash disposal is shown in Table 6.

Table 6: Disposal Costs

	Scenario A (Current Sales)	Scenario B (No Sales)	Scenario C (Reduced Sales, ASM)
Unit Rate Capital and O&M ($/ton disposed)	$18.06	$11.18	$13.91
Annual Capital and O&M ($/yr)	$1,987,000	$5,870,000	$3,262,000

5.3 Lost Sales

The current fly ash sales are supported by a large investment in capital infrastructure as well as a large operations and maintenance contingency. Changes to the quantity of fly ash marketed and sold will have a direct impact on fly ash management costs, as the revenue currently used to offset fly ash management will be lost. The lost fly ash sales revenue is based on the 2010 average price per ton FOB of $41.00; with 30% of the sale price going to GRE as revenue. The cost impact of the potential loss in fly ash sales in shown in Table 7.

Table 7: Lost Fly Ash Sales

	Scenario A (Current Sales)	Scenario B (No Sales)	Scenario C (Reduced Sales, ASM)
Lost Fly Ash Sales Revenue ($/ton lost sales)	$12.30	$12.30	$12.30
Annual Lost Fly Ash Sales Revenue ($/yr)	$0	$5,105,000	$1,531,000

5.4 Combined Impact to Fly Ash Management

The combination of the ASM post-processing, fly ash disposal, and lost fly ash sales revenue is shown in Table 8. This table also shows the additional cost impact of Scenario B and Scenario C in comparison with the current sales (Scenario A).

Table 8: Total Fly Ash Management Costs

	Scenario A (Current Sales)	Scenario B (No Sales)	Scenario C (Reduced Sales, ASM)
Total (Disposal + Post Processing + Lost Sales)			
Annual Cost ($/yr)	$1,987,000	$10,975,000	$6,422,000
Unit Cost ($/ton produced)	$3.79	$20.91	$12.23
Additional Cost (Scenario B/C - Scenario A)			
Fly Ash Management Cost ($/yr)	-	$8,988,000	$4,435,000
Fly Ash Management Cost ($/ton produced)	-	$17.12	$8.45

The total additional cost impact to fly ash management as a result of an SNCR is between $4.4 and $9.0 million per year.

We appreciate the opportunity to provide this third-party review of Headwater's ASM technology, and an estimate of the potential impact of SNCR on fly ash management costs including disposal and sales. Please contact us if you have any questions about the information provided.

GOLDER ASSOCIATES INC.

Fawn W. Bergen, PE
Senior Project Engineer

Ron Jorgenson
Principal

FWB/TS/dls

6.0 REFERENCES

1. *EPA Air Pollution Control Cost Manual*, Sixth Edition, EPA/452/B-02-001, January 2002.

2. Email from Rafic Minkara, PhD, PE, Vice President – Technology, Headwaters Energy Services, July 15, 2011.

3. RSMeans, 2010. *Heavy Construction Cost Data, 24th Annual Edition*. Construction Publishers & Consultants; Kingston, MA.

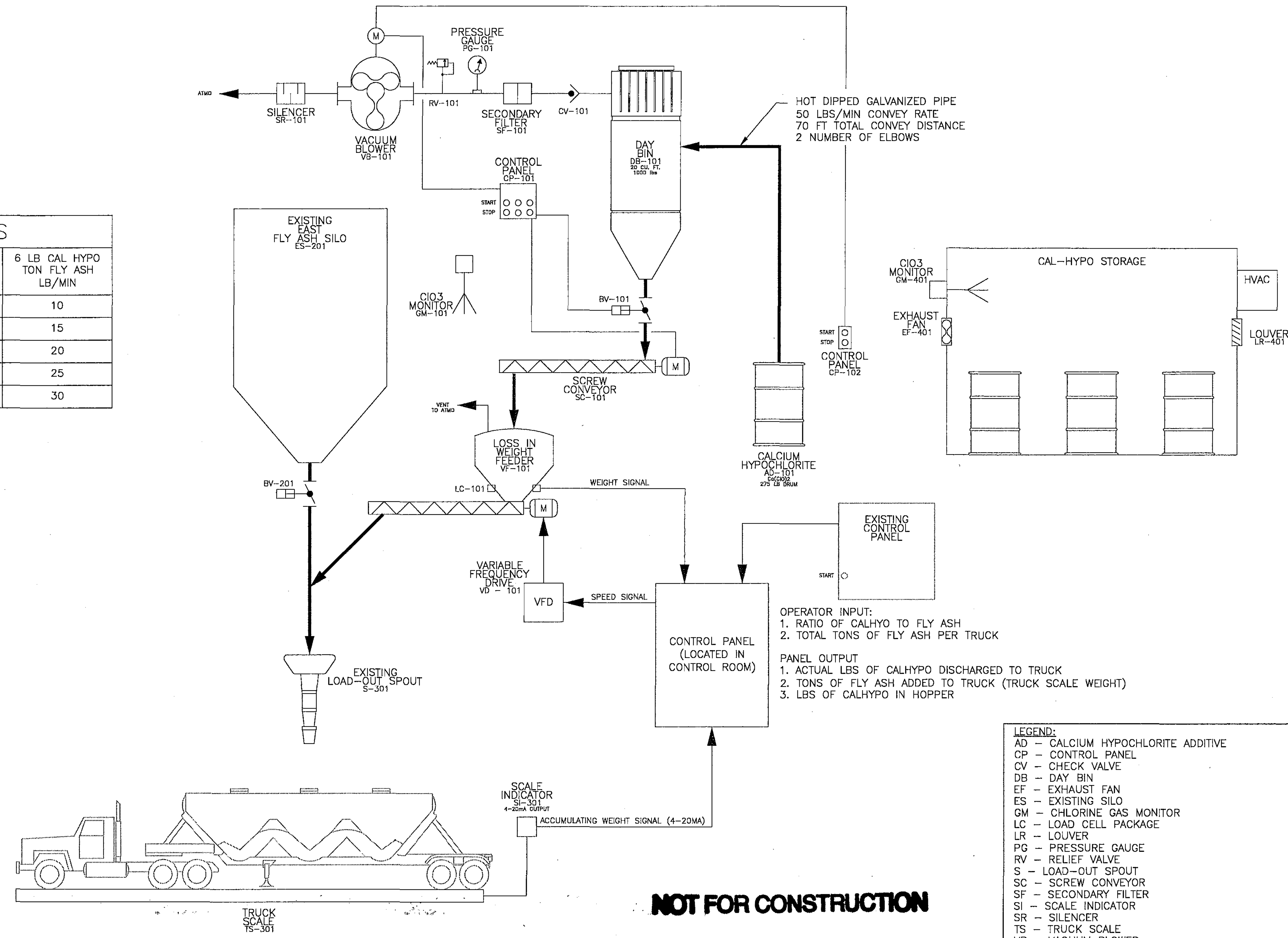
APPENDIX A

EASTLAKE ASM DESIGN DRAWINGS (HEADWATERS RESOURCES)

NOTES:
1. APPROXIMATELY 1½ TO 6 LBS CALCIUM HYPOCHLORITE/TON FLY ASH OR 38 LBS (1½*25) TO 150 LBS (6*25)/TRUCK
2. 30 TRUCKS MAX PER DAY. 1140 LBS (38*30) TO 4500 LBS (150*30) PER DAY
3. FLY ASH FEED RATE 300 TONS/HR TO 150 TONS/HR
4. CALCIUM HYPOCHLORITE FEED RATE 2.5 LBS/MIN TO 30 LBS/MIN
5. TRUCK LOAD TIME BETWEEN 5 AND 10 MINUTES
6. FLY ASH PH BETWEEN 11.5 TO 12
7. FLY ASH DENSITY 70 LBS LOOSE 100 LBS VIBRATED
8. CALHYPO APPROX. 50 LBS/FT³
9. CALHYPO DRUM 275 LBS

LOSS IN WEIGHT FEEDER RATES

FLY ASH LOAD-OUT TON/HR	1.5 LB CAL HYPO TON FLY ASH LB/MIN	2 LB CAL HYPO TON FLY ASH LB/MIN	4 LB CAL HYPO TON FLY ASH LB/MIN	6 LB CAL HYPO TON FLY ASH LB/MIN
100	2.5	3.3	6.7	10
150	3.75	5.0	10.0	15
200	5	6.7	13.3	20
250	6.25	8.3	16.7	25
300	7.5	10.0	20.0	30



OPERATOR INPUT:
1. RATIO OF CALHYO TO FLY ASH
2. TOTAL TONS OF FLY ASH PER TRUCK

PANEL OUTPUT
1. ACTUAL LBS OF CALHYPO DISCHARGED TO TRUCK
2. TONS OF FLY ASH ADDED TO TRUCK (TRUCK SCALE WEIGHT)
3. LBS OF CALHYPO IN HOPPER

LEGEND:
AD - CALCIUM HYPOCHLORITE ADDITIVE
CP - CONTROL PANEL
CV - CHECK VALVE
DB - DAY BIN
EF - EXHAUST FAN
ES - EXISTING SILO
GM - CHLORINE GAS MONITOR
LC - LOAD CELL PACKAGE
LR - LOUVER
PG - PRESSURE GAUGE
RV - RELIEF VALVE
S - LOAD-OUT SPOUT
SC - SCREW CONVEYOR
SF - SECONDARY FILTER
SI - SCALE INDICATOR
SR - SILENCER
TS - TRUCK SCALE
VB - VACUUM BLOWER
VD - VARIABLE SPEED DRIVE
VF - VIBRATORY FEEDER

NOT FOR CONSTRUCTION

HEADWATERS RESOURCES

HEADWATERS RESOURCES, INC.
10653 S. RIVER FRONT PARKWAY
SUITE 300
SOUTH JORDAN, UT 84095
(801) 984-9400
FAX (801) 984-9419
www.headwaters.com

DATE	NO.	REVISION DESCRIPTION	BY
8/13/07	G	ADDED EXHAUST FAN & LOUVER	DCB
8/2/07	F	ADDED CONTROL PANELS	DCB
7/16/07	E	ADDED GAS MONITORS AND STORAGE BUILDING	DCB
5/21/07	B	GENERAL REV.	DCB

EAST LAKE AMMONIA SLIP MITIGATION PROCESS FLOW DIAGRAM

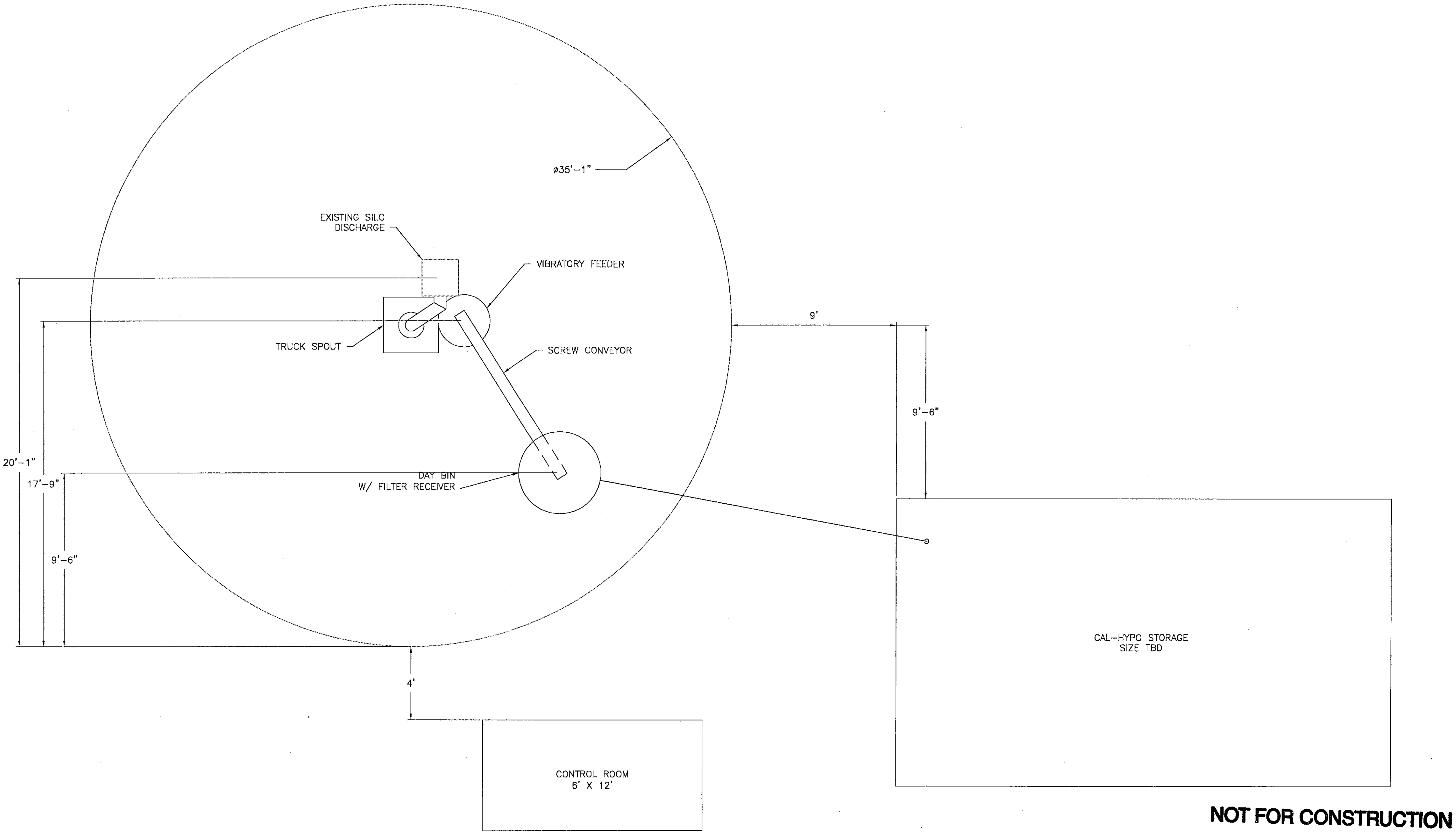
EAST LAKE, OH

SCALE: NO SCALE	
DATE: 05-18-07	
DESIGN BY:	LS
DRAWN BY:	DCB
CHECKED BY:	
APPROVED BY:	

SHEET NO. PF100

REVISION NO. G

PROJECT NO. R070H0



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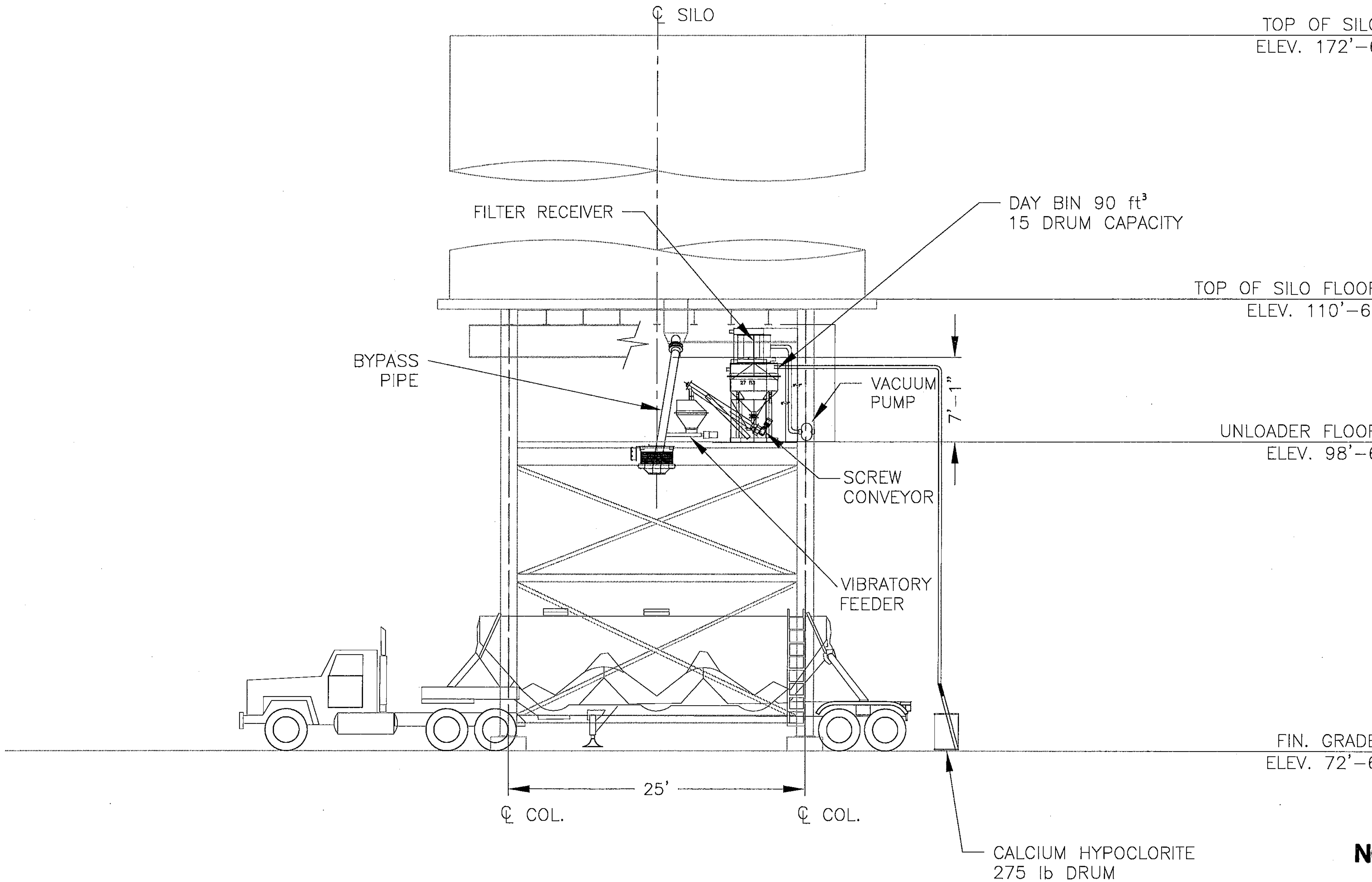
DATE	NO.	REVISION DESCRIPTION	BY
7/18/07	A	DRAWING CREATED	DCB

EAST LAKE
AMMONIA SLIP MITIGATION
PLAN VIEW
EAST LAKE, OH

SCALE: 3/16" = 1'
DATE: 07-18-07
DESIGN BY: LAS
DRAWN BY: DCB
CHECKED BY:
APPROVED BY:

SHEET NO. M100
REVISION NO. A
PROJECT NO. R07OH0



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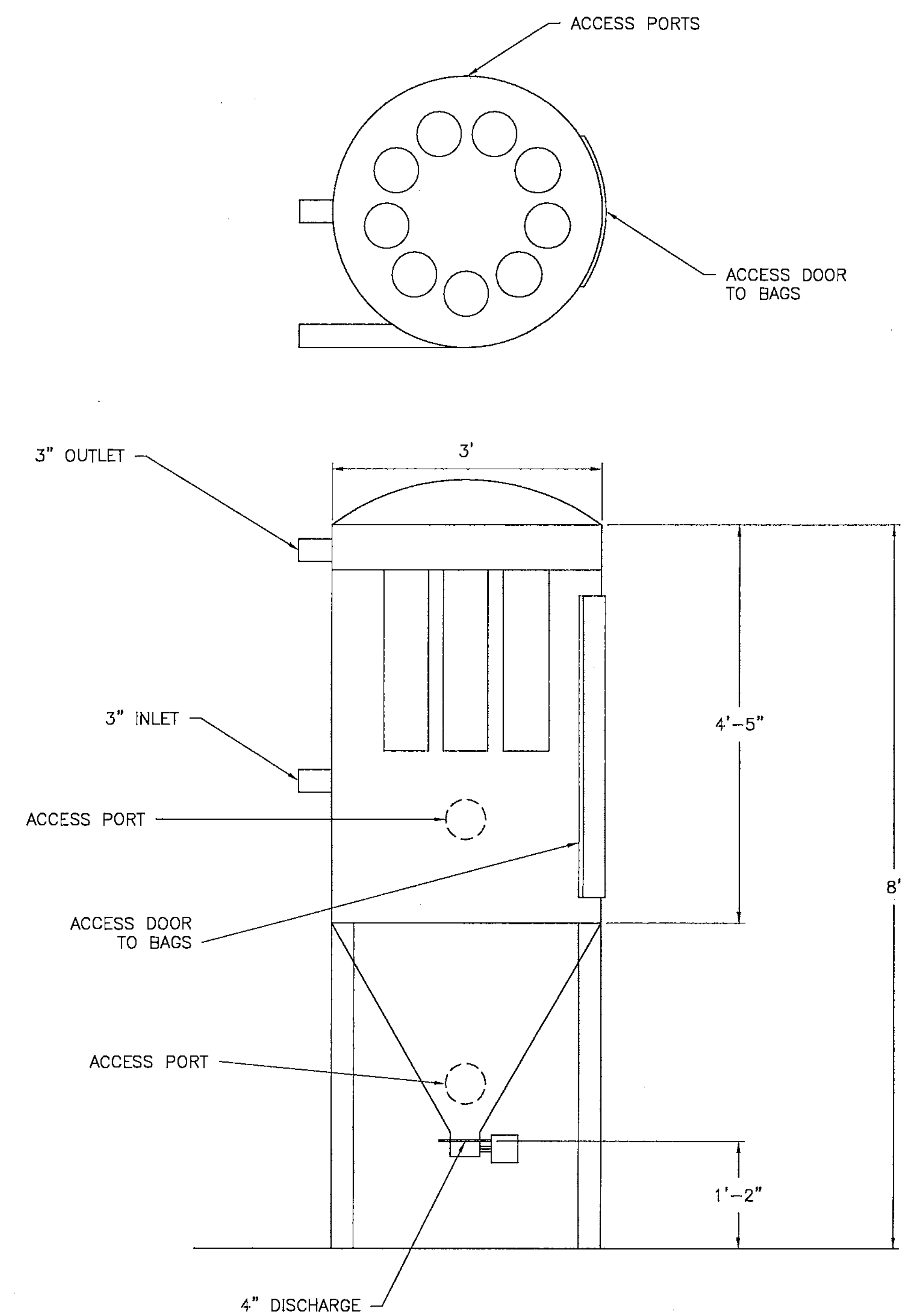
DATE	NO.	REVISION DESCRIPTION	BY
7/18/07	A	DRAWING CREATED	DCB

EAST LAKE
AMMONIA SLIP MITIGATION
ELEVATION
EAST LAKE, OH

SCALE: 1"=10'	
DATE: 07-18-07	
DESIGN BY:	LAS
DRAWN BY:	DCB
CHECKED BY:	
APPROVED BY:	

SHEET NO. M101
REVISION NO. A
PROJECT NO. R070H0

NOTE:
1. EPOXY PAINT INSIDE AND OUT
2. TOTAL CAPACITY – 17 FT^3
3. USE 2' TEFLON-COATED BAGS



NOT FOR CONSTRUCTION

HEADWATERS RESOURCES

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DATE	NO.	REVISION DESCRIPTION	BY
8/6/07	B	RELOCATED ACCESS PORTS	DCB
8/3/07	A	DRAWING CREATED	DCB

EAST LAKE
AMMONIA SLIP MITIGATION
FILTER RECEIVER
EAST LAKE, OH

SCALE: 1/2" = 1'	
DATE: 08-03-07	
DESIGN BY:	LAS
DRAWN BY:	DCB
CHECKED BY:	
APPROVED BY:	

SHEET NO. M200
REVISION NO. B
PROJECT NO. R07OH0

APPENDIX B
COST ESTIMATE DETAILS

Legend

Fly Ash Stream

Calcium Hypo–Chlorite Mixing System

Notes

1. Eastlake Generating Plant has a truck loadout for both untreatable fly ash destined for disposal (silos 1 and 2) and treated fly ash (silo 4).

250 0 250

SCALE FEET

FOR DISCUSSION PURPOSES ONLY

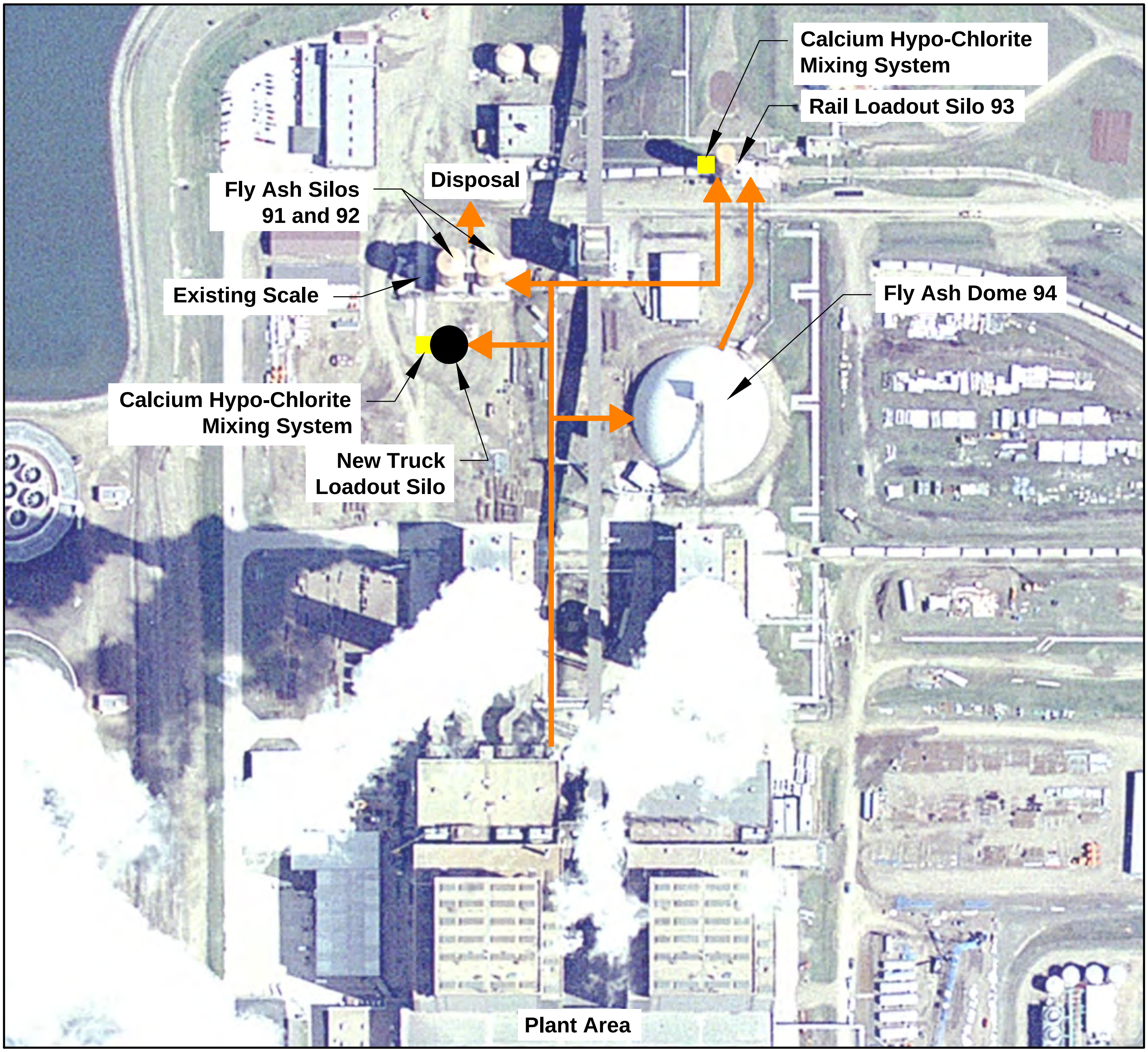
Golder Associates

Fly Ash Loadout Schematic
Eastlake Generating Plant

FIGURE 1

PROJECT No. 113–82161 CADD CCS DATE 11/1/11 FILE No. 11382161_Figures.dwg

Drawing File: J:\11JOBS\113-82161 GRE SNCR\Figures\ 11382161_Figures.dwg | Layout: Fly Ash Loadout-Eastlake | Modified: Nov 02, 2011 16:04 CSchuettpelz | Plotted: 11/02/11 4:05pm CSchuettpelz



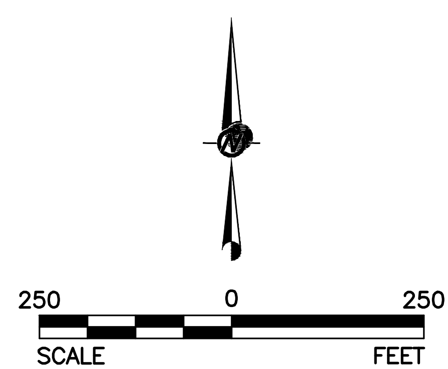
Legend

Fly Ash Stream

Calcium Hypo–Chlorite Mixing System

Notes

1. New truck loadout silo and scale are required to store treatable fly ash for sale.
2. Two Calcium Hypo–Chlorite Mixing Systems would be required near the new truck loadout silo and the rail loadout silo (93) for treating fly ash available for sale.
3. The existing fly ash silos (91 and 92) are available to store untreatable fly ash for disposal.
4. The existing Fly Ash Dome (94) is available to store treatable fly ash for rail sale.



Golder Associates

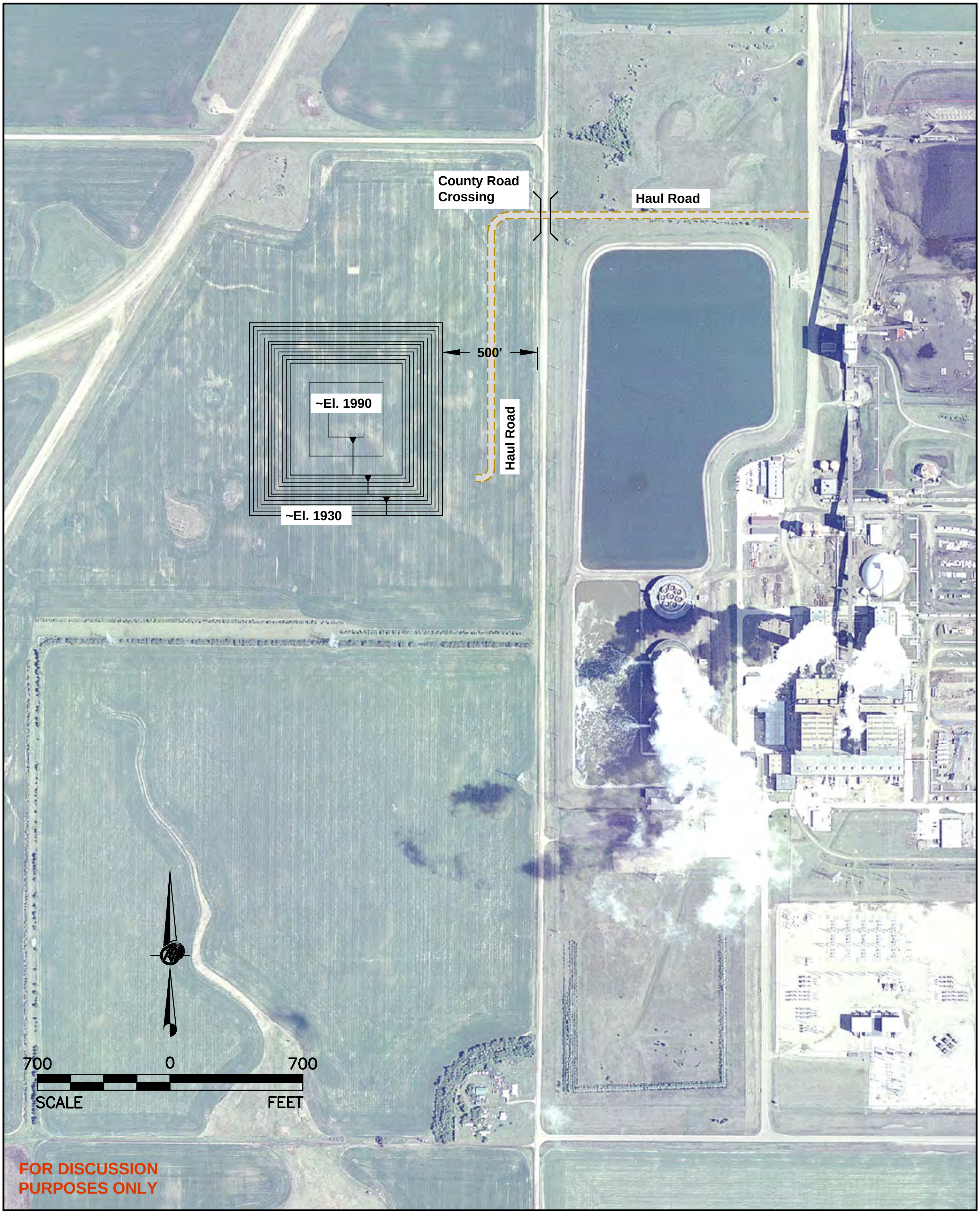
FOR DISCUSSION PURPOSES ONLY

Fly Ash Loadout Schematic Coal Creek Station

FIGURE 2

PROJECT No. 113–82161 CADD CCS DATE 11/1/11 FILE No. 11382161_Figures.dwg

Drawing File: J:\11JOBS\113-82161 GRE SNCR\Figures\ 11382161_Figures.dwg | Layout: Fly Ash Loadout-CCS | Modified: Nov 02, 2011 16:04 CSchuettpelz | Plotted: 11/02/11 4:05pm CSchuettpelz



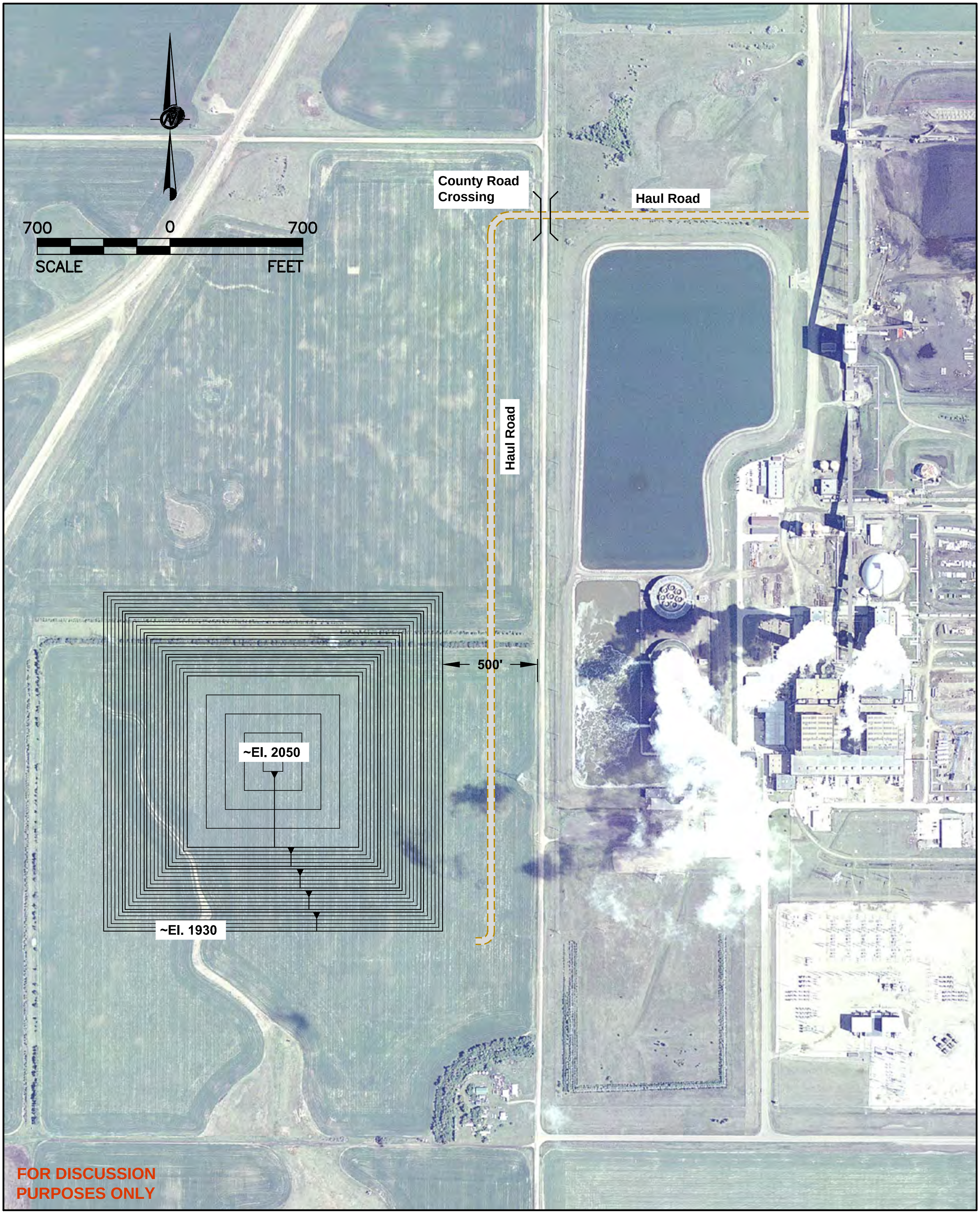
Scenario A
Fly Ash Containment Facility

Golder Associates

FIGURE 3

PROJECT No. 113-82161 CADD CCS DATE 11/1/11 FILE No. 11382161_Figures.dwg

Drawing File: J:\11JOBS\113-82161 GRE SNCR\Figures\ 11382161_Figures.dwg | Layout: Small Facility | Modified: Nov 02, 2011 16:04 CSchuettpelz | Plotted: 11/02/11 4:05pm CSchuettpelz



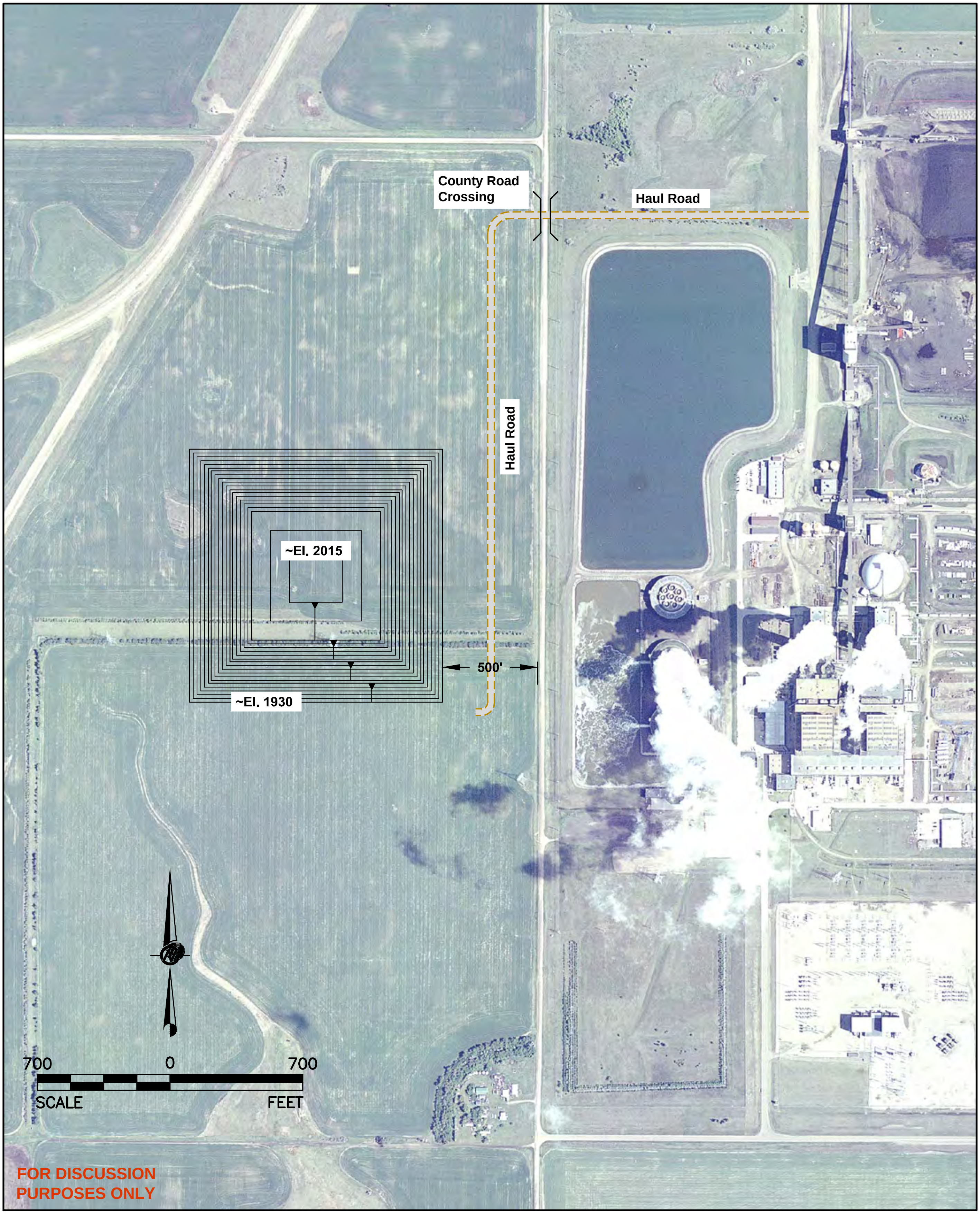
Scenario B
Fly Ash Containment Facility

Golder Associates

FIGURE 4

PROJECT No. 113-82161 CADD CCS DATE 11/1/11 FILE No. 11382161_Figures.dwg

Drawing File: J:\11JOBS\113-82161 GRE SNCR\Figures\ 11382161_Figures.dwg | Layout: Large Facility | Modified: Nov 02, 2011 16:04 CSchuettpelz | Plotted: 11/02/11 4:05pm CSchuettpelz



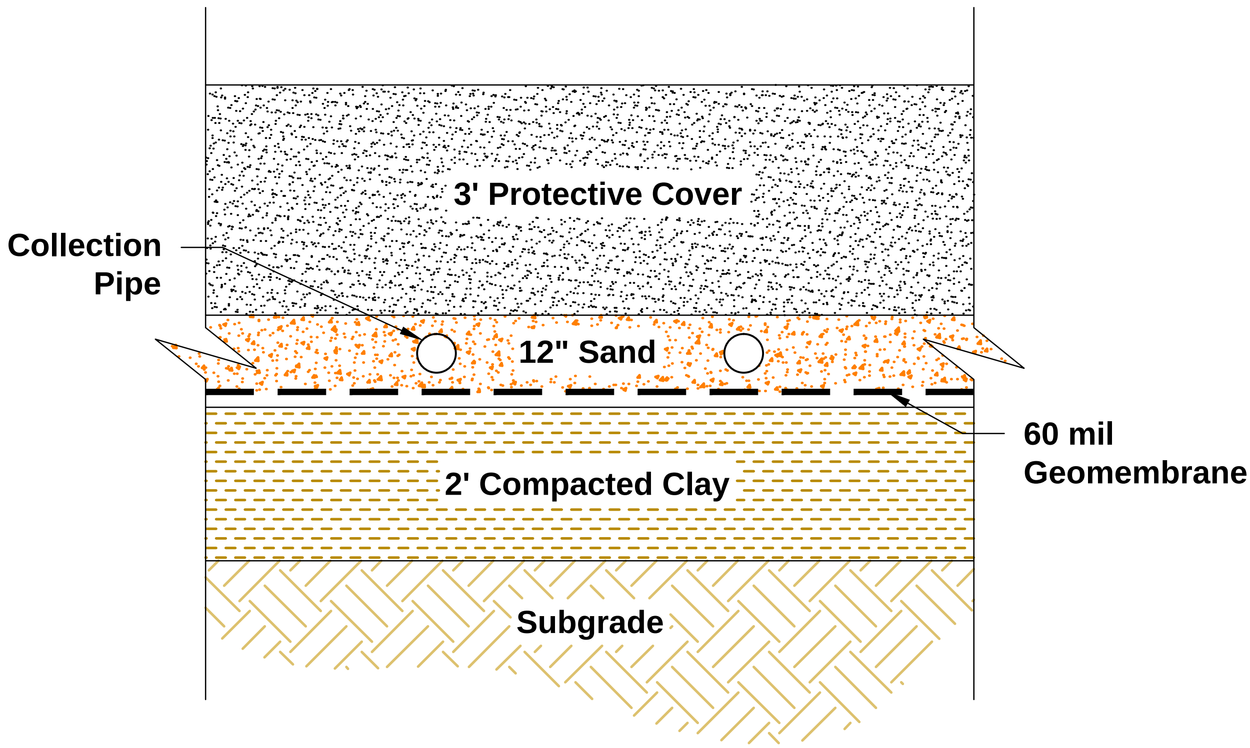
Scenario C
Fly Ash Containment Facility

Golder Associates

FIGURE 5

PROJECT No. 113-82161 CADD CCS DATE 11/1/11 FILE No. 11382161_Figures.dwg

Drawing File: J:\11JOBS\113-82161 GRE SNCR\Figures\ 11382161_Figures.dwg | Layout: Medium Facility | Modified: Nov 02, 2011 16:04 CSchuettpelz | Plotted: 11/02/11 4:05pm CSchuettpelz



FOR DISCUSSION
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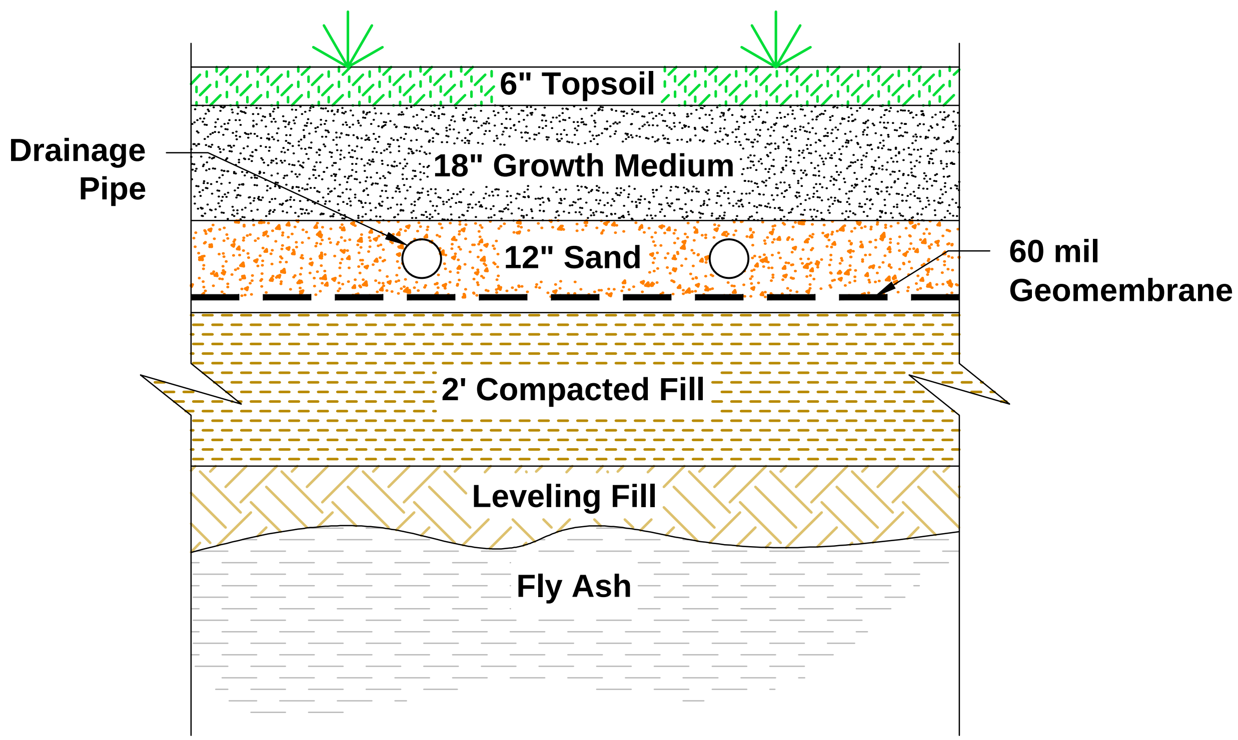
Composite Liner

FIGURE 6

PROJECT No. 113-82161 CADD CCS DATE 11/1/11 FILE No. 11382161_Figures.dwg

Drawing File: J:\11JOBS\113-82161 GRE SNCR\Figures\ 11382161_Figures.dwg | Layout: Liner | Modified: Nov 02, 2011 16:04 CSchuettpelz | Plotted: 11/02/11 4:05pm CSchuettpelz



FOR DISCUSSION PURPOSES ONLY

Golder Associates

Cover

FIGURE 7

PROJECT No. 113-82161 CADD CCS DATE 11/1/11 FILE No. 11382161_Figures.dwg

Drawing File: J:\11JOBS\113-82161 GRE SNCR\Figures\ 11382161_Figures.dwg | Layout: Cover | Modified: Nov 02, 2011 16:04 CSchuettpelz | Plotted: 11/02/11 4:06pm CSchuettpelz

Fly Ash Management Impact Evaluation Summary (November 15, 2011)

	Option A	Option B	Option C
	Current fly ash sales with new RCRA Subtitle D landfill	No fly ash sales with new RCRA Subtitle D landfill	ASM technology to allow reduced fly ash sales with new RCRA Subtitle D landfill
Fly Ash Quantities			
Fly Ash production (ton/yr)	525,000	525,000	525,000
Fly Ash Sales (ton/yr)	415,000	0	290,500
Fly Ash Disposal (ton/yr)	110,000	525,000	234,500
Lost Fly Ash Sales (ton/yr)	0	415,000	124,500
ASM Fly Ash Post Processing			
ASM Unit Rate Capital and O&M ($/ton sold)	$ -	$ -	$ 5.61
ASM Annual Capital and O&M ($/yr)	$ -	$ -	$ 1,629,000
Fly Ash Disposal			
Lined Footprint (acres)	24.0	73.5	41.0
Unit Rate Capital and O&M ($/ton disposed)	$ 18.06	$ 11.18	$ 13.91
Annual Capital and O&M ($/yr)	$ 1,987,000	$ 5,870,000	$ 3,262,000
Lost Fly Ash Sales			
Lost Fly Ash Sales Revenue ($/ton lost sales)	$ 12.30	$ 12.30	$ 12.30
Annual Lost Fly Ash Sales Revenue ($/yr)	$ -	$ 5,105,000	$ 1,531,000
Total (Disposal + Post Processing + Lost Sales)			
Annual Cost ($/yr)	$ 1,987,000	$ 10,975,000	$ 6,422,000
Unit Cost ($/ton produced)	$ 3.79	$ 20.91	$ 12.23
Additional Cost (Scenario B/C - Scenario A)			
Fly Ash Management Cost ($/yr)	-	$ 8,988,000	$ 4,435,000
Fly Ash Management Cost ($/ton produced)	-	$ 17.12	$ 8.45

Notes:

Capital costs annualized based on 20-year life and 5.5% interest rate.

Disposal costs based on new facility built across county road from Coal Creek Station with 20-year life.

RCRA Subtitle D type facility (composite liner, leachate collection system, and composite cover).

Disposal costs only include fly ash disposal and not facility airspace or O&M for other CCPs.

Ammonia slip mitigation costs based on existing facility site visit and historic costs for fly ash infrastructure.

All costs are in 2011 dollars.

Lost fly ash sales revenue based on expected 2011 average price per ton FOB of $43 and 30% of sale price to GRE.

Existing fly ash sales infrastructure and O&M costs are not included.

Scenario A - Current Sales

Project	113-82161
Date	11/15/2011
By	TJS
Checked	JJS

Sizing Information

Annual Fly Ash Disposal	110,000	tn	
20yr Fly Ash Disposal	2,200,000	tn	
Fly Ash Dry Density (in-situ)	90	pcf	
20yr Fly Ash Quantity	1,811,000	cy	
Lined Footprint	24.0	ac	75,000 cy/ac
Disturbance Footprint	34.5	ac	100' offset on liner footprint
Berm Length	4,240	ft	20' offset on liner footprint
Total Footprint	160		500' offset on liner footprint, nearest 1/8 section
Total Cover Area	26.5	ac	1.1 ration of cover area to liner area

Direct/Capital Costs

Item	Rate		#		Total Cost	
Land Acquisition	$ 2,000	/ac	160.0	ac	$ 320,000	
Infrastructure Development	$ 649,500	ea	1.0	LS	$ 649,500	
County Road Crossing	$ 1,730,500	ea	1.0	LS	$ 1,730,500	
Liner Construction	$ 178,300	/ac	24.0	ac	$ 4,279,200	
Final Cover Construction	$ 143,000	/ac	26.5	ac	$ 3,789,500	
Post-Closure Care	$ 50,000	/yr	30.0	yr	$ 1,500,000	
Facility Design & Permitting (on construction)	10.0%	-	$ 10,448,700	LS	$ 1,044,870	
Construction Quality Assurance (on construction)	5.0%	-	$ 10,448,700	LS	$ 522,435	
GRE Internal Costs (on construction, design, CQA, & land purchase)	10.0%	-	$ 13,836,005	-	$ 1,384,000	
Project Contingency (on construction & land)	15.0%	-	$ 10,768,700	-	$ 1,615,000	
			Total Direct/Capital Costs		$ 16,835,005	
			Annualized Capital Cost*		$ 1,409,000	/yr
			Capital Costs		$ 12.81	/tn

Operational Costs

Hauling Costs	$ 2.14	/tn	110,000	tn/yr	$ 235,469	/yr
Placement Costs	$ 1.71	/tn	110,000	tn/yr	$ 188,000	/yr
Maintenance Costs	$ 154,500	/yr	1	yr	$ 154,500	/yr
			Annual Operational Costs		$ 578,000	/yr
			Operational Costs		$ 5.26	/tn

TOTAL DISPOSAL COSTS

Annual Costs	$ 1,987,000	/yr
20-Year Total Costs	$ 39,740,000	
Per Ton Cost	$ 18.06	/tn

Notes:
*Annualized capital cost based on 20-year life and 5.5% interest rate.
All costs are in 2011 dollars.

Scenario B - No Fly Ash Sales

Project	113-82161
Date	11/15/2011
By	TJS
Checked	JJS

Sizing Information

Annual Fly Ash Disposal	525,000	tn	
20yr Fly Ash Disposal	10,500,000	tn	
Fly Ash Dry Density (in-situ)	90	pcf	
20yr Fly Ash Quantity	8,642,000	cy	
Lined Footprint	73.5	ac	118,000 cy/ac
Disturbance Footprint	91.0	ac	100' offset on liner footprint
Berm Length	7,320	ft	20' offset on liner footprint
Total Footprint	240		500' offset on liner footprint, nearest 1/8 section
Total Cover Area	81.0	ac	1.1 ration of cover area to liner area

Direct/Capital Costs

Item	**Rate**		**#**		**Total Cost**	
Land Acquisition	$ 2,000	/ac	240.0	ac	$ 480,000	
Infrastructure Development	$ 924,000	ea	1.0	LS	$ 924,000	
County Road Crossing	$ 1,730,500	ea	1.0	LS	$ 1,730,500	
Liner Construction	$ 174,500	/ac	73.5	ac	$ 12,825,750	
Final Cover Construction	$ 132,400	/ac	81.0	ac	$ 10,724,400	
Post-Closure Care	$ 108,500	/yr	30.0	yr	$ 3,255,000	
Facility Design & Permitting (on construction)	10.0%	-	$ 26,204,650	LS	$ 2,620,465	
Construction Quality Assurance (on construction)	5.0%	-	$ 26,204,650	LS	$ 1,310,233	
GRE Internal Costs (on construction, design, CQA, & land purchase)	10.0%	-	$ 33,870,348	-	$ 3,387,000	
Project Contingency (on construction & land)	15.0%	-	$ 26,684,650	-	$ 4,003,000	
			Total Direct/Capital Costs		$ 41,260,348	
			Annualized Capital Cost*		$ 3,453,000	/yr
			Capital Costs		$ 6.58	/tn

Operational Costs

Hauling Costs	$ 2.14	/tn	525,000	tn/yr	$ 1,123,830	/yr
Placement Costs	$ 1.71	/tn	525,000	tn/yr	$ 897,273	/yr
Maintenance Costs	$ 396,000	/yr	1	yr	$ 396,000	/yr
			An. Operational Costs		$ 2,417,000	/yr
			Operational Costs		$ 4.60	/tn

TOTAL DISPOSAL COSTS

Annual Costs	$ 5,870,000	/yr
20-Year Total Costs	$ 117,400,000	
Per Ton Cost	$ 11.18	/tn

Notes:
*Annualized capital cost based on 20-year life and 5.5% interest rate.
All costs are in 2011 dollars.

Scenario C - Partial Fly Ash Sales with ASM

Project	113-82161
Date	11/15/2011
By	TJS
Checked	JJS

Sizing Information

Annual Fly Ash Disposal	234,500	tn	
20yr Fly Ash Disposal	4,690,000	tn	
Fly Ash Dry Density (in-situ)	90	pcf	
20yr Fly Ash Quantity	3,860,000	cy	
Lined Footprint	41.0	ac	94,000 cy/ac
Disturbance Footprint	54.0	ac	100' offset on liner footprint
Berm Length	5,500	ft	20' offset on liner footprint
Total Footprint	160		500' offset on liner footprint, nearest 1/8 section
Total Cover Area	45.0	ac	1.1 ration of cover area to liner area

Direct/Capital Costs

Item	Rate		#		Total Cost	
Land Acquisition	$ 2,000	/ac	160.0	ac	$ 320,000	
Infrastructure Development	$ 779,500	ea	1.0	LS	$ 779,500	
County Road Crossing	$ 1,730,500	ea	1.0	LS	$ 1,730,500	
Liner Construction	$ 175,600	/ac	41.0	ac	$ 7,199,600	
Final Cover Construction	$ 138,500	/ac	45.0	ac	$ 6,232,500	
Post-Closure Care	$ 72,500	/yr	30.0	yr	$ 2,175,000	
Facility Design & Permitting (on construction)	10.0%	-	$ 15,942,100	LS	$ 1,594,210	
Construction Quality Assurance (on construction)	5.0%	-	$ 15,942,100	LS	$ 797,105	
GRE Internal Costs (on construction, design, CQA, & land purchase)	10.0%	-	$ 20,828,415	-	$ 2,083,000	
Project Contingency (on construction & land)	15.0%	-	$ 16,262,100	-	$ 2,439,000	
			Total Direct/Capital Costs		$ 25,350,415	
			Annualized Capital Cost*		$ 2,121,000	/yr
			Capital Costs		$ 9.05	/tn

Operational Costs

Hauling Costs	$ 2.14	/tn	234,500	tn/yr	$ 501,977	/yr
Placement Costs	$ 1.71	/tn	234,500	tn/yr	$ 400,782	/yr
Maintenance Costs	$ 238,500	/yr	1	yr	$ 238,500	/yr
			An. Operational Costs		$ 1,141,000	/yr
			Operational Costs		$ 4.87	/tn

TOTAL DISPOSAL COSTS

Annual Costs	$ 3,262,000	/yr
20-Year Total Costs	$ 65,240,000	
Per Ton Cost	$ 13.91	/tn

Notes:
*Annualized capital cost based on 20-year life and 5.5% interest rate.
All costs are in 2011 dollars.

ASM Post-Processing

Project	113-82161
Date	11/15/2011
By	REN
Checked	TJS

Sizing Information

Annual Fly Ash Sales	290,500	tn

Direct/Capital Costs

Item	Rate		#		Total Cost	
New Truck Load-out Silo	$ 1,568,500	ea	1.0	LS	$ 1,568,500	
Cal-Hypo Feed Systems (Rail silo)	$ 246,000	ea	1.0	LS	$ 246,000	
Cal-Hypo Feed Systems (New silo)	$ 328,500	ea	1.0	LS	$ 328,500	
System Design & Engineering (on construction)	10.0%	-	$ 2,143,000	-	$ 214,000	
GRE Internal Costs (on all)	10.0%	-	$ 2,357,000	-	$ 236,000	
Project Contingency (on construction)	15.0%	-	$ 2,143,000	-	$ 321,000	
			Total Direct/Capital Costs		$ 2,914,000	
			Annualized Capital Cost*		$ 244,000	/yr
			Capital Costs		$ 0.84	/tn

Operational Costs

Maintenance	$ 75.00	$/hr	4,600	hr	$ 345,000	/yr
Maintenance Materials	50%	-	$ 345,000	-	$ 172,500	/yr
Operations Materials	$ 75.00	$/hr	5,750	hr	$ 431,250	/yr
Operations Materials (Cal-Hypo)	$ 0.50	/tn	290,500	tn/yr	$ 145,250	/yr
Technology Royalty	$ 1.00	/tn	290,500	tn/yr	$ 290,500	/yr
			An. Operational Costs		$ 1,385,000	/yr
			Operational Costs		$ 4.77	/tn

TOTAL ASM COSTS

Annual Costs	$ 1,629,000	/yr
20-Year Total Costs	$ 32,580,000	
Per Ton Cost	$ 5.61	/tn

Notes:

*Annualized capital cost based on 20-year life and 5.5% interest rate.

Capital costs based on previous silo construction and discussions with Headwaters.

Assumed calcium hypo-chlorite cost of $1.00/lb.

Calcium hypo-chlorite mix rate is estimated between 0.3 and 1.3 lbs per 3,000 lbs of fly ash.

Scenario A (Current Sales) Unit Rate Details

PROJECT COMPONENT	QTY	UNIT	UNIT PRICE	TOTAL	Source	NOTES
Infrastructure Development			Total	$ 649,325	$ 649,500	
General						
Mobilize/Demobilize	5%	%	$ -	$ 29,515		
Miscellaneous Site Work & Materials	5%	%	$ -	$ 29,515		Erosion controls, offices, toilets, temporary roads, survey control, etc.
Civil						
Road Topsoil Stripping and Stockpiling	7,778	CY	$ 2.21	$ 17,181	Ames 2005 construction bid	18" topsoil
Access Road Construction	140,000	SF	$ 1.55	$ 217,101	RSMeans 2010 (01 55 23.50-0100)	8" Gravel temporary road ($13.55/SY = $1.51/sf), 4,000' x 35'
Return Water Pipeline	2,640	LF	$ 41.52	$ 109,622	RSMeans 2008 (33 11 13.25-4160)	6" PVC, 3' deep
Fence	8,090	LF	$ 23.66	$ 191,391	GRE Estimate	7' Chain link fence, GRE paid $22.30/ft in 2009
Overhead Power (Plant to Landfill)	1	EA	$ 25,000	$ 25,000	Golder Estimate	$25,000 for 1/2 mile distribution w/ transformer
Monitoring Well Installation	5	EA	$ 6,000	$ 30,000	Golder Estimate	
County Road Crossing			Total	$ 1,730,693	$ 1,730,500	
General						
Mobilize/Demobilize	5%	%	$ -	$ 78,668		
Misc. (erosion controls, toilets, etc)	5%	%	$ -	$ 78,668		Erosion controls, offices, toilets, temporary roads, survey control, etc.
Civil						
Topsoil Stripping and Stockpiling	4,577	CY	$ 2.21	$ 10,111	Ames 2005 construction bid	18" topsoil
Embankment Fill	35,591	CY	$ 3.59	$ 127,906	Northern 2006 construction bid	
County Road Sub-Base Course	2,385	CY	$ 3.59	$ 8,572	Northern 2006 construction bid	2' Sub-base preparation
County Road Base Course	32,200	SF	$ 1.55	$ 49,933	RSMeans 2010 (01 55 23.50-0100)	8" Gravel temporary road ($13.55/SY = $1.51/sf) 920' x35'
Bridge Deck Construction	5,250	SF	$ 262	$ 1,376,836	2008 California DOT Average	150 ft bridge deck, 35 ft wide
Liner Construction			Total	$ 4,278,853	Cost Per Acre of Liner	$ 178,300
General						
Mobilize/Demobilize	5%	%	$ -	$ 194,493		
Miscellaneous Site Work & Materials	5%	%	$ -	$ 194,493		Erosion controls, offices, toilets, temporary roads, survey control, etc.
Civil						
Clearing and Grubbing	35	AC	$ 6,077.00	$ 209,657	RSMeans 2010 (31 11 10.10-0200)	Clear & grub brush including stumps
Topsoil Stripping & Stockpiling (18")	-	CY	$ 2.21		Ames 2005 construction bid	
	35	AC	$ 5,346	$ 184,429		
Subgrade Cut to Stockpile	291,093	CY	$ 3.00	$ 873,280	Golder Estimate	10' across liner area: for liner, berms and cover
Subgrade Cut/Embankment Fill	96,107	CY	$ 3.59	$ 345,383	Northern 2006 construction bid	612 ft2 cross section area
Low Permeability Soil Liner (24")	-	CY	$ 4.32		Northern 2008 construction bid	
	24	AC	$ 13,927	$ 334,252		
60-mil HDPE Liner	-	SF	$ 0.76		Northern 2008 construction bid	materials, waste, conformance testing, installation
	24	AC	$ 33,319	$ 799,666		
Leachate Collection Layer, Sand (12")		CY	$ 25.00		Golder Estimate	
	24	AC	$ 40,333	$ 968,000		
Protective Cover (3')	-	CY	$ 4.04		Northern 2008 construction bid	fly ash as protective cover
	6	AC	$ 19,569	$ 117,411		contractor place 25% (side slopes, haul routes)
Piping						
LCS 4" Piping	4,475	LF	$ 5.25	$ 23,472	Northern 2008 construction bid	4" ADS N-12
LCS 8" Piping	900	LF	$ 12.02	$ 10,818	Northern 2008 construction bid	8" ADS N-12
LCS Sump/Riser	1	EA	$ 17,314	$ 17,314	Northern 2005 construction bid	
Equipment and Electrical						
Power Posts at Pumps/Sumps	1	EA	$ 1,185	$ 1,185	RSMeans 2010 (26 24 16.30-0150)	Panelboard/utility box with outlets
Collection pump	1	EA	$ 5,000	$ 5,000	Golder Estimate	

Scenario A (Current Sales) Unit Rate Details

PROJECT COMPONENT		QTY	UNIT	UNIT PRICE	TOTAL	Source	NOTES
Final Cover				Total	$ 3,790,408	Cost Per Acre of Cover	$ 143,000
General							
	Mobilize/Demobilize	5%	%	$ -	$ 172,291		
	Miscellaneous Site Work & Materials	5%	%	$ -	$ 172,291		Erosion controls, offices, toilets, temporary roads, survey control, etc.
Civil							
	Leveling Fill (6") & Compacted Fill (24")	-	CY	$ 3.59		Northern 2006 construction bid	
		27	AC	$ 14,495	$ 384,112		
	60-mil HDPE Liner	-	SF	$ 0.76		Northern 2008 construction bid	materials, waste, conformance testing, installation
		27	AC	$ 33,319	$ 882,965		
	Leachate Collection Layer, Sand (12")		CY	$ 25.00		Golder Estimate	
		27	AC	$ 40,333	$ 1,068,833		
	Growth Medium (18")		CY	$ 4.92		Northern 2010 construction bid	
		27	AC	$ 11,915	$ 315,738		
	Topsoil (6")		CY	$ 4.92		Same as Growth Medium	
		27	AC	$ 3,972	$ 105,246		
	Downchute Channels	57,600	SF	$ 10.82	$ 622,944	Northern 2010 construction bid	36' wide, 4 downchutes
	Seed and Mulch	27	AC	$ 2,490.11	$ 65,988	RSMeans 2010 (32 92 19.14-4600)	Slope mix, with mulch & fertilizer
Post Closure Care				Total	$ 50,020	$ 50,000	
	Groundwater Monitoring & Reporting	1	EA	$ 15,000	$ 15,000	Golder Estimate	$1,000 per well + $10,000 for the report
	Annual Site Inspection	1	EA	$ 1,060	$ 1,060	Golder Estimate	$1,000 per 25 acres
	Final Cover Repair	1	EA	$ 4,210	$ 4,210	Golder Estimate	2% of cover area, 12" growth medium/topsoil fill
	Seeding Repair	1	EA	$ 6,600	$ 6,600	Golder Estimate	10% of cover area
	Mowing and/or rodent, weed, & tree control	1	EA	$ 2,120	$ 2,120	Golder Estimate	$2,000 per 25 acres
	Surface Water Controls Maintenance	1	EA	$ 12,230	$ 12,230	Golder Estimate	1% of armored channel replaced + other repairs
	Gate and/or fence Maintenance	1	EA	$ 1,910	$ 1,910	Golder Estimate	1% of fence
	Recordkeeping	1	EA	$ 1,590	$ 1,590	Golder Estimate	$1,500 per 25 acres
	Direct Expenses	1	EA	$ 5,300	$ 5,300	Golder Estimate	$5,000 per 25 acres
Annual Operations & Maintenance Costs (not haul and place)				Total	$ 154,710	$ 154,500	
	Groundwater Monitoring & Reporting	1	EA	$ 15,000	$ 15,000	Golder Estimate	$1,000 per well + $10,000 for the report
	Annual Site Inspection	1	EA	$ 12,000	$ 12,000	Golder Estimate	$1,000 per 25 acres of liner per month
	Engineering Support	1	EA	$ 48,000	$ 48,000	Golder Estimate	$50,000 per 25 acres of liner
	Survey Control	1	EA	$ 25,000	$ 25,000	Golder Estimate	GPS unit(s), $25,000 per year
	Gate and/or fence Maintenance	1	EA	$ 1,910	$ 1,910	Golder Estimate	1% of fence
	Recordkeeping	1	EA	$ 4,800	$ 4,800	Golder Estimate	$5,000 per 25 acres
	Misc Work (contact water, dust, erosion, grading, etc)	1	EA	$ 48,000	$ 48,000	Golder Estimate	$50,000 per 25 acres
Haul & Place Costs							
	Haul Cost	1	CY	$ 2.14	$ 2.14	RSMeans 2010 (32 23 23.20-8180)	60cy Off-road, 20 min wait, 15 mph, 2 mile cycle
	Haul Cost	1	TON	$ 2.14	$ 2.14	Golder Estimate	75pcf haul density (1 ton/cy)
	Place Cost	1	CY	$ 1.42	$ 1.42	RSMeans 2010 (31 23 23.17-0020)	Dozer, no compaction
	Place Cost	1	TON	$ 1.71	$ 1.71	Golder Estimate	90pcf placed density (1.2 ton/cy)

Scenario B (No Sales) Unit Rate Details

PROJECT COMPONENT	QTY	UNIT	UNIT PRICE	TOTAL	Source	NOTES
Infrastructure Development			Total	$ 924,006	$ 924,000	
General						
Mobilize/Demobilize	5%	%	$ -	$ 42,000		
Miscellaneous Site Work & Materials	5%	%	$ -	$ 42,000		Erosion controls, offices, toilets, temporary roads, survey control, etc.
Civil						
Road Topsoil Stripping and Stockpiling	11,667	CY	$ 2.21	$ 25,772	Ames 2005 construction bid	18" topsoil
Access Road Construction	210,000	SF	$ 1.55	$ 325,652	RSMeans 2010 (01 55 23.50-0100)	8" Gravel temporary road ($13.55/SY = $1.51/sf), 6,000' x 35'
Return Water Pipeline	2,640	LF	$ 41.52	$ 109,622	RSMeans 2008 (33 11 13.25-4160)	6" PVC, 3' deep
Fence	11,157	LF	$ 23.66	$ 263,960	GRE Estimate	7' Chain link fence, GRE paid $22.30/ft in 2009
Overhead Power (Plant to Landfill)	1	EA	$ 25,000	$ 25,000	Golder Estimate	$25,000 for 1/2 mile distribution w/ transformer
Monitoring Well Installation	15	EA	$ 6,000	$ 90,000	Golder Estimate	
County Road Crossing			Total	$ 1,730,693	$ 1,730,500	
General						
Mobilize/Demobilize	5%	%	$ -	$ 78,668		
Misc. (erosion controls, toilets, etc)	5%	%	$ -	$ 78,668		Erosion controls, offices, toilets, temporary roads, survey control, etc.
Civil						
Topsoil Stripping and Stockpiling	4,577	CY	$ 2.21	$ 10,111	Ames 2005 construction bid	18" topsoil
Embankment Fill	35,591	CY	$ 3.59	$ 127,906	Northern 2006 construction bid	
County Road Sub-Base Course	2,385	CY	$ 3.59	$ 8,572	Northern 2006 construction bid	2' Sub-base preparation
County Road Base Course	32,200	SF	$ 1.55	$ 49,933	RSMeans 2010 (01 55 23.50-0100)	8" Gravel temporary road ($13.55/SY = $1.51/sf) 920' x35'
Bridge Deck Construction	5,250	SF	$ 262	$ 1,376,836	2008 California DOT Average	150 ft bridge deck, 35 ft wide
Liner Construction			Total	$ 12,827,387	Cost Per Acre of Liner	$ 174,500
General						
Mobilize/Demobilize	5%	%	$ -	$ 583,063		
Miscellaneous Site Work & Materials	5%	%	$ -	$ 583,063		Erosion controls, offices, toilets, temporary roads, survey control, etc.
Civil						
Clearing and Grubbing	91	AC	$ 6,077.00	$ 553,007	RSMeans 2010 (31 11 10.10-0200)	Clear & grub brush including stumps
Topsoil Stripping & Stockpiling (18")	-	CY	$ 2.21		Ames 2005 construction bid	
	91	AC	$ 5,346	$ 486,465		
Subgrade Cut to Stockpile	1,019,880	CY	$ 3.00	$ 3,059,640	Golder Estimate	10' across liner area: for liner, berms and cover
Subgrade Cut/Embankment Fill	165,920	CY	$ 3.59	$ 596,275	Northern 2006 construction bid	612 ft2 cross section area
Low Permeability Soil Liner (24")	-	CY	$ 4.32		Northern 2008 construction bid	
	74	AC	$ 13,927	$ 1,023,647		
60-mil HDPE Liner	-	SF	$ 0.76		Northern 2008 construction bid	materials, waste, conformance testing, installation
	74	AC	$ 33,319	$ 2,448,978		
Leachate Collection Layer, Sand (12")		CY	$ 25.00		Golder Estimate	
	74	AC	$ 40,333	$ 2,964,500		
Protective Cover (3')	-	CY	$ 4.04		Northern 2008 construction bid	fly ash as protective cover
	18	AC	$ 19,569	$ 359,572		contractor place 25% (side slopes, haul routes)
Piping						
LCS 4" Piping	15,640	LF	$ 5.25	$ 82,033	Northern 2008 construction bid	4" ADS N-12
LCS 8" Piping	3,340	LF	$ 12.02	$ 40,147	Northern 2008 construction bid	8" ADS N-12
LCS Sump/Riser	2	EA	$ 17,314	$ 34,628	Northern 2005 construction bid	
Equipment and Electrical						
Power Posts at Pumps/Sumps	2	EA	$ 1,185	$ 2,369	RSMeans 2010 (26 24 16.30-0150)	Panelboard/utility box with outlets
Collection pump	2	EA	$ 5,000	$ 10,000	Golder Estimate	

Scenario B (No Sales) Unit Rate Details

PROJECT COMPONENT		QTY	UNIT	UNIT PRICE	TOTAL	Source	NOTES
Final Cover				Total	$ 10,724,703	Cost Per Acre of Cover	$ 132,400
General							
	Mobilize/Demobilize	5%	%	$ -	$ 487,486		
	Miscellaneous Site Work & Materials	5%	%	$ -	$ 487,486		Erosion controls, offices, toilets, temporary roads, survey control, etc.
Civil							
	Leveling Fill (6") & Compacted Fill (24")	-	CY	$ 3.59		Northern 2006 construction bid	
		81	AC	$ 14,495	$ 1,174,078		
	60-mil HDPE Liner	-	SF	$ 0.76		Northern 2008 construction bid	materials, waste, conformance testing, installation
		81	AC	$ 33,319	$ 2,698,874		
	Leachate Collection Layer, Sand (12")		CY	$ 25.00		Golder Estimate	
		81	AC	$ 40,333	$ 3,267,000		
	Growth Medium (18")		CY	$ 4.92		Northern 2010 construction bid	
		81	AC	$ 11,915	$ 965,085		
	Topsoil (6")		CY	$ 4.92		Same as Growth Medium	
		81	AC	$ 3,972	$ 321,695		
	Downchute Channels	103,680	SF	$ 10.82	$ 1,121,299	Northern 2010 construction bid	36' wide, 4 downchutes
	Seed and Mulch	81	AC	$ 2,490.11	$ 201,699	RSMeans 2010 (32 92 19.14-4600)	Slope mix, with mulch & fertilizer
Post Closure Care				Total	$ 108,670	$ 108,500	
	Groundwater Monitoring & Reporting	1	EA	$ 25,000	$ 25,000	Golder Estimate	$1,000 per well + $10,000 for the report
	Annual Site Inspection	1	EA	$ 3,240	$ 3,240	Golder Estimate	$1,000 per 25 acres
	Final Cover Repair	1	EA	$ 12,870	$ 12,870	Golder Estimate	2% of cover area, 12" growth medium/topsoil fill
	Seeding Repair	1	EA	$ 20,170	$ 20,170	Golder Estimate	10% of cover area
	Mowing and/or rodent, weed, & tree control	1	EA	$ 6,480	$ 6,480	Golder Estimate	$2,000 per 25 acres
	Surface Water Controls Maintenance	1	EA	$ 17,210	$ 17,210	Golder Estimate	1% of armored channel replaced + other repairs
	Gate and/or fence Maintenance	1	EA	$ 2,640	$ 2,640	Golder Estimate	1% of fence
	Recordkeeping	1	EA	$ 4,860	$ 4,860	Golder Estimate	$1,500 per 25 acres
	Direct Expenses	1	EA	$ 16,200	$ 16,200	Golder Estimate	$5,000 per 25 acres
Annual Operations & Maintenance Costs (not haul and place)				Total	$ 396,140	$ 396,000	
	Groundwater Monitoring & Reporting	1	EA	$ 25,000	$ 25,000	Golder Estimate	$1,000 per well + $10,000 for the report
	Annual Site Inspection	1	EA	$ 34,800	$ 34,800	Golder Estimate	$1,000 per 25 acres of liner per month
	Engineering Support	1	EA	$ 147,000	$ 147,000	Golder Estimate	$50,000 per 25 acres of liner
	Survey Control	1	EA	$ 25,000	$ 25,000	Golder Estimate	GPS unit(s), $25,000 per year
	Gate and/or fence Maintenance	1	EA	$ 2,640	$ 2,640	Golder Estimate	1% of fence
	Recordkeeping	1	EA	$ 14,700	$ 14,700	Golder Estimate	$5,000 per 25 acres
	Misc Work (contact water, dust, erosion, grading, etc)	1	EA	$ 147,000	$ 147,000	Golder Estimate	$50,000 per 25 acres
Haul & Place Costs							
	Haul Cost	1	CY	$ 2.14	$ 2.14	RSMeans 2010 (32 23 23.20-8180)	60cy Off-road, 20 min wait, 15 mph, 2 mile cycle
	Haul Cost	1	TON	$ 2.14	$ 2.14	Golder Estimate	75pcf haul density (1 ton/cy)
	Place Cost	1	CY	$ 1.42	$ 1.42	RSMeans 2010 (31 23 23.17-0020)	Dozer, no compaction
	Place Cost	1	TON	$ 1.71	$ 1.71	Golder Estimate	90pcf placed density (1.2 ton/cy)

Scenario C (Reduced Sales with ASM) Unit Rate Details

PROJECT COMPONENT		QTY	UNIT	UNIT PRICE	TOTAL	Source	NOTES
Infrastructure Development				Total	$ 779,431	$ 779,500	
General							
	Mobilize/Demobilize	5%	%	$ -	$ 35,429		
	Miscellaneous Site Work & Materials	5%	%	$ -	$ 35,429		Erosion controls, offices, toilets, temporary roads, survey control, etc.
Civil							
	Road Topsoil Stripping and Stockpiling	9,722	CY	$ 2.21	$ 21,476	Ames 2005 construction bid	18" topsoil
	Access Road Construction	175,000	SF	$ 1.55	$ 271,376	RSMeans 2010 (01 55 23.50-0100)	8" Gravel temporary road ($13.55/SY = $1.51/sf), 5,000' x 35'
	Return Water Pipeline	2,640	LF	$ 41.52	$ 109,622	RSMeans 2008 (33 11 13.25-4160)	6" PVC, 3' deep
	Fence	9,346	LF	$ 23.66	$ 221,099	GRE Estimate	7' Chain link fence, GRE paid $22.30/ft in 2009
	Overhead Power (Plant to Landfill)	1	EA	$ 25,000	$ 25,000	Golder Estimate	$25,000 for 1/2 mile distribution w/ transformer
	Monitoring Well Installation	10	EA	$ 6,000	$ 60,000	Golder Estimate	
County Road Crossing				Total	$ 1,730,693	$ 1,730,500	
General							
	Mobilize/Demobilize	5%	%	$ -	$ 78,668		
	Misc. (erosion controls, toilets, etc)	5%	%	$ -	$ 78,668		Erosion controls, offices, toilets, temporary roads, survey control, etc.
Civil							
	Topsoil Stripping and Stockpiling	4,577	CY	$ 2.21	$ 10,111	Ames 2005 construction bid	18" topsoil
	Embankment Fill	35,591	CY	$ 3.59	$ 127,906	Northern 2006 construction bid	
	County Road Sub-Base Course	2,385	CY	$ 3.59	$ 8,572	Northern 2006 construction bid	2' Sub-base preparation
	County Road Base Course	32,200	SF	$ 1.55	$ 49,933	RSMeans 2010 (01 55 23.50-0100)	8" Gravel temporary road ($13.55/SY = $1.51/sf) 920' x35'
	Bridge Deck Construction	5,250	SF	$ 262	$ 1,376,836	2008 California DOT Average	150 ft bridge deck, 35 ft wide
Liner Construction				Total	$ 7,200,075	Cost Per Acre of Liner	$ 175,600
General							
	Mobilize/Demobilize	5%	%	$ -	$ 327,276		
	Miscellaneous Site Work & Materials	5%	%	$ -	$ 327,276		Erosion controls, offices, toilets, temporary roads, survey control, etc.
Civil							
	Clearing and Grubbing	54	AC	$ 6,077.00	$ 328,158	RSMeans 2010 (31 11 10.10-0200)	Clear & grub brush including stumps
	Topsoil Stripping & Stockpiling (18")	-	CY	$ 2.21		Ames 2005 construction bid	
		54	AC	$ 5,346	$ 288,672		
	Subgrade Cut to Stockpile	536,800	CY	$ 3.00	$ 1,610,400	Golder Estimate	10' across liner area: for liner, berms and cover
	Subgrade Cut/Embankment Fill	124,667	CY	$ 3.59	$ 448,021	Northern 2006 construction bid	612 ft2 cross section area
	Low Permeability Soil Liner (24")	-	CY	$ 4.32		Northern 2008 construction bid	
		41	AC	$ 13,927	$ 571,014		
	60-mil HDPE Liner	-	SF	$ 0.76		Northern 2008 construction bid	materials, waste, conformance testing, installation
		41	AC	$ 33,319	$ 1,366,097		
	Leachate Collection Layer, Sand (12")		CY	$ 25.00		Golder Estimate	
		41	AC	$ 40,333	$ 1,653,667		
	Protective Cover (3')	-	CY	$ 4.04		Northern 2008 construction bid	fly ash as protective cover
		10	AC	$ 19,569	$ 200,578		contractor place 25% (side slopes, haul routes)
Piping							
	LCS 4" Piping	7,770	LF	$ 5.25	$ 40,754	Northern 2008 construction bid	4" ADS N-12
	LCS 8" Piping	1,220	LF	$ 12.02	$ 14,664	Northern 2008 construction bid	8" ADS N-12
	LCS Sump/Riser	1	EA	$ 17,314	$ 17,314	Northern 2005 construction bid	
Equipment and Electrical							
	Power Posts at Pumps/Sumps	1	EA	$ 1,185	$ 1,185	RSMeans 2010 (26 24 16.30-0150)	Panelboard/utility box with outlets
	Collection pump	1	EA	$ 5,000	$ 5,000	Golder Estimate	

Scenario C (Reduced Sales with ASM) Unit Rate Details

PROJECT COMPONENT		QTY	UNIT	UNIT PRICE	TOTAL	Source	NOTES
Final Cover				Total	$ 6,232,264	Cost Per Acre of Cover	$ 138,500
General							
	Mobilize/Demobilize	5%	%	$ -	$ 283,285		
	Miscellaneous Site Work & Materials	5%	%	$ -	$ 283,285		Erosion controls, offices, toilets, temporary roads, survey control, etc.
Civil							
	Leveling Fill (6") & Compacted Fill (24")	-	CY	$ 3.59		Northern 2006 construction bid	
		45	AC	$ 14,495	$ 652,266		
	60-mil HDPE Liner	-	SF	$ 0.76		Northern 2008 construction bid	materials, waste, conformance testing, installation
		45	AC	$ 33,319	$ 1,499,374		
	Leachate Collection Layer, Sand (12")		CY	$ 25.00		Golder Estimate	
		45	AC	$ 40,333	$ 1,815,000		
	Growth Medium (18")		CY	$ 4.92		Northern 2010 construction bid	
		45	AC	$ 11,915	$ 536,158		
	Topsoil (6")		CY	$ 4.92		Same as Growth Medium	
		45	AC	$ 3,972	$ 178,719		
	Downchute Channels	80,640	SF	$ 10.82	$ 872,122	Northern 2010 construction bid	36' wide, 4 downchutes
	Seed and Mulch	45	AC	$ 2,490.11	$ 112,055	RSMeans 2010 (32 92 19.14-4600)	Slope mix, with mulch & fertilizer
Post Closure Care				Total	$ 72,390	$ 72,500	
	Groundwater Monitoring & Reporting	1	EA	$ 20,000	$ 20,000	Golder Estimate	$1,000 per well + $10,000 for the report
	Annual Site Inspection	1	EA	$ 1,800	$ 1,800	Golder Estimate	$1,000 per 25 acres
	Final Cover Repair	1	EA	$ 7,150	$ 7,150	Golder Estimate	2% of cover area, 12" growth medium/topsoil fill
	Seeding Repair	1	EA	$ 11,210	$ 11,210	Golder Estimate	10% of cover area
	Mowing and/or rodent, weed, & tree control	1	EA	$ 3,600	$ 3,600	Golder Estimate	$2,000 per 25 acres
	Surface Water Controls Maintenance	1	EA	$ 14,720	$ 14,720	Golder Estimate	1% of armored channel replaced + other repairs
	Gate and/or fence Maintenance	1	EA	$ 2,210	$ 2,210	Golder Estimate	1% of fence
	Recordkeeping	1	EA	$ 2,700	$ 2,700	Golder Estimate	$1,500 per 25 acres
	Direct Expenses	1	EA	$ 9,000	$ 9,000	Golder Estimate	$5,000 per 25 acres
Annual Operations & Maintenance Costs (not haul and place)				Total	$ 238,610	$ 238,500	
	Groundwater Monitoring & Reporting	1	EA	$ 20,000	$ 20,000	Golder Estimate	$1,000 per well + $10,000 for the report
	Annual Site Inspection	1	EA	$ 19,200	$ 19,200	Golder Estimate	$1,000 per 25 acres of liner per month
	Engineering Support	1	EA	$ 82,000	$ 82,000	Golder Estimate	$50,000 per 25 acres of liner
	Survey Control	1	EA	$ 25,000	$ 25,000	Golder Estimate	GPS unit(s), $25,000 per year
	Gate and/or fence Maintenance	1	EA	$ 2,210	$ 2,210	Golder Estimate	1% of fence
	Recordkeeping	1	EA	$ 8,200	$ 8,200	Golder Estimate	$5,000 per 25 acres
	Misc Work (contact water, dust, erosion, grading, etc)	1	EA	$ 82,000	$ 82,000	Golder Estimate	$50,000 per 25 acres
Haul & Place Costs							
	Haul Cost	1	CY	$ 2.14	$ 2.14	RSMeans 2010 (32 23 23.20-8180)	60cy Off-road, 20 min wait, 15 mph, 2 mile cycle
	Haul Cost	1	TON	$ 2.14	$ 2.14	Golder Estimate	75pcf haul density (1 ton/cy)
	Place Cost	1	CY	$ 1.42	$ 1.42	RSMeans 2010 (31 23 23.17-0020)	Dozer, no compaction
	Place Cost	1	TON	$ 1.71	$ 1.71	Golder Estimate	90pcf placed density (1.2 ton/cy)

ASM Unit Rate Details

PROJECT COMPONENT	QTY	UNIT OF MEASURE	UNIT PRICE	TOTAL	Source	NOTES
New Silo			Total	$ 1,568,494	$ 1,568,500	
Miscellaneous Site Work & Materials	10%	%	$ -	$ 142,590		Erosion controls, offices, toilets, temporary roads, survey control, etc.
Silo slab on grade	1	EA	$ 536,796	$ 536,796	2003 Irondale CO Unit less RR & land	Site prep, silo & handling equipment, permit
Starvac reclaimer	1	EA	$ 83,455	$ 83,455	2003 Irondale CO Unit less RR & land	
Truck scale	1	EA	$ 81,474	$ 81,474	2003 Irondale CO Unit less RR & land	Beside the silo on grade
Screw conveyor	1	EA	$ 24,626	$ 24,626	2003 Irondale CO Unit less RR & land	From Starvac reclaimer to bucket elevator
Bucket Elevator	1	EA	$ 88,927	$ 88,927	2003 Irondale CO Unit less RR & land	From screw conveyor to overhead airslide
Air Slide	1	EA	$ 26,906	$ 26,906	2003 Irondale CO Unit less RR & land	From bucket elevator to new weigh hopper
Truck load-out spout	1	EA	$ 45,604	$ 45,604	2003 Irondale CO Unit less RR & land	From new weigh hopper to truck
Building	1	EA	$ 11,401	$ 11,401	2003 Irondale CO Unit less RR & land	With scales and ASM controls
Feed piping & valves	1	EA	$ 329,202	$ 329,202	Golder Estimate	From each of the four fly ash conveying lines
Dust collectors	1	EA	$ 197,512	$ 197,512	Golder Estimate	Higher capacity to handle high air flow from ESP
Cal-Hypo Feed System (Rail Load-out Silo)			Total	$ 245,960	$ 246,000	
Miscellaneous Site Work & Materials	10%	%	$ -	$ 22,360		
Storage & Conveying Building	1,000	SF	$ 50.00	$ 50,000	GRE 2009 Construction Project	$35/sf for large insulated bldg, use $50/sf
Building Foundation	62	CY	$ 300.00	$ 18,600	Worley Parsons Jul09	12' x 40' x 1' thick plus 1' x 5' perimeter
Day Storage Hopper	1	EA	$ 15,000	$ 15,000	Golder Estimate	On the silo weigh bin floor
Conveying System	1	EA	$ 20,000	$ 20,000	Golder Estimate	From stroage building to the day storage hopper
Variable speed conveyor	1	EA	$ 20,000	$ 20,000	Golder Estimate	To feed cal-hypo into the existing weigh hopper
ASM System Controls	1	EA	$ 100,000	$ 100,000	Golder Estimate	
Cal-Hypo Feed System (New Truck Load-out Silo)			Total	$ 328,460	$ 328,500	
Miscellaneous Site Work & Materials	10%	%	$ -	$ 29,860		
Weigh Hopper	1	EA	$ 75,000	$ 75,000	Golder Estimate	Above truck load-out spout
Storage & Conveying Building	1,000	SF	$ 50.00	$ 50,000	GRE 2009 Construction Project	$35/sf for large insulated bldg, use $50/sf for 25'x40
Building Foundation	62	CY	$ 300.00	$ 18,600	Worley Parsons Jul09	25' x 40' x 1' thick plus 1' x 5' perimeter
Day Storage Hopper	1	EA	$ 15,000	$ 15,000	Golder Estimate	On the silo weigh bin floor
Conveying System	1	EA	$ 20,000	$ 20,000	Golder Estimate	From stroage building to the day storage hopper
Variable speed conveyor	1	EA	$ 20,000	$ 20,000	Golder Estimate	To feed cal-hypo into the existing weigh hopper
ASM System Controls	1	EA	$ 100,000	$ 100,000	Golder Estimate	

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Appendix D

Visibility Impact Tables

Summary of Modeling Inputs

Description		Emission Rate Input										
		Stack Velocity	Stack Height	PM10		PM2.5 (fine)	PM (coarse)	SO_2		NOx		
NOx Control	Units	m/s (ft/s)	m (ft)	% reduction	lb/hr	lb/hr	lb/hr	% reduction	lb/hr	% reduction	lb/hr	30-Day Rolling lb/MMBtu
Pre-BART Protocol	1	25.9 (85)	201.0 (659.4)	NA - base	249.2	101.9	147.3	NA - base	5733.5	NA - base	1772.3	NA - base
	1& 2	25.9 (85)	201.0 (659.4)	NA - base	465.3	190.3	275.0	NA - base	10702.8	NA - base	3594.7	NA - base
LNC3+	1	19.5 (64)	208.2 (682.7)	0%	249.2	101.9	147.3	69%	1756.4	31%	1227.6	0.187
	1& 2	19.5 (64)	208.2 (682.7)	0%	465.3	190.3	275.0	67%	3514.8	32%	2456.5	0.187
LNC3+ with Tuning	1	19.5 (64)	208.2 (682.7)	0%	249.2	101.9	147.3	69%	1756.4	38%	1104.4	0.168
	1& 2	19.5 (64)	208.2 (682.7)	0%	465.3	190.3	275.0	67%	3514.8	39%	2210.0	0.168
SNCR	1	19.5 (64)	208.2 (682.7)	0%	249.2	101.9	147.3	69%	1756.4	39%	1082.7	0.165
	1 & 2	19.5 (64)	208.2 (682.7)	0%	465.3	190.3	275.0	67%	3514.8	40%	2166.7	0.165
SNCR with LNC3+	1	19.5 (64)	208.2 (682.7)	0%	249.2	101.9	147.3	69%	1756.4	50%	880.6	0.134
	1& 2	19.5 (64)	208.2 (682.7)	0%	465.3	190.3	275.0	67%	3514.8	51%	1762.2	0.134

Year 2000 Modeling Results

Description		Average Improvement (98th%)	Visibility Impairment											
			TRNP South Unit			TRNP North Unit			TRNP Elkhorn Ranch			Lostwood WA		
NOx Control	Units		Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV	Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV	Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV	Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV
Pre-BART Protocol	1	--	24	0.299	1.229	21	0.318	0.941	18	0.212	0.777	37	0.503	1.183
	1& 2	--	41	0.553	2.176	41	0.586	1.836	35	0.401	1.391	58	0.945	2.157
LNC3+	1	60%	7	0.124	0.495	6	0.117	0.376	2	0.088	0.321	6	0.219	0.445
	1& 2	57%	17	0.243	0.965	17	0.232	0.778	10	0.175	0.632	28	0.427	0.884
LNC3+ with Tuning	1	62%	7	0.117	0.472	6	0.115	0.354	2	0.084	0.311	6	0.207	0.428
	1& 2	59%	17	0.231	0.922	17	0.228	0.743	10	0.167	0.608	26	0.407	0.844
SNCR	1	62%	7	0.116	0.468	6	0.114	0.351	2	0.084	0.308	6	0.204	0.427
	1 & 2	59%	16	0.229	0.914	17	0.227	0.736	10	0.167	0.602	26	0.404	0.837
SNCR with LNC3+	1	65%	7	0.110	0.431	6	0.111	0.315	2	0.076	0.280	4	0.187	0.415
	1& 2	62%	16	0.218	0.842	13	0.220	0.667	10	0.150	0.549	25	0.367	0.810

Year 2001 Modeling Results

Description		Average Improvement (98th%)	Visibility Impairment											
			TRNP South Unit			TRNP North Unit			TRNP Elkhorn Ranch			Lostwood WA		
NOx Control	Units		Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV	Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV	Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV	Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV
Pre-BART Protocol	1	--	21	0.251	1.209	27	0.372	1.154	16	0.192	1.056	40	0.522	2.362
	1& 2	--	34	0.466	2.181	46	0.694	2.094	27	0.365	1.949	56	0.984	4.038
LNC3+	1	58%	7	0.097	0.498	7	0.129	0.470	7	0.076	0.478	18	0.221	0.971
	1& 2	54%	19	0.193	0.974	22	0.255	0.918	15	0.152	0.937	31	0.437	1.855
LNC3+ with Tuning	1	60%	7	0.096	0.477	6	0.126	0.452	5	0.075	0.449	17	0.211	0.943
	1& 2	56%	19	0.191	0.933	21	0.251	0.883	13	0.149	0.880	30	0.418	1.803
SNCR	1	60%	7	0.097	0.473	6	0.126	0.449	5	0.075	0.444	17	0.209	0.938
	1 & 2	56%	19	0.191	0.926	21	0.250	0.877	13	0.149	0.870	30	0.414	1.794
SNCR with LNC3+	1	63%	5	0.090	0.438	6	0.125	0.419	4	0.071	0.395	15	0.193	0.892
	1& 2	59%	18	0.179	0.859	18	0.247	0.822	10	0.142	0.776	30	0.382	1.709

Year 2002 Modeling Results

Description		Average Improvement (98th%)	Visibility Impairment											
			TRNP South Unit			TRNP North Unit			TRNP Elkhorn Ranch			Lostwood WA		
NOx Control	Units		Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV	Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV	Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV	Days Above 0.5 Δ-dV	90th % Δ-dV	98th % Δ-dV
Pre-BART Protocol	1	--	38	0.540	2.559	30	0.385	2.113	23	0.310	1.703	32	0.385	1.814
	1& 2	--	50	0.971	4.475	45	0.706	3.557	42	0.581	3.039	45	0.707	3.190
LNC3+	1	55%	22	0.210	1.096	15	0.147	0.967	13	0.140	0.840	12	0.143	0.806
	1& 2	50%	33	0.422	2.109	24	0.291	1.850	19	0.277	1.609	24	0.284	1.547
LNC3+ with Tuning	1	57%	20	0.202	1.040	14	0.144	0.910	13	0.132	0.795	12	0.139	0.763
	1& 2	53%	32	0.407	2.006	23	0.283	1.745	19	0.261	1.524	24	0.275	1.466
SNCR	1	58%	20	0.201	1.030	14	0.143	0.899	13	0.131	0.787	12	0.138	0.755
	1 & 2	53%	32	0.405	1.987	23	0.283	1.726	19	0.258	1.510	24	0.275	1.452
SNCR with LNC3+	1	62%	20	0.189	0.936	14	0.138	0.804	12	0.117	0.711	12	0.134	0.683
	1& 2	58%	30	0.381	1.814	23	0.269	1.550	18	0.232	1.369	24	0.266	1.319

Average Incremental Control Comparison for 98th % Δ-dV

Description		Year 2000			Year 2001			Year 2002			Year 2000-2002 Average		
NOx Control	Units	Average Impairment	Improvement from Protocol	Incremental Improvement [1]	Average Impairment	Improvement from Protocol	Incremental Improvement [1]	Average Impairment	Improvement from Protocol	Incremental Improvement [1]	Average Impairment	Improvement from Protocol	Incremental Improvement [1]
Pre-BART Protocol	1	1.033	NA	NA	1.445	NA	NA	2.047	NA	NA	1.508	NA	NA
	1& 2	1.890	NA	NA	2.566	NA	NA	3.565	NA	NA	2.674	NA	NA
LNC3+	1	0.409	0.623	0.623	0.604	0.841	0.841	0.927	1.120	1.120	0.647	0.861	0.861
	1& 2	0.815	1.075	1.075	1.171	1.395	1.395	1.779	1.787	1.787	1.255	1.419	1.419
LNC3+ with Tuning	1	0.391	0.641	0.018	0.580	0.865	0.024	0.877	1.170	0.050	0.616	0.892	0.031
	1& 2	0.779	1.111	0.036	1.125	1.441	0.046	1.685	1.880	0.093	1.196	1.477	0.058
SNCR	1	0.389	0.644	0.003	0.576	0.869	0.004	0.868	1.180	0.009	0.611	0.898	0.005
	1 & 2	0.772	1.118	0.007	1.117	1.449	0.008	1.669	1.897	0.017	1.186	1.488	0.011
SNCR with LNC3+	1	0.360	0.672	0.028	0.536	0.909	0.040	0.784	1.264	0.084	0.560	0.948	0.051
	1& 2	0.717	1.173	0.055	1.042	1.524	0.075	1.513	2.052	0.156	1.091	1.583	0.095

[1] Average incremental improvement as compared to the next highest emission rate; not necessarily a reflection of physical control option (e.g. SNCR alone is not a feasible option for Unit 2 because LNC3+ has already been installed. This scenario would require removal of LNC3+ on Unit 2 to be achieved.)

Appendix E

Low-Baseline NOx SNCR Demonstration (EPRI Study)

This appendix contains confidential business information and is being submitted under separate seal.
Copyrighted material is not currently available for public release.

Appendix F

URS SNCR Evaluation Supplement

URS

March 30, 2012

Debra Nelson
Great River Energy
12300 Elm Creek Boulevard
Maple Grove, MN 55369

RE: URS Response to EPA FIP Exchange

Dear Debra:

Great River Energy (GRE) contracted URS Energy & Construction (URS) to conduct a review of the costs and performance capability of Selective Non-Catalytic Reduction (SNCR) at their Coal Creek Station (CCS) Units 1 & 2. This review was requested to provide:

- A site-specific rough order of magnitude estimate with a stated accuracy of ±30% for the 2011 capital cost required for installation of SNCR onto the Coal Creek units
- Site-specific operating and maintenance costs for SNCR operation at Coal Creek
- The level of NOx reduction expected when using SNCR on these units.

Cost Estimating Methodology - The basis for the cost estimates was stated to be the EPRI IECCOST model, which URS previously developed for the Electric Power Research Institute. This model provides site-specific cost estimates for all types of emissions control system installations, including individual systems that are designed to remove SO_2, NOx, Hg, and particulate matter. It also evaluates costs for multi-pollutant control systems, producing conceptual cost estimates that are site-specific based on the plant location, current operating characteristics, fuels burned, etc.

EPRI IECCOST Model development has continued for more than ten years; during that period URS has installed all of the commercial systems at utility installations, and become intimately familiar with all emissions control technologies. Consequently URS is very familiar with the relationship between the vendor island costs and the Total Capital Requirement for an emissions control retrofit. This extensive project experience also identified the performance capabilities and emission rate guarantees for the various technologies through review of bid documents and budgetary quote submittals under real world conditions.

The model is updated and escalated continuously as new projects are completed, calibrating the cost estimating results against actual project costs and performance. The economic model used for these calculations is IECCOST Version 3.1 that will be published by EPRI later in 2012.

URS Capabilities and Qualifications - URS is an engineering and construction company that has provided emissions control technology assessments, economic analyses, balance of plant designs, construction, construction management and startup assistance to utility and other industrial clients since the 1970's. During this period, URS participated in more than 30 SNCR projects at multiple sites using systems supplied by multiple vendors.

Total Capital Requirement Cost Estimates - URS is not a technology supplier. The supplier is typically responsible for installation of only their process island and system performance guarantees. The installation of the balance of plant (BOP) equipment, construction management, foundations, utility tie-ins (electrical, water, air, instrumentation and controls interface,

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interconnecting piping, new flue gas emissions monitoring equipment, boiler and air heater modifications, retrofit difficulty due to existing plant access and congestion issues, et al) typically falls outside of the scope of supply for the SNCR vendor. Published cost estimates and vendor proposals in many cases do not consider these BOP cost impacts on the Total Capital Requirement for the installation of emissions control equipment. URS's project experience provides a basis for the assessment of these BOP costs that must be added to the vendor supplied equipment's installed costs to determine the true total capital cost of an installation.

Retrofit Factor - A site visit was made to the Coal Creek plant by one of the URS air quality control engineering staff. Based on his assessment of the site and the location for installation of the SNCR equipment, the retrofit difficulty for this plant was established to be moderately difficult due the constraints provided by existing equipment at the plant. Based on previous industry assessments of the cost impacts of retrofit difficulty, a retrofit factor of 1.6 was established for this moderately difficult SNCR installation. Previous industry surveys by Radian and Kellogg (EPA-450/3-74-015 – "Factors Affecting Ability to Retrofit FGD Systems" & EPA R2-72-100 – "Applicability of SO_2-Control Processes to Power Plants" and the EPA/600/S7-90/008 – "Verification of Simplified Procedure for Site-Specific SO_2 and NOx Control Cost Estimates") attempted to quantify the retrofit cost impacts compared to new equipment installations. These surveys established retrofit factors based on retrofit difficulty that are multiplied times the new plant installed cost estimates to determine the retrofit installed cost. The site assessment by the URS staff resulted in the moderately difficult retrofit assessment, which was translated in the capital cost estimate as a 60% adder to the new equipment installation cost to account for decreasing productivity due to movement of parts and materials around existing equipment and structures, limited access to construction sites due to overhead, underground and side obstructions by existing equipment, crane access, etc.

SNCR Expected Performance – SNCR system performance is directly impacted by the flue gas temperature at the point of urea/ammonia injection, and by the current concentration of NOx in the outlet flue gas. Injection outside the correct temperature window results in significant reductions in reduction efficiency. The lower the current NOx concentration in the outlet flue gas, the lower the reduction efficiency that can be achieved (reduced driving force for the NOx reduction reactions). The performance claims in published articles are typically short term, optimized test results, and are typically inflated compared to the performance guarantees that are actually offered for actual installations. Given the relatively low NOx concentrations in the Coal Creek flue gas, the reduction capabilities of SNCR were set at values in the 20-30% range based on data from other recent projects. The urea feed rate used in the calculation of operating costs

For comparison, recent FuelTech papers (one of the major SNCR vendors) stated that larger utility boilers (such as exist at Coal Creek at 605MW) have reported lower performance mainly due to the size of the units, inaccessible areas for injection, and load following control issues. NOx reductions in the range of 20 – 30% are common for units that start with NOx emission rates of 0.15-0.25 lbs NOx/MMBtu. Urea injection rates to obtain these reduction efficiencies varied from site to site, but fell in the range of 1.1-1.5 normalized stoichiometric ratio while maintaining acceptable ammonia slip rates. All-in costs for these systems were stated to be in the range of $10-20/kW. The injection rates assumed for this URS analysis of SNCR for Coal Creek used NSR injection rates that varied from 1.3-1.5 over the range of control evaluated of 20-30% NOx reduction. All of these performance values and estimated capital costs fall in the ranges stated in the supplier papers.

If you have any additional questions, please contact me.

Sincerely,

Robert J. Keeth
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Appendix G

Golder Fly Ash Evaluation Supplement

April 2, 2012 Project No. 113-82161

Diane Stockdill
Great River Energy
Coal Creek Station
2875 Third Street SW
Underwood, North Dakota 58576

RE: SNCR IMPACT TO FLY ASH MARKETABILITY AND MANAGEMENT COSTS

Dear Diane:

1.0 BACKGROUND

Golder Associates Inc. (Golder) submitted a report to Great River Energy (GRE) on November 15, 2011, providing a third party review of Headwater's ammonia slip mitigation (ASM) technology. Additionally, the review included a detailed engineering estimate of potential disposal costs associated with fly ash impacted by ammonia slip from selective non-catalytic reduction (SNCR) emission controls at GRE's Coal Creek Station (CCS).

This report was included as part of GRE's submittal of November 21, 2011 to the U.S. EPA Region 8 (EPA), with comments responding to the Proposed Rule for the Approval and Promulgation of Implementation Plans: North Dakota Regional Haze State Implementation Plan, Federal Implementation Plan for Interstate Transport of Pollution Affecting Visibility and Regional Haze (Docket ID No. EPA-R08-OAR-2010-0406).

The EPA provided a prepublication version of the "final rule" to GRE on March 2, 2012, which included EPA's response to various comments including those in GRE's November 21, 2011 submittal:

- Section V: Issues Raised by Commenters and EPA's Responses;
- Part E: Comments on BART Determination;
- Subpart 2: CCS Units 1 and 2;
- Item d: CCS Coal Ash had several comments; and
- EPA responses addressing the potential for SNCR to impact fly ash sales and the cost of this impact.

Below are Golder's responses to the EPA's comments on our November 15, 2011 report concerning the potential impact of SNCR controls to fly ash marketability at CCS and the potential cost impact if fly ash requires ASM technology and is less marketable and therefore, placed in greater quantities into disposal facilities.

2.0 SNCR IMPACT TO FLY ASH MARKETABILITY

The potential impact to fly ash marketability is a function of the SNCR ammonia slip adsorption onto the fly ash particles, and the acceptable (allowable) ammonia levels in fly ash by the fly ash end users.

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2.1 Ammonia Adsorption onto Fly Ash

Based on available literature, the adsorption of ammonia onto fly ash from SNCR emission controls is highly variable and dependent upon factors such as SNCR operation, fuel type/fuel mix, boiler configuration, ash content, ash mineralogy, ash alkalinity, ash sulfur content, and temperature. Limited published data are available for ammonia levels in fly ash for coal-fired power plants utilizing SNCR emissions controls, with no published information being found for energy generation facilities burning lignite coal.

In a 2007 EPRI study on the handling, disposal, and sale of ammoniated fly ash (EPRI 2007), responses from eight units utilizing SNCRs were discussed. All the units fired a PRB/eastern bituminous coal blend, were predominantly smaller units, were predominantly wall-fired, and had actual ammonia slip up to 5 parts per million (ppm). Only four units had tested levels of ammonia in the fly ash, with the measured levels ranging from less than 100 ppm to over 200 ppm. Several references attempt to relate the amount of ammonia slip to the ammonia levels in fly ash and suggest that a 2 ppm ammonia slip may result in fly ash ammonia levels from less than 50 ppm to several hundred ppm (Murarka 2003, Bittner 2001, Hinton 2012, Larrimore 2002). In addition, when explaining ash sales impacts at CCS, Sahu (2011) references a figure created by Larrimore (2002) that indicates ammonia slip levels above 2 ppm can lead to “restricted use” of fly ash and ammonia slip levels above 4 ppm may lead to “unmarketable” fly ash for use in ready mix.

2.2 Allowable Ammonia Present In Fly Ash

The amount of “allowable” ammonia present in fly ash destined for beneficial use varies depending on ash marketer preferences and the ultimate end use. Higher concentrations of ammonia present in fly ash are a result of ammonia slip in SCR or SNCR systems (EPRI 2007). Fly ash impacted with elevated levels of ammonia results in ammonia being released into the air when water is added. At low levels, ammonia is a nuisance; however, at higher exposure levels, ammonia can cause irritation of the eyes, throat, and nose as well as difficulty breathing (NIOSH 2011). Strength characteristics do not appear to be affected by the presence of ammonia in fly ash (Rathbone and Robl 2001).

Elevated concentrations of ammonia in fly ash contribute to releases into the environment during placement (with the presence of water), and a reluctance of fly ash marketers and users (i.e. Headwaters Resources, Lafarge, etc.) to buy fly ash for sales to the construction industry. EPRI (2007) explains that the “…industry rule-of-thumb indicates that ammonia contamination on fly ash that is destined for concrete/cement utilization must have less than 100 ppm ammonia to be useable.” Headwaters indicated (January 11, 2010) that they “…quit shipping anything over 100 ppm…” in reference to the Eastlake facility, which has had an SNCR system since 2007. Eastlake has attempted to decrease ammonia content in the fly ash to less than 50 ppm using ASM to improve fly ash marketability. Lafarge (January 26, 2010) has found “…when the ammonia levels exceed 40 part per million in the fly ash that the consumer notices the ammonia and finds it to be objectionable.” Additional references have generally found that approximately 100 ppm is the maximum “acceptable” ammonia level in fly ash (Bittner et al. 2001, Giampi 2000, Bittner and Gasiorowski 2005). Other sources cite 100 ppm as an acceptable allowable ammonia level in fly ash for enclosed spaces, but allow a higher limit of 200 ppm in well ventilated areas (Brendel et al. 2000, Larrimore 2002).

The amount of ammonia in fly ash can be related to the ammonia off-gassed during placement. Both NIOSH and OSHA have health-based exposure limits for ammonia in the air. NIOSH has a recommended exposure limit (REL) of 25 ppm and OSHA’s permissible exposure limit (PEL) is 50 ppm. A “comfortable” threshold of 10 ppm ammonia is referenced by Rathbone and Robl (2001). Rathbone and Robl (2001) evaluated the relationship between ammonia in fly ash and the corresponding amount in air using laboratory and field-scale test methods:

$$NH_{3\,ash} = \frac{(NH_{3\,water})(Water-to-Cement\ ratio)}{(Fly\ Ash\ Content)}$$

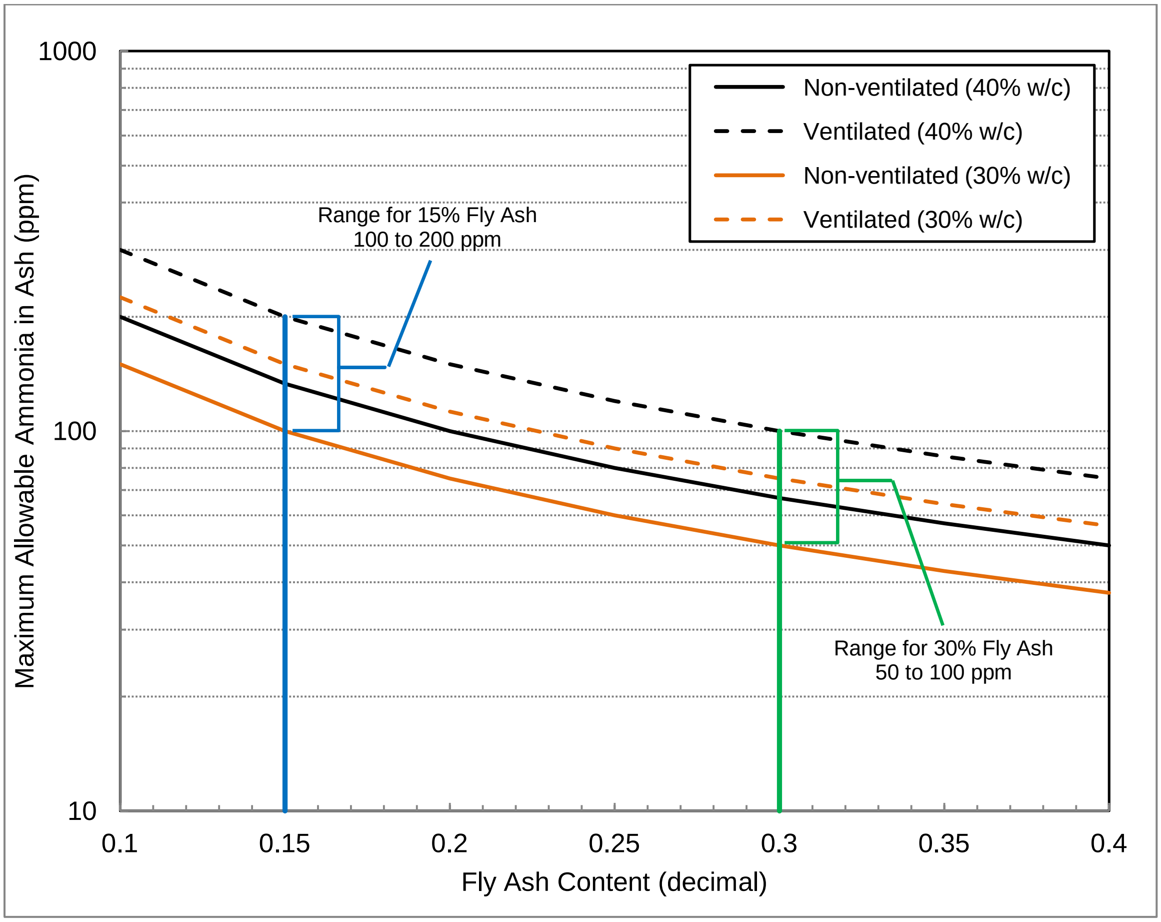
The lab and field scale testing found allowable ammonia levels in the concrete water prior to setting (for 10 ppm in the air), to be approximately 50 mg/l for non-ventilated spaces and 75 mg/l for well ventilated spaces.

Fly ash from CCS is a desirable high quality material and has been used extensively in North Dakota, Minnesota, Colorado, and as far as California. In a review of fly ash uses in North Dakota, the Energy & Environmental Research Center (EERC) stated:

> "NDDOT uses fly ash in almost all concrete projects at a replacement rate of 30%. A replacement rate between 15% and 30% is specified by most state DOTs (if they specify fly ash use at all), making NDDOT's specification on the higher end compared to other states. For mass pours, a replacement rate of 40% is allowed and is more typical." (EERC 2011)

Based on these uses of CCS fly ash, the above relationship was used to evaluate the maximum allowable ammonia content in fly ash for 15% and 30% fly ash mixtures, for water cement ratios between 30% and 40%, and for well-ventilated and non-ventilated areas. Results of the calculations are shown in the following table and the figure below.

Condition	**Ammonia in Air***	**Water/Cement Ratio**	**Allowable Ammonia Content in Fly Ash (15% fly ash mixture)**	**Allowable Ammonia Content in Fly Ash (30% fly ash mixture)**
	ppm	**-**	**ppm**	**ppm**
Ventilated	10	0.4	200	100
Non-Ventilated	10	0.4	133	67
Ventilated	10	0.3	150	75
Non-Ventilated	10	0.3	100	50
*Practical limit based on experience (Rathbone and Robl 2001)				



2.3 Marketability Conclusions

When ammoniated fly ash is used in concrete, the ammonia can be released into the air during placement and may cause irritation to individuals placing the concrete. The amount of ammonia released into the air is a function of fly ash content, the water/cement ratio of the concrete batch, and the ammonia concentration in the ash. Generally, industry experience indicates that fly ash used for concrete should have less than 100 ppm ammonia to prevent handling issues from limiting the marketability of the ash. Based on the use of CCS fly ash as a high percentage cement replacement (30%), a calculated allowable ammonia level in the fly ash may range between 50 ppm and 100 ppm. When discussing ash sales impacts at CCS, Sahu (2011) cites Larrimore (2002) in concluding that 2 ppm ammonia slip can result in 100 ppm ammonia in ash. According to Larrimore (2002), 4 ppm ammonia slip can result in 200 ppm ammonia in ash, a potentially unmarketable level of ammonia for use in ready mix. Because the ash marketer and ready mix user may not know the exact use of fly ash when it is purchased and placed in a silo, the practical limit for CCS fly ash is 50 ppm or less to allow its use in a wide variety of applications. This limit is also supported by the anecdotal comments from both Headwaters and Lafarge.

Definitive information is not available for the levels of ammonia that could be present in the fly ash at CCS due to SNCR ammonia slip. However, review of available literature indicates a reasonably high probability that ammonia concentrations would be in the range that is problematic for marketers and end users of CCS fly ash. Therefore, it is prudent for engineering costs evaluations to assume ammonia levels in CCS fly ash will be higher than the acceptable ammonia levels for CCS fly ash destined for beneficial use, and therefore to assume that CCS fly ash will be disposed or will require treatment with ASM technology to be sold for beneficial use.

3.0 SNCR COST IMPACT TO FLY ASH MANAGEMENT

Golder previously provided a detailed engineering cost estimate for the potential impact to fly ash management as a result of SNCR emissions controls at CCS. Based on the EPA responses, supporting information and clarifications are provided below.

3.1 Fly Ash Disposal Facility Design Basis

The previous evaluation indicated that each cost estimate was prepared assuming that fly ash will be disposed of in a new landfill with a design based on RCRA Subtitle D practices. This may have been taken as a speculative/highly conservative estimate based on impending coal combustion residue (CCR) regulations being developed by the EPA (see EPA response to comment on page 111 of rule prepublication).

In actuality, the assumed design is based on current North Dakota Department of Health (NDDH) regulations (NDDH, http://www.legis.nd.gov/information/acdata/html/33-20.html), which are in-line with RCRA Subtitle D practices. In the early 1990s the NDDH revised its Solid Waste Management and Land Protection rules adopting environmentally sound controls such as composite liners, leachate collection systems, surface water controls, and ground water monitoring.

3.2 Fly Ash Disposal Unit Cost Estimate

Disposal costs of $11 to $18 per ton were estimated based on site-specific designs for the disposal of fly ash at CCS. These disposal costs were based on a detailed engineering cost estimate for CCS including costs from landfill development to post-closure care. In the EPA's responses (page 110), they indicated "we find a disposal cost of $5/ton is reasonable in the improbable event that some ash would need to be disposed."

The cost estimate of $5/ton deemed reasonable by the EPA is not supported by an engineering cost estimate, is not supported by industry information, and is not supported by recent work published by the EPA.

In 2010, the EPA estimated baseline (i.e. current) CCP disposal costs in their Regulatory Impact Analysis for EPA's Proposed RCRA Regulation of Coal Combustion Residues (CCR) Generated by the Electric Utility Industry (EPA 2010). In Chapter 3 of that report, the EPA provided a cost estimate for the management of CCRs and estimated a range of $2/ton to $80/ton with an average of $59/ton. In discussion of these results, the report indicates that $2/ton is reflective of unlined, near-plant impoundments in states with low regulatory requirements, and the high end of $80/ton is reflective of off-site commercial disposal in landfills. Fly ash disposal facilities at CCS are clay- or composite-lined, engineered impoundments and landfills located at varying distances from the plant. North Dakota has comprehensive regulatory requirements in place for ash disposal facilities.

The EPA report further references information from the American Coal Ash Association (ACAA) to validate its cost estimate. The ACAA routinely collects ash disposal and beneficial use information from its members and has developed estimates for the disposal of CCPs. From the ACAA website and referenced in the EPA report:

> "As one can see, a variety of factors enter into determining disposal costs. The lowest cost occurs when a disposal site is located near the power plant and the material being disposed can be easily handled. If the material can be piped, rather than trucked, costs are usually lower. In these types of situations, cost may be as low as $3.00 to $5.00 per ton. In other areas, when distance is far away and the material must be handled several times due to its moisture content or volume, costs could range from $20.00 to $40.00 a ton. In some areas, the costs are even higher. If new sites are required and extensive permitting processes take place, the total cost of the facility may be increased, resulting in higher disposal costs over time." (ACAA, http://acaa.affiniscape.com/displaycommon.cfm?an=1&subarticlenbr=5#Q13)

The disposal of fly ash at CCS does not fall at either cost extreme (unlined impoundment or off-site commercial disposal), and the engineering estimate of $11 to $18 per ton appears well within the EPA's cost estimate and industry practice.

3.3 Lost Fly Ash Sales Revenue

Part of the cost impact to fly ash management is the loss of fly ash sales revenue currently being generated. Based on information from GRE, the 2010 average fly ash sales price per ton was $41.00 with 30% of the sales price going to GRE ($12.30/ton) as revenue and 70% of the sales price going to the fly ash marketer Headwaters ($28.70/ton).

EPA commented that GRE should use $5/ton rather than the updated value of $12.30/ton, and suggested that the lost revenue price included lost revenue to other parties. Based on follow-up discussions with GRE, it was confirmed that the $41/ton is the 2010 average FOB Coal Creek Station sales price and the $12.30/ton portion attributed to GRE does not include lost revenue to other parties. Based on this confirmation, the $12.30/ton rather than the $5/ton is more appropriate for the conditions at Coal Creek Station.

3.4 Cost Impact Conclusions

The fly ash disposal cost estimate is based on an engineering design reflective of the practice in North Dakota, and Golder's engineering estimate of $11 to $18 per ton for fly ash disposal appears to be well within the EPA's cost estimate and consistent with industry practice. Further, the lost fly ash sales revenue of $12.30/ton reported in the cost impact evaluation is reflective of current conditions at CCS.

The disposal and lost revenue cost estimates are valid, and based on the uncertainty with respect to ammonia levels in fly ash, the previous evaluation with respect to fly ash management cost is reasonable.

GOLDER ASSOCIATES INC.

Ron R. Jorgenson
Principal

Todd Stong, P.E.
Senior Engineer

TJS/RRJ/kcs

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Great River Energy's
Legal and Technical Review Of
U.S. EPA's BART Determination for Coal Creek Station

I. INTRODUCTION

On March 2, 2012, EPA issued its *Approval and Promulgation of Implementation Plans; North Dakota; Regional Haze State Implementation Plan; Federal Implementation Plan for Interstate Transport of Pollution Affecting Visibility and Regional Haze*, 76 Fed. Reg. ____(April __, 2012) ("FIP"). EPA largely upheld the North Dakota Department of Health's ("NDDH's") SIP with two exceptions: the NOx Best Available Retrofit Technology ("BART") requirement for Great River Energy's Coal Creek Station ("CCS"), and Reasonable Progress requirements for Basin Electric's Antelope Valley Station. Below, GRE addresses EPA's FIP and its rationale for requiring selective non-catalytic reduction ("SNCR") at CCS. In particular, GRE explains that EPA failed to rationally apply the Clean Air Act's ("CAA's") five-factor BART analysis and GRE responds to key EPA arguments for rejecting NDDH's BART determination.

In rejecting NDDH's BART determination for CCS, EPA made numerous errors, including the following:

- Conducted an improper cost analysis by ignoring the existing controls in use at CCS, including LNC3+ and DryFining™;
- Failed to analyze, or ignored, the incremental cost of SNCR compared to existing and planned controls at CCS, including LNC3+ and DryFining;
- Ignored the demonstrated lack of visibility benefits resulting from its requirement to install SNCR at CCS; and
- Rejected, without validated support, the likelihood of ammonia slip and fly ash contamination.

Beyond these errors, EPA purported to reject NDDH's BART determination for CCS because NDDH relied on cost analyses that contained an error in one component of the costs – the cost of ash contamination and disposal. While objecting to this one component, EPA rejected NDDH's entire BART analysis and NDDH's valuation of the other four, equally important, factors in the BART determination.

The foregoing errors, as well as EPA's failure to give any credence to the values that NDDH's placed on the other BART factors, demonstrate that EPA did not conduct a valid BART analysis for CCS. EPA failed to comply with the CAA requirements and the Agency's own guidelines.

II. EPA's "COST OF CONTROLS" ANALYSIS IS INCONSISTENT WITH THE STATUTE AND EPA'S OWN GUIDANCE

EPA's principal basis for rejecting NDDH's BART determination was NDDH's reliance on purportedly incorrect information regarding the cost associated with ammonia contamination of merchantable fly ash resulting from using SNCR. GRE has addressed the cost issue that EPA raised and has reflected those changes in GRE's Supplemental Best Available Retrofit Technology Refined Analysis for NOx Emissions, April 5, 2012 ("BART Supplement"). EPA asserts, incorrectly, that there should be no ammonia slip or fly ash contamination from using SNCR.[1] However, EPA's own cost analysis is seriously flawed and inconsistent with both the CAA and its own Guidance. EPA made two significant errors in conducting its cost analysis of SNCR. First, it ignored the emission controls already installed and in use that have significantly reduced NOx emissions at CCS. Second, EPA failed to examine the incremental, or marginal, costs of SNCR beyond the existing and planned controls at CCS.

A. EPA Failed to Consider Existing Pollution Controls in Use at CCS and Current Emissions in Performing Its Cost Analysis

Under CAA §169A, the State (or EPA Administrator) must take into consideration five factors in determining BART. One of the five factors is "any existing pollution control technology in use at the source." 42 U.S.C. § 7491(g)(2). EPA completely disregarded this obligation and, instead, relied on 9-year-old emissions data in its cost analysis. The effect of using the inaccurate, inflated emissions data is to distort EPA's cost numbers and make SNCR seem more cost-effective than it is.

EPA relied on emissions data from 2003 and 2004 in its cost analysis. EPA did this notwithstanding its acknowledgement that current emissions are significantly lower. *See* FIP at 20. Since 2004, GRE has made multiple improvements in the combustion and emissions at CCS, including: (1) installing new, adjustable SOFA nozzles in Unit 1 in 2005; (2) installing expanded over-fire air registers in Unit 2 in 2007; (3) installing close coupled over-fire air (CCOFA) on Unit 2 in 2010; and (4) installing DryFining at both units in 2010. All of these measures had beneficial impacts on NOx formation and emissions, reducing emission rates at Unit 2 from 0.22 lbs/mmBtu in 2004 to 0.153 currently. For Unit 1, emissions were reduced from 0.22 in 2004 to 0.20 lbs/mmBtu in 2010.

EPA's failure to acknowledge these installed controls is inconsistent with the plain language of the statute and EPA's own BART guidance. "[B]aseline emissions rate should represent a realistic depiction of anticipated annual emissions for the source." *See* 69 Fed. Reg. 25224. EPA's reliance on 2003 - 2004 emissions from CCS is not a "realistic depiction" of CCS's current or anticipated emissions. By using incorrect emissions data, EPA created and relied on admittedly inaccurate cost effectiveness numbers, the very grounds on which it rejected NDDH's BART determination.

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[1] EPA's assertion is addressed below in Section IV, and by Golder Associates in Exhibit G to the BART Supplement.

EPA's explanation for using inaccurate emission data is both irrational and inapposite to CCS. EPA argues that using emissions resulting from existing emission controls (as required by the statute) would "reward sources that install lesser controls in advance of a BART determination in an effort to avoid more stringent controls." FIP at 95. Whatever EPA's policy considerations, GRE did not install such controls to "game" the BART process. The DryFining technology involved a multi-year, $270 million investment in partnership with the Department of Energy to improve the emissions resulting from coal combustion. The installation of new SOFA nozzles and LNC3+ was done as part of DryFining and in cooperation with the NDDH to achieve better combustion and lower NOx emissions. There is nothing in the record to suggest any of this was done to avoid more stringent BART. It was not.

EPA's statement that these controls were "voluntary" and, thus, EPA need not consider them in evaluating BART is nonsensical. There is nothing in the statute that says voluntarily installed emission controls can or should be ignored. The statute says that EPA must take into consideration "*existing pollution control technology in use at the source*." EPA cannot simply assume emissions that do not exist to bolster its goal of making SNCR appear more cost effective than it is. Further, this is a policy decision beyond EPA's authority. Congress expressly requires EPA to consider existing controls when determining BART. *See* 42 U.S.C. § 7491(g)(2); *St. Mary's Hosp. of Rochester, Minnesota v. Leavitt*, 535 F.3d 802, 806 (8th Cir. 2008) ("The plain meaning of a statute controls, if there is one, regardless of an agency's interpretation."). Although that may result in companies having to do less under BART, that may be precisely what Congress intended. Encouraging sources to install controls voluntarily – as CCS did – results in achieving emission reductions and visibility improvements earlier than might otherwise be required. EPA's policy would discourage companies from ever voluntarily reducing emissions; in other words, EPA is pursuing the "no good deed goes unpunished" theme of regulation.[2]

Finally, EPA acknowledges that it refused to use accurate, current emission rates from CCS because using the lower emission levels would "skew the 5-factor BART analysis by reducing the emissions reductions from combinations of control options and increasing the cost effectiveness values." FIP at 98. This admission lays bare the inaccuracy of the Agency's cost effectiveness assertions and the inappropriateness of EPA's BART determination for CCS.

B. EPA Failed to Properly Calculate and Consider the Incremental Cost of SNCR in Making Its BART Determination

EPA also failed to consider the incremental cost of SNCR in contravention of its own regulations and guidance. EPA guidelines direct the states as follows. "In addition to the average cost effectiveness of a control option, you *should* also calculate incremental cost effectiveness. You *should* consider the incremental cost effectiveness in combination with the total cost effectiveness in order to justify elimination of a control option. *See* 69 Fed. Reg. 25224 (emphases added); 70 Fed. Reg. 39127 ("We *continue* to believe that *both* average and

[2] By EPA's logic, GRE should have done nothing over the past nine years while waiting for a BART determination. This would have postponed any NOx reductions from approximately 2005 until 2018 (five years after BART is determined).

incremental costs provide information useful for making control determinations.") (emphases added).

To justify SNCR, EPA inexplicably ignored half of its own "cost of controls" analysis. Instead, EPA looked only at the total cost of installing both LNC3+ *and* SNCR (as opposed to SNCR alone) and compared that total cost to the emission reductions achieved using both technologies. As discussed above, the emission reductions from LNC3+ (in addition to the DryFining) already have been achieved at Unit 2 and the LNC3+ is planned for Unit 1. The cost of LNC3+ is a small fraction of the costs of SNCR, yet it generates most of the NOx emission reductions. By combining the two costs into one control option, EPA further distorts the cost-effectiveness of SNCR. If EPA had looked at the cost-effectiveness of SNCR alone (i.e., incremental cost), it would have to admit that the emission rate would decline by only 0.023 lbs/mmBtu: from 0.153 lbs/mmBtu to EPA's proposed rate of 0.13 lbs/mmBtu.

The impact of EPA's error is dramatic. Even if we accepted EPA's unfounded assumption that there would be no fly ash contamination resulting from SNCR, the incremental cost of using SNCR would be $8,534 per ton for Unit 1 and $4,688 per ton for Unit 2. EPA's estimate that the cost effectiveness is under $2,500 per ton is misleading because the cost-efficient reductions come from the use of LNC3+, a technology already installed at Unit 2 and planned for Unit 1.[3] *See* BART Supplement, Table 3.1. SNCR cannot be justified on the basis of achieving such a small incremental reduction in NOx emissions at such high costs, particularly in light of the other factors that weigh against SNCR.

III. EPA Failed to Properly Consider the Lack of Visibility Benefits Resulting From the Installation of SNCR

The flaws in EPA's BART analysis were not limited to only cost-related considerations. EPA also failed to give serious consideration to other statutory factors that Congress required to be part of any BART analysis, especially the lack of any demonstrable visibility benefit resulting from SNCR. The modeling on which both NDDH and EPA relied demonstrates that there would be no discernable visibility improvement resulting from installation of SNCR. *See* 76 Fed. Reg. 58,622. The degree of predicted visibility improvement, approximately 0.105 deciviews, is only one tenth of the level that EPA asserts is perceivable by the human eye. Given the many sources of variability of inputs to CALPUFF's visibility analysis versus actual impacts, a difference of 0.1 deciviews between options may reflect no real difference at all. *See* attached Memorandum from Andrew Skoglund, Barr Engineering, to William Bumpers (April 4, 2012).

EPA made no effort in its final rule to dispute that there will be no real improvement in visibility resulting from SNCR. Instead, EPA surprisingly states that "perceptibility of visibility improvement is not a test for the suitability of BART controls." FIP at 112. While EPA later acknowledges that deciview improvements is one of the five factors, it then says that the "Guidelines provide flexibility in determining the weight and significance to be assigned to each factor" and that achieving a perceptible benefit of 0.5 deciview is not a prerequisite for selecting

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[3] The significantly higher incremental costs associated with Unit 1 are due to lower utilization and associated emissions at Unit 1 compared to Unit 2.

BART. FIP at 112. While Congress made clear that the state has great discretion in deciding the weight to accord each factor, EPA has effectively eliminated any import associated with the one factor (visibility) that is the central focus of the regional haze rule. EPA is simply imposing controls and costs on CCS notwithstanding that EPA cannot predict with any confidence that there will be any visibility improvement. This is contrary to the entire objective of the statute.

EPA's only attempt to justify ignoring the lack of visibility benefits resulting from its proposed BART was to note that NDDH was satisfied with a similarly small improvement at another source. *See* 76 Fed. Reg. 58,623. But this explanation completely ignores NDDH's source-specific determination for CCS that an estimated 0.1 deciview improvement did not justify the large costs of SNCR. *See* 76 Fed. Reg. 58,624. EPA's attempt to cherry pick the visibility level from a separate BART analysis ignores NDDH's valuation of all of the other four factors, including a much lower cost, that affected the determination.

Even the theoretical improvement of 0.105 deciviews is likely exaggerated. EPA criticizes the modeling that GRE provided because the various control scenarios were modeled together; that is, the NOx control options were modeled along with the SO_2 reductions. But EPA has repeatedly recognized that its modeling requirements overstate real-world visibility improvements by five to seven times. *See, e.g.,* EPA North Dakota Proposed FIP, Technical Support Document, B-41; FIP at 55. EPA's justification is that modeling based on "current degraded visibility conditions would result in a smaller relative benefit than would a comparison relative to natural background visibility." FIP at 55.[4] Importantly, EPA admits that it undertook no independent modeling of the prescribed emission reductions, so EPA cannot state that SNCR will result in *any* visibility improvement, FIP at 99.

IV. EPA's Conclusion that SNCR Will Result In No Fly Ash Contamination Is Unrealistic

The principal basis EPA cites for rejecting NDDH's BART determination is that NDDH had relied on costs provided by GRE for installation of SNCR that included one incorrect value – the cost of disposing of contaminated fly ash.[5] *See* 76 Fed. Reg. 58,603-04. GRE has corrected that value.[6] As discussed above, even if we assumed that there would be zero contamination of the fly ash, the marginal cost of SNCR ($4,688 per ton for Unit 2 and $8,534 per ton for Unit 1) coupled with the lack of any visibility benefit cannot justify SNCR. But EPA's assertion in the FIP that there will be no wastage of fly ash is not supportable. Exhibit G to the BART Supplement is a report from Golder Associates, addressing EPA's assertion that SNCR would not result in any fly ash contamination and reaffirming the expected costs of fly ash disposal. As demonstrated by Golder Associates and below (1) EPA's assertion that CCS could maintain ammonia slip to below 2 ppm is unsupported and almost certainly wrong; and (2) even at 2 ppm

[4] Put differently, EPA does not allow modeling of what is expected to actually happen because that would confirm EPA's approach results in little or no real-world visibility improvements.
[5] GRE had initially included FOB price of ash. The value was not in error, but GRE agreed that the FOB price was not the correct value for the BART cost analysis.
[6] Golder Associates concludes that a cost of $12.30 per ton is the expected cost of lost fly ash sales resulting from ammonia contamination. BART Supplement, Exhibit G at 6.

ammonia slip, a significant amount of CCS's fly ash would become unmerchantable and require disposal.

In EPA's proposed BART determination, EPA recognized that using SNCR could, and likely would, result in some contamination of GRE's merchantable fly ash at CCS. *See* 76 Fed. Reg. 58,620-21. Consequently, EPA assigned costs to SNCR associated with the lost sales and increased disposal costs associated with the contaminated fly ash. *Id*. In the final FIP, EPA asserts that SNCR at CCS would not contaminate any fly ash because "current technology has made it possible to control ammonia slip from SNCR to levels . . . in a range of 2 ppm or less." *See* FIP at 102. In making this remarkable assertion, EPA relies essentially on a single case study – the "Andover Report." *See* FIP at 102 n.32. The Andover Report provides virtually no support for EPA's claims.

The Andover Report's results cannot be relied on to make any operating assumptions about CCS. It states upfront that "[e]xperience with the TDLAS method on coal power plants has had mixed success – and unfortunately, *far more failures than successes*." Andover Report at page 5 (emphasis added). In the course of examining this technology further, the Andover Report analyzes the use of SNCR at the CP Crane station in Baltimore. The CP Crane station consists of two, 200MW cyclone boilers. It is subject to the Maryland Healthy Air Act, a law that imposes a company-wide, NOx tonnage limitation on power plant owners. CP Crane is one of multiple plants owned and operated by Constellation Energy in Maryland. Constellation installed NOx controls on all of its plants in Maryland, installing SCR on its larger, base load plants, and installing SNCR on CP Crane. GRE contacted Constellation about EPA's assertions. Constellation officials informed GRE that the plant conducted four, one-hour performance tests when commissioning the system,[7] on which the Andover Report is based. Since this commissioning test, Constellation has rarely run the SNCR at CP Crane. Constellation's plant is not subject to a short term NOx rate limit, is not subject to an ammonia slip limit and Constellation does not monitor the ammonia slip. The SNCR system has process monitors but they are not certified. The initial NOx rate at these cyclone burners is approximately 0.4 lbs/mmBtu. Because there is no enforceable NOx rate, the level of ammonia injection is completely discretionary. Constellation does not know what its actual ammonia slip rate is, or would be if the SNCR were actually being utilized. Thus, Mr. Staudt's paper, which is based on the initial, short-term, commissioning test, in no way represents a reasoned basis for EPA's assertions that ammonia slip can be held consistently below 2 ppm or that there will be no fly ash loss as a result of installing SNCR at CCS.[8]

In response to EPA's FIP, Golder Associates ("Golder") has re-examined the literature on the impact of ammonia on fly ash, including the studies referenced by Dr. Sahu in the FIP. *See* FIP at 102 n.35. Golder demonstrates that there is no literature that supports EPA's contention that no fly ash wastage is expected. To the contrary, even if ammonia slip could be limited to 2 ppm on a constant basis – something that has never been demonstrated – ammonia

[7] This short-term commissioning test is hardly an indication of what can be achieved at a much larger facility over a longer term and a wider range of operating levels.
[8] EPA's reference to the Big Brown plant in Texas is similarly unpersuasive. According to EIA data and Luminant, Big Brown landfills approximately one third of its fly ash.

concentration in fly ash could be as high as 100 ppm, which Golder concludes would significantly limit the sale of CCS's fly ash. BART Supplement, Exhibit G at 3-4.

Golder also addresses EPA's criticism of the costs assigned for disposing of contaminated fly ash. BART Supplement, Exhibit G at 5-6. Golder points out that its costs are based on NDDH Solid Waste Management and Land Protection regulations (NDDH, http://www.legis.nd.gov/information/acdata/html/33-20.html). NDDH's rules require controls such as composite liners, leachate collection systems, surface water controls, and ground water monitoring. As a result, Golder estimates the cost of fly ash disposal to be between $11 and $18 per ton. Golder also demonstrates that EPA's estimate of $5 per ton is not supported by any analysis and is inconsistent with EPA's own regulatory impact analysis from 2010, which estimated a range of $2 to $80 per ton, with an average cost of $59 per ton. BART Supplement, Exhibit G at 5. Golder also confirms that the cost of lost fly ash sales for GRE is $12.30 per ton. BART Supplement, Exhibit G at 6.

Perhaps recognizing the fundamental weakness of its assertion, EPA noted that even if SNCR did cause some ammonia contamination, "three possible systems" could be used to cure the problem. *See* FIP at 102 n.35. EPA did not even bother to analyze whether any of these technologies might actually work at CCS. The manufacturer of one of those technologies stated that "[t]he limited current experience in commercial application and lack of research is not adequate for Headwaters to be able to provide any guarantee that the process can be successfully applied to treat lignite ash at the Coal Creek Station." *See* July 15, 2011 Email from Rafic Minkara, PhD., PE (Headwaters) to John Weeda (GRE), forwarded to Gail Fallon and Carl Daly (EPA) on July 15, 2011. Despite the manufacturer's lack of confidence as to whether its own technology would work, EPA asserted its "consultants are aware of no technical reason that ASM technology would not be effective to mitigate ammonia on fly ash from lignite." *See* FIP at 102 n.35. EPA cites nothing to justify its conclusion that the technology in question should work when the technology's own creator refused to support the conclusion. Making bald assertions that are unsupported at best, and flatly contradicted at worst, by evidence in the record is textbook arbitrary and capricious.

III. EPA'S CONSIDERATION OF THE OTHER FACTORS WAS IRRATIONAL

A. Other Cost Errors

1. EPA Arbitrarily Rejected URS's Cost Data

EPA's disregard of construction cost analysis of SNCR at CCS is unfounded. URS is a leading engineering and construction company that has participated in the construction and installation of SNCR projects at more than 30 coal-fired power plants. EPA's criticism that URS is not an SNCR vendor, and thus unable to opine on the costs of installing SNCR at CCS is arbitrary and capricious. *See* FIP at 121-124. As URS states:

> URS is not a technology supplier. The supplier is typically responsible for installation of only their process island and system performance guarantees. The installation of the balance of plant (BOP) equipment, construction management, foundations, utility tie-ins (electrical, water, air, instrumentation and controls

> interface, interconnecting piping, new flue gas emissions monitoring equipment, boiler and air heater modifications, retrofit difficulty due to existing plant access and congestion issues, et al) typically falls outside of the scope of supply for the SNCR vendor. Published cost estimates and vendor proposals in many cases do not consider these BOP cost impacts on the Total Capital Requirement for the installation of emissions control equipment. URS's project experience provides a basis for the assessment of these BOP costs that must be added to the vendor supplied equipment's installed costs to determine the true total capital cost of an installation.

See Letter from URS to Debra Nelson, March 30, 2012, BART Supplement, Exhibit F.

URS also has reconfirmed the basis for the retrofit factor of 1.6 based on the difficulty of installation at CCS. *See* BART Supplement, Exhibit F. URS also further explains the basis for its skepticism regarding SNCR's effectiveness when the initial NOx emission rates are in the lower range, similar to the NOx rate at CCS Unit 2. *See* BART Supplement, Exhibit F. EPA simply had no reasoned basis for disregarding URS's cost and performance analysis. EPA repeatedly refers to information from SNCR-designer Fuel Tech, but EPA's information appears to have been gleaned largely from a promotional website rather than site-specific analysis. *See* FIP at 20 n.2, 97 n.29. EPA's claim that its "consultant" received some sort of input from a SNCR vendor is so vague as to render it useless. *See* FIP at 102 n.34. The record does not show that EPA asked Fuel Tech to evaluate whether its technology would work at CCS. In any event, the follow up analysis provided by URS demonstrates that its cost analysis is well grounded.

2. EPA Provided No Rational Basis for Departing From its Guidelines' Presumptive Values

EPA's FIP ignored the Agency's own Guidelines, which require careful consideration of EPA's presumptive emissions limits. EPA's Guidelines explain that "we believe that States should carefully consider the specific NOx rate limits for different categories of coal-fired utility units, differentiated by boiler design and type of coal burned, set forth below as likely BART limits." *See* 70 Fed. Reg. 39134. EPA went on to note that "States have the ability to consider the specific characteristics of the source at issue and to find that the presumptive limits would not be appropriate for that source." However, EPA's BART analysis does not even acknowledge the existence of its own presumptive emissions limits much less reflect "careful" consideration of them. *See* 76 Fed. Reg. 58620-23. Furthermore, EPA offers no explanation why a departure from them is appropriate in this particular case, particularly where no visibility benefit would result from doing so. EPA cannot ignore its own Guidelines and nonetheless claim to have undertaken a legally-adequate BART analysis. EPA certainly would not allow a state to do so.

B. Energy and Non-Air Quality Environmental Impacts of Compliance

The CAA also requires consideration of the energy and non-air quality environmental impacts resulting from the use of relevant control technologies. This includes the energy requirements of the technology, the local availability of necessary fuels, and the generation of solid or hazardous wastes as a result of applying a control technology. *See* 70 Fed. Reg. 39,169. As already discussed above, EPA assumed contrary to all reasonable evidence that no fly ash

would be contaminated due to SNCR. EPA was therefore able to avoid considering the non-air environmental impacts arising from the creation of hundreds of thousands of tons of solid waste (and perhaps hazardous wastes depending on EPA's consideration of how to regulate fly ash). EPA's unsupported conclusion about fly ash therefore prevented EPA from properly considering two factors – the cost of controls and non-air environmental impacts.

IV. CONCLUSION

EPA rejected NDDH's entire BART analysis principally because of a purported error in a single cost component: the cost of contaminated fly ash. EPA then utilized flawed cost analysis and inaccurate emissions data to justify installation of SNCR. EPA effectively ignored all of the other BART factors, especially the lack of any measurable visibility improvement that might result from investing tens of millions of dollars to install and operate SNCR. GRE has provided NDDH with a revised BART analysis, including a refined cost analysis that examines the average and incremental cost, and cost-effectiveness of various levels of NOx emissions control. In light of the lack of any discernable visibility improvement at any Class I area, NDDH would be justified in supporting its initial BART determination at any cost level, including EPA's artificially low average cost per ton of $2500 per ton. The actual incremental cost of SNCR will be $4,688 per ton and, for Unit 1, will be $8,534 per ton, even if no costs are assigned to the loss of merchantable fly ash. The costs are significantly higher, and other environmental impacts worse, if fly ash contamination were to result from using SNCR. The documentation demonstrates this is very likely.

NDDH's initial BART determination was in compliance with the statutory obligations. With the refined BART analysis, and updated cost information, NDDH can make its own BART determination, assigning its own values to the five BART factors and should not accept EPA's usurpation of NDDH's authority.

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April 5, 2012

Mr. Terry O'Clair
Director, Division of Air Quality
North Dakota Department of Health
918 E. Divide Ave.
Bismarck, ND 58501-1947

RE: Coal Creek NOx BART Analysis

Dear Mr. O'Clair:

We are herewith responding to your letter of February 28, 2012, in which you requested that Great River Energy ("GRE") provide additional information to assist the North Dakota Department of Health ("NDDH") with its ongoing Best Available Retrofit Technology ("BART") determination for Coal Creek Station ("CCS"). You requested that GRE address some issues with its year 2000 visibility modeling, verify certain costs and data related to various pollution control options, and address some inconsistencies between GRE's cost analysis and the U.S. EPA's Control Cost Manual for certain cost components.

Enclosed is GRE's Supplemental Best Available Retrofit Technology Refined Analysis for NOx Emissions, April 5, 2012 ("BART Supplement"), which provides a supplemental BART analysis that addresses the issues raised in the February 28, 2012 letter (as well as issues raised in your January 19, 2012 letter). In particular, GRE asked Barr Engineering to rerun the visibility modeling analysis as requested by NDDH. The revised visibility modeling, reflected in both Table 3.2 and Appendix D of the BART Supplement, demonstrates that the incremental visibility improvement of adding SNCR to Units 1 and 2 is essentially non-existent at only 0.106 deciviews. The BART Supplement also includes additional cost information from URS addressing your questions about the EPA Control Cost Manual and URS's departures from assumptions that EPA makes about costs. Barr Engineering also has included the cost/economic analyses regarding the impact of ammonia contamination on fly ash marketability and disposal costs based upon information provided by Golder Associates. Those costs are reflected in Table 3.1 of the BART Supplement. The costs reflect the expected costs depending on whether 0%, 30% or 100% of the fly ash becomes unmarketable due to ammonia contamination. Barr Engineering concluded that, even if no costs are attributable to ammonia contamination, installing SNCR on to already existing or planned controls would reduce NOx emissions at Unit 2 at a rate of $4,688/ton and $8,534/ton at Unit 1. Thus, SNCR remains well outside the range of cost-effective control technologies.

GRE's revised BART analysis provided today includes a refined cost analysis that examines the average and incremental cost, and cost-effectiveness, of various levels of NOx emissions control as well as a revised visibility impact analysis of various levels of control. In light of the lack of any discernable visibility improvement at any Class I area, NDDH would be justified in supporting its initial BART determination at any cost level, including EPA's artificially low average cost of less than $2,500 per ton. The actual incremental cost of SNCR will be in excess of $4,500 per ton for Unit 2 and over $8,000 per ton for Unit 1, even if no costs are assigned to the loss of merchantable fly ash. The actual costs will be even higher.

GRE greatly appreciates NDDH's continued work on the CCS BART. Please do not hesitate to contact me or my staff if you would like to discuss any of these matters in greater detail.

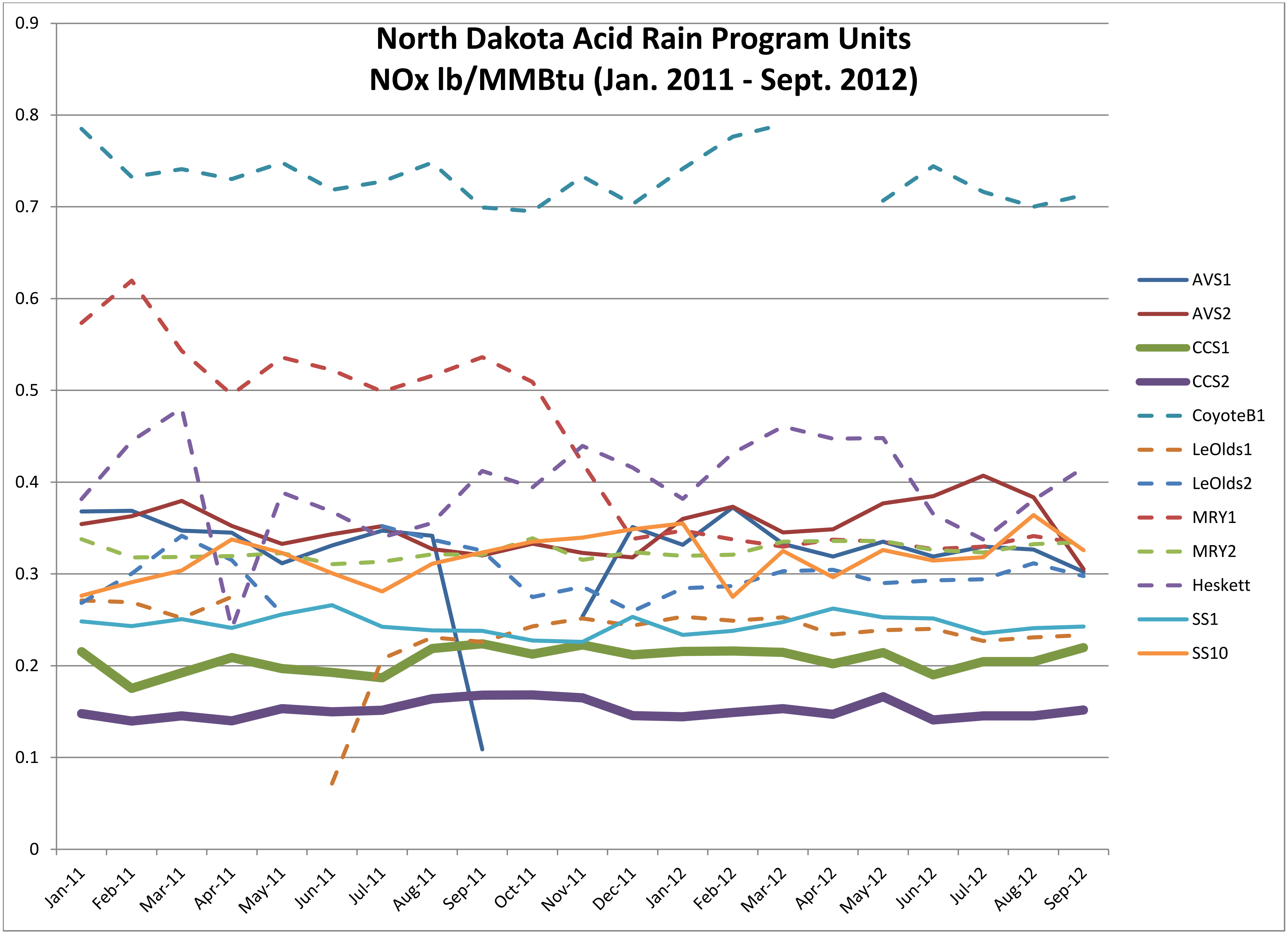
Sincerely,

Mary Jo Roth

Mary Jo Roth
Manager, Environmental Services

Enclosures

c: William M. Bumpers, Esq.
Eric Olsen, GRE
Deb Nelson, GRE


North Dakota Acid Rain Program Units
NOx lb/MMBtu (Jan. 2011 - Sept. 2012)
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
Jan-11
Feb-11
Mar-11
Apr-11
May-11
Jun-11
Jul-11
Aug-11
Sep-11
Oct-11
Nov-11
Dec-11
Jan-12
Feb-12
Mar-12
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May-12
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Jul-12
Aug-12
Sep-12
AVS1
AVS2
CCS1
CCS2
CoyoteB1
LeOlds1
LeOlds2
MRY1
MRY2
Heskett
SS1
SS10

SNCR Operation Workshop

February 7, 2011

NO_x Roundtable Conference

Birmingham, AL

Kevin Dougherty - Fuel Tech

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  - Slag and Corrosion Reduction
  - Controls SO_3 Emissions and Addresses Related Issues
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  - Markets Outside the US and Canada where Coal Ash is more difficult for ESP collection
  - Sonic Horns for Economizer and Backend Issues
- SO_2 - Sorbent Injection Systems Low Capital Option (30-40% Reduction)
- SO_3 - TIFI controls backend issues
- Large Particle Ash - TIFI reduces Popcorn Ash Cleaning

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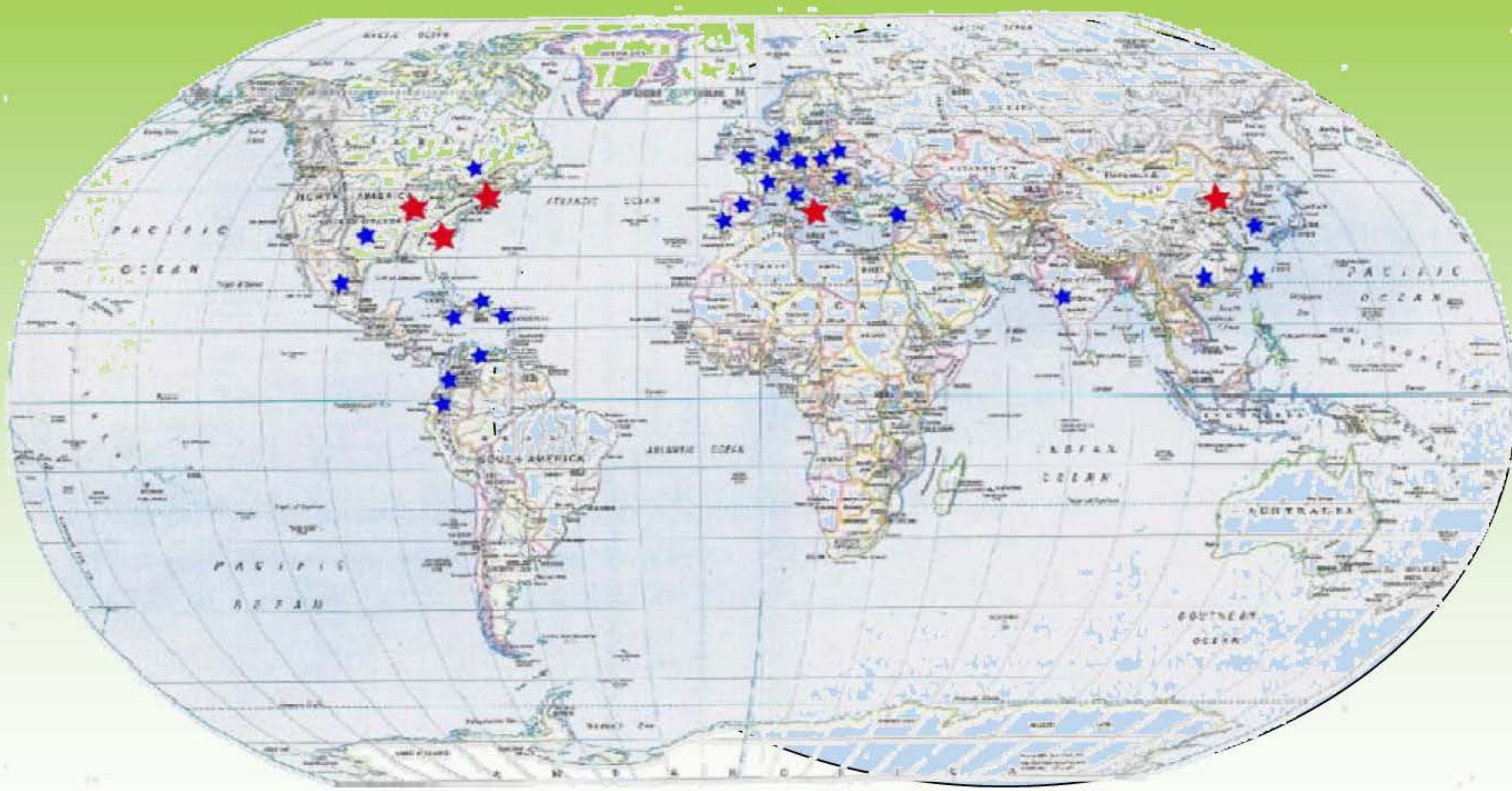

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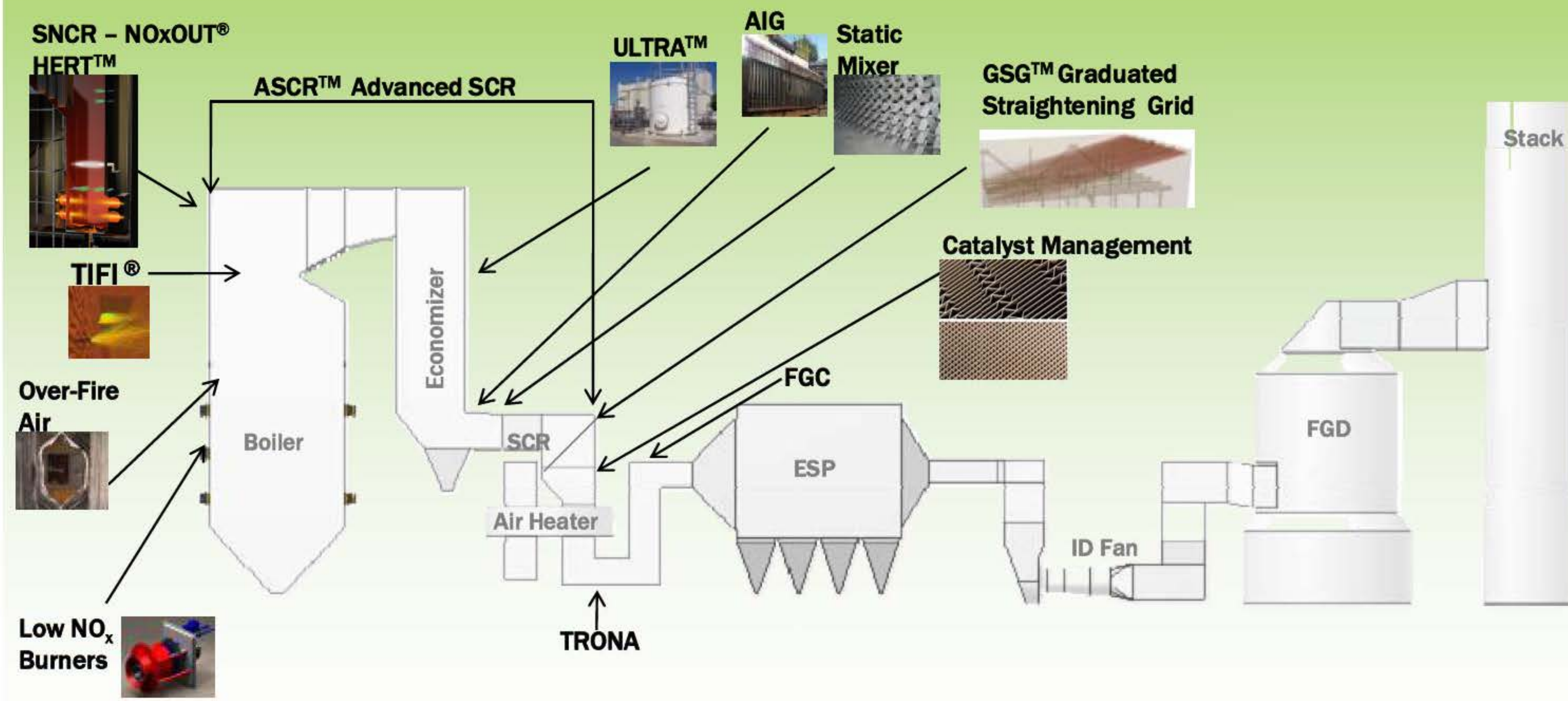
Beijing, China

Typical Power Plant



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FUEL CHEM®

- Multiple Solutions
- Operating Program
- Overview

FUEL CHEM® Program

- Slag – the iron, sodium and other minerals in coal that do not burn
- Above the ash fusion temperature these minerals melt and adhere to steam pipes and boiler walls
- More economical coals can have higher slagging properties
- Traditional removal methods
  - During Operations:
    - Air / water cannons
    - Thermal shocking
  - Shotguns
  - During Outages (6-10 days):
    - Dynamite
    - Mechanical Removal with Scrapers / Chisels / Etc.

Example of a clinker fall

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FUEL CHEM® Program Benefits

- **Efficiency**
  - Recovery of Derated MW
  - Heat Rate Improvement for Steam Production
  - Reduced Fan Power Requirements
  - Reduced Sootblowing
  - Reduced Operating O_2 Level
  - Reduced CO in Furnace and at the Stack
  - Increased Fuel Flexibility

- **Availability and Reliability**
  - Reduced Forced Outage Time
  - Reduced Derates
  - Increased Capacity and Boiler Availability
  - Reduced Outage Cleaning Times
  - Reduced Exit Gas Temperatures

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FUEL CHEM® Program Benefits

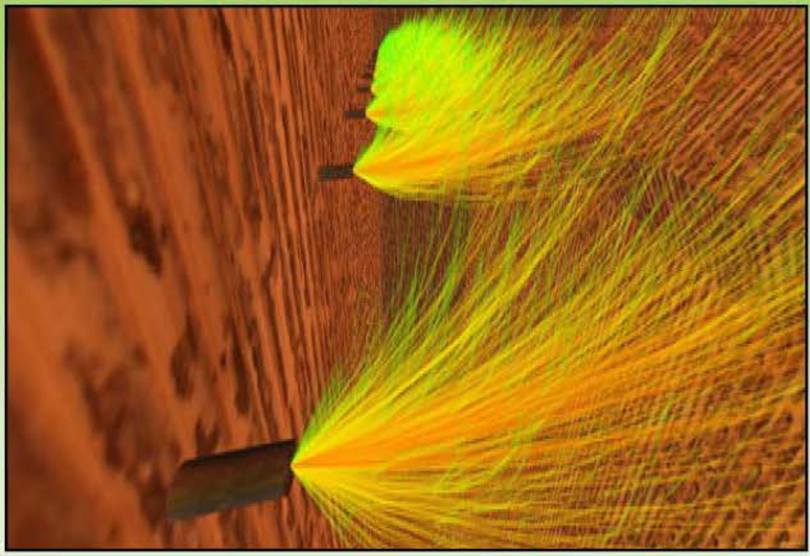
- **Environmental**
  - CO_2 Reduction
  - SO_3 Reduction
  - Opacity Improvement
  - Promotes Mercury Capture
  - Reduced Large Particle Ash (LPA)
- **Safety**
  - Reduced Maintenance Operations
- **Maintenance**
  - Reduced Corrosion in Economizer, Air Heater, Ductwork, and Stack
  - Reduced Clinker Grinder Maintenance
  - Tube Life Extension
    - Reduced Sootblowing
    - Reduced Slag Damage
  - Reduced Cleaning Expenses
    - Less Explosives
    - Lower Water Consumption

FUEL TECH

TIFI® Targeted In-Furnace Injection™ Program

TIFI® Targeted In-Furnace Injection™ Technology

- Improves Fuel Flexibility
- Reduces Slagging and Fouling
  - Providing Greater Boiler Efficiency
- SO_3 Plume & Opacity Control
- Heat Rate Improvement



TIFI® Injector on boiler wall

Fuel Types

Coal	Alternative Fuels	Residual Fuels
• PRB • ILB • Lignite • CAPP	• Biomass • Pet Coke • Hog Fuels • WTE Fuels	• No. 6 Fuel • Waste Oil • Bunker C • Liquid Waste Fuels • Black Liquor

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TIFI ® Technology Overview

TIFI MG™	TIFI XP™	TIFI MP™	TIFI Flux™	TIFI BlueCat™	TIFI Hybrid™	TCI™
• Utilizes magnesium hydroxide slurry • Sprayed into the combustion unit at locations defined by computer modeling. • TIFI MG solution reacts with slag as it is forming and penetrate existing deposits.	• Builds upon TIFI technology • Designed to provide users both slag control and fuel flexibility. • Allows users to burn less-expensive, yet higher-slagging coals such as ILB	• Furnace chemical injection program • Uses two reagents for the reduction of SO_2	• Specifically designed for cyclone boilers • Focused on burning PRB and other low iron coals	• Copper based product • Used to lower carbon monoxide (CO) and unburned coal (LOI) • Can be used in combination with TIFI MP to provide SO_2 trim control	• Designed for oil-fired boilers • Uses a combination of TIFI MG combined with in-fuel injection	• Designed principally for boilers in the waste-to-energy (WTE) industry • Inhibits corrosion and slag build-up

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Air Pollution Control Technologies

APC Technology Overview

Combustion

LNB
- 40-60% NO_x Reduction
- Industrial & utility applications
- Upgrades to existing burners available

OFA
- 35-70% NO_x Reduction over Low NO_x burners
- Unique port design enhances mixing to limit impact on combustion efficiency

Post-Combustion

SNCR
- 20-50% NO_x Reduction
- Urea-based maximized performance with minimal ammonia slip

ASCR
- 80+% NO_x Reduction
- 30-70% Less capital then traditional SCR

ULTRA
- Proprietary urea conversion process to generate ammonia for SCR systems
- Safer than ammonia
- Compatible with a wide range of urea sources

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NOx Regulations

- Clean Air Interstate Rule
  - 0.15 lb/MMBtu for 2009
  - 0.12 lb/MMBtu by 2015
- Transport Rule (final by mid-2011 for 2012 compliance)
- Transport Rule 2 (final by 2012 for 2014 compliance)
- Carper/Alexander Legislation (2011?)
- Boiler MACT and CISWI Rule
  - MACT Sources < 250MMBtu
  - Final Rule by February 2012 – 3 years to implement
- Other State Options and Rules

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Reducing NOx Emissions

- Fuel Switching
- Combustion Tuning
- Combustion Controls
  - Low-NOx Burners
  - Over-Fired Air
- Post-Combustion Controls
  - Selective Non-Catalytic Reduction
    - Fuel-Rich Reducing Environment
    - Fuel-Lean Oxidizing Environment
  - Selective Catalytic Reduction

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Reducing NOx Emissions

- How to Capture the Strengths?
- How do we expand the Limits?
- Are there Synergies?

- Customized Solutions:
  - Emission Requirements
  - Existing NOx Controls
  - Total Site Emissions: GHG, CO, etc.
- A Complete Site Perspective

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A Complete Site Perspective

- Coal Specifications
- Combustion Systems: Burners & OFA
- Furnace Slag / Fouling
- Heat Rate and Furnace Efficiency
- Unit Capacity Factor
- Excess O2 / LOI
- Post-Combustion NOx Control
- SO2 and SO3

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NOx Reduction Strategies

- Cost Effective Total NOx Reduction
  - Starts with Combustion
  - Capitalize on Synergies of Combining Technologies
  - Get Guaranteed Performance on each Technology
- Fuel Tech Advanced SCR (ASCR)
  - LNB/OFA
  - SNCR
  - Reduced SO_3 Levels
  - ASCR catalyst will provide Hg Oxidation
  - Reduced On-going Catalyst Replacement Costs
  - NOx Reduction at Low Boiler Load and Low SCR Temperature
  - 80-85% Combined NOx Reduction

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NOx Reduction Technologies

Post-Combustion Options without Full Scale SCR

- **SNCR - NO_xOUT® and HERT Systems**
  - $5-20/kW Capital Cost including Installation
  - 25-50% Reduction
- **SNCR/RRI**
  - $7-22/kW and 40-60% Reduction
- **ASCR™ Advanced SCR Systems**
  - $30-75/kW and 65-85% Reduction

Full Scale SCR Technology

- Up to $300+/kW with *85-90% Reduction*
- Fuel Tech Option for Safe Urea Reagent Supply – ULTRA™ ($2-3M Capital)

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NOx Reduction Technologies – Summary

- Low Capital Cost NOx Reduction Solutions
- Guaranteed NOx Reduction Process Performance and Compliance Assurance
- Complete Plant/Process Integration & Seamless Control
- Minimal Maintenance Requirements & Proven System Reliability
- Full Line of NOx Control Solutions
- More Than 25 Years Serving Owners of Power and Steam Generating Facilities

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APC Installed Experience

- Advanced Combustion Systems
  - Over 100 Units to Date for Low NOx Burners, OFA, and Combustion Optimization from 20 MW to 1200 MW
- NOxOUT® and HERT™ SNCR Systems
  - Over 600 Units to Date, With > 100 Utility Units
  - All Combustion and Fuel Types
- NOxOUT ULTRA® Systems
  - Over 24 Units to Date, 5 to 1,250 PPH of SCR Reagent Feed Systems
- SCR Design and Modeling Services
  - Over 55,000 MW's of SCR Design, 20,000 MW's of AIG Tuning
  - Modeling Solutions for Scrubbers, ESPs, FF, Dry Sorbent, HXs, Etc.

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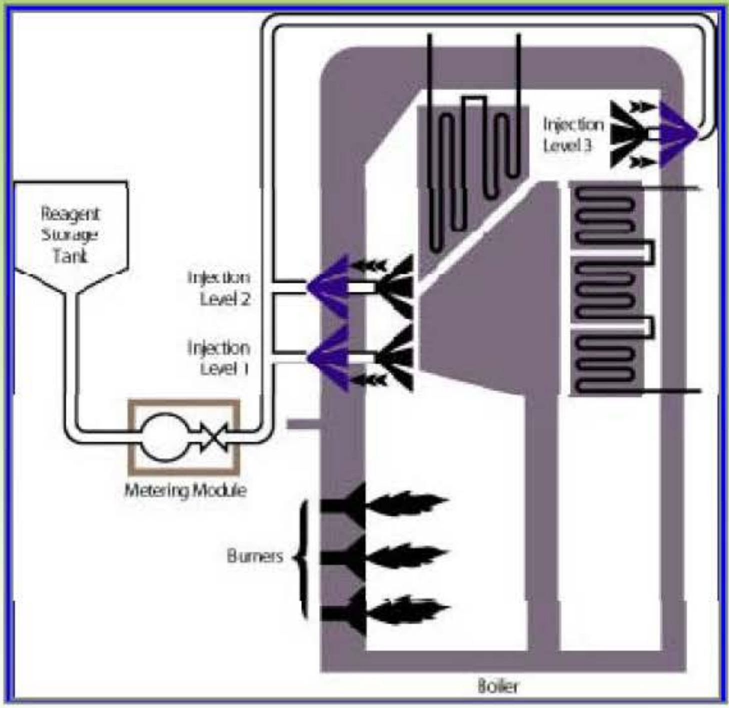
Selective Non-Catalytic Reduction (SNCR)

SNCR Technology Overview: NOxOUT® and HERT™ Systems

- In-furnace, Post-combustion NO_x Control
- Injection of Urea in Upper Furnace
- Process Reaction Temperature Range: 1600°F to 2200°F
- NO_x Reduction Range
  - Utility Boilers: 25 to 50%
  - Industrial Boilers: 30 to 70%



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Selective Non-Catalytic Reduction

SNCR Process Chemical Reactions

(1) $4NO + 2CO(NH2)_2 + O_2 \Rightarrow 4N_2 + 4H_2O + 2CO_2$

(2) $2NO_2 + 2CO(NH2)_2 + O_2 \Rightarrow 3N_2 + 4H_2O + 2CO_2$

Nitrogen Oxides + Urea + Oxygen ⇨ Nitrogen + Water Vapor + Carbon Dioxide

Typically 95% of NOx is associated with Eq 1

SNCR Technology Overview

- In-furnace, Post-combustion Control
  - Injection of Aqueous Urea Droplets
  - 25 – 70% NOx Reduction
  - Many Injection Options:
    - Compressed Air
    - Mechanical
    - Multiple Nozzle Lances – Water Cooled
  - Package Boilers to Utility Boilers
  - Option for Aqueous or Anhydrous Ammonia

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Advantages of Fuel Tech's SNCR System

- Guaranteed Proven NOx Reduction
  - 15 – 35% Utility
  - 20 – 70% Industrial/Incineration
  - Repeatable
  - Controlled NH3 Slip
- Low Capital Cost
- Fast Implementation
- Turn On/Off As Needed
- Compatible with Other APC Technologies
  - LNB/OFA
  - ASCR or SCR
  - ESP's and Fabric Filters

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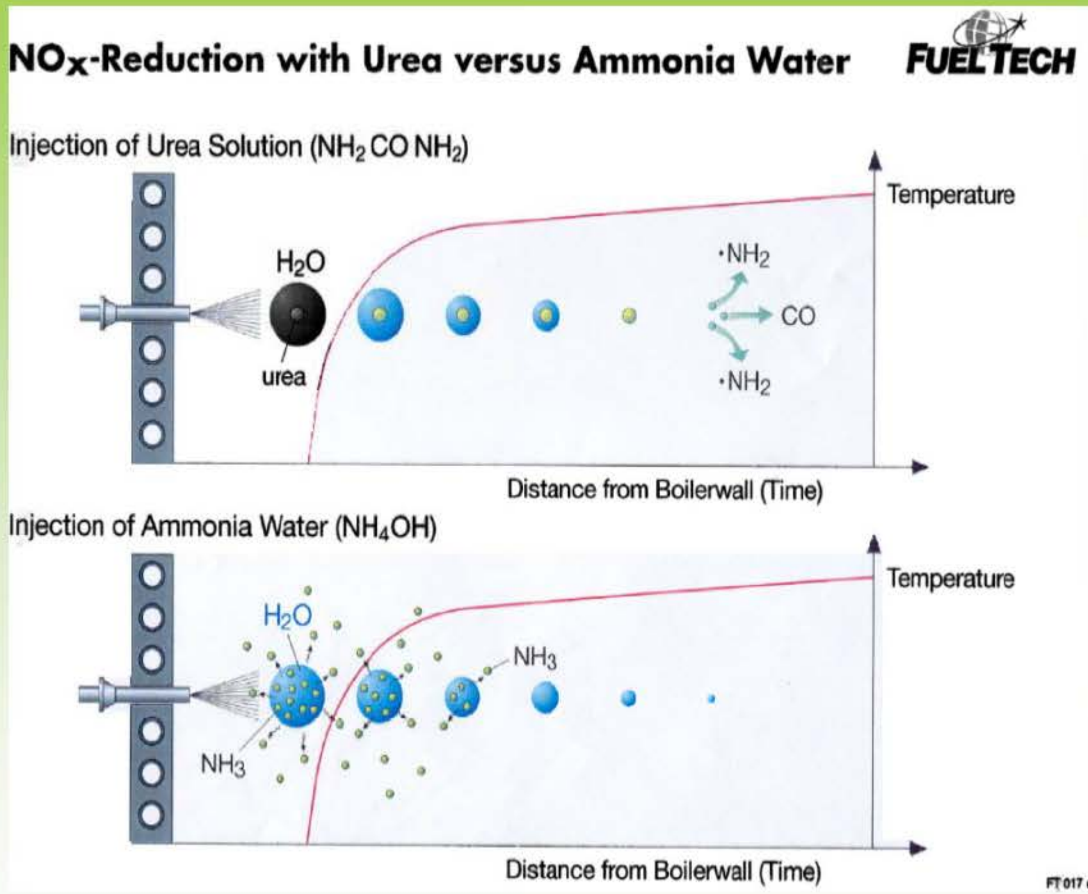
Urea vs. Ammonia for SNCR



Urea droplets formed by FTI injectors are characterized in test facilities using laser Doppler techniques.

SNCR Boiler and Fuel Experience

Utility Boilers

- T-fired
- Wet Bottom
- Wall Fired
- Cyclone
- Tower

Industrial

- Circulating Fluidized Bed
- Bubbling Fluidized Bed
- Stoker, Grate Fired
- Incinerators
- Industrial

Coal

- Bituminous
- Sub-bituminous
- Lignite

Other Fuels

- Oil – #2 and #6
- Natural Gas
- Refinery Gases (High CO)
- Municipal Solid Waste
- Tire Derived Fuel
- Wood
- Sludge

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SNCR Systems – Industry Experience

- Electric Utilities
- Wood-fired IPPs / CoGen
- TDF Plants
- Pulp & Paper
  - Grate-fired
  - Sludge Combustors
  - Recovery Boilers
  - Wellons Boilers
  - Cyclones
- Refinery Process Furnaces
- CO Boilers
- Petrochemical Industry
- CoGeneration Boilers
- Municipal Solid Waste
- Process Units
- Cement Kilns

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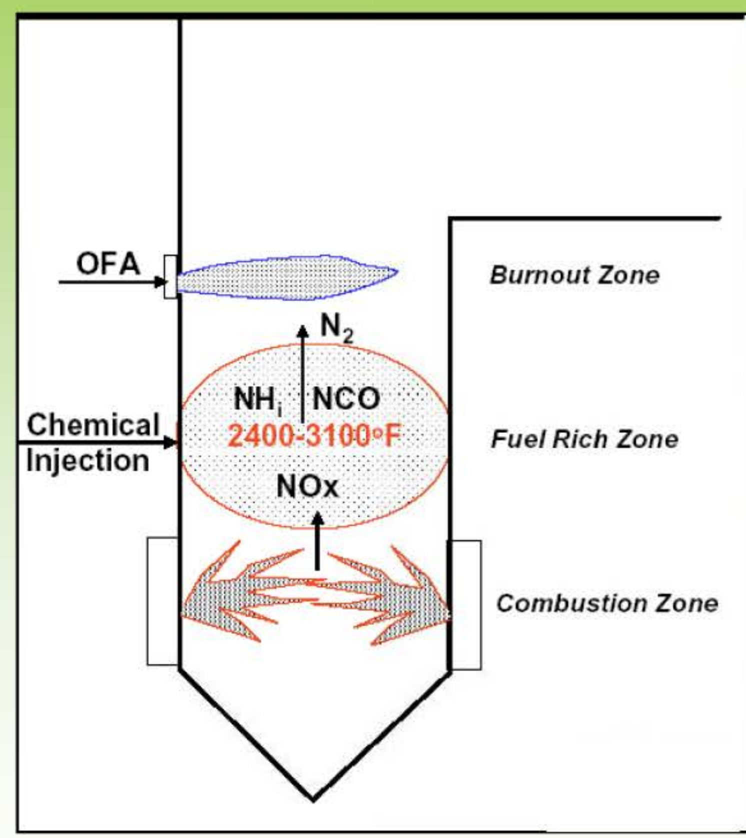
Rich Reagent Injection (RRI) Technology Overview

- 40 to 60% NO_x Reduction Combined with SNCR on Cyclone Boilers
- NO_x Reduction in 30% Range with RRI Only
- Non-catalytic Reduction of NO_x via Urea Injection in Sub-stoichiometric Conditions (SR: 0.85 to 0.95)
- No Reagent Slip Due to High Residence Time and Reagent Oxidation in the Burnout Zone
- Process Reaction Temperature Range: 2600°F to 3100°F
- Technology Licensed from REI



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SNCR PROCESS DESIGN AND MODELING

SNCR Critical Process Parameters

- Effective Temperature Window for Chemical Release and Reaction – 1600°F to 2200°F, Depending on Application
- Temperature too High ⇨ NH2 Oxidation to NOx, Temperature too Low ⇨ Ammonia Slip
- Flue Gas Velocity and Residence Time Considerations
- Background Gas Composition – NOx, CO, O_2, and Sulfur Content of the Fuel

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Controlling Risks SNCR:

- Carefully Target the Injection Zone
  - CFD Modeling
  - Field Assessments / Demonstrations
- Understand the Chemistry
  - Urea and ammonia Mechanisms
  - Ammonium Bisulfate Formation
- Refer to Experience Database
  - More Than 500 Applications
  - More Than 100 Utility Furnaces

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SNCR Process Design

Computational Fluid Dynamics (CFD)

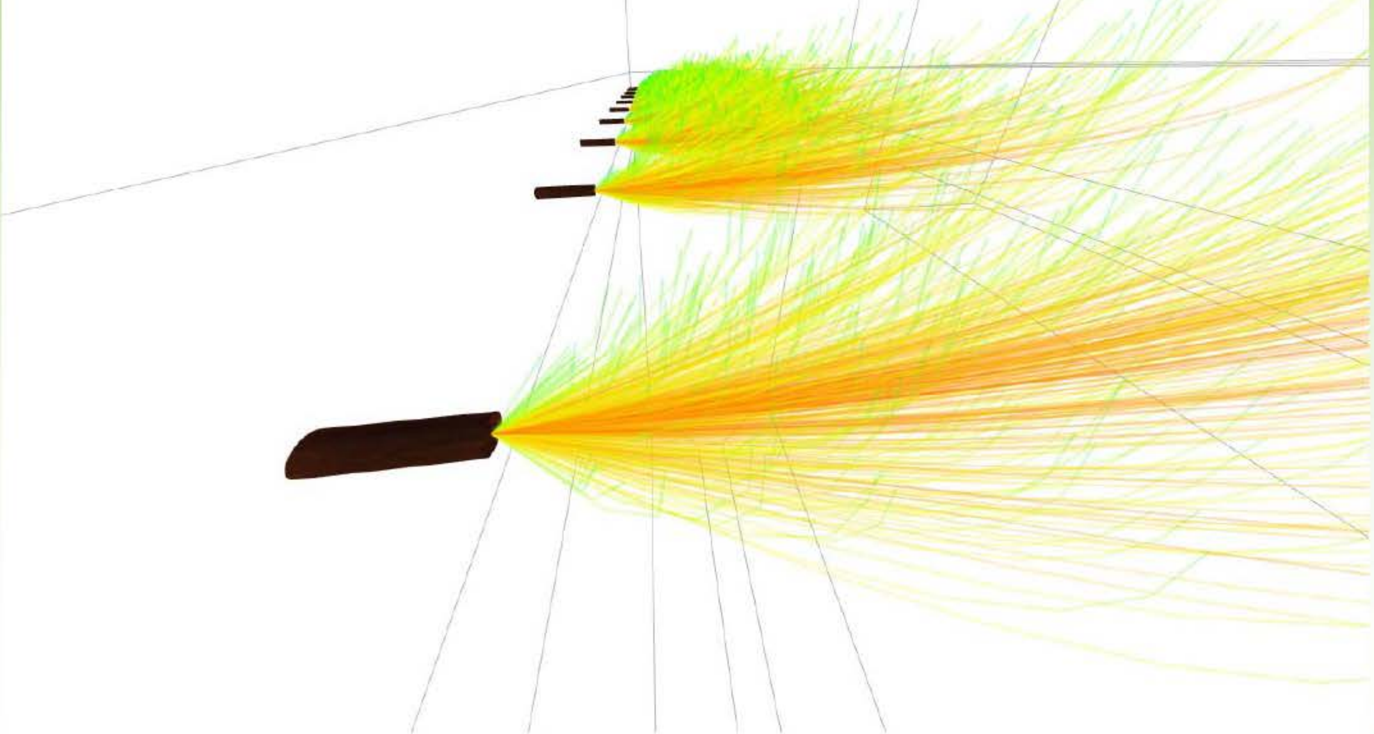
Used to Define Effective Boundaries of Critical Process Parameters, Test Effectiveness of Distribution Strategies, Identify/Locate/Define Gas Species Concentrations – Physical Unit Data (Drawings, etc.) and Field Testing as Input

Chemical Kinetic Model (CKM)

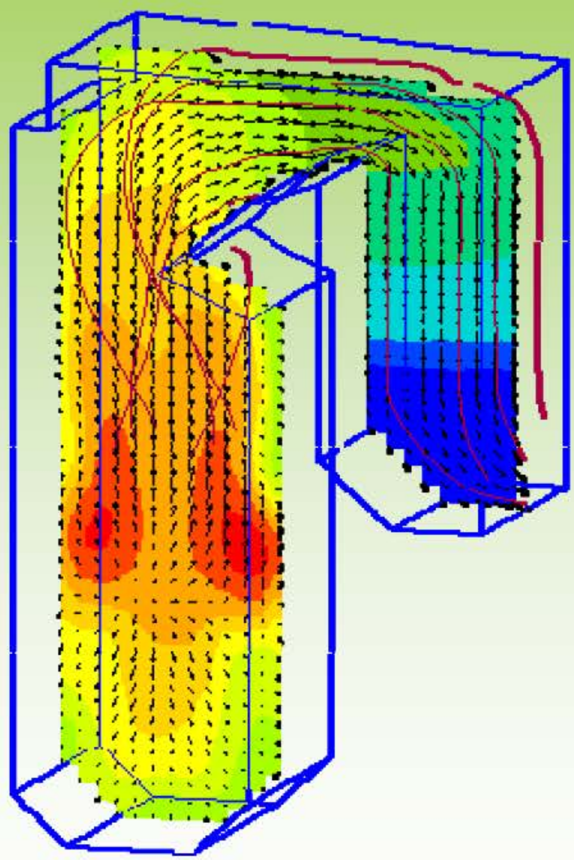
Used to Calculate Each Specific Time/Temperature Reduction Reaction – Overlay the SNCR Process on the CFD

SNCR Process Application

- Computational Fluid Dynamics
- Chemical Kinetics Model
- Injection Model



SNCR Process Modeling Steps



Step 1:	Define the Unit Geometry
Step 2:	Block Out Obstructed Cells and Faces
Step 3:	Define Mass and Heat Sources
Step 4:	Solve for Flue Gas Temperatures and Velocities
Step 5:	Generate Temperature Versus Residence Time Data for CKM
Step 6:	Identify Temperature Limits for Effective NOxOUT Performance
Step 7:	Select Injector Locations and Spray Characteristics

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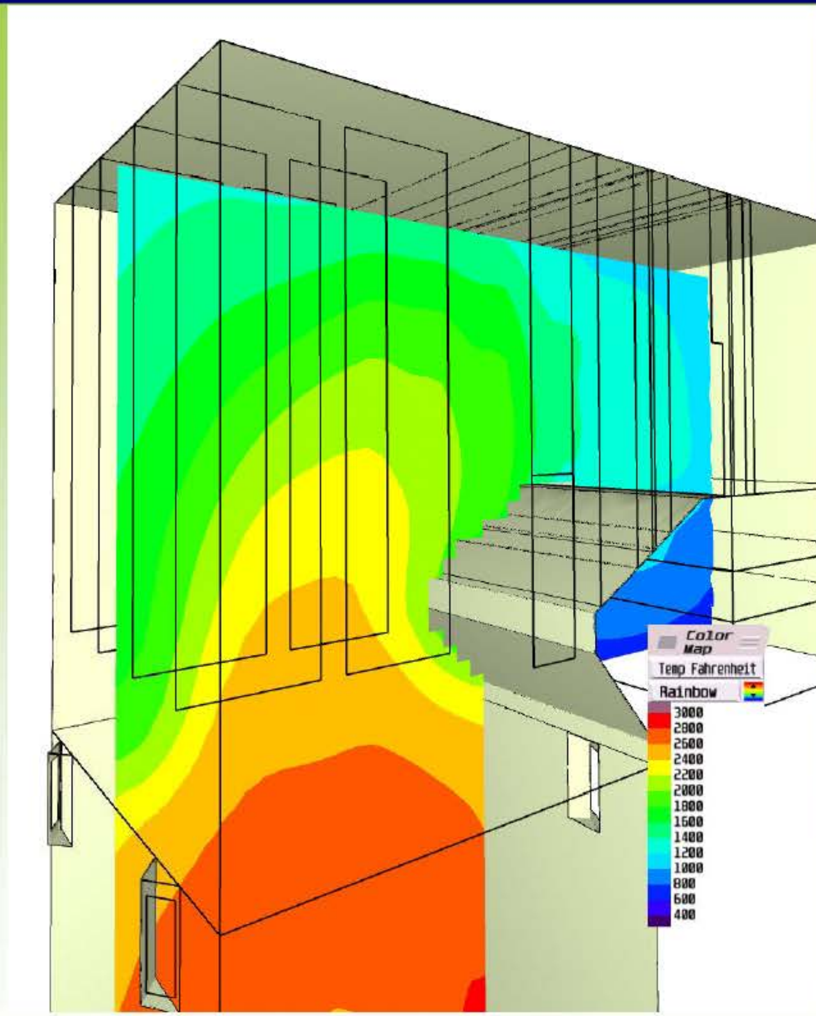
Baseline Testing (HVT) for CFD/CKM



- High Velocity Thermocouple Suction Pyrometer and Portable Gas Analyzer Used to Gather Temperature and Flue Gas Composition
- Develop Grid of Measurements Based on Actual Operating Conditions
- Build CFD Model Using Data Gathered from Field
- Overlay SNCR Process on CFD to Determine Reagent Distribution and Performance

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Temperature and Species Mapping

- Three (3) Boiler Loads
  - Full, Mid, and Low Load Depending on NOx Removal Requirements
- Typical One (1) Week Service
  - One (1) Field Engineer, Two (2) Technicians
- Fuel Tech to Provide All Equipment Including High Velocity Thermocouple (HVT), Cooling Water Pumps, Hoses, and Analyzers
- Scope By Others
  - Maintain Steady State Boiler Conditions for 4 – 6 Hours per Load
  - DCS Data during Testing
  - Water and Electrical Hook-ups
  - Observation Doors or Ports for HVT Testing
  - Fuel and Operational Data, Boiler Drawings

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SNCR Baseline Testing - HVT

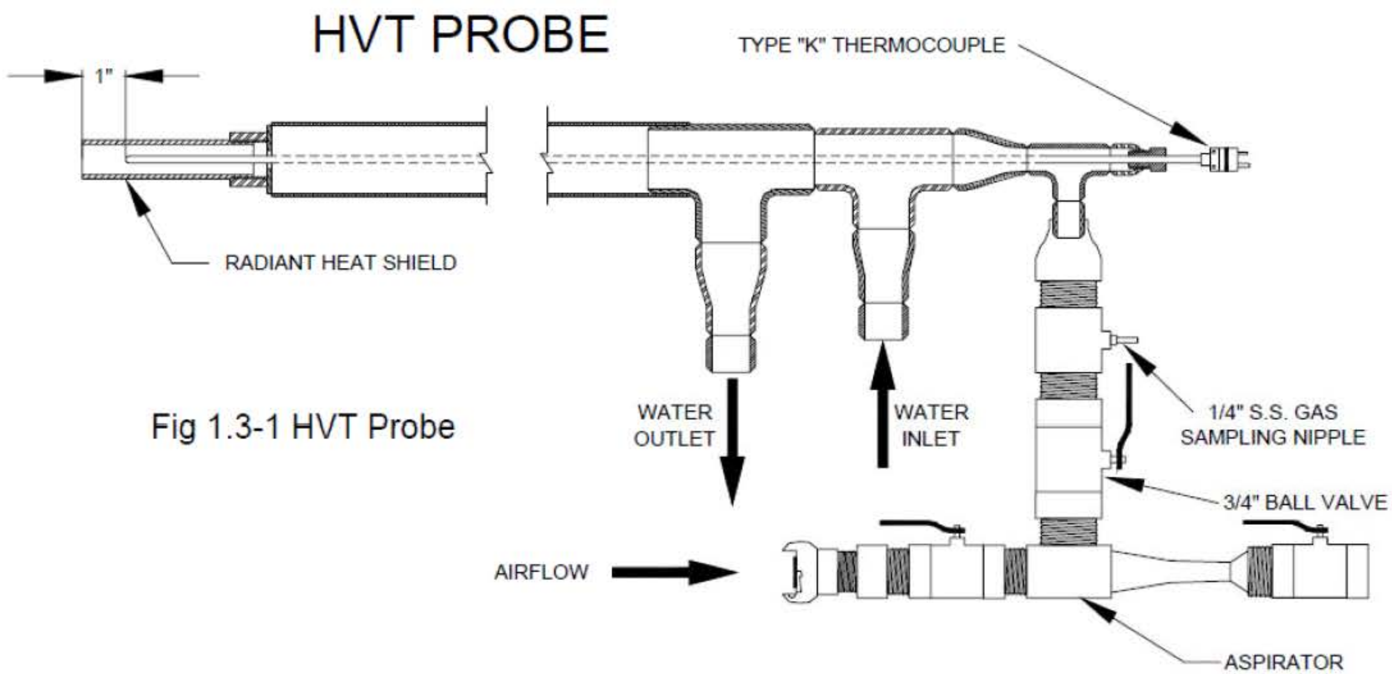
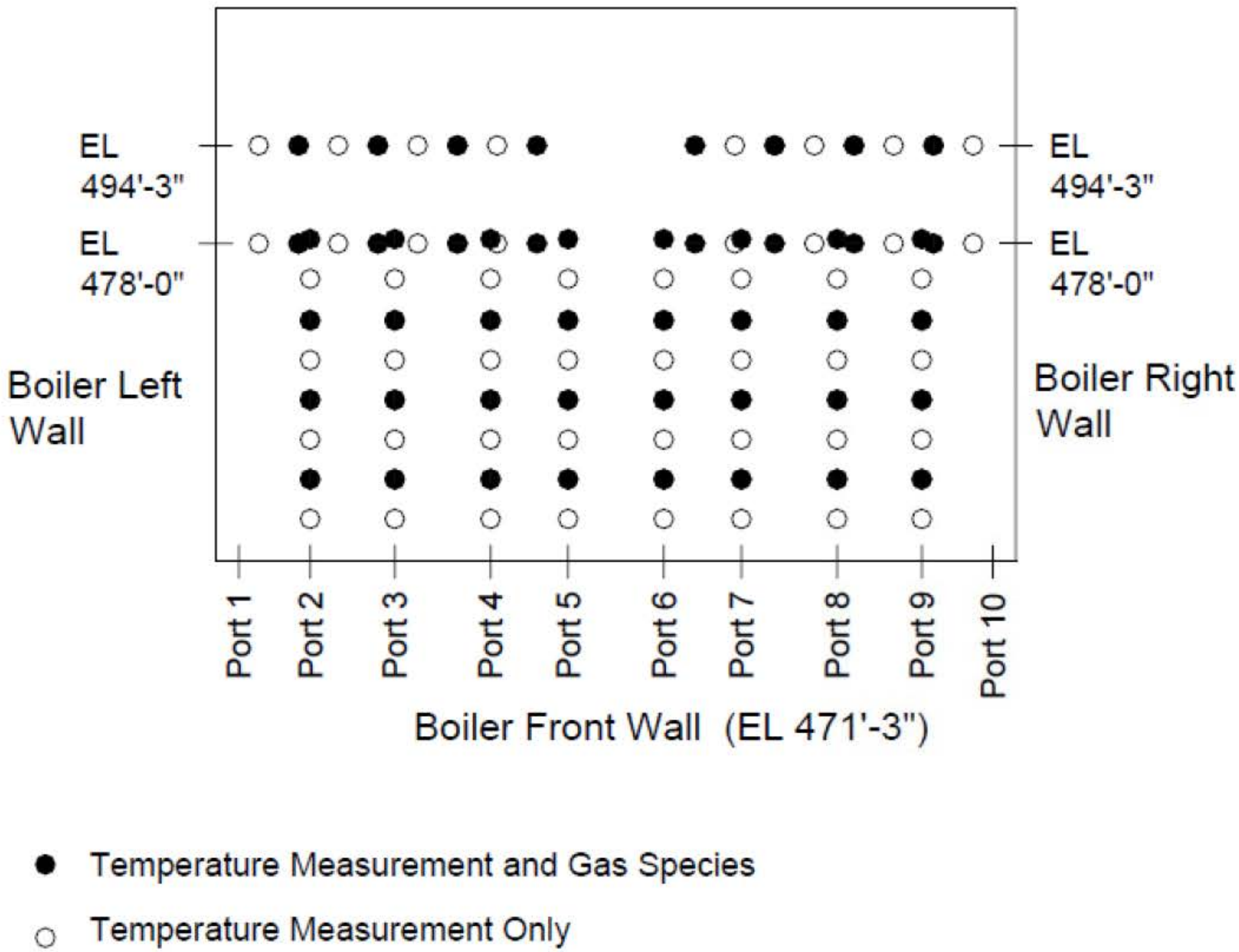


Fig 1.3-1 HVT Probe

SNCR Baseline Testing - HVT



SNCR Baseline Testing - HVT

	Start Time:	12:42		Finish:	12:58	
Eastern Port (forward of RH Pend Platen) Elevation 506'-3"						
Depth	Temp.	%Oxygen		CO (ppm)	NO (ppm)	NO (corr)
2'	2,003°F					
4'	2,105°F	0.0	0.0	49,910	114	98
6'	2,136°F					
8'	2,173°F	0.3	0.7	22,095	122	107
10'	2,181°F					
12'	2,187°F	2.1	2.6	5,648	94	91
14'	2,154°F					
16'	2,184°F	6.8	7.4	239	72	93
18'	2,222°F	6.1	6.9	72	73	91
Average	*2,149°F*	*3.29*		*15,593*	*95*	*96*
Low	*2,003°F*	*0.00*		*72*	*72*	*91*
High	*2,222°F*	*7.40*		*49,910*	*122*	*107*

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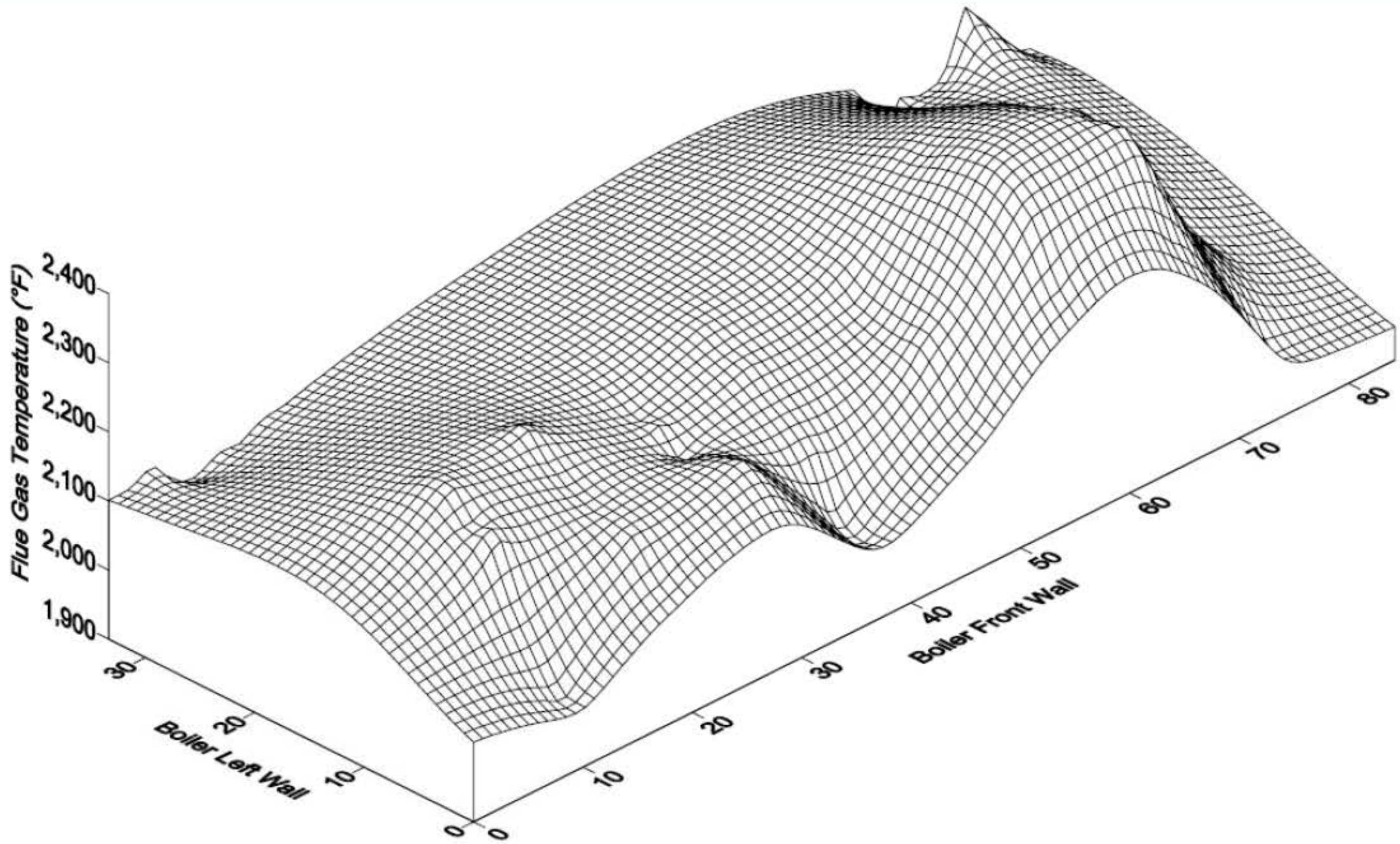
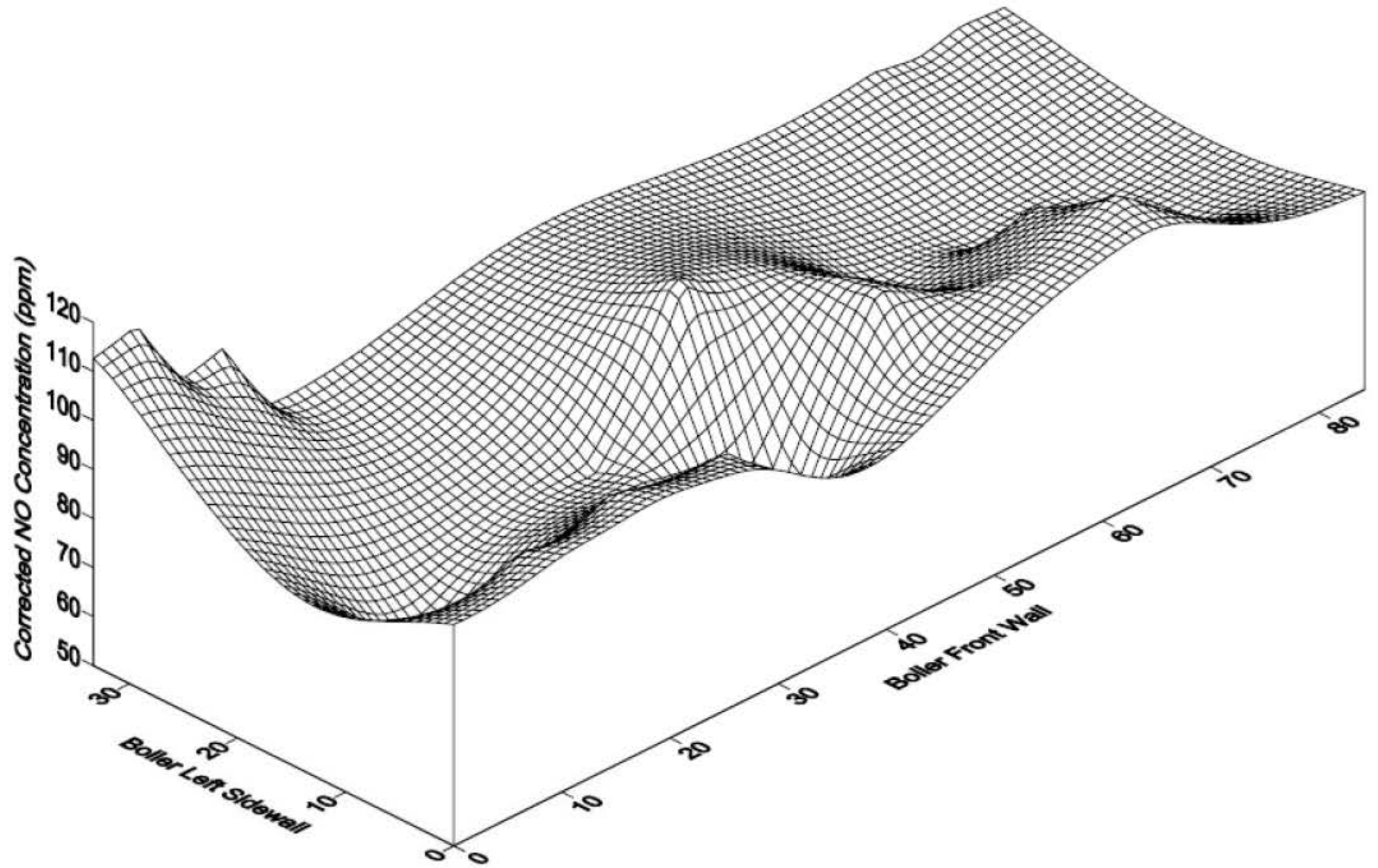
HVT Testing – Temperature (°F)



HVT Testing – NOx Concentration (ppm)



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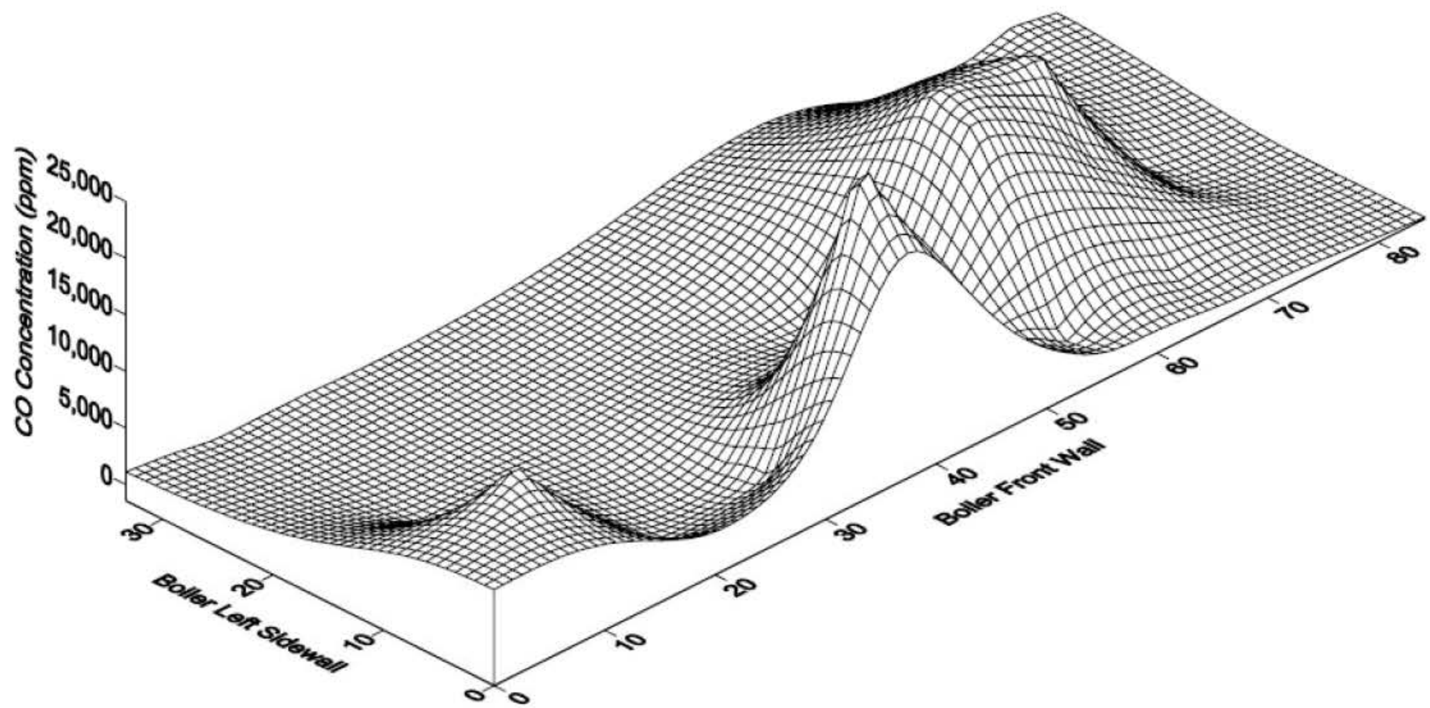
HVT Testing – CO Concentration (ppm)



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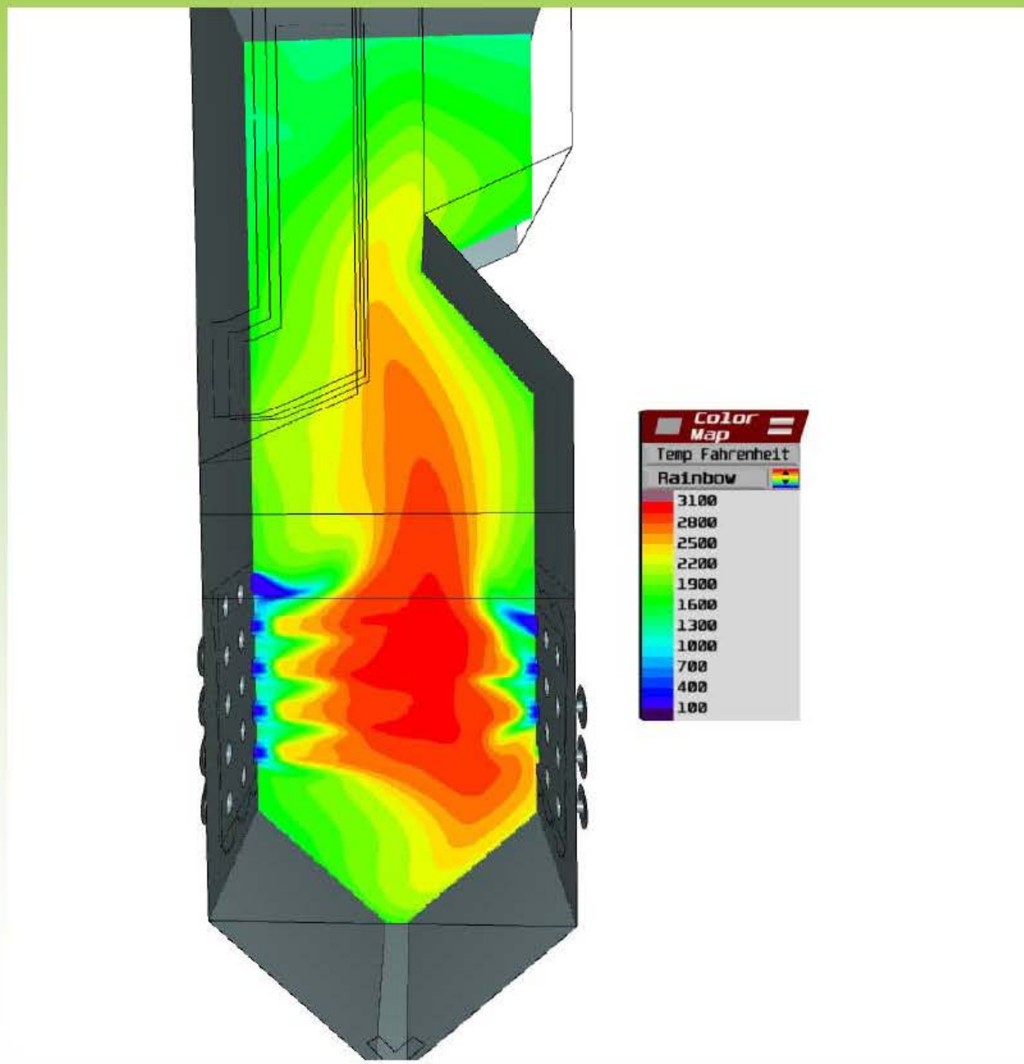
Baseline Furnace Model



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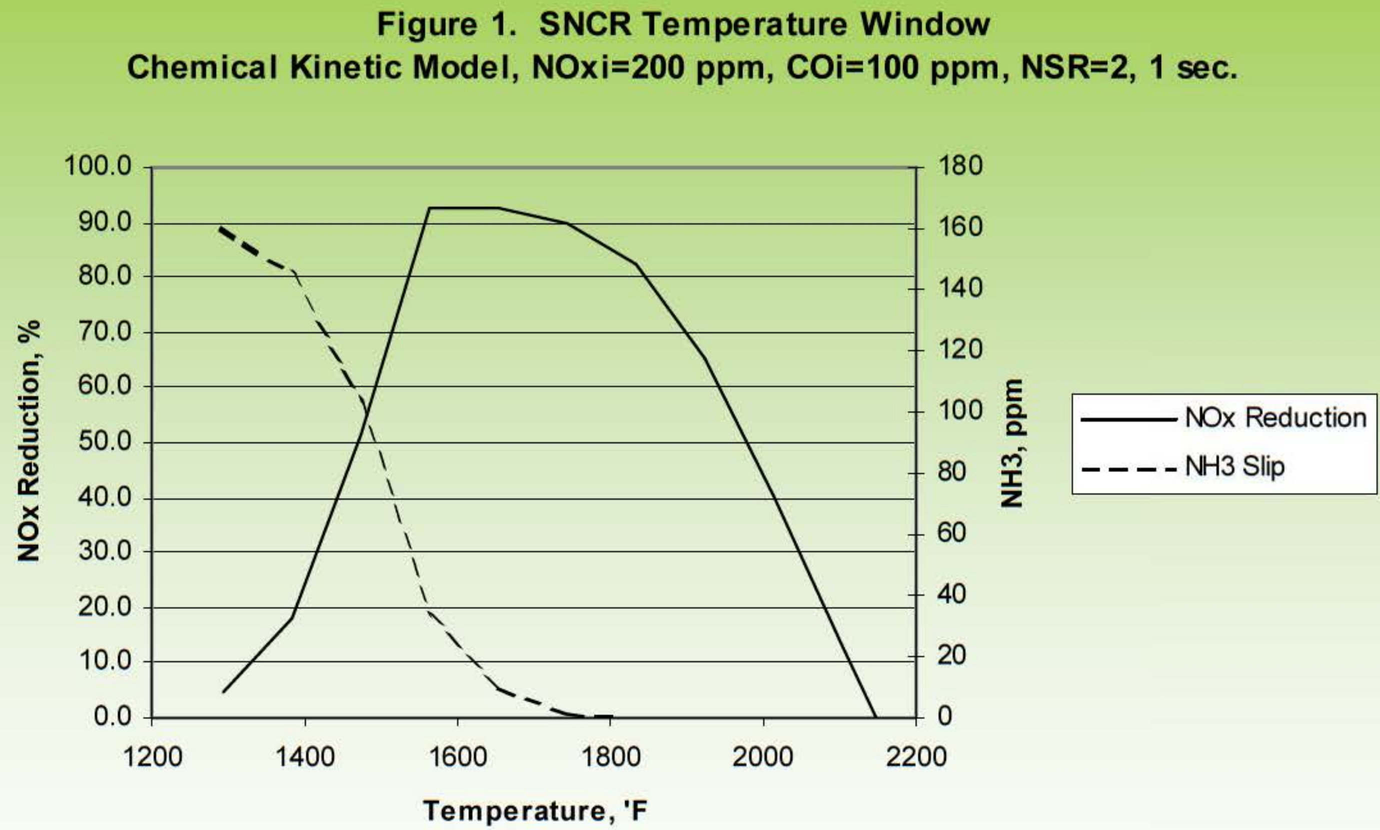
SNCR Design – Temperature Window



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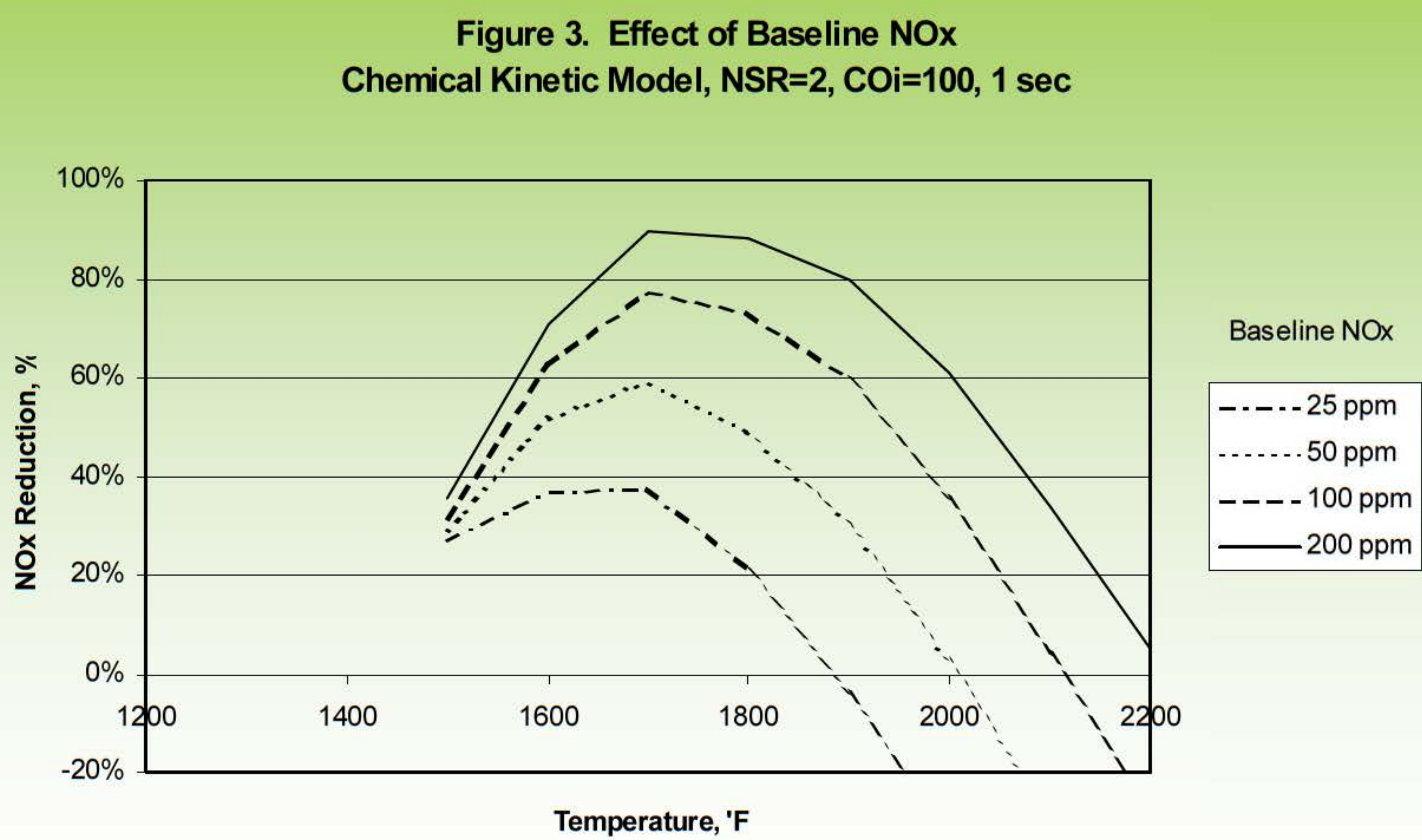
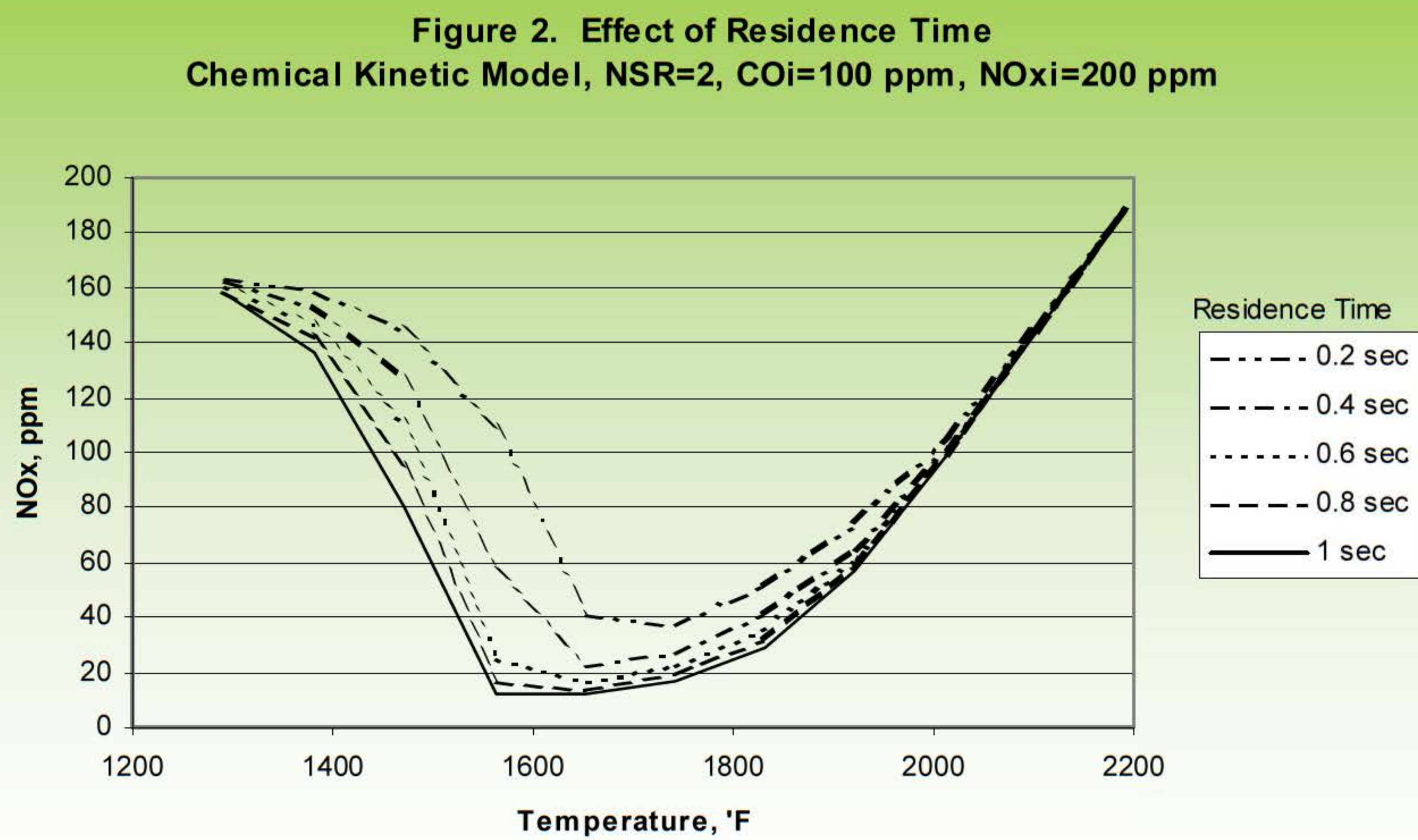
SNCR Design – Baseline NOx



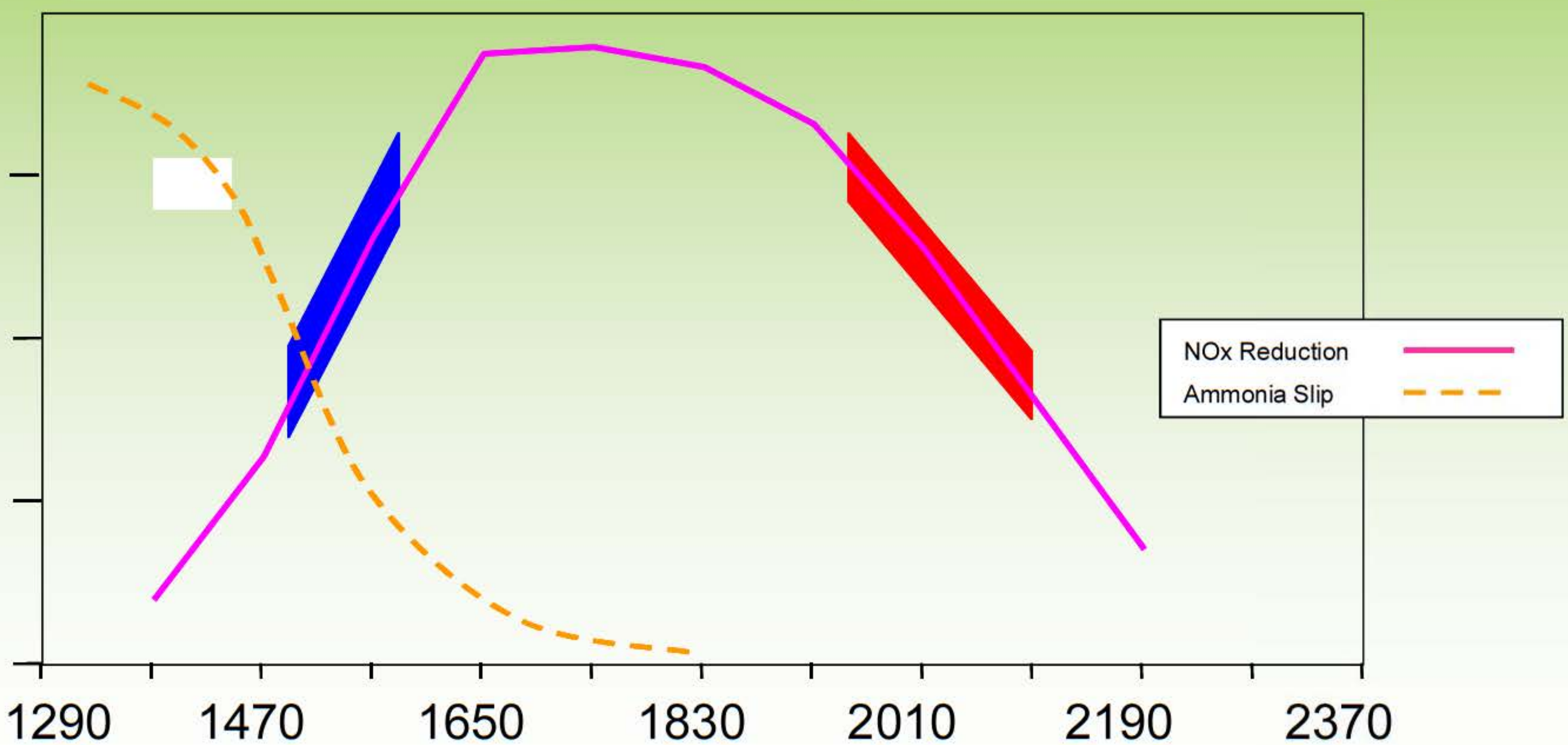
SNCR Design – Residence Time



"Right Side of Slope" Injection

Low Temperature Issues
- Slow Droplet Evaporation
- Slow Kinetics
- Low OH Concentration
- Ammonia Slip Increase

High Temperature Issues
- Rapid Droplet Evaporation
- Fast Kinetics
- Increased OH Concentration
- Urea Oxidation to NOx



Influence of CO on SNCR Process

1) $NH_3 + OH \Rightarrow NH_2 + H_2O$ and $HNCO + OH \Rightarrow NCO + H_2O$

   Note: Reaction rates increase with temperature, which explains low ammonia slip for high temperature applications. Clearly, OH is needed for this step.

2) $NH_2 + NO \Rightarrow NNH + OH \Rightarrow N_2 + H_2O$

   $NCO + NO \Rightarrow N_2O + CO \Rightarrow N_2 + CO_2$

   Note: NH2 and NCO are NOx reducing species – these reactions take place if working within the appropriate temperature window.

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Influence of CO on SNCR Process

3) $NH_2 + OH \Rightarrow NH + H_2O$

$NH + OH \Rightarrow HNO + H$

$HNO + OH \Rightarrow NO + H_2O$ (*NOx Formation*)

$NCO + OH \Rightarrow NO + CO + H$ (*NOx Formation*)

Note: If the operating temperature is high, these reactions will occur rather than the desirable NOx reducing reactions. In this case, the OH works against us… CO Enters into the picture –

4) $CO + O_2 + H_2O \Rightarrow CO_2 + 2OH$

Note: The higher the CO concentration, the higher the OH generated. The elevated OH concentration generates increased levels of NH2 and NCO (Equation 1), even at low temperatures.

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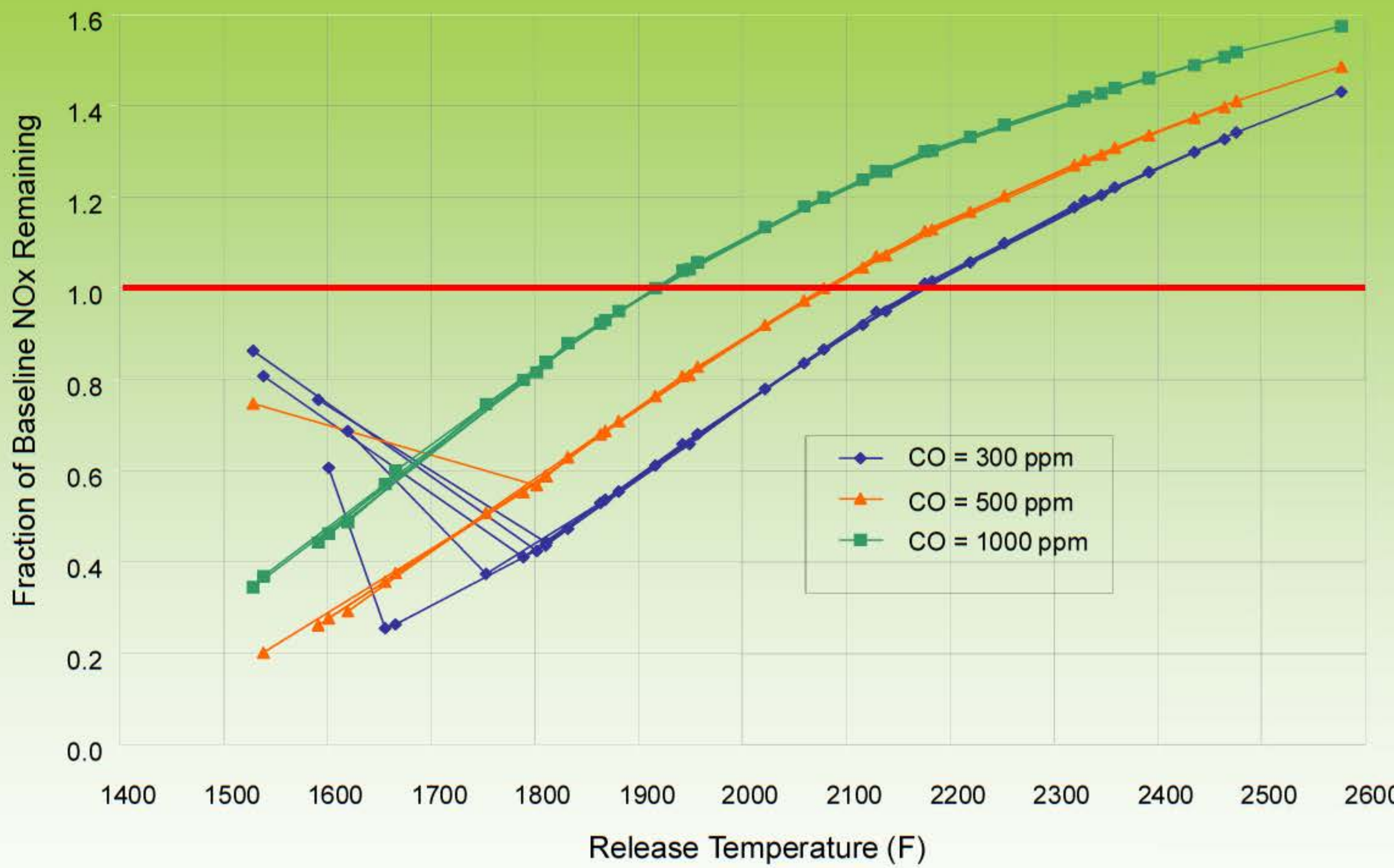
Influence of CO on SNCR Process



Note: Higher CO Levels Increase the Rates of NH2 Formation and NH3 Oxidation to NO; Effective NOx Reduction Window for Process is Shifted to a Lower Temperature.

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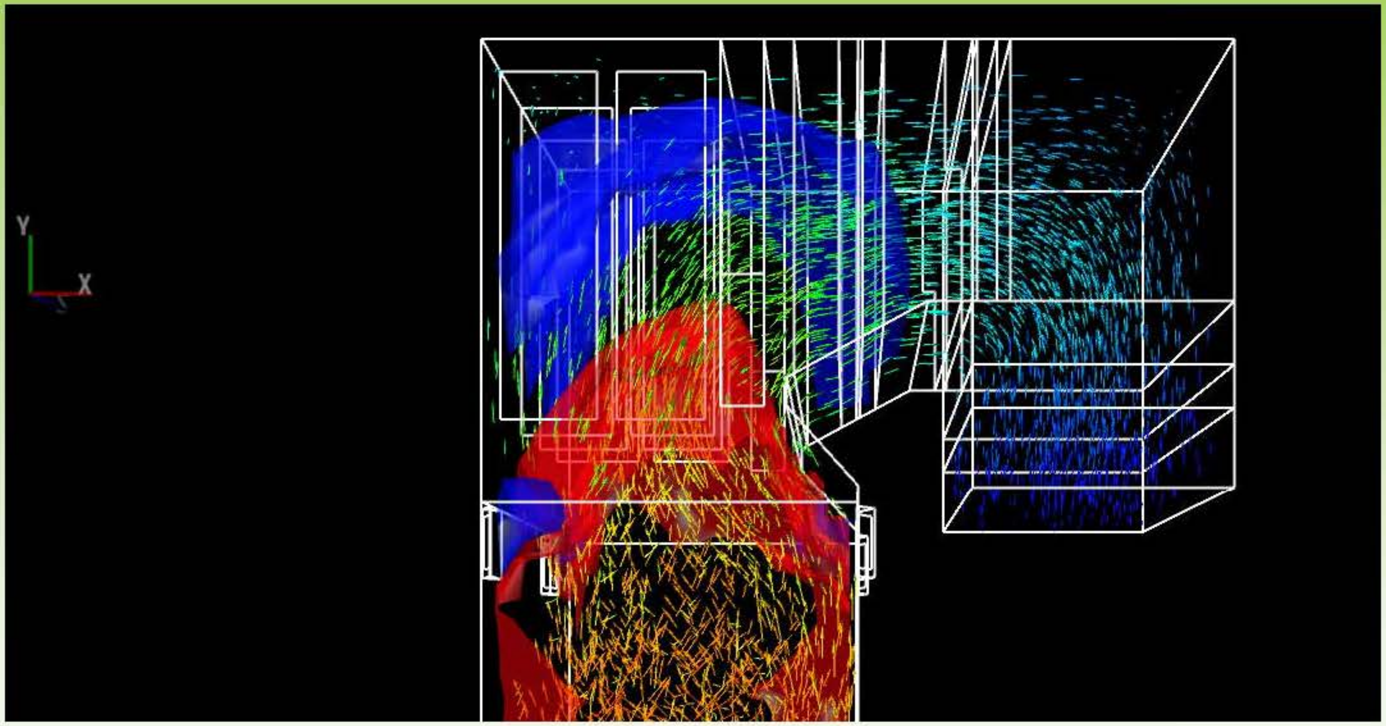
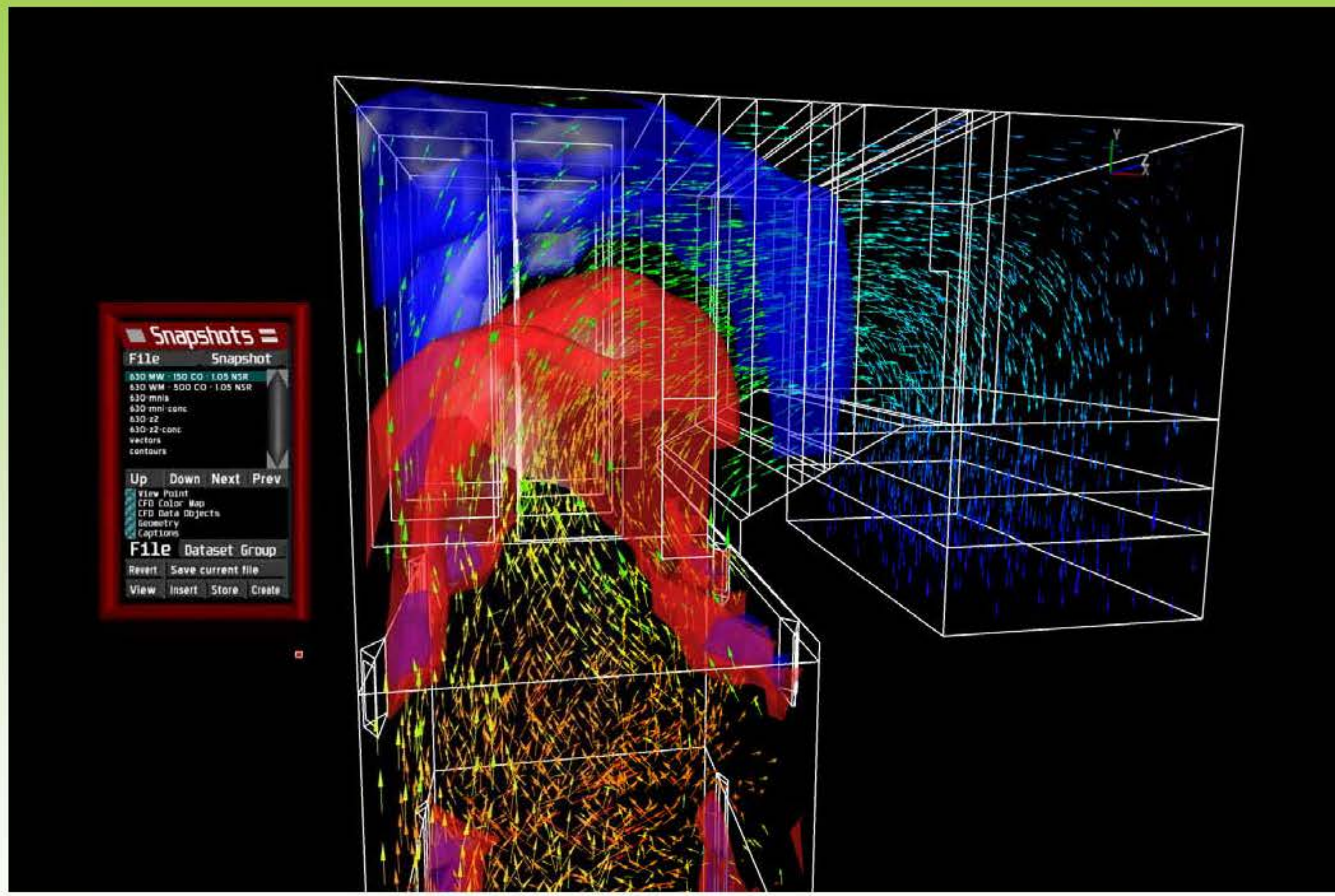
SNCR Effective Temperature Window



2200°F 1600°F

Temperature Window – 150 ppm CO



1950°F 1750°F

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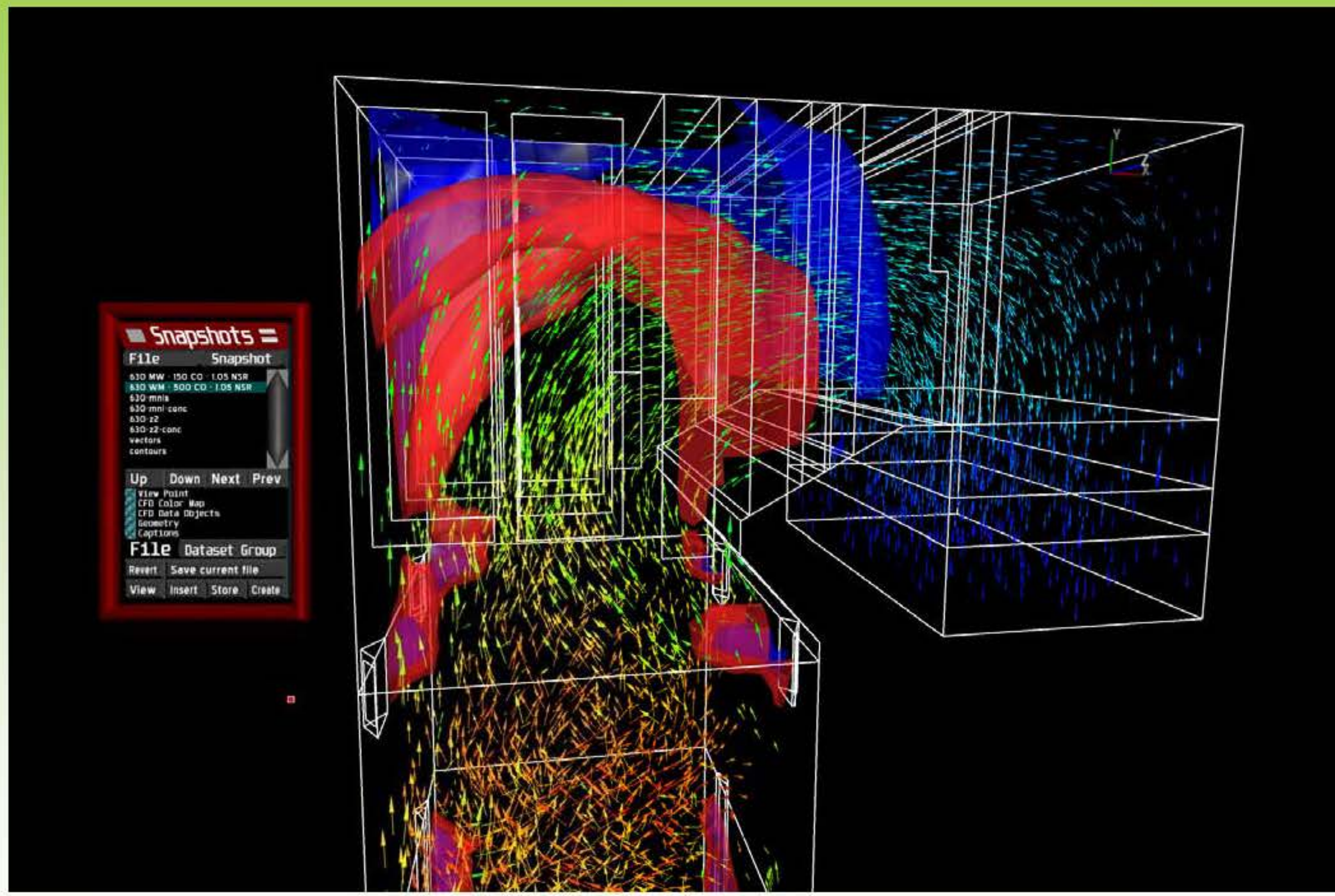
Temperature Window – 500 ppm CO



1750°F 1450°F

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SNCR INJECTION SYSTEMS

SNCR Injection Strategies

- NOxOUT® Technology
  - Air Atomized Urea Injection
  - Larger Droplet Size for Hot and/or Large Boilers and Furnaces
- High Energy Reagent Technology (HERT)
  - Mechanically Atomized Urea Injection through OFA Ports (High Momentum Injectors) and Additional Levels of Injectors in Upper Furnace (Low Momentum Injectors)
  - Recent Applications with Low Baseline Applications and Control Levels at or Below 0.100 lb/MMBtu
- Multiple Nozzle Lances (MNLs)
  - Air Atomized, Fine Mist
  - Convection Pass Injection
- Combined Injection Strategy for Significant NOx Reduction with NH3 Low Slip Control

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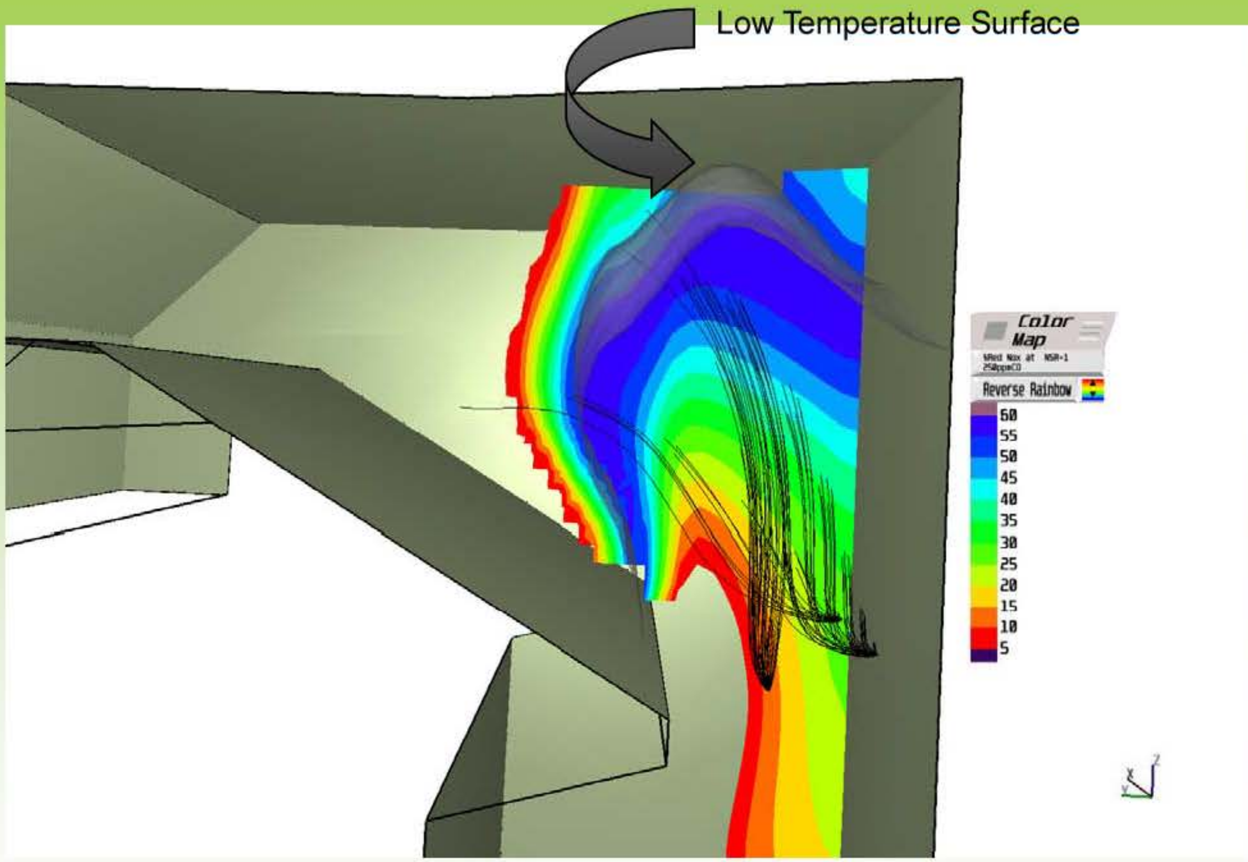
Injection Strategy for SNCR Process



In this figure, the CKM results are overlaid on the ammonia slip limit surface from the previous slide. The colored bands illustrate that NOx reduction is very limited near the plane formed by the bullnose while NOx reduction approaching 60% can be achieved near the low temperature limit.

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SNCR Injection Options

- HERT
  - Lower ammonia slip
  - Higher allowable injection rates
  - Higher NOx reduction performance and higher chemical usage
- NOxOUT
  - More flexibility to control reaction zone
  - Lower chemical usage
  - Ammonia slip can be used with ASCR

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HERT™ Injection Dynamics

- Air Jet penetrates the flue gas flow
- Small urea droplets
- Air and flue gas (NOx) mix
- Droplets heat up and evaporate
- Urea and NO_x Mix
- Urea decomposes to N_2 and H_2O
- Urea reacts with NO

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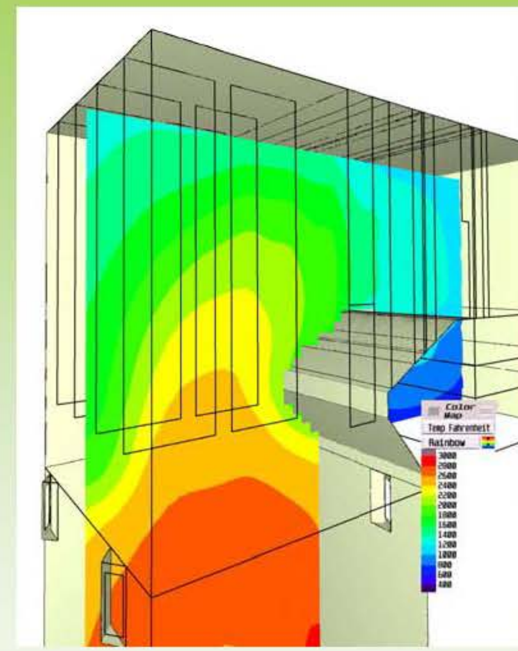
SNCR PERFORMANCE

SNCR NOx Reduction Performance

- Gathering of Data and Information
  - Operational Data
  - Drawings
- Temperature and Species Mapping
  - Upper Furnace Temperatures, NOx, CO, and O2
- Computational Fluid Dynamics (CFD) and Chemical Kinetics Modeling (CKM)
  - Boiler Model for Performance and Injector Placement
- Demonstration System Option
  - 2 to 3 Week Test System
  - Fuel Tech Personnel for Setup, Operation, and Teardown



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HERT Performance

- High reductions from low NOx baseline conditions
- Outlet NOx below 0.1 lb/MMBtu
- Low ammonia slip
- Experience on Range of boiler sizes and types
- Over 40 Combined Commercial and Demonstration Systems

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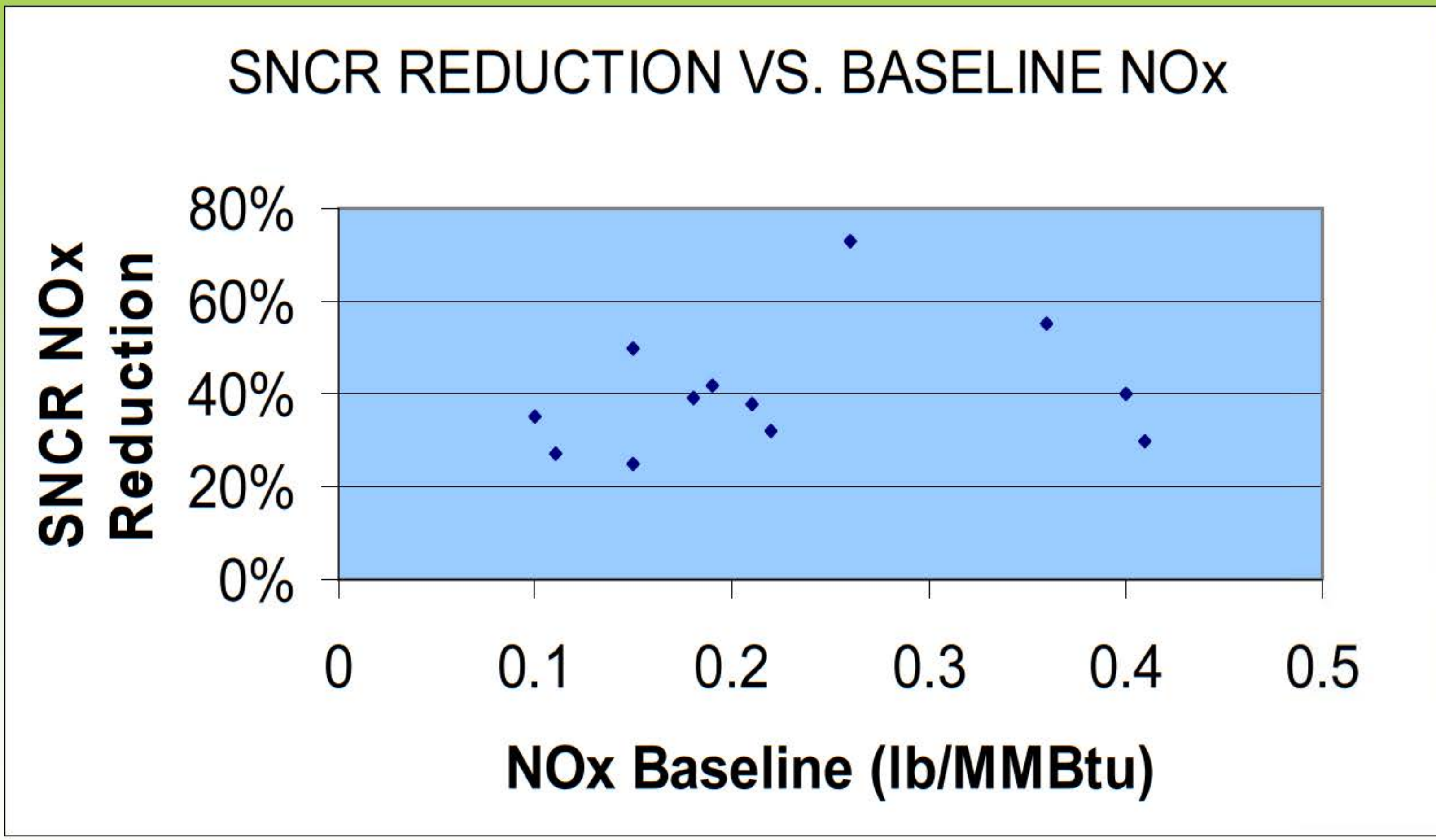
HERT Performance



HERT Performance Summary

Partial List of Commercial and Demo (D) Systems

MW	BASELINE NOx	% REDUCTION	OUTLET NOx
45	0.18	39%	0.11
60	0.19	42%	0.11
100	0.21	38%	0.13
120	0.22	32%	0.15
180	0.40	40%	0.24
200	0.15	25%	0.11
200	0.15	50%	0.08
275 D	0.11	27%	0.08
275 D	0.10	35%	0.07
350 D	0.36	55%	0.16
425 D	0.26	73%	0.07
600 D	0.41	30%	0.29

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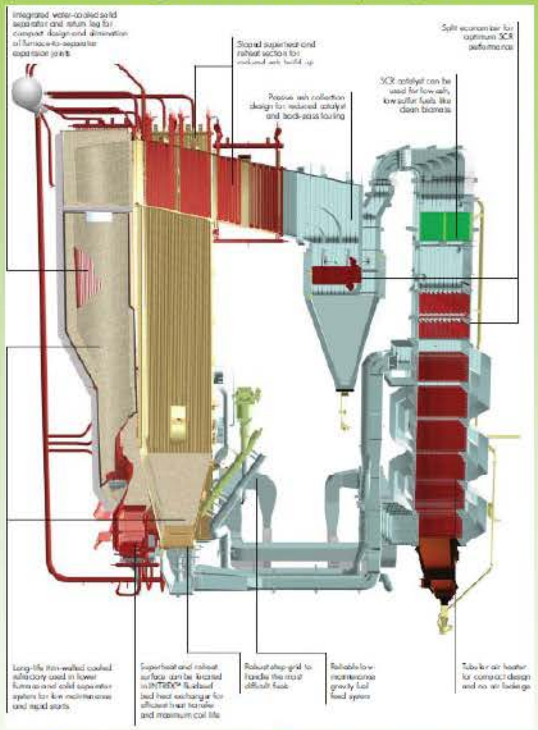
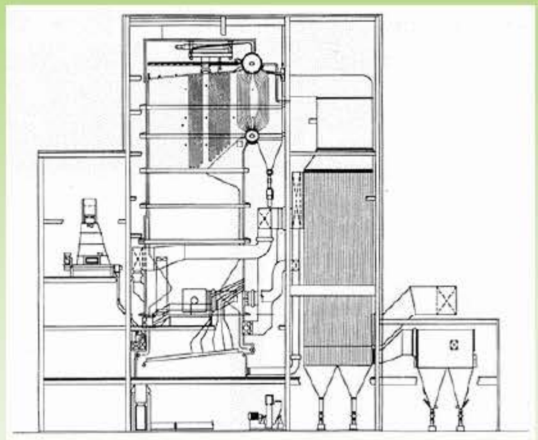
Biomass-fired Applications – Boiler Options

Circulating Fluidized Bed (CFB) Boilers



Drawing courtesy of Foster Wheeler

Grate-fired Stoker Boilers

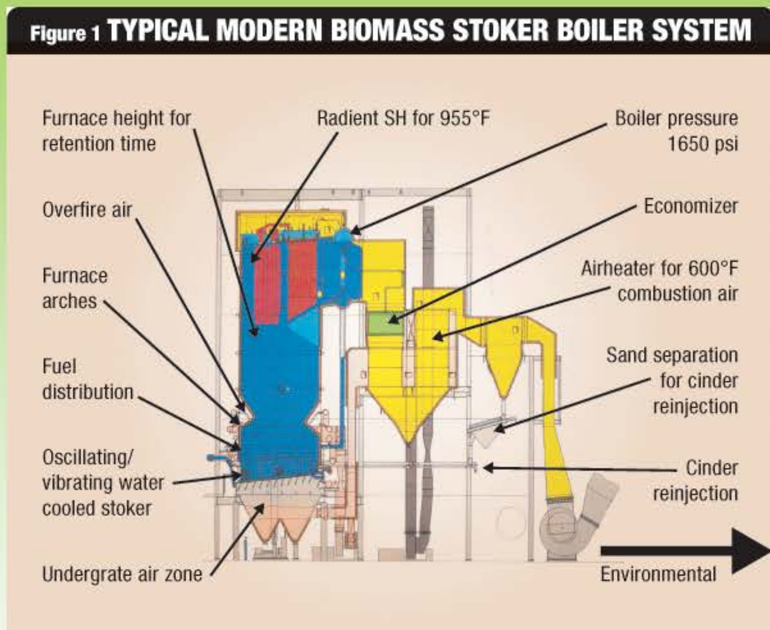


Drawing courtesy of McBurney

Bubbling Fluidized Bed (BFB) Boilers

Drawing courtesy of B&W

SNCR for Grate-fired Stoker

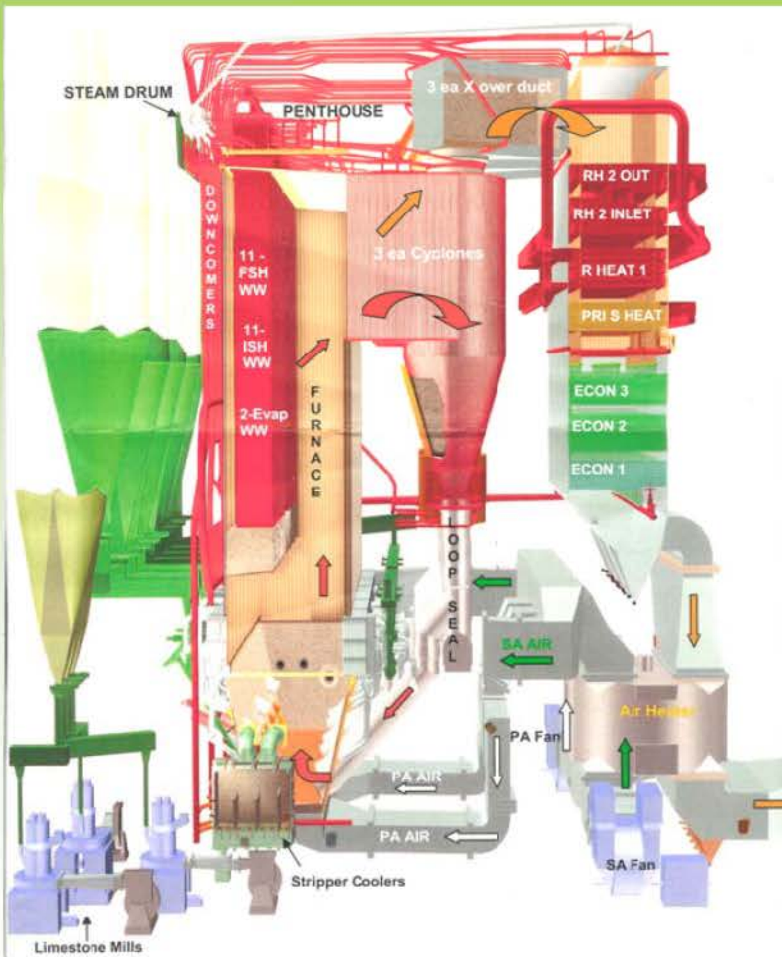


Drawing Courtesy of Babcock & Wilcox

Stoker Boiler Example

- 50 MW Design
- Uncontrolled NOx: 0.25 lb/MMBtu
- Flue Gas Temp @ SH Entrance: 1850°F to 1950°F
- Upper Furnace CO: 400 ppm
- SNCR Performance: 40-50%
- NH3 Slip: 20 ppm
- Comments
  - Working with boiler OEMs to modify designs to provide more favorable upper furnace conditions for SNCR – reducing temperature and increasing residence time

SNCR for Circulating Fluidized Bed (Utility)



CFB Boiler Example

- 2 × 325 MW Boilers
- Uncontrolled NOx: 0.150 lb/MMBtu
- Flue Gas Temp @ Cyclone Entrance: 1575°F to 1650°F
- Upper Furnace CO: < 100 ppm
- SNCR Performance: 40-60%
- NH3 Slip: 20 ppm
- Comments
  - Eight (8) SNCR Injectors per Cyclone, Three Cyclones
  - NOx Controlled to 0.085 lb/MMBtu
  - Aqueous NH3 Used

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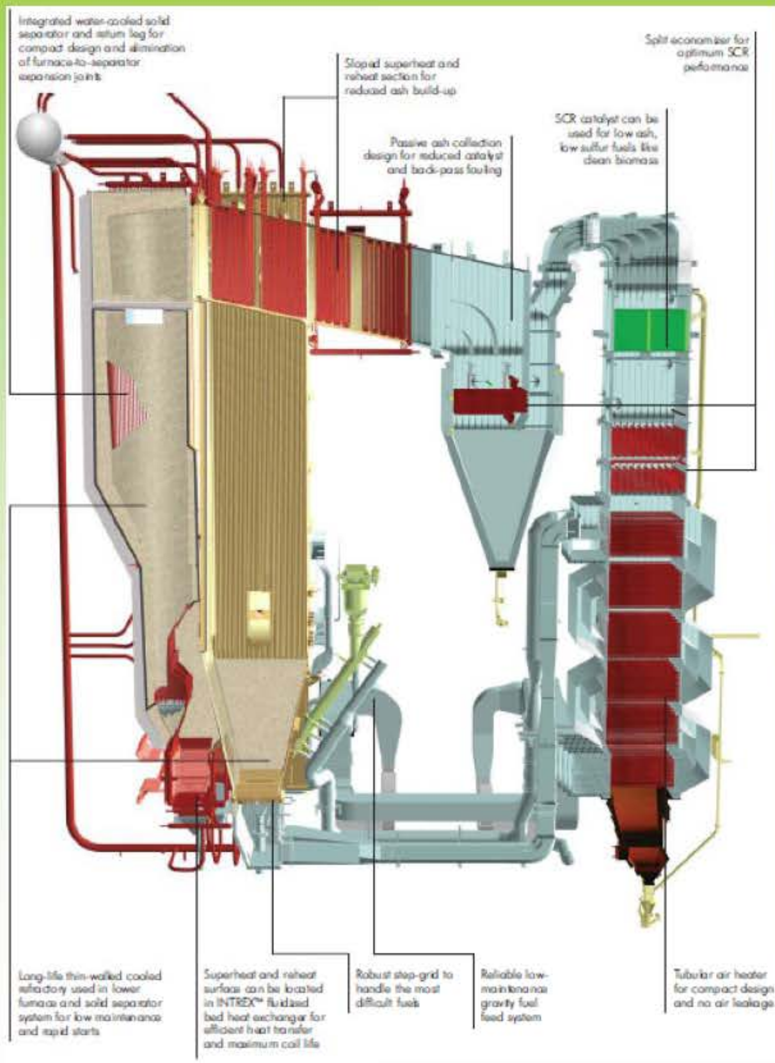
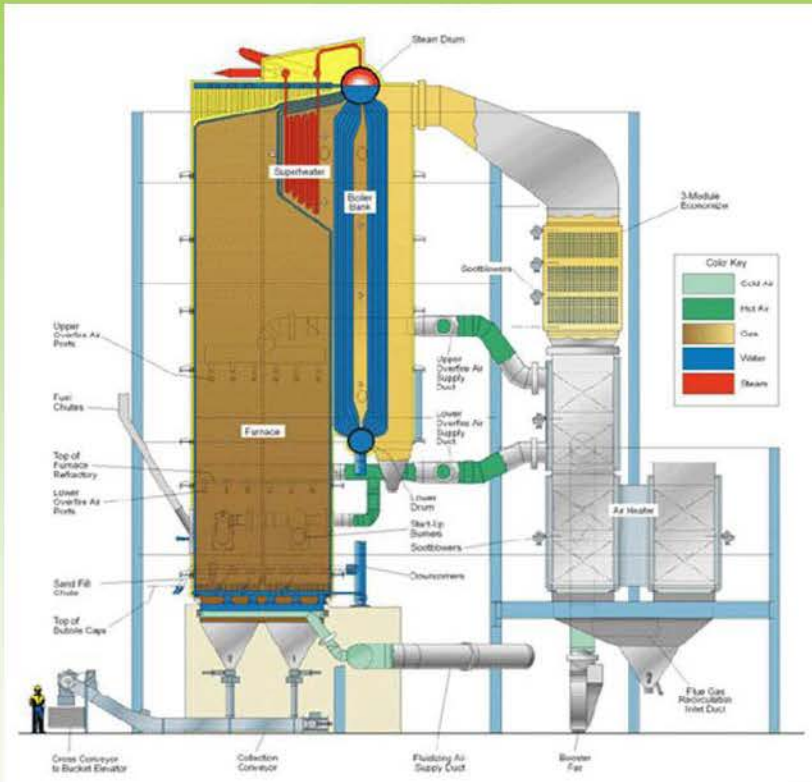
SNCR for Circulating Fluidized Bed (Industrial)



CFB Boiler Example

- 50 MW Design
- Uncontrolled NOx: 0.18 lb/MMBtu to 0.20 lb/MMBtu
- Flue Gas Temp @ Cyclone Entrance: 1600°F to 1650°F
- Upper Furnace CO: < 200 ppm
- SNCR Performance: 50% to 70%
- NH3 Slip: 20 ppm
- Comments
  - NOx Controlled to 0.075 lb/MMBtu
  - Urea and Aqueous NH3 Options, Low Temperature and Long Residence Time Favors Both

SNCR for Bubbling Fluidized Bed



BFB Boiler Example

- 50 MW Design
- Uncontrolled NOx: 0.18 lb/MMBtu to 0.20 lb/MMBtu
- Flue Gas Temp @ Cyclone Entrance: 1600°F to 1650°F
- Upper Furnace CO: < 200 ppm
- SNCR Performance: 50% to 75%
- NH3 Slip: 20 ppm
- Comments
  - Controlled NOx = 0.075 lb/MMBtu
  - Urea and Aqueous NH3 Options, Low Temperature and Long Residence Time Favors Both

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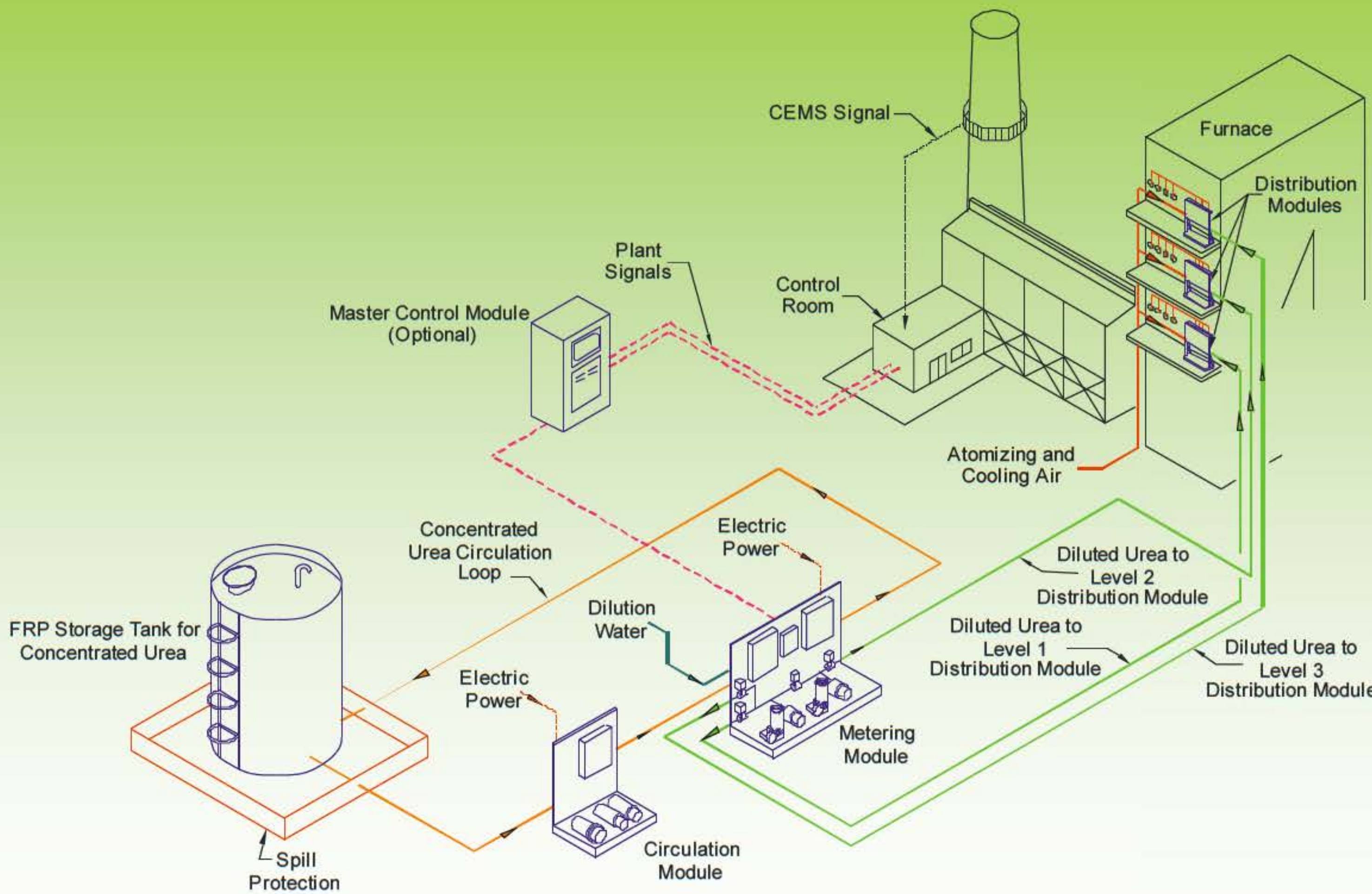
SNCR EQUIPMENT LAYOUT AND COMPONENTS

NOxOUT® SNCR Process Schematic



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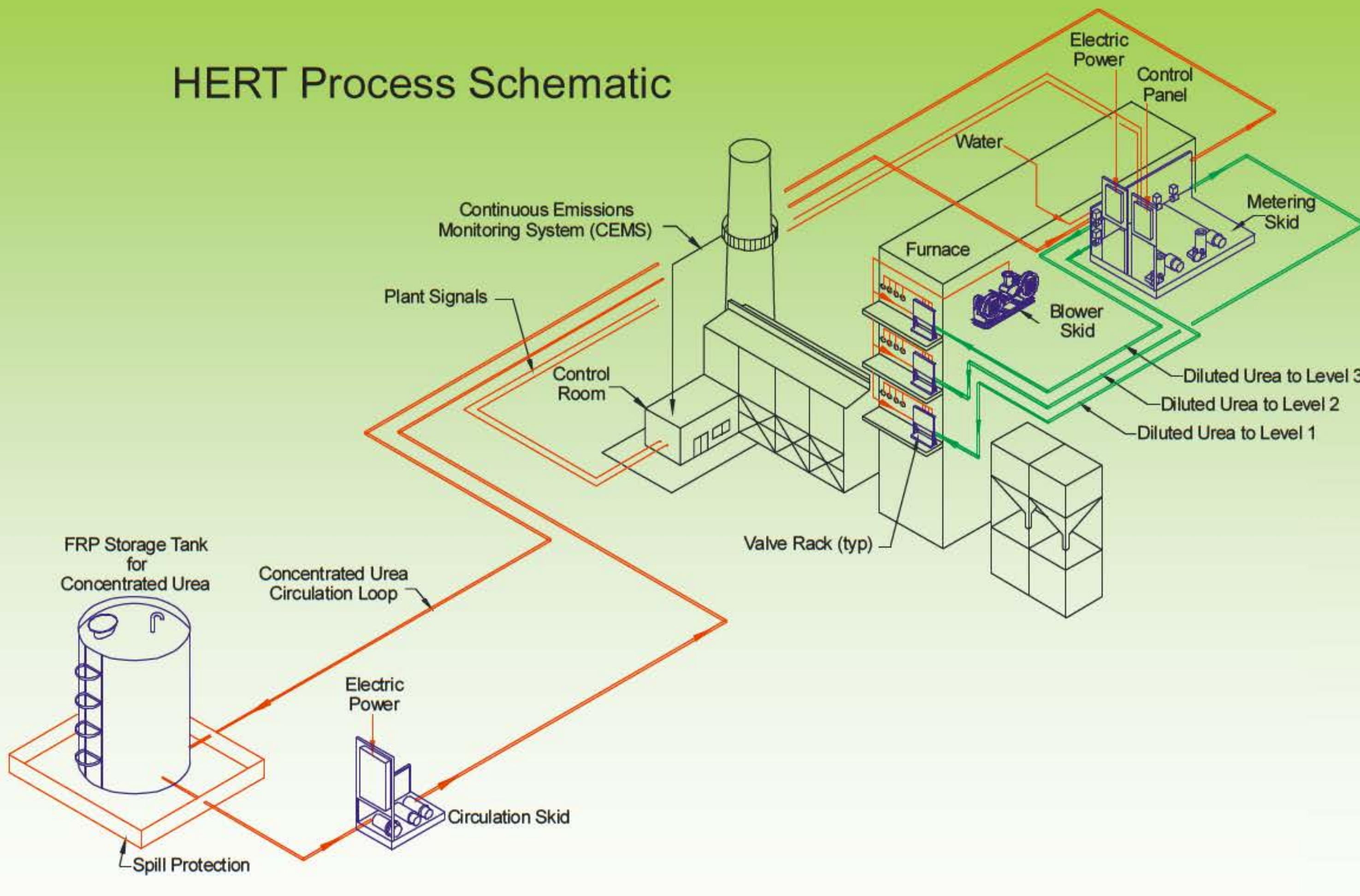
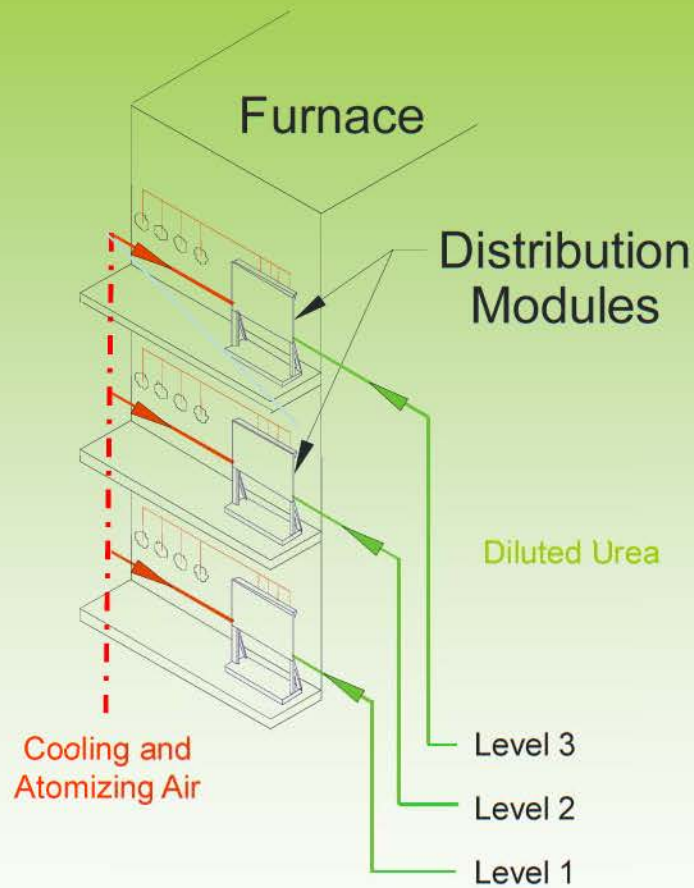
HERT™ SNCR Process Schematic



Note: A key difference between HERT and NOxOUT SNCR is the use of small, mechanically atomized droplets that are guided to the high NOx regions using high momentum injectors installed in OFA ports and low momentum injectors in upper level ports where blower air guides the diluted urea.

SNCR Distribution Modules & NOxOUT Injectors



Notes

1) Number of levels is determined by the furnace geometry and the desired load range for SNCR operation.
2) The location of injectors is generally dictated by access and physical obstructions – CFD/CKM model determines preferred locations.
3) Compressed air and diluted urea is sent from the Metering Module to the Distribution Modules, where the air pressure and urea flow rate to each injector are controlled.

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Urea Tanks

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Urea Tank

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NOxOUT Reagent Storage

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Circulation Modules

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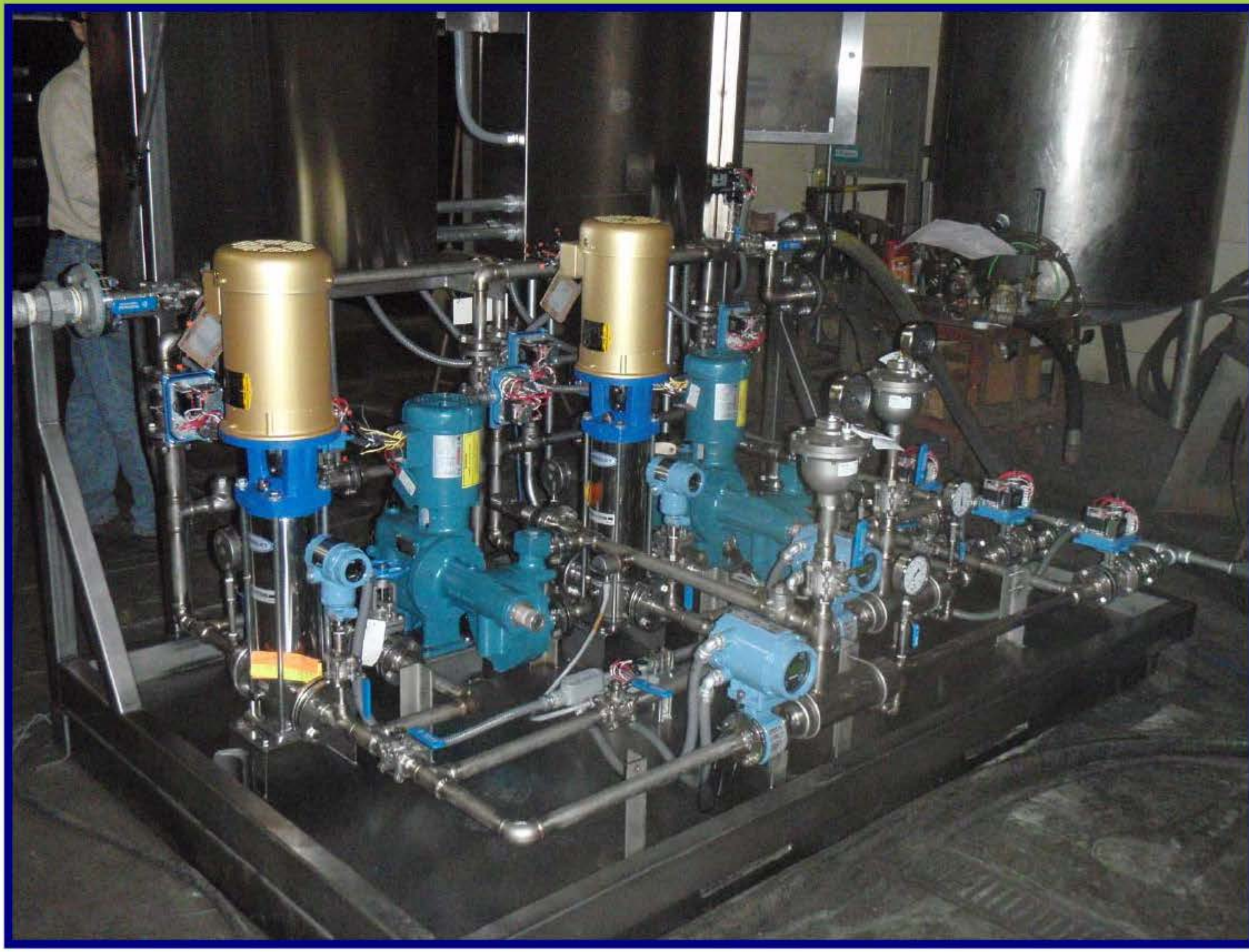
HERT Circulation Skid



Metering Module

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HERT System Solenoid Rack

NOxOUT Injection

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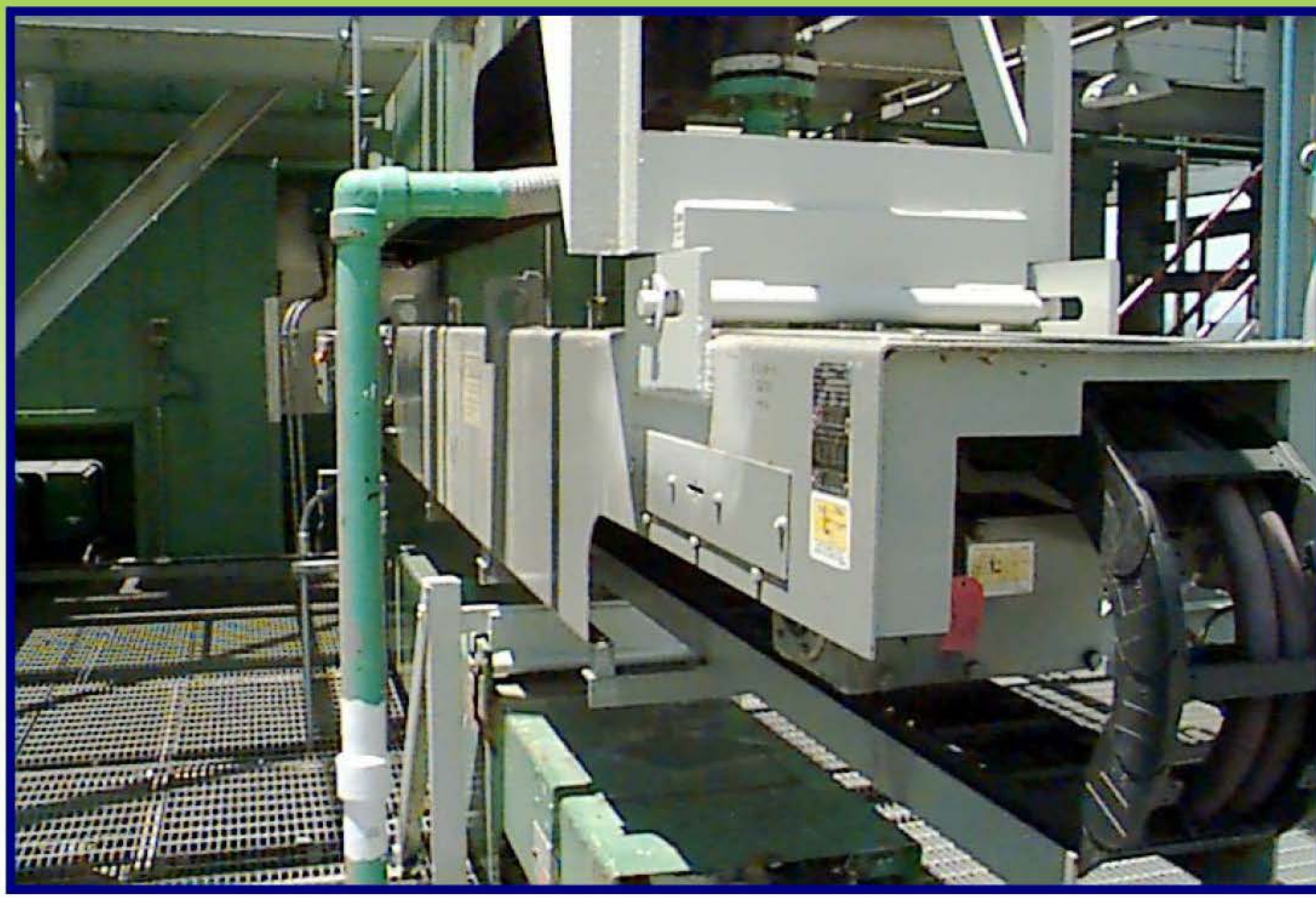
Multiple Nozzle Lances



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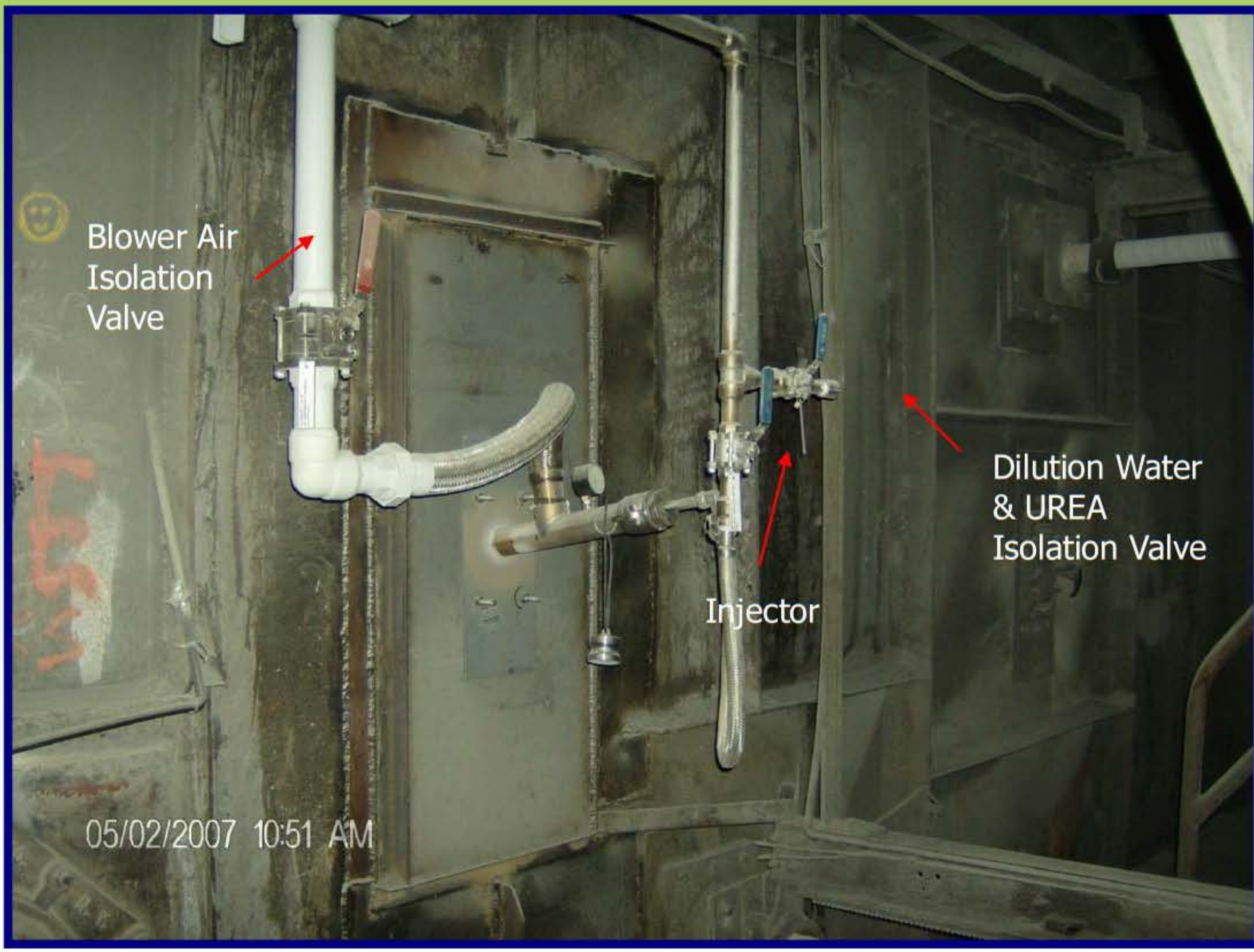
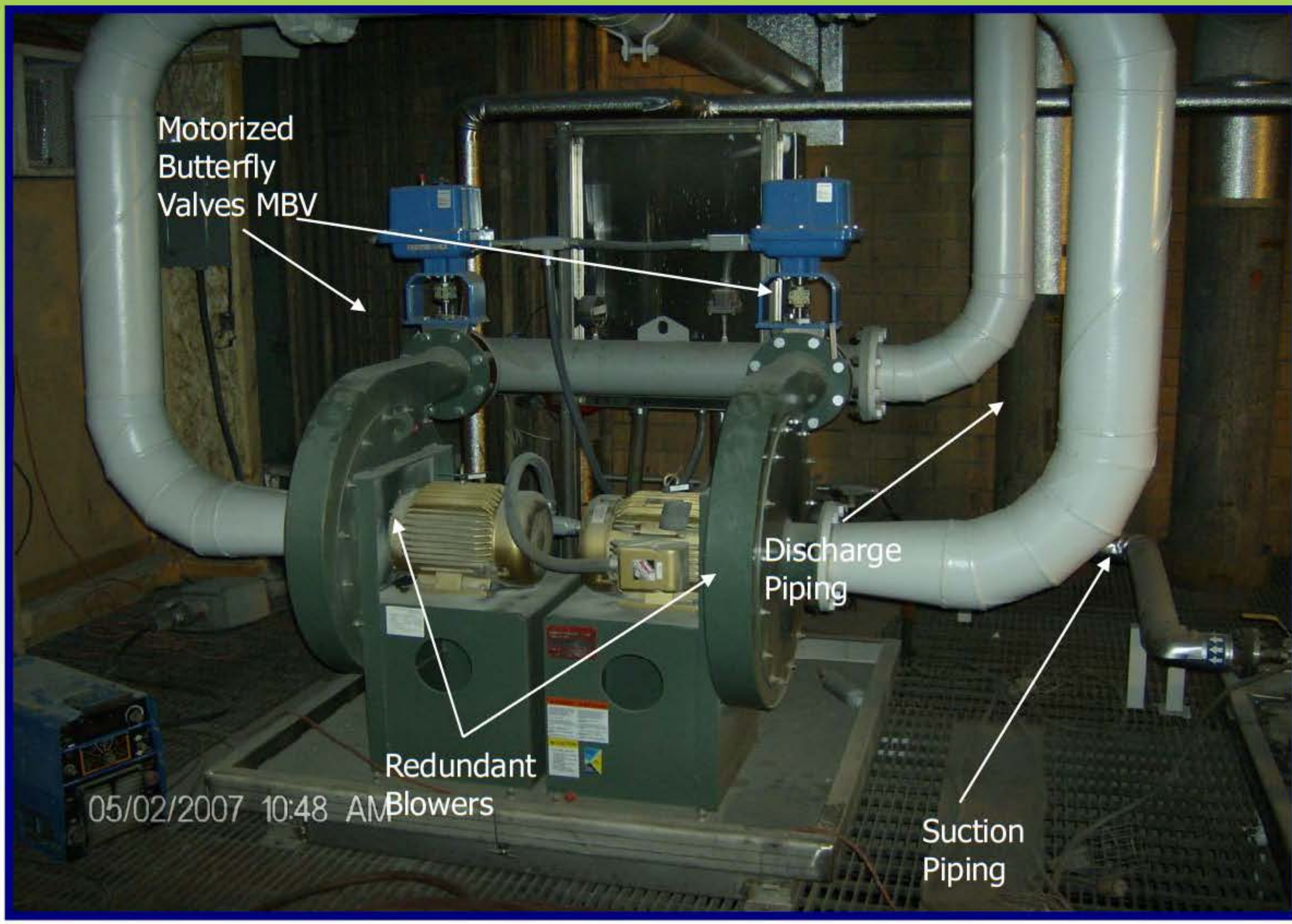
HERT INJECTOR



Blower Skid



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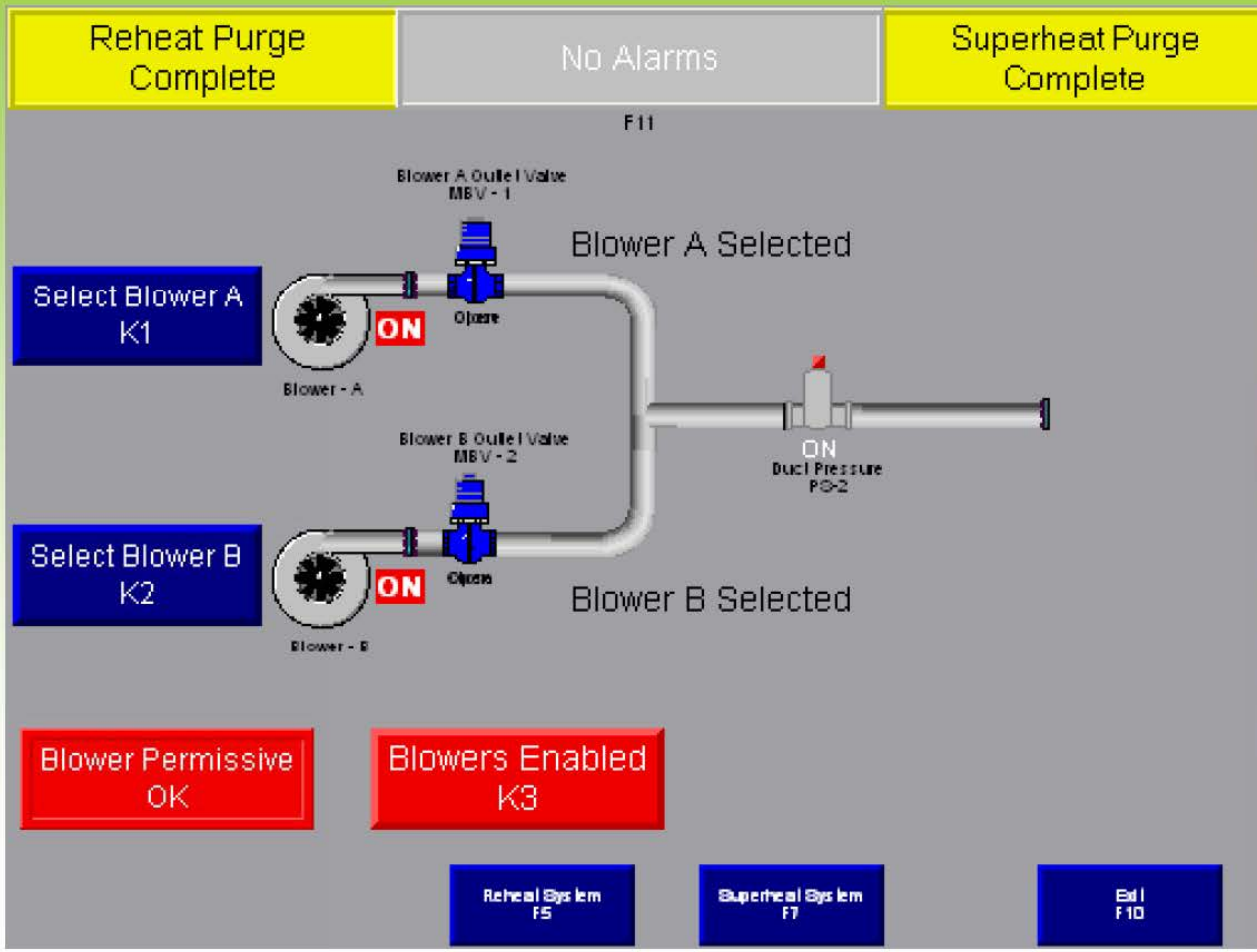
Blower Skid Screen



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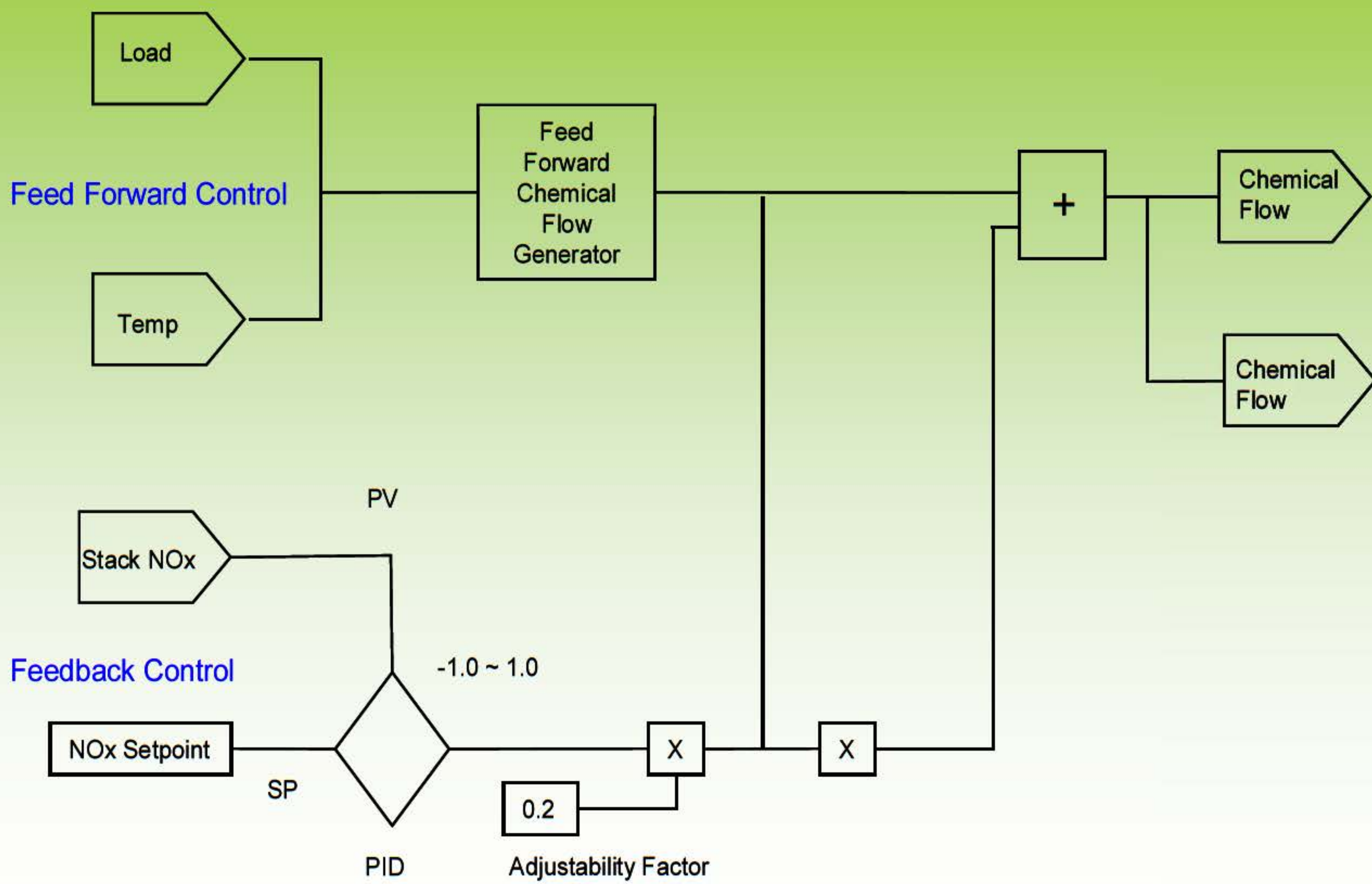
NOxOUT® SNCR Control Loop



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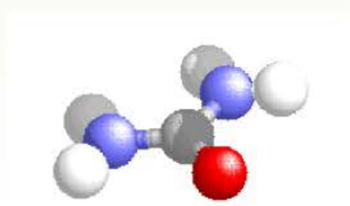
UREA REAGENT OPTIONS

Liquid Urea Properties – NH_2CONH_2

at 60°F	NOxOUT LT		NOxOUT A		Urea Liquor	
Urea Concentration	**32.5%**	**40.0%**	**50.0%**	**60.0%**	**70.0%**	**85.0%**
Specific Gravity	1.0897	1.1113	1.1400	1.1688	1.1976	1.2407
Pounds per Gallon	9.085	9.265	9.505	9.643	9.767	9.970
Crystallization Temperature (°F)	11.3	33	62	96	135	195
Boiling Point (°F)		220	225	231	240	
Biuret	0.14	0.17	0.21	0.3 to 0.4	0.3 to 0.4	0.36
pH	7.0 to 10.0	7.0 to 10.0	7.0 to 10.0	7.0 to 10.0	7.0 to 10.0	7.0 to 10.0
lb-NH3/gallon	1.67	2.10	2.70	3.28	3.88	4.81



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Urea and Dilution Water Quality

QUALITY SPECIFICATIONS – UREA				
	NOxOUT® A	NOxOUT® HP	UNSTABILIZED UREA	NOxOUT® LT
Description	Modified 50% Aqueous Solution of Urea	Modified 50% Aqueous Solution of Urea	50% Aqueous Solution of Urea	Modified 32.5% Aqueous Solution of Urea
Density (g/ml @ 25° C)	1.13 - 1.15	1.13 - 1.15	1.13 - 1.15	1.085 - 1.105
pH	7.0 - 10.8	7.0 - 10.8	7.0 - 10.8	5.0 - 10.8
Appearance	Light Yellow, Clear to Slightly Hazy	Light Yellow, Clear to Slightly Hazy	Light Yellow, Clear to Slightly Hazy	Light Yellow, Clear to Slightly Hazy
Salt Out Freeze Point	64°F (18°C)	64°F (18°C)	64°F (18°C)	40°F (4°C)
Foam (after bottle is shaken)	Foam Lasts > 15 seconds	Foam Lasts > 15 seconds	Not Applicable	Foam Lasts > 15 seconds
Free NH3	< 5000 ppm	< 5000 ppm	< 5000 ppm	< 3000 ppm
Biuret Content	< 5000 ppm	< 5000 ppm	< 5000 ppm	< 3000 ppm
Organic Phosphate	55 - 85 ppm as PO4	22 - 40 ppm as PO4	Not Applicable	55 - 85 ppm as PO4
Orthophosphate	< 6 ppm as PO4	< 6 ppm as PO4	< 2 ppm as PO4	< 6 ppm as PO4
Suspended Solids	< 10 ppm	< 10 ppm	< 10 ppm	< 10 ppm
Urea Makeup Water	Total Hardness as CaCO3 ≤ 300 ppm	Total Hardness as CaCO3 ≤ 150 ppm	Total Hardness as CaCO3 ≤ 20 ppm	Total Hardness as CaCO3 ≤ 300 ppm

QUALITY SPECIFICATIONS – DILUTION WATER				
	NOxOUT® A	NOxOUT® HP	UNSTABILIZED UREA	NOxOUT® LT
	Dilution Water Analysis	Dilution Water Analysis	Dilution Water Analysis	Dilution Water Analysis
Total Hardness as CaCO3 (ppm)	<450	<150	<20	<450
"M" Alkalinity as CaCO3 (ppm)	<300	<100	<100	<300
Conductivity (µmho)	<2500	<1000	<1000	<2500
Silica as SiO2 (ppm)	<60	<60	<60	<60
Iron as Fe (ppm)	<1.0	<1.0	<1.0	<1.0
Manganese as Mn (ppm)	<0.3	<0.3	<0.3	<0.3
Phosphate as P (ppm)	<1.0	<1.0	<1.0	<1.0
Sulfate as SO4 (ppm)	<200	<200	<200	<200
Turbidity (NTU)	< 10	< 10	< 10	< 10
pH	<8.3	<8.3	<8.3	<8.3

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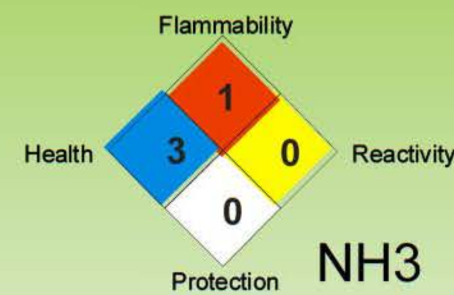
Urea vs. Ammonia

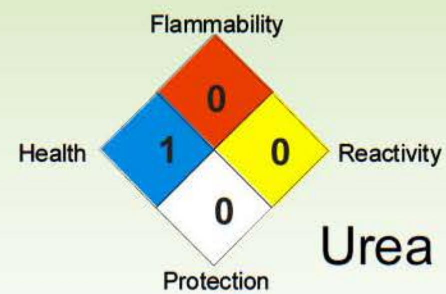
- **Safety Considerations**
  - **Safety can be Engineered into the Design, but Considerations may Drive the Decision**
- **Natural Gas Pricing**
  - **Elevated Price of NG in North America is Forcing the Shutdown of NH3 Productions and an Increase in Dry Urea Imports**
  - **LNG is an Alternative but Supply Insufficient to Cover Demand**
- **On-site Ammonia Storage**
  - **DHS has Promulgated Final Rule for On-site Storage of Chemicals – Unsure How this Will Impact Anhydrous NH3 Storage for SCR's**
- **Transportation**
  - **"Chain of Custody" Regulations for TIH* Rail Shipments Driving Transportation Costs Considerably Higher, Some Carriers May Opt and are Currently Being Forced to Reroute Shipments to Avoid HTUA's**

* The TSA component of the DHS is about to implement a series of federal regulations affecting the transportation of Toxic Inhalation Hazard (TIH) materials such as Chlorine and Anhydrous Ammonia – will require "documented chain of command handoffs" along distribution zone.

Reagent Alternatives for SNCR Systems

- **Anhydrous Ammonia**
  - **Highest Risk Reagent**
  - **Decrease in US Ammonia Production**
- **Aqueous Ammonia**
  - **19% Concentration**
  - **29% Concentration - limited availability**
- **Urea for On-Site Ammonia Generation**
  - **Significant Safety Advantages**
  - **Worldwide Availability of Urea**
  - **Equivalent SCR Performance**





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Anhydrous Ammonia – Safety Considerations

- Ammonia Storage
  - Department of Homeland Security (DHS) has indentified ammonia as a chemical of interest for anti-terrorism standards
- Transportation
  - Rail carrier risks and freight rate increases to handle anhydrous ammonia
  - Department of Transportation Restrictions
  - State and local restrictions on shipping and routing
- Safety Risks
  - *EPA Worst Case Release Analysis* – Toxic Endpoint for 60,000 Gallon Release Covers a Radius of 7 to 10 Miles[1]

1 http://yosemite.epa.gov/oswer/ceppoweb.nsf/vwResourcesByFilename/backup.pdf/$File/backup.pdf

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Aqueous Ammonia – Safety Considerations

- **Ammonia Storage**
  - Containment for possible liquid leaks/spills
- **Transportation**
  - 29% Aqueous ammonia is restricted by Department of Transportation in many areas
  - State and local restrictions on shipping and routing
- **Safety Risks**
  - Increased transportation risk due to more shipments of dilute chemical
  - 1.2 mile toxic radius for 60,000 gallon spill
  - Much higher unloading frequency at plant site raises potential incident probability

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Licensed NOxOUT Reagent Suppliers

Licensee Corporate Office	Address	Contact Person	Telephone/Fax
CDI, Inc.	P.O. Box 9083 Brea, CA 92821 -or- 471 W. Lambert Rd Suite 100 Brea, CA 92821	Luis Cervantes Rick Gross	714.990.3940 714.329.2281 (cell) 714.990.4073 (fax) (901) 867-8186 office (901) 233-2336 mobile
Distribution Points	– Crossett, AR – Casa Grande, AZ - City of Industry, CA – Imperial, CA – San Jose, CA – Stockton, CA – Greeley, CO – Jacksonville, FL – Augusta, GA – Kimberly, ID – Baltimore, MD – St. Paul, MN – Albany, NY – Elizabeth, NY – Cincinnati, OH – Lima, OH – Deer Island, OR – Russellville, SC – Memphis, TN – Houston, TX – Lufkin, TX – Pasco, WA		
Mosaic Company (formerly Cargill, Inc)	12800 Whitewater Dr MS 190 Minnetonka, MN 55343	Bob Ness	800.918.8270 763.577.2781 952.742.7313 (fax)
Distribution Points	– Brandon, FL – Baltimore, MD – St. Paul, MN – Albany, NY – Cincinnati, OH – Wellsville, OH – Philadelphia, PA – Menomonie, WI		
PCS Nitrogen, Inc	1101 Skokie Blvd Northbrook, IL 60062	Jennifer A. Zagorski	847.849.4377 (office) 847.612.5301 (cell) 847.849.4489 (fax)
Distribution Points	– Augusta, GA - Lima, OH		

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Licensed NOxOUT Reagent Suppliers

Monson Companies, Inc.	One Runway Rd P.O. Box 2405 South Portland, ME 04116-2406	Jeff Pellerin	207.885.5072 x 423 207.885.0569 (fax)
Distribution Points	– South Portland, ME		
Agrium USA	13132 Lake Fraser Dr SE Calgary, AB T2J7E8 CANADA	Gerry Kroon	403.335.7597 403.471.6473 (cell)
Distribution Points	– Stockton, CA		
The Andersons, Inc.	480 W. Dussel Drive P.O. Box 119 Maumee, OH 43537	Bill Wolf	419.897.3689
Distribution Points	– Logansport, IN – Maumee, OH		
Colonial Chemical Co.	78 Carranza Rd Tabernade, NJ 08088	Eric Wegelius	609.268.1200 x 112 609.268.2117 (fax)
Distribution Points	– Frederick, MD – Tabernacle, NJ		

Information Needed by Licensees:

- Company Name
- Location
- Scheduled Start-Up Date
- If rail delivery- specify railroad
- NOxOUT® Reagent Type Required (A, HP, LT)
- NOxOUT® Reagent Usage Rate
- NOxOUT® Reagent Storage Tank Size

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SNCR Combined with other NO_x Control Technologies

Layered NOx Reduction

- Combustion NOx Control
  - Combustion Tuning
  - Low-NOx Burners
  - OFA
- Post-Combustion NOx Control
  - Rich Reagent Injection
  - Selective Non-Catalytic Reduction
  - Selective Catalytic Reduction

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Combining NOx Reduction Technologies

Technology	Strength	Limitations
Low-NOx Burners	Low Capital and Operating	Combustion, Corrosion, CO
Combustion Mods / OFA	Low Capital and Operating	Combustion, Corrosion, CO
SNCR	Low Capital NOx Red%	NH3 Slip ABS
SCR	NOx Red% Low NH3 Slip	High Capital SO_3 Oxidation

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Retrofit Low-NOx Burner Installation

Technology	Strength	Limitations
Low-NOx Burners	Low Capital and Operating	Combustion, Corrosion, CO
Combustion Mods / OFA	Low Capital and Operating	Combustion, Corrosion, CO
SNCR	Low Capital NOx Red%	NH3 Slip ABS
SCR	NOx Red% Low NH3 Slip	High Capital SO_3 Oxidation

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Moderate Combustion Modifications

Technology	Strength	Limitations
Low-NOx Burners	<u>Low Capital and Operating</u>	Combustion, Corrosion, CO
Combustion Mods / OFA	<u>Low Capital and Operating</u>	Combustion, Corrosion, CO
SNCR	Low Capital NOx Red%	NH3 Slip ABS
SCR	NOx Red% Low NH3 Slip	High Capital SO_3 Oxidation

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Conservative SNCR application

Technology	Strength	Limitations
Low-NOx Burners	Low Capital and Operating	Combustion, Corrosion, CO
Combustion Mods / OFA	Low Capital and Operating	Combustion, Corrosion, CO
SNCR	Low Capital NOx Red%	No NH3 Slip No ABS
SCR	NOx Red% Low NH3 Slip	High Capital SO_3 Oxidation

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Aggressive SNCR application

Technology	Strength	Limitations
Low-NOx Burners	Low Capital and Operating	Combustion, Corrosion, CO
Combustion Mods / OFA	Low Capital and Operating	Combustion, Corrosion, CO
SNCR	Low Capital > Red%	NH3 Slip ABS
SCR	NOx Red% Low NH3 Slip	High Capital SO_3 Oxidation

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In-Duct or Small SCR Space

Technology	Strength	Limitations
Low-NOx Burners	Low Capital and Operating	Combustion, Corrosion, CO
Combustion Mods / OFA	Low Capital and Operating	Combustion, Corrosion, CO
SNCR	Low Capital > Red%	NH3 is OK Feed to SCR
Single Layer SCR	More Red% Low NH3 Slip	Mod Capital, SO_3 and Cost

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Advanced SCR Application

Technology	Reduction	Total %
Low-NOx Burners	30%	30%
Combustion Mods / OFA	30%	51%
SNCR	30%	66%
Single Layer SCR	45%	81%

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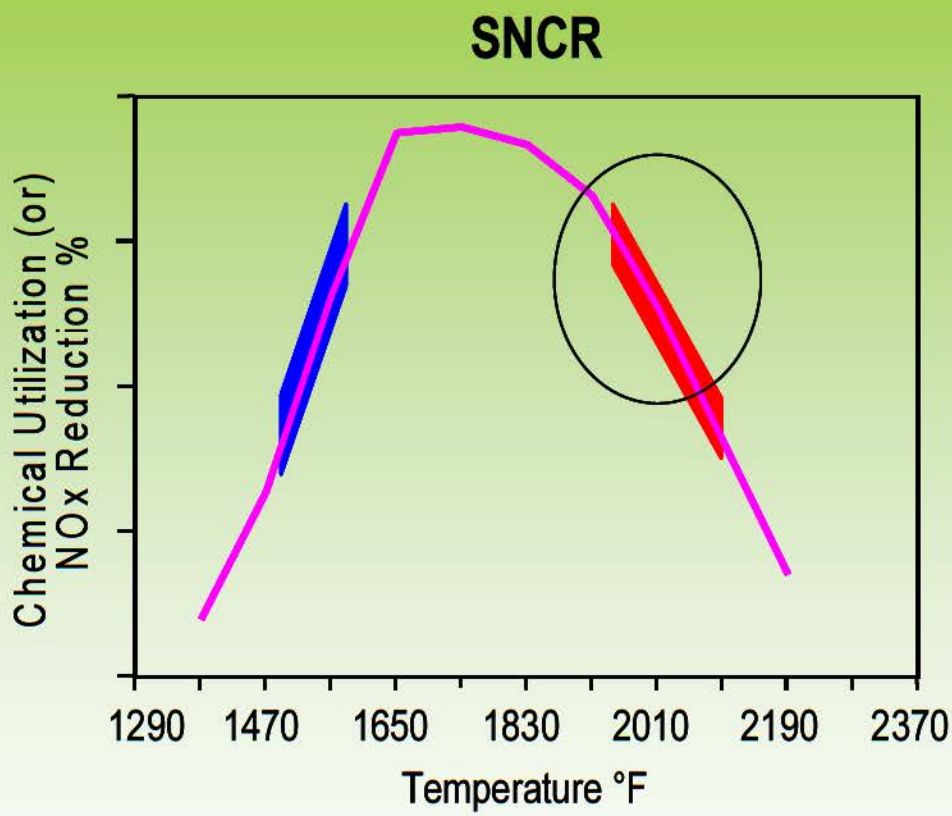
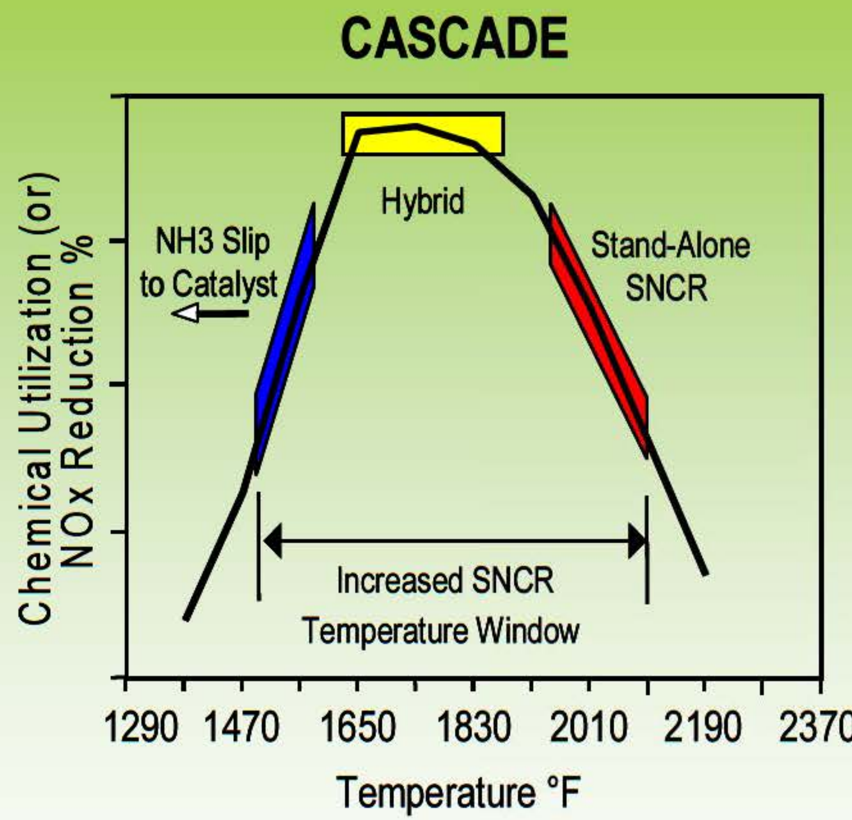
Chemical Release Point Comparison





Releasing chemical at or near the top of the curve versus "right side of the slope" favors increased NOx reduction efficiency and better utilization of reagent – NH3 slip is absorbed by catalyst.

Benefits of Hybrid SNCR + SCR System

- SNCR Not Restricted to "Right Side of Slope" Injection Strategy
- Impact of "High" CO can, in many cases, be Minimized
- Controlled Increase in Ammonia Slip (versus SNCR) is Desirable, Significant Improvement in SNCR Efficiency and Chemical Utilization
- Relax Inlet Conditions to SCR, Design for Incremental SCR Reduction and NH3 Absorption
- Pressure Drop is Minimized as a Result of Reduced Volume and Treatment Length, Allowable Gas Velocity Now Higher with State-of-the-Art Flue Gas Mixing and Straightening Devices
- Reduced Conversion of SO_2 to SO_3
- Lower Catalyst Replacement Cost, Single Layer

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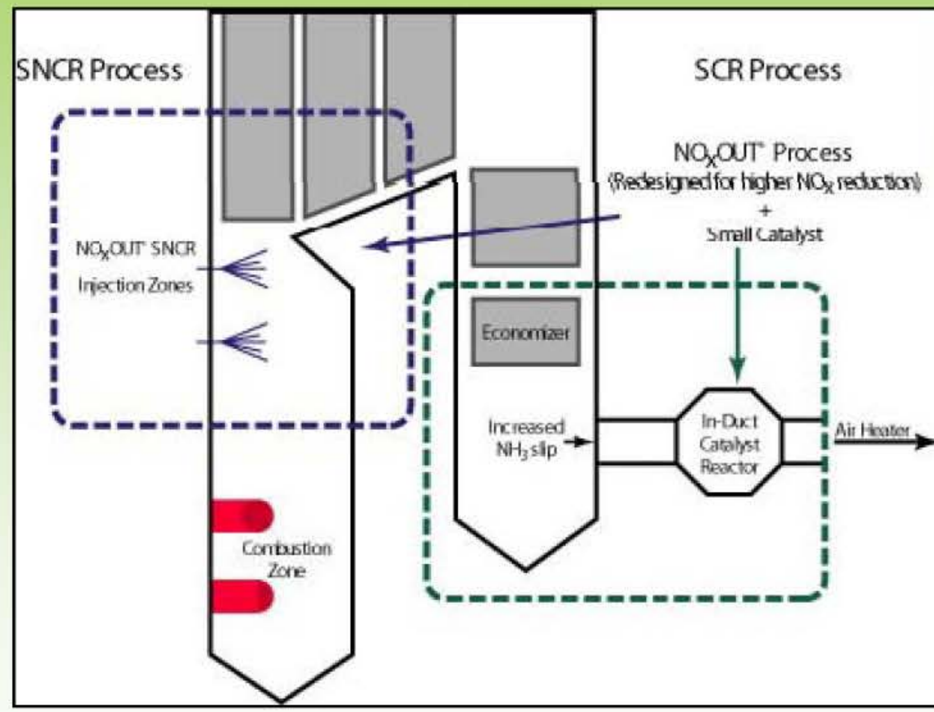
NOxOUT CASCADE® Technology Overview

- Combined SNCR/SCR Process
- Single Layer SCR Catalyst – Reduced Volume
- Improved SNCR Chemical Utilization and Reduction Efficiency with Higher, Controlled Level of Ammonia Slip
- Ammonia Slip from SNCR Provides Reagent for Catalytic Reactions
- NO_x Reduction Performance - 65-85%
- Lower Capital Cost ($30 to $75 per kW) compared to Full Scale SCR (Up to >$300/kW)
- Demonstrated Mercury Oxidation of >90% with Single Layer Catalyst for Capture with FGD System



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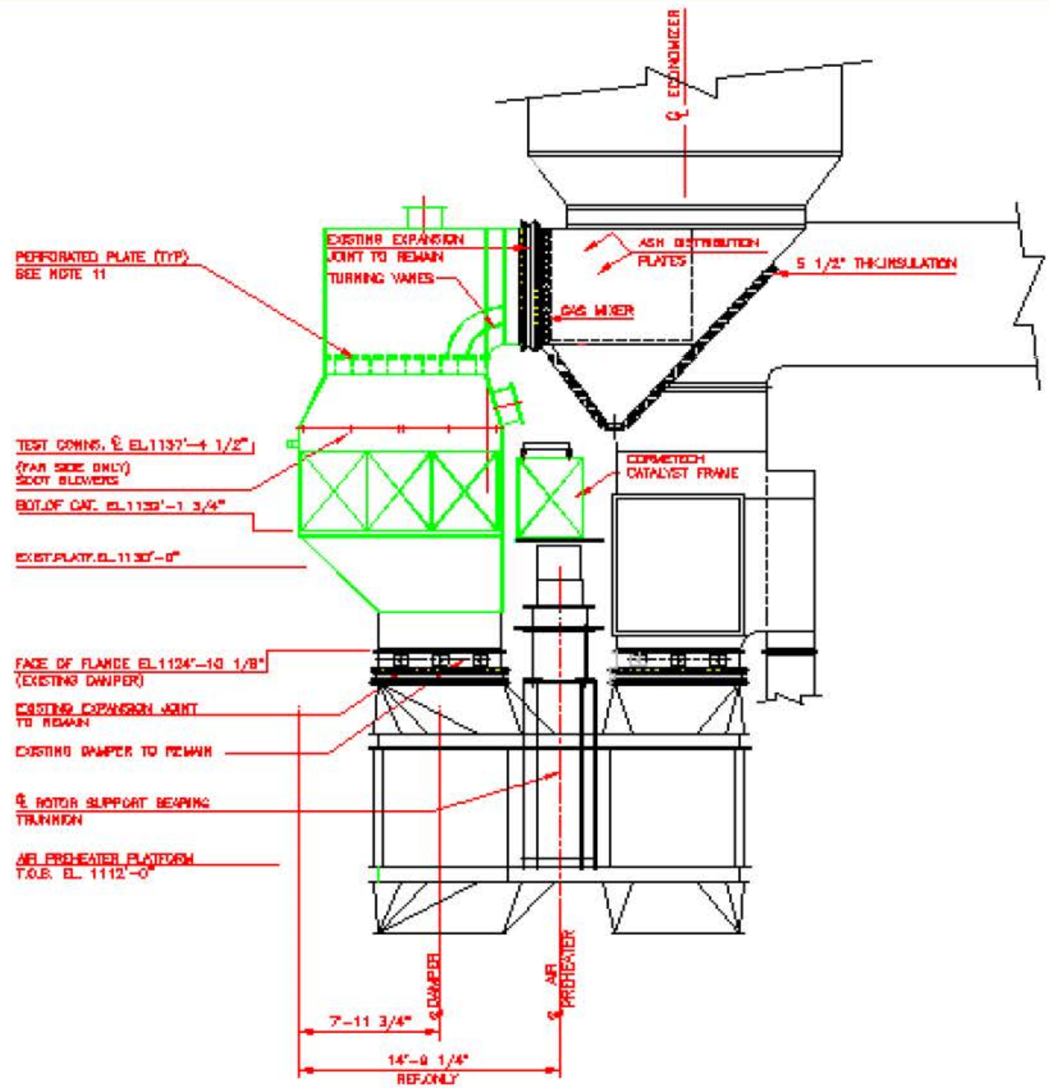
Penelec Seward Duct Modifications



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AES Greenidge – Multi-P w/ CASCADE

AES Greenidge Unit 4
(Boiler 6)

ELECTRIC POWER CONFERENCE & EXHIBITION

- Dresden, NY
- Commissioned in 1953
- 107 MW_e (net) reheat unit
- Boiler:
  - Combustion Engineering tangentially-fired, balanced draft
  - 780,000 lb/h steam flow at 1465 psig and 1005 °F
- Fuel:
  - Eastern bituminous coal
  - Biomass (waste wood) – up to 10% heat input
- Existing emission controls:
  - Overfire air (natural gas reburn not in use)
  - ESP
  - No FGD - mid-sulfur coal to meet permit limit of 3.8 lb SO_2/MMBtu

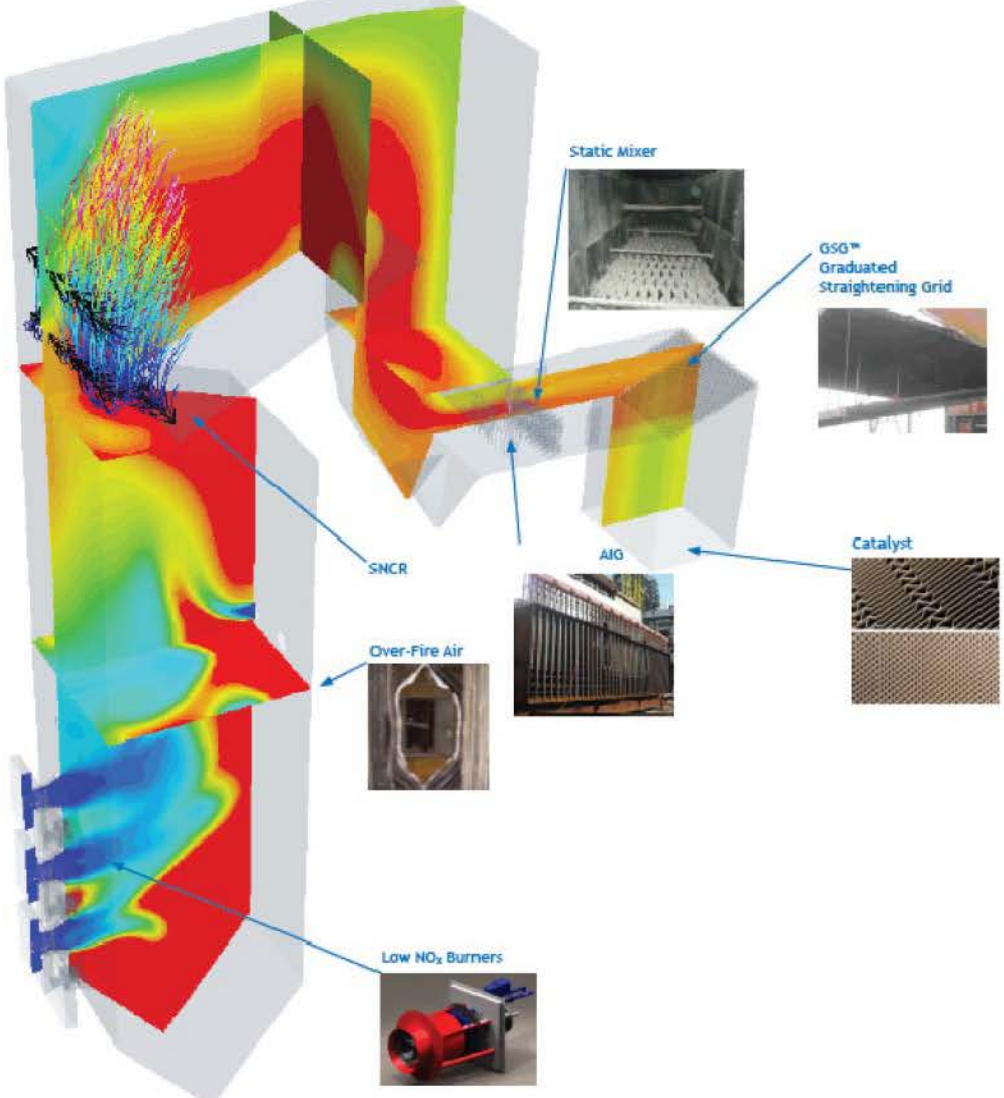
FUEL TECH
Technologies to enable clean efficient energy

AES Greenidge – Multi-P w/ CASCADE

- DOE Cooperative Agreement signed May 2006
- Goal: Demonstrate a Multi-pollutant Control System to Cost-effectively Reduce Emissions of NOx, SO2, Hg, Acid Gases (SO3, HCl, HF), and PM Smaller Coal-fired Power Plants
- 115 MW Coal-fired Boiler, 2.9% Sulfur Bituminous Coal, 10% Biomass
- SNCR: Two Levels of Wall Injectors, plus Multiple Nozzle Lances
- BPI Designed SCR Reactor and Delta Wing Flue Gas Mixing
- In-duct SCR Reactor, Single Layer of Catalyst
- SNCR NOx Reduction = 42%, SCR NOx Reduction = 30%
- Overall Post-combustion NOx Reduction ≈ 60%
- SNCR Chemical Utilization ≈ 40%

FUEL TECH
Technologies to enable clean efficient energy

ASCR™ Advanced SCR



- 80+% NO_x Reduction
- 40-60% less than conventional SCR

Advantages of ASCR Technology

- Capital Cost
  - Limited Structural Steel – Modify Existing, No New Steel to Grade
  - Less Catalyst
  - Less Ductwork
- Better Reagent Utilization
  - SNCR Process
  - Separate AIG
- Low Pressure Drop
- Low SO_2 to SO_3 Conversion Rate
- Broader Range of Operation
  - Lower Electrical Demand

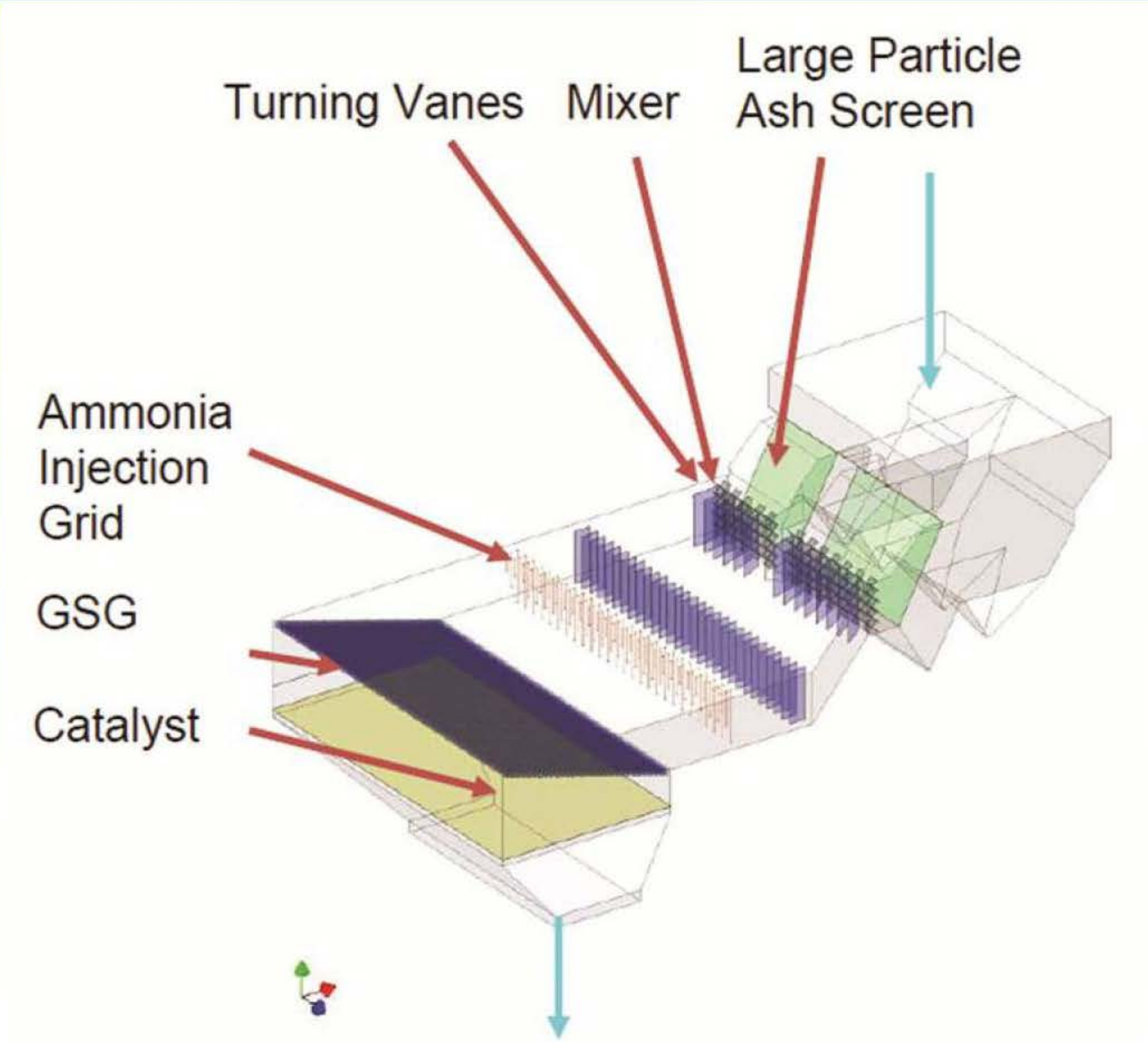
FUEL TECH
Technologies to enable clean efficient energy™

ASCR™ Advanced SCR

- Maximize In-furnace NOx Reduction through Combustion Modifications and Post-combustion Controls
- Apply SNCR for Maximum Performance, NH_3 Slip Control
- On-site Urea Conversion with AIG for 90+% Chemical Utilization
- Employ FTI Mixing and Flow Correction Devices to Provide Uniform Flow and Distribution Across Catalyst Face
- Utilize Catalyst That Maximizes Use of Available Space
- NOx Reduction Efficiency Across Single Layer is Increased As the NOx Entering the SCR is Reduced

FUEL TECH
Technologies to enable clean efficient energy™

Optimized SCR System



Summary

- Flexible, Cost Effective NOx Reduction
- SNCR complementary to other NOx control technologies

Questions?

North Dakota Regional Haze
EPA-R08-OAR-2010-0406
Boilers Equipped with SNCR and that are Controlling NOx to under 0.17 lb/MMBtu
(from 2010 annual Title IV data)

STATE	FACILITY_NAME	Unique ID	OP_YEAR	NOX_RATE	OWNER	UNIT TYPE	PRIMARY FUEL	NOX_CONTROL_INFO	CAPACITY MMBtu/hr
MA	Salem Harbor	1626_1	2010	0.158	Dominion Energy Salem Harbor, LLC (Owner/Operator)	Dry bottom wall-fired boiler	Bit	Selective Non-catalytic Reduction Low NOx Burner Technology (Dry Bottom only)	954
MA	Salem Harbor	1626_2	2010	0.1634	Dominion Energy Salem Harbor, LLC (Owner/Operator)	Dry bottom wall-fired boiler	Bit	Selective Non-catalytic Reduction Low NOx Burner Technology (Dry Bottom only)	966
MA	Somerset	1613_8	2010	0.1263	Somerset Power, LLC (Owner/Operator)	Tangentially-fired	Bit	Selective Non-catalytic Reduction Combustion Modification/Fuel Reburning	1186
MN	Taconite Harbor Energy Center	10075_1	2010	0.1393	Minnesota Power, Inc. (Owner/Operator)	Tangentially-fired	Sub	Overfire Air Selective Non-catalytic Reduction	745
MN	Taconite Harbor Energy Center	10075_2	2010	0.1458	Minnesota Power, Inc. (Owner/Operator)	Tangentially-fired	Sub	Overfire Air Selective Non-catalytic Reduction	745
TX	*Big Brown*	*3497_1*	*2010*	*0.1376*	*Big Brown Power Company LLC (Owner) Luminant Generation Company LLC (Operator)*	*Tangentially-fired*	*Lignite*	*Low NOx Burner Technology w/ Separated OFA Selective Non-catalytic Reduction*	*7901*

Boilers Equipped with SNCR and that are Controlling NOx to under 0.17 lb/MMBtu
(from 2010 annual Title IV data)

STATE	FACILITY_NAME	Unique ID	OP_YEAR	NOX_RATE	OWNER	UNIT TYPE	PRIMARY FUEL	NOX_CONTROL_INFO	CAPACITY MMBtu/hr
TX	Big Brown	3497_2	2010	0.1437	Big Brown Power Company LLC (Owner) Luminant Generation Company LLC (Operator)	Tangentially-fired	Lignite	Low NOx Burner Technology w/ Separated OFA Selective Non-catalytic Reduction	8132
TX	*Monticello*	*6147_1*	*2010*	*0.1294*	*Luminant Generation Company LLC (Owner/Operator)*	*Tangentially-fired*	*Lignite*	*Low NOx Burner Technology w/ Separated OFA Selective Non-catalytic Reduction*	*7382*
TX	*Monticello*	*6147_2*	*2010*	*0.1315*	*Luminant Generation Company LLC (Owner/Operator)*	*Tangentially-fired*	*Lignite*	*Low NOx Burner Technology w/ Separated OFA Selective Non-catalytic Reduction*	*7055*
WI	Edgewater (4050)	4050_4	2010	0.1464	Wisconsin Public Service Corporation (Owner) Wisconsin Power & Light Company (Owner/Operator)	Cyclone boiler	Sub	Overfire Air Other Selective Non-catalytic Reduction	4629

Note: Facilities listed in red italics are referenced as examples in EPA's final rule for North Dakota regional haze.

ACT ADVANCED COMBUSTION TECHNOLOGY

NEW COAL BURNERS AND LOW NOx CONTROL TECHNOLOGIES

Peikang Jin, Ph.D, P.E.
Travis West

August 3, 2005
Dalian, China

ACT

AGENDA □容安排

1. Company Information
2. NOx Control Philosophy
3. Capability (Layered Technology Approach)
   a) Combustion Optimization
   b) Low NOx Burner
   c) CFD
   d) OFA
   e) T-fired Boiler
   f) HERT
4. Experiences and Cases
5. ACT Layered Approach Summary

COMPANY INFORMATION
公司□介

- ACT: Headquarters in New Hampshire, USA; Offices in Baton Rouge (LA), Raleigh (NC), Oxnard (CA), Hamburg (NJ), and Marlborough (CT)
- ACT China: A subsidiary company of ACT；Offices in Baton Rouge (LA) and Nanjing, China
- Designs, supplies and installs low NOx combustion systems on utility and large industrial boilers
- Extensive combustion and emission control expertise and experience
- over 100 NOx control projects planned, designed, and implemented (25 to 1100 MW)
- Proprietary Low NOx Burner Hardware
- HERT - ACT Patented Technology

ACT

NOx CONROL PHILOSOPHY

□□整体策略

- **Custom Solution**
  Design a plant-specific layered technical approach for NOx reduction tailored to client's specific needs

- **Minimize Operational Impact**
  Evaluate each layer of NOx reduction technology with minimal impact on unit operation and/or performance.

- **Lowest Cost Per Ton Ratio**
  Achieve the client's NOx emissions objectives at the lowest cost per ton ratio

- **Performance Guarantee**

ACT

CAPABILITY 公司能力
(Layered Technology Approach)

- Layer 1 - Boiler Optimization □□□化
  - Combustion Airflow Testing (CAT) 燃□□流□□
  - Coal Flow Balancing 煤粉流□□
- Layer 2 - Low NOx Burner Upgrades and New Low NOx Burner
  燃□器改造或完全采用ACT的低NOx燃□器
- Layer 3 - Over Fire Air (OFA) 燃□□系□
- Layer 4 - High Energy Reagent Technology (HERT) 高能量反□□技□
  Advanced SNCR (Selective Non-Catalytic Reduction)
- Computational Fluid Dynamics (CFD) Modeling 流体□力□模□

ACT Layered NOx Reduction System

ACT NOx分□控制系□

80%+NOx reduction at the lowest cost/ton

以最低价位□到**80%**以上□□率

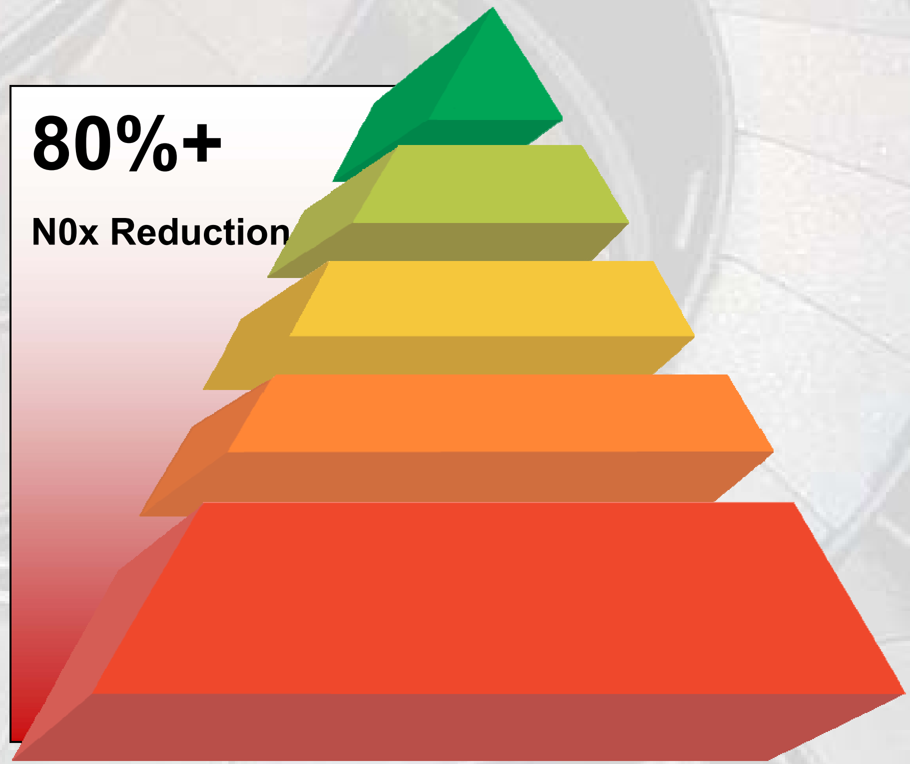
Layer 4 HERT System
第四□　高能量反□□技□

Layer 3 Overfire Air
第三□　燃□□系□

Layer 2B Low NOx Burner (LNB)
第二□ 低**NOx**燃□器

Layer 2A LNB Modification
第二□　燃□器改造

Layer 1 Boiler Optimization
第一□ □□□化



ACT

IMPACTS ON NOx

- **Burner zone heat release**
- **Outer zone secondary air to primary air velocity ratio (1.5 to 1.0)**
- **Primary air & coal velocity (75 to 80 ft/s)**
- **Burner throat diverging angle (30 deg)**
- **Throat diameter to diverging length ratio (4 to 1)**
- **Burner swirl number (0.6 to 0.7)**
- **Excess O_2 (impacted by coal fineness)**
- **Position of coal pipe in throat**

IMPACTS ON LOI

- Burner zone heat release
- Excess O_2
- Position of coal pipe in burner
- Primary air velocity
- Coal fineness
- Burner swirl number
- % Ash in coal

ACT

COMBUSTION OPTIMIZATION

第一□ □□□化

ACT

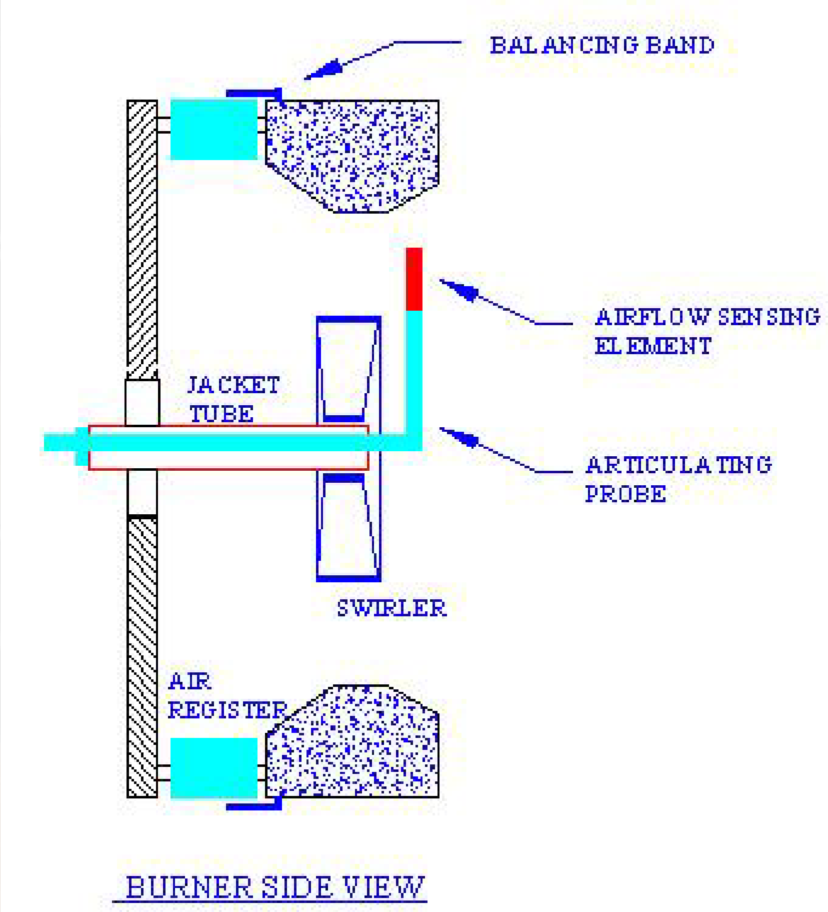
COMBUSTION OPTIMIZATION

燃□□化

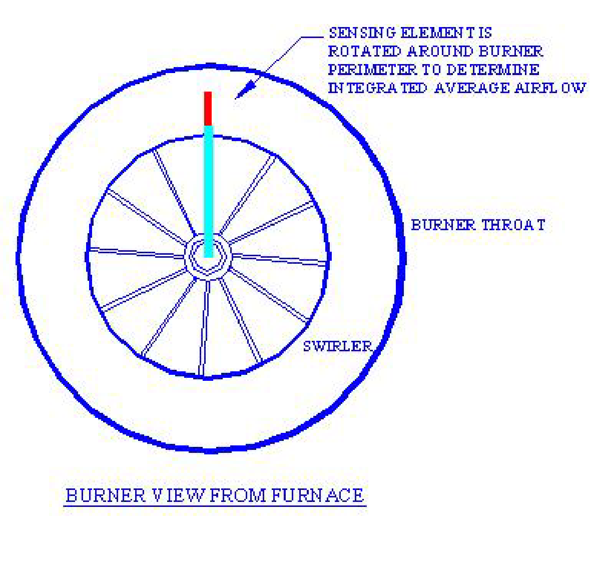
- Coal Flow Balancing
    - Rotor Or ASME Probe
    - Dirty Air Testing
- Secondary Airflow Balancing
    - Combustion Airflow Testing (CAT)

Combustion Air Test (CAT)

燃□□流□□和□□



A test probe is inserted along the burner centerline. A sensing element is raised up and rotated around the burner perimeter. Data is collected around the perimeter to determine the burner average and distribution. An average of all burners determines the boiler mean.

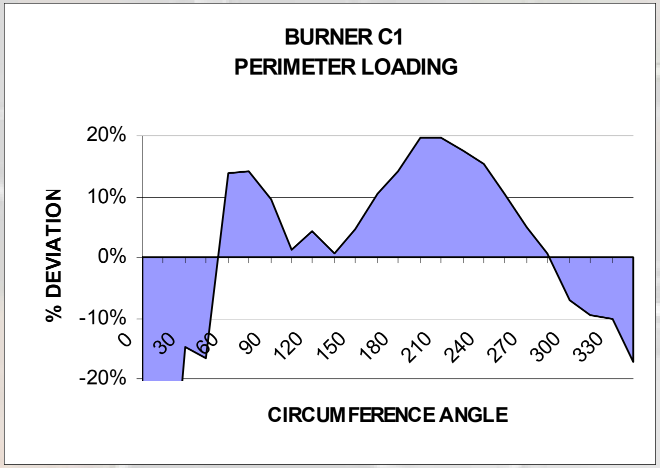


Burner Point Deviations

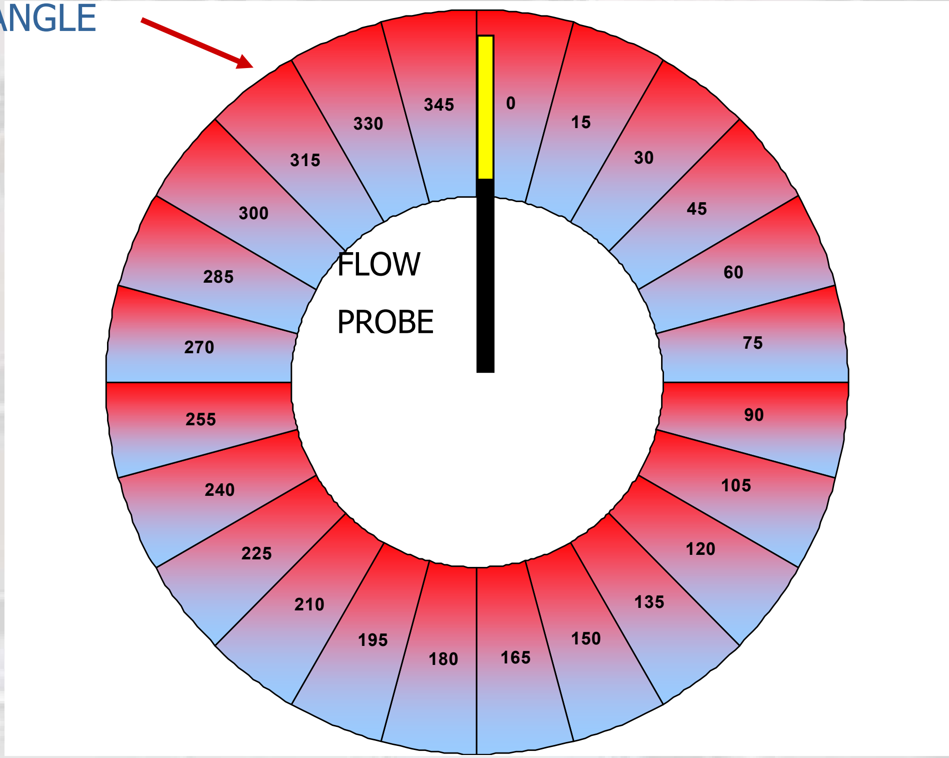
Large flow deviations around the burner can lead to burner instability and high CO, O2 and NOx emissions. These are caused by vortex flows in the windbox. Correcting this problem often requires CFD modeling.

This graph illustrates the point deviations from the burner mean around the CAT grid at the burner throat.

% DEVIATION FROM BURNER MEAN



CIRCUMFERENCE ANGLE



TEST GRID AT BURNER THROAT

ACT

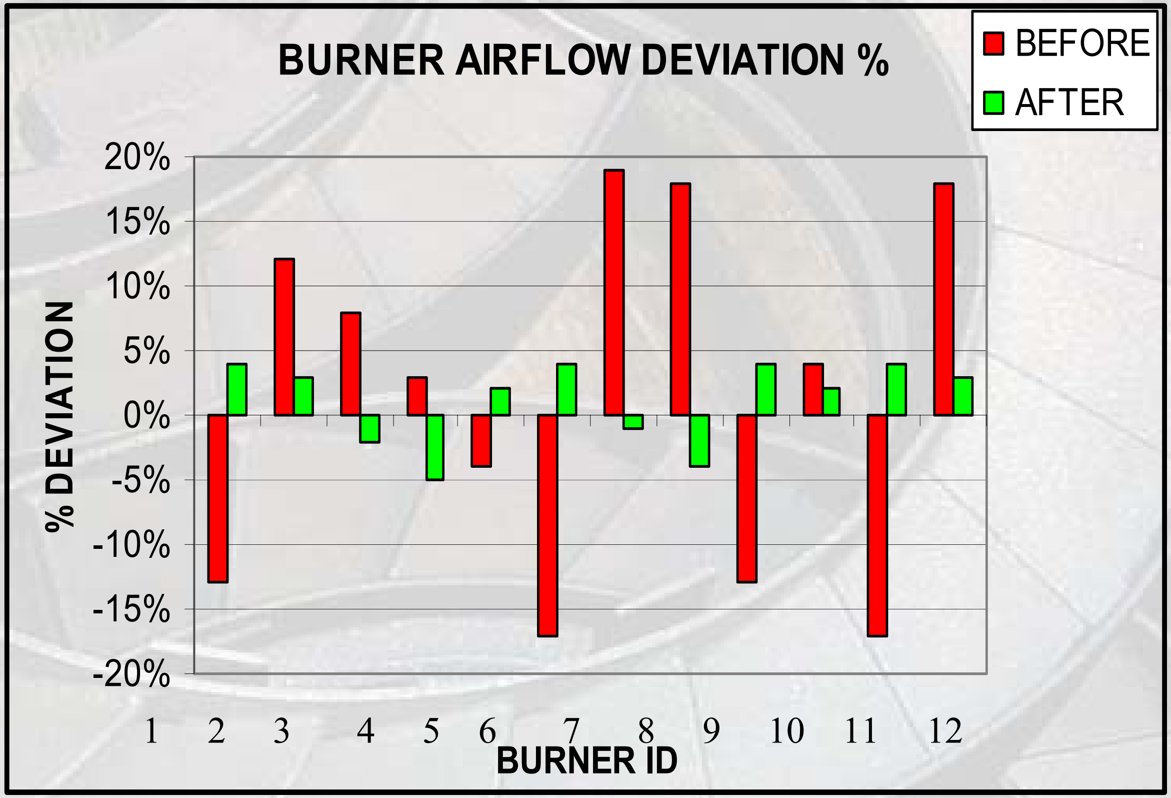
CAT Test Results

CAT□□□果

•Inlet register area of high flow burners is reduced to increase burner resistance. Airflow is forced from the high flow to the low flow burners.

•Testing is repeated to ensure the balance criteria is met.

•This graph illustrates baseline and post balancing testing of a 12 burner unit.

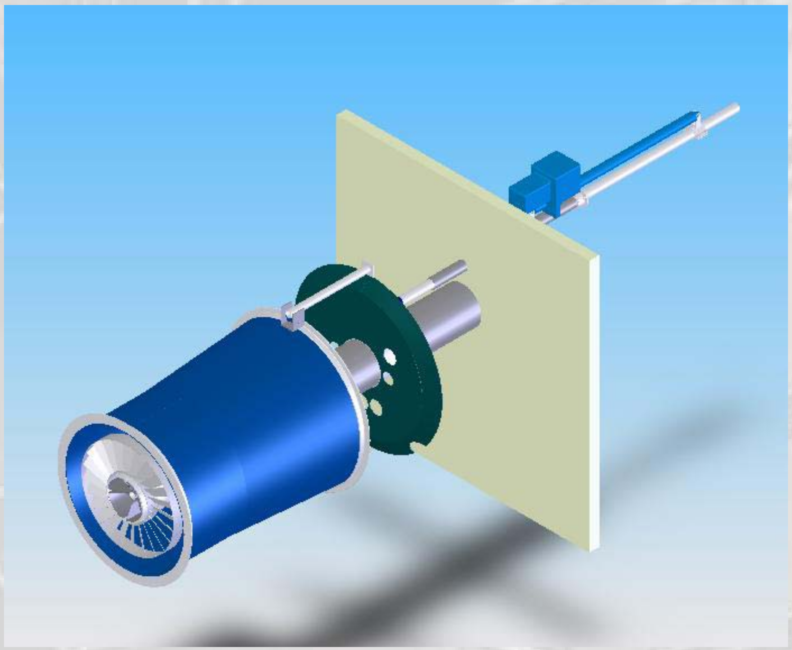


LOW NOx BURNER

第二□　低□燃□器

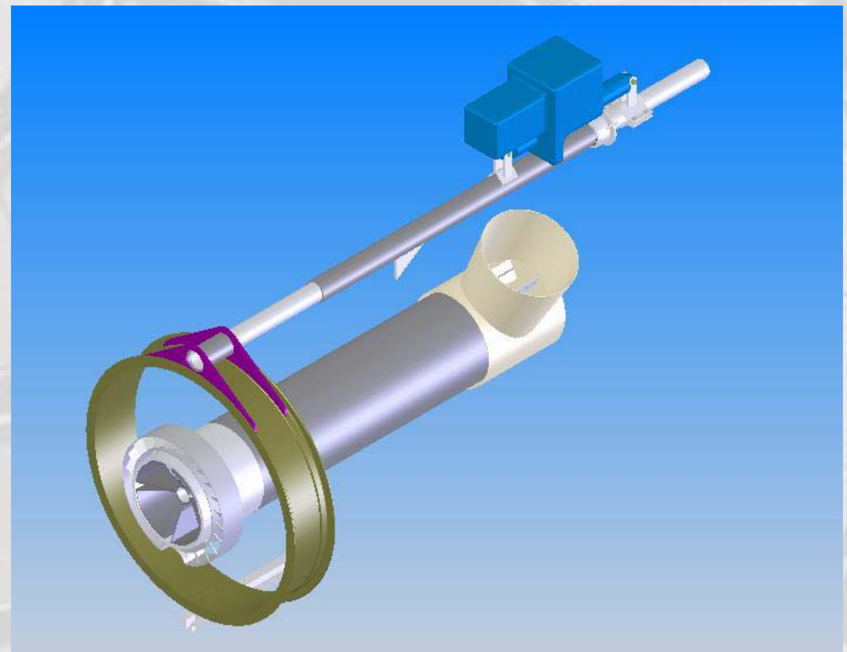
ACT Low NOx Burner Hardware

ACT低□燃□器硬件



VH600K LOW NOx BURNER

采用**ACT**□□完全替□**OEM**燃□器



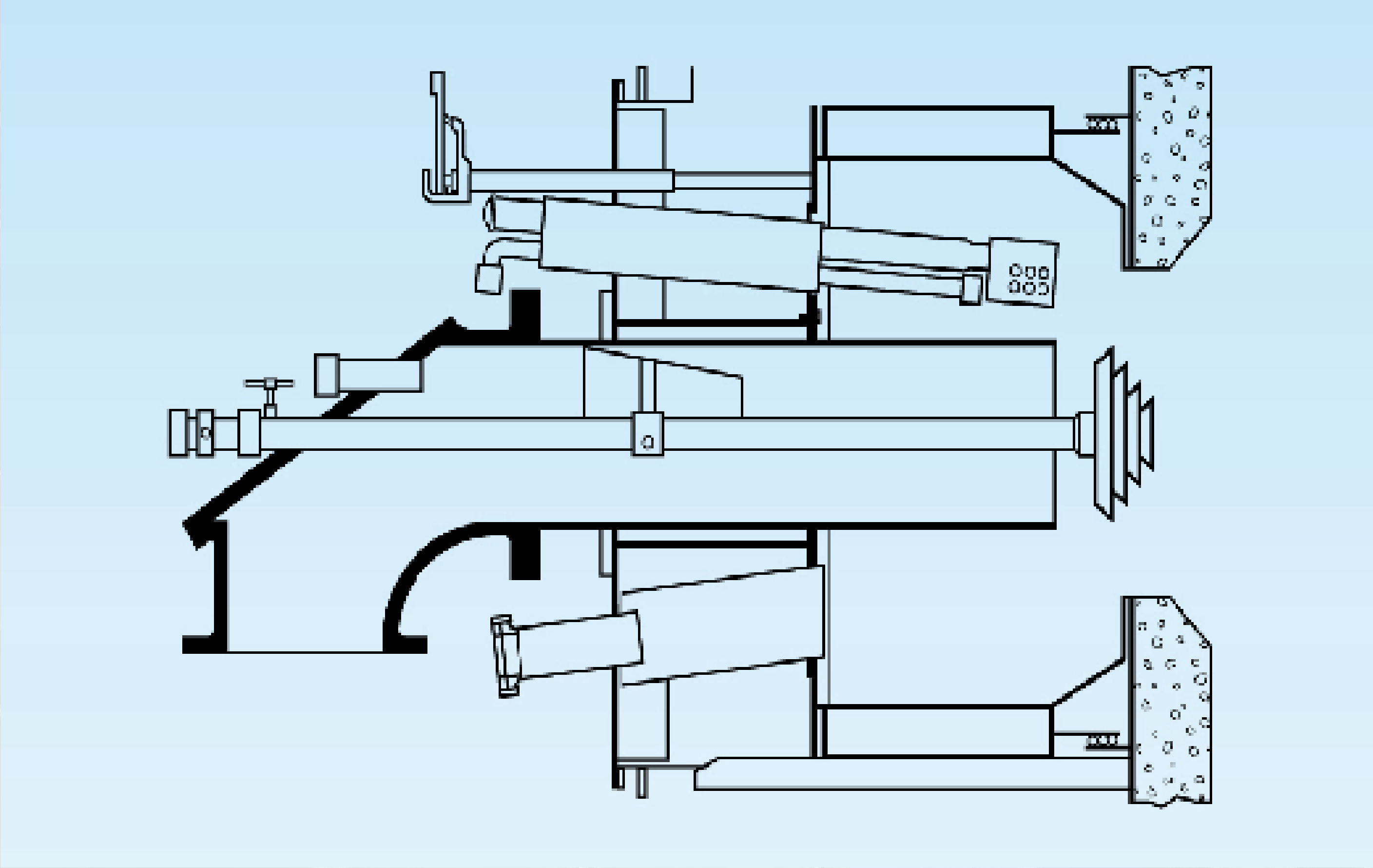
BURNER UPGRADE COMPONENTS

□**OEM**提供的常□低□燃□器升□改造到**ACT**□□的低□燃□器**,** 用**ACT**的燃料□嘴□□替□**OEM**的□□**.**

ACT

Typical OEM Low NOx Burner

典型的OEM燃□器



OEM Coal Burner Dynamics

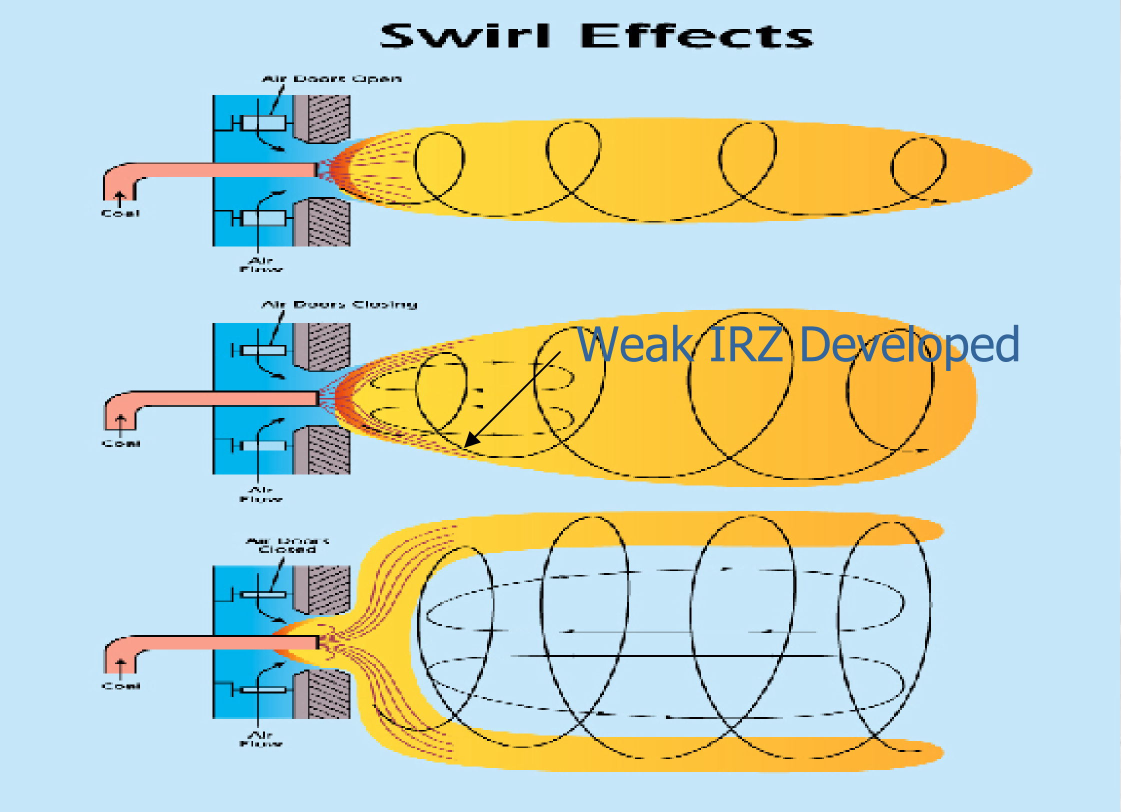
OEM燃□器□力系□

Swirl Number (Sn), Swirl Effects & IRZ

TOO LITTLE SPIN
Sn 0.3

JUST RIGHT
Sn 0.6

TOO MUCH SPIN
Sn 0.9



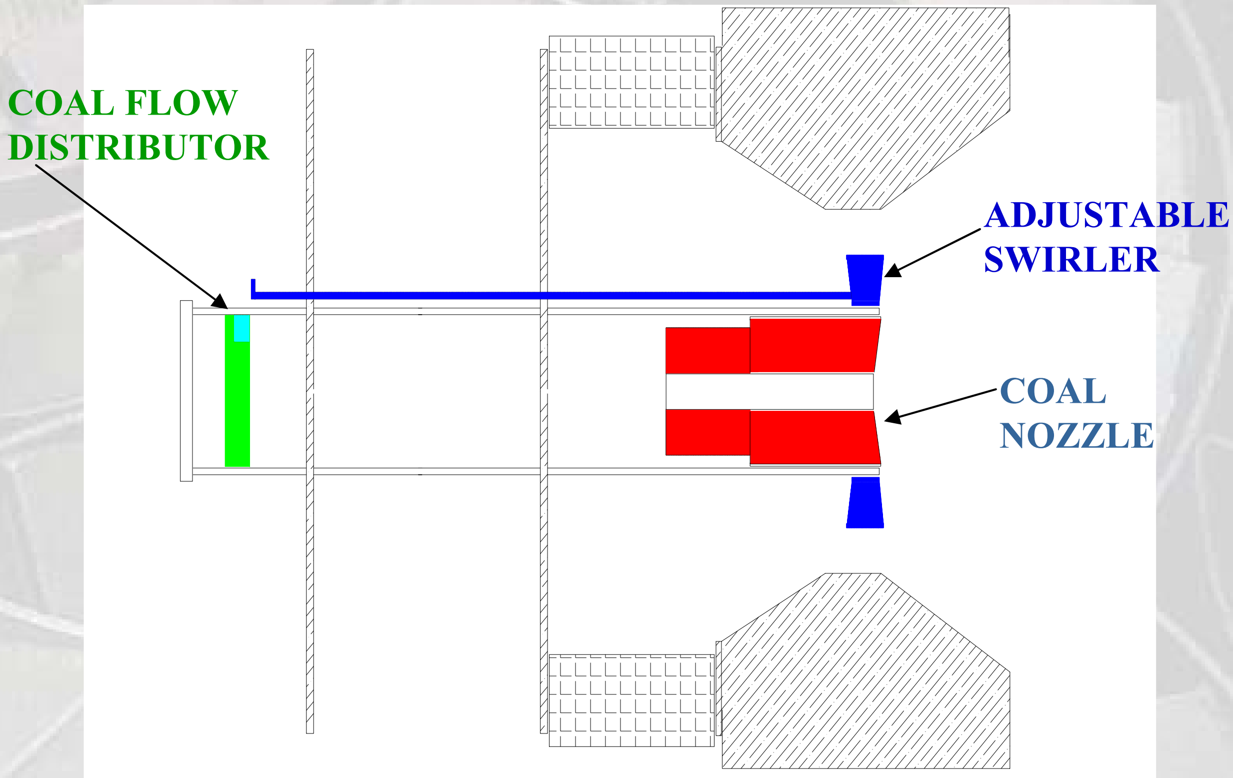
Typical OEM Low NOx Burner Upgrade To ACT Burner

OEM燃□器升□改造到ACT低□燃□器

ACT's low NOx swirler establishes a strong IRZ.

Coal is injected into the IRZ at the burner outlet to deeply stage combustion.

Airflow flowing around the swirler mixes downstream to complete combustion.



BURNER SIDE VIEW

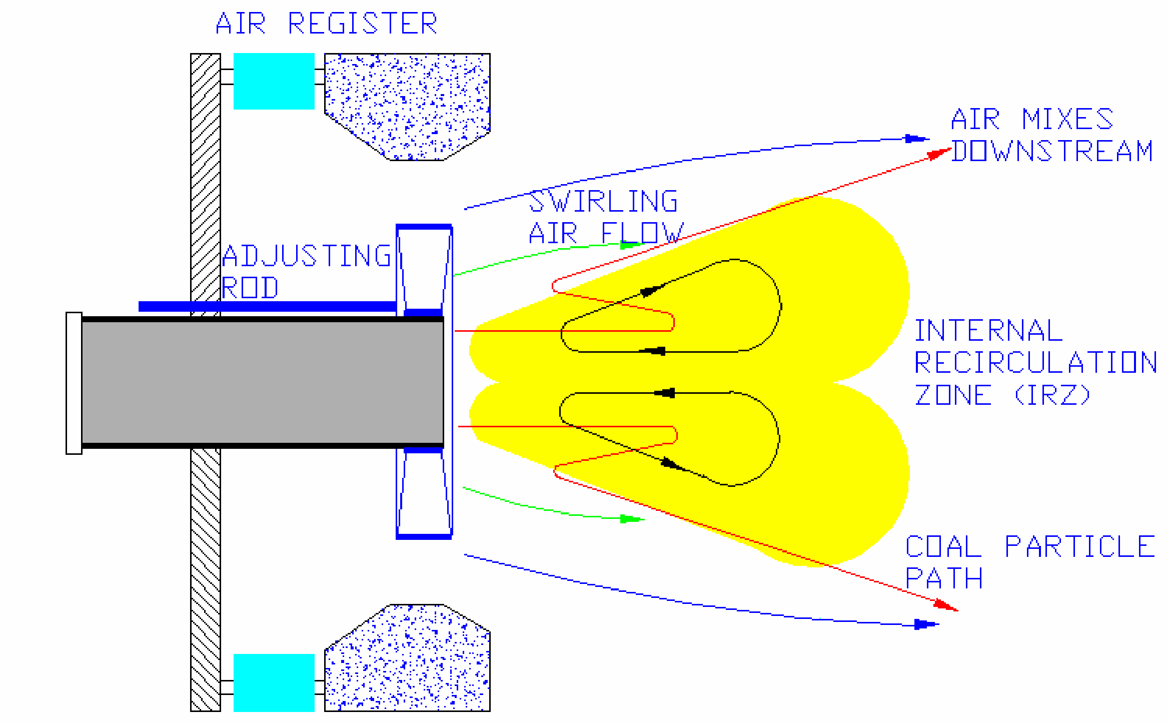
ACT Low NOx Burner Dynamics

ACT低□燃□器□力系□

IRZ, Coal Nozzle Position, Radial Staging

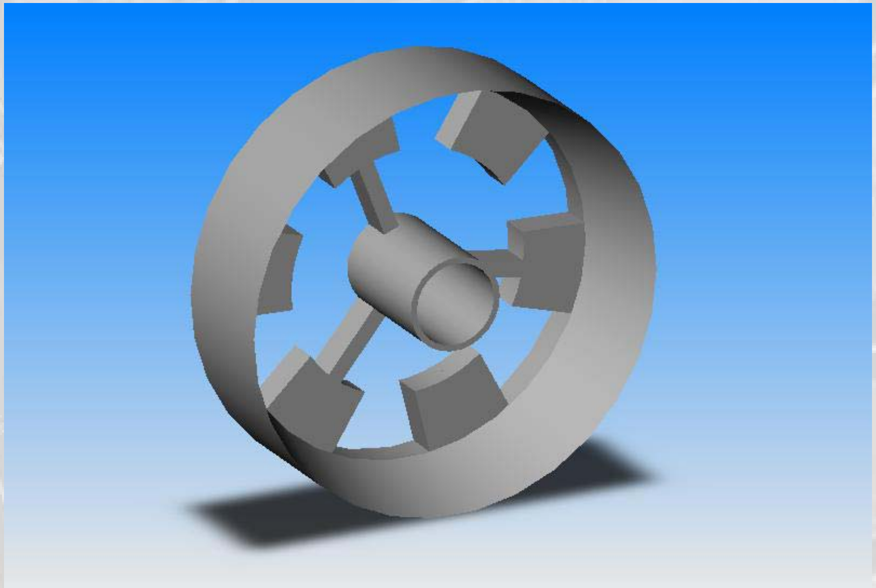
Swirling airflow from the swirler creates a strong IRZ at the burner outlet.

Air register is typically operated in the 40% to 60% to increase the strength of the IRZ.



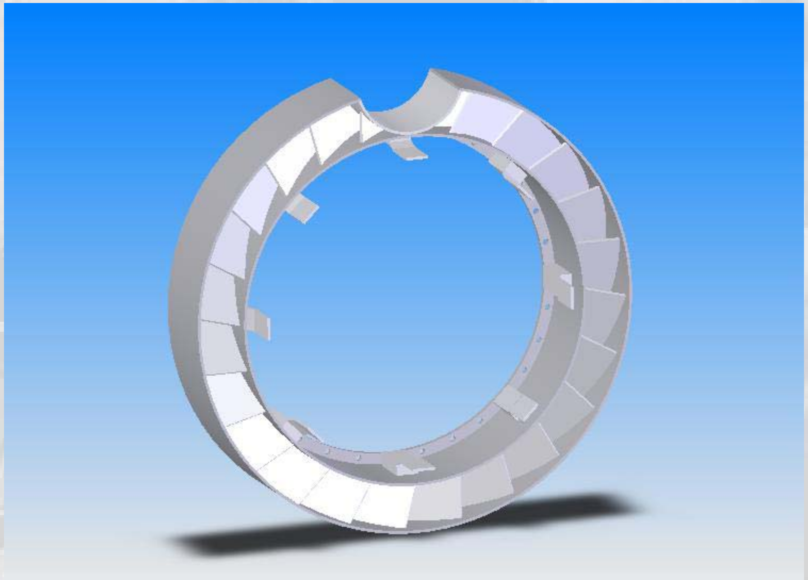
Coal Burner Upgrade Hardware

燃□器改造主要部件



Coal Distribution Disk

煤粉分布控制器



Low NOx Swirler

低**NOx**旋流器

ACT

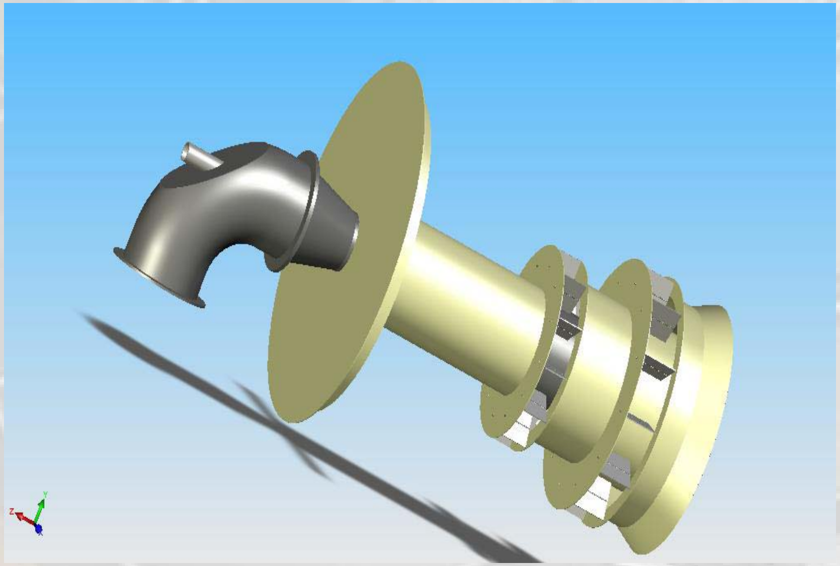
Low NOx Coal Nozzle □嘴

ACT’s low NOx coal nozzle is manufactured from 309 SS with AR500 wear strips on the main wear surface. The nozzle ensures the primary air and coal stream is injected with a purely axial flow into the IRZ at the burner exit. Four small flame holders are positioned around the nozzle discharge for flame attachment. The nozzle is welded to the oil gun guide tube and can be adjusted from the burner front.

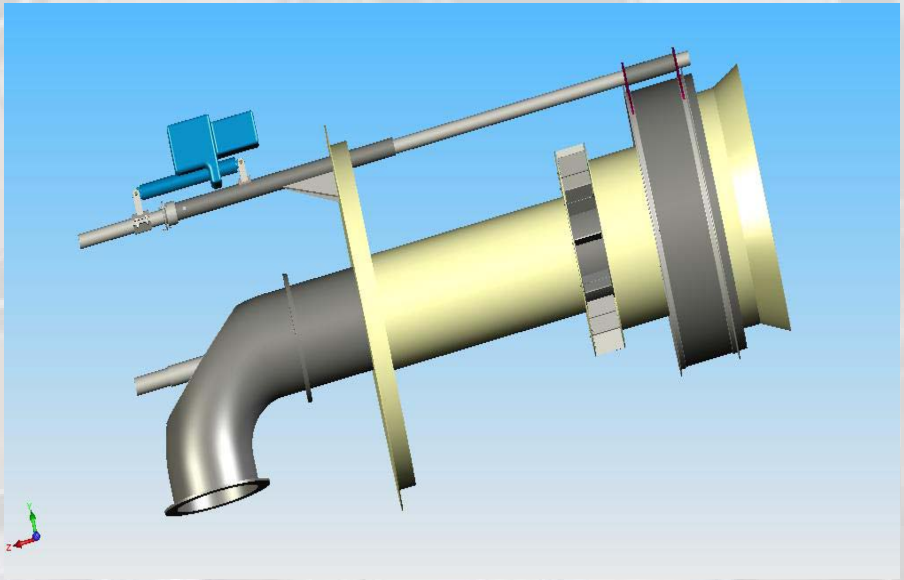
ACT

Low NOx Burner Upgrade

OEM Burner

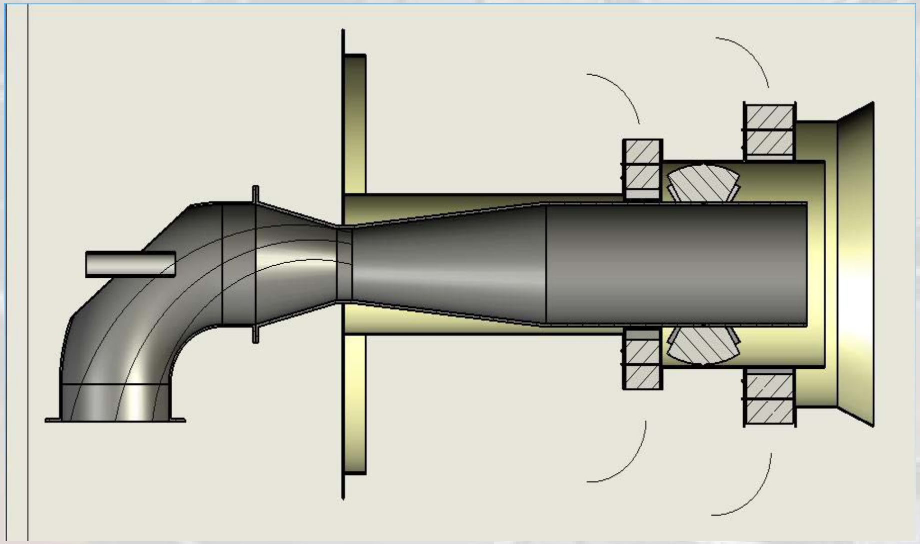


ACT Modified Burner

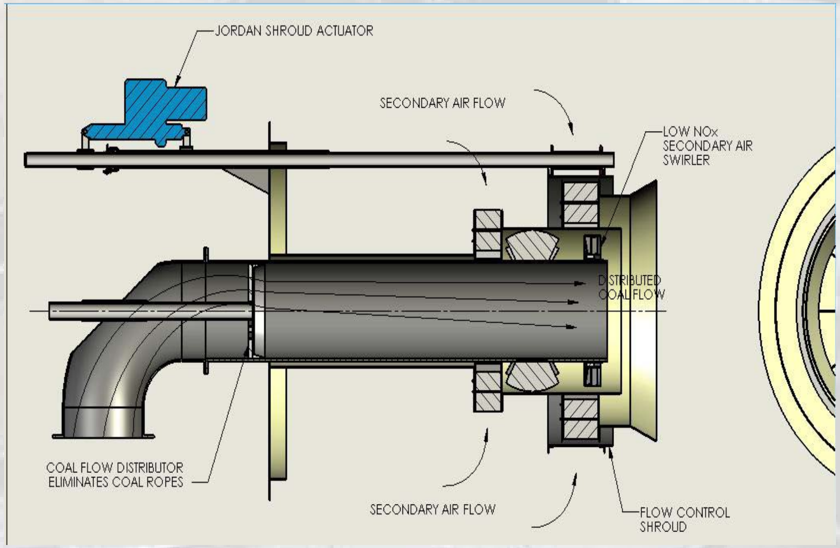


Low NOx Burner Upgrade

Existing OEM Burner Cut View



ACT Modified Burner Cut View



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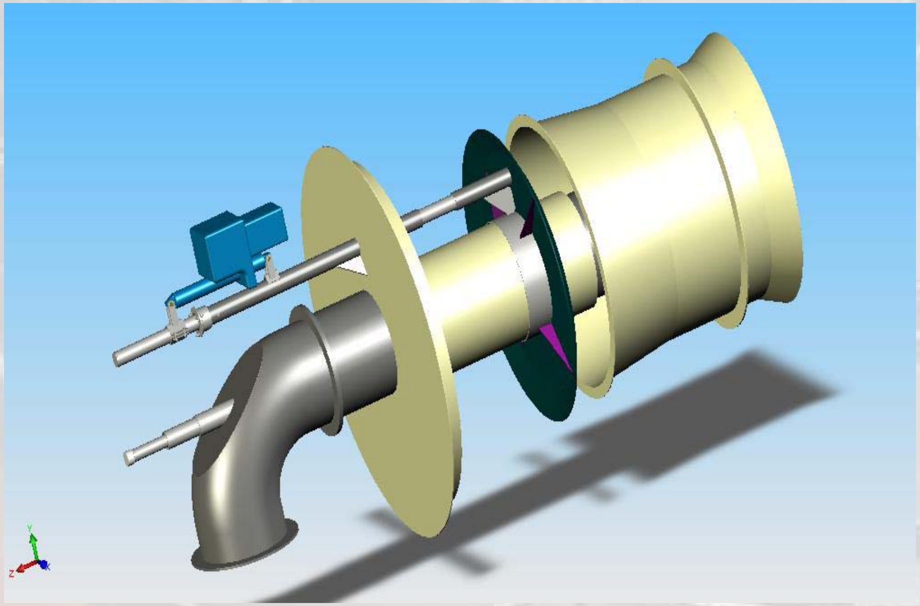
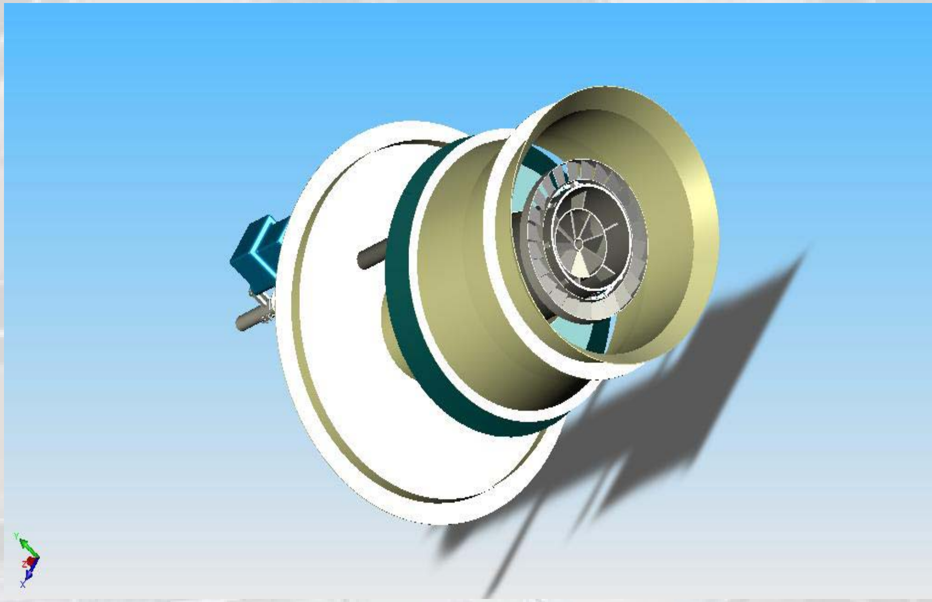
ACT New Burner





Low NOx Burner
□例

Baseline Burner	Upgraded Burner
	

ACT

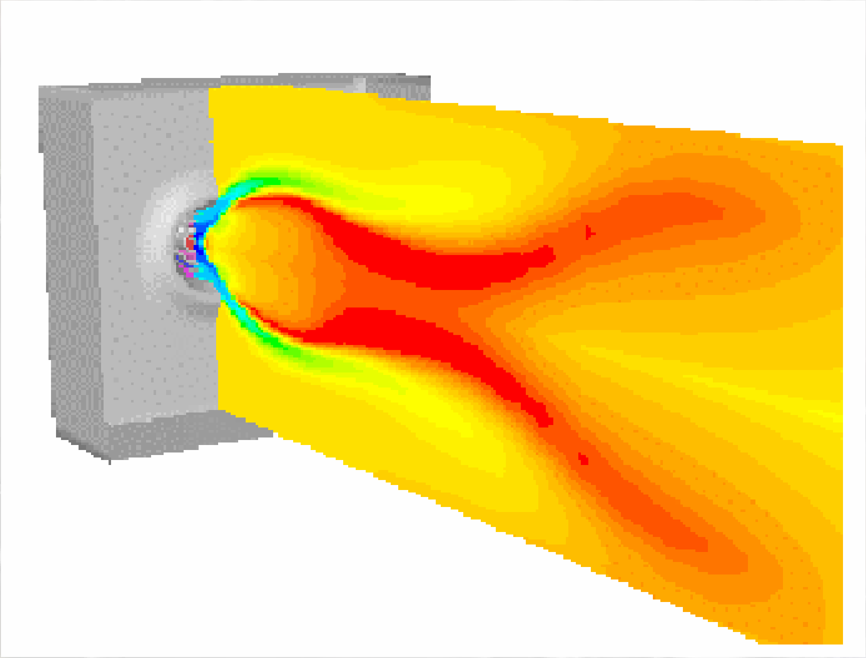
Upgraded Burner

Upgraded Burner

CFD MODELING

CFD MODELING & DESIGN PROCESS

(Seeing the Problem is half way to solving it)

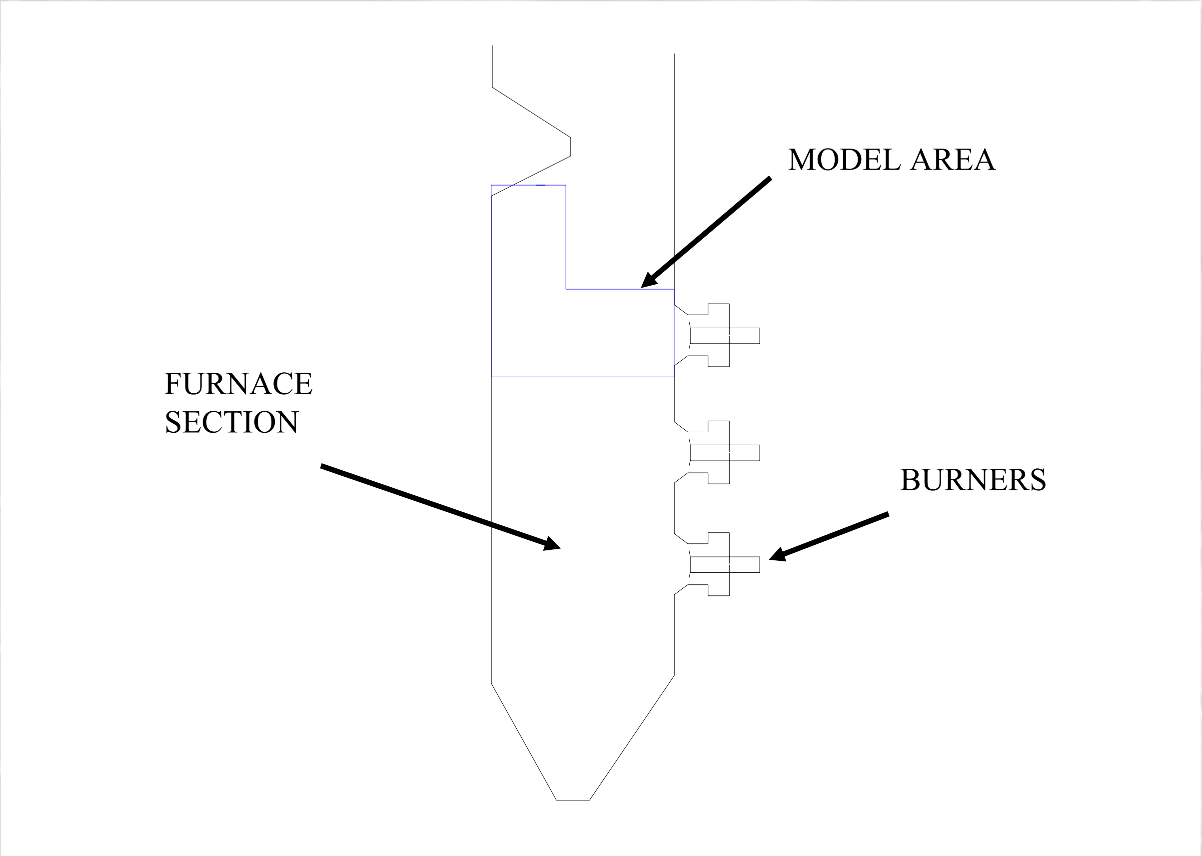


- COMPUTATIONAL FLUID DYNAMICS (CFD) MODEL OF BASELINE BURNER
  - BURNER DESIGN
  - FURNACE DESIGN
  - FUEL TYPE
- INCORPORATE NEW DESIGN INTO CFD MODEL
  - NOx
  - CO
  - O2
- REVIEW RESULTS AND MODIFY DESIGN AS REQUIRED

CFD MODELING IS USED TO VALIDATE ALL DESIGNS PRIOR TO MANUFACTURING

RELEASE DESIGN FOR FABRICATION

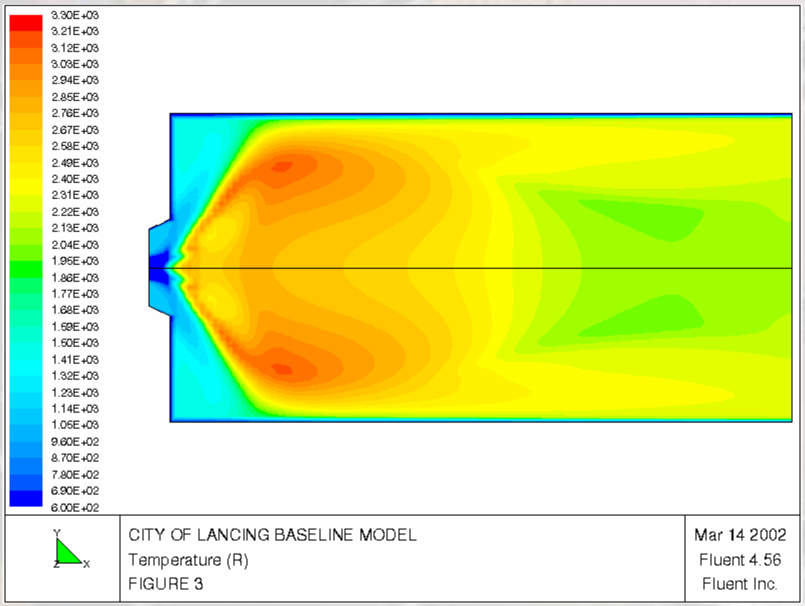
Furnace Section



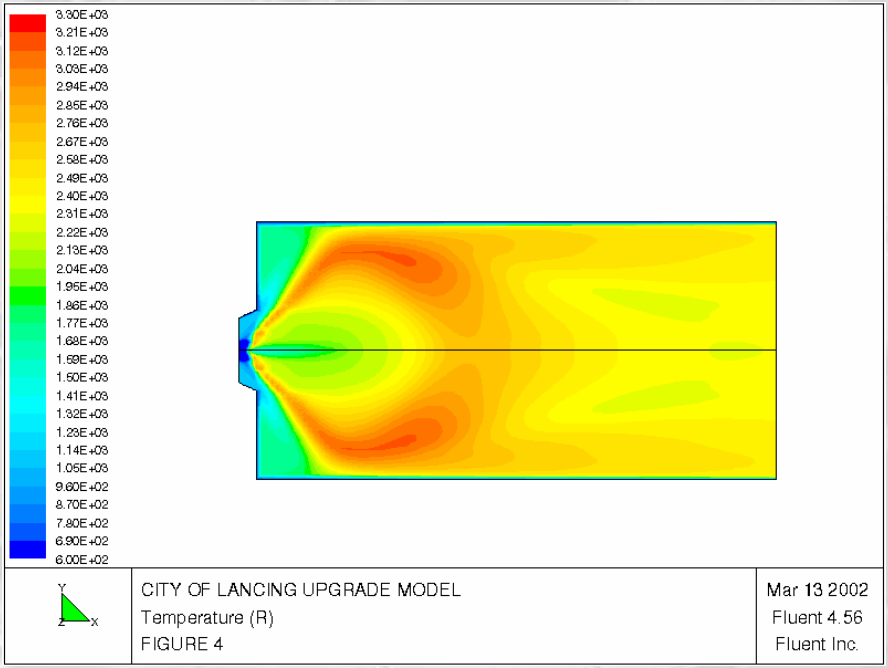
ACT

Temperature Contour

Baseline

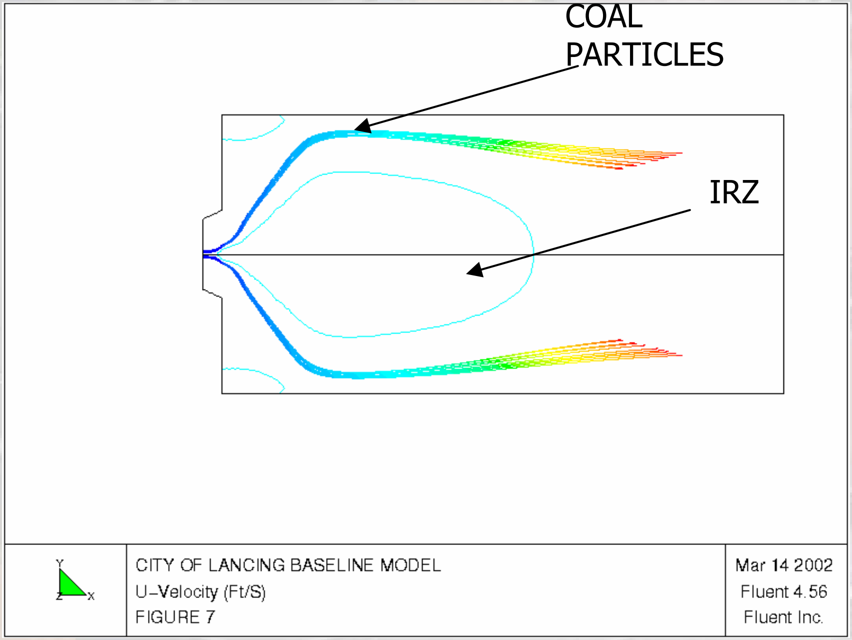


Upgraded

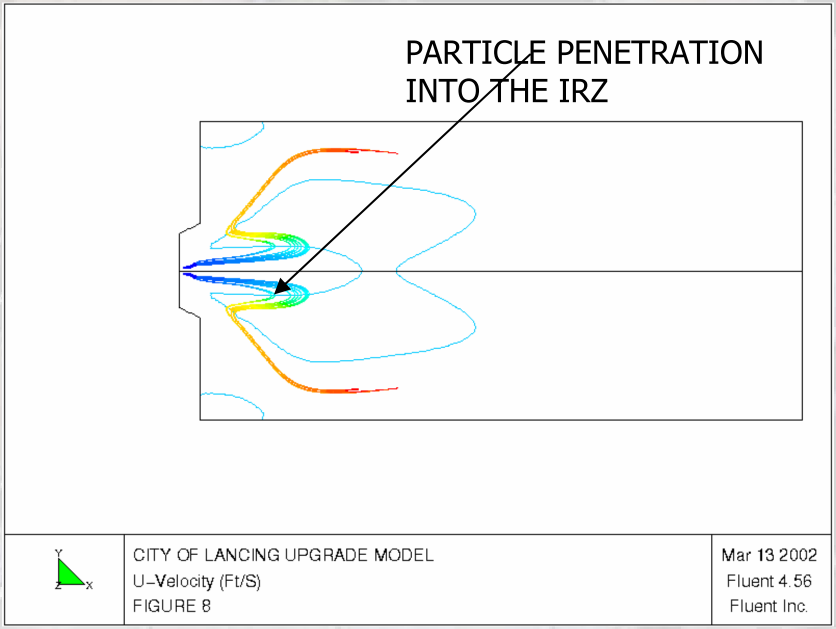


Coal Particle Path

Baseline



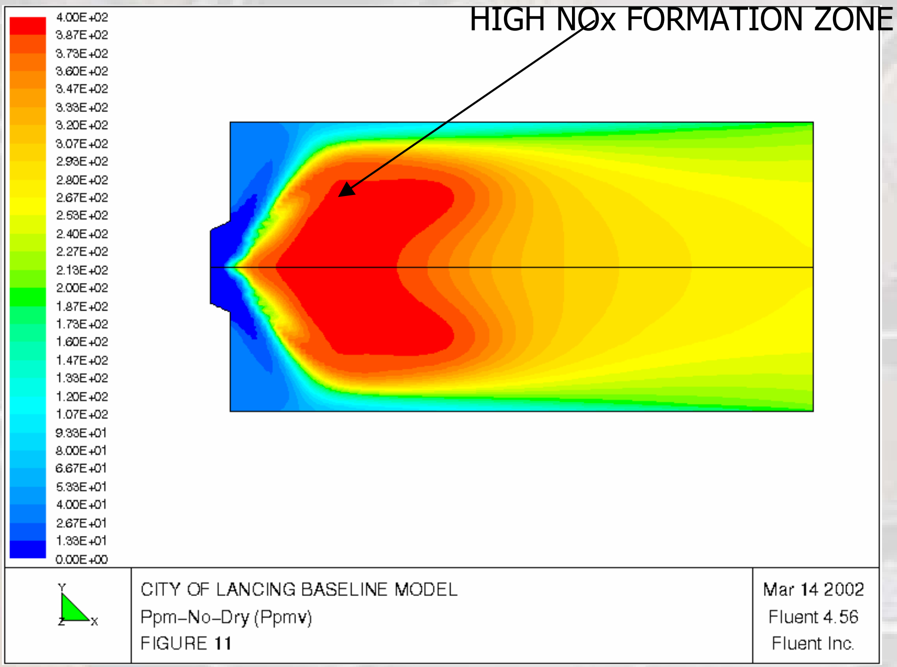
Upgrade



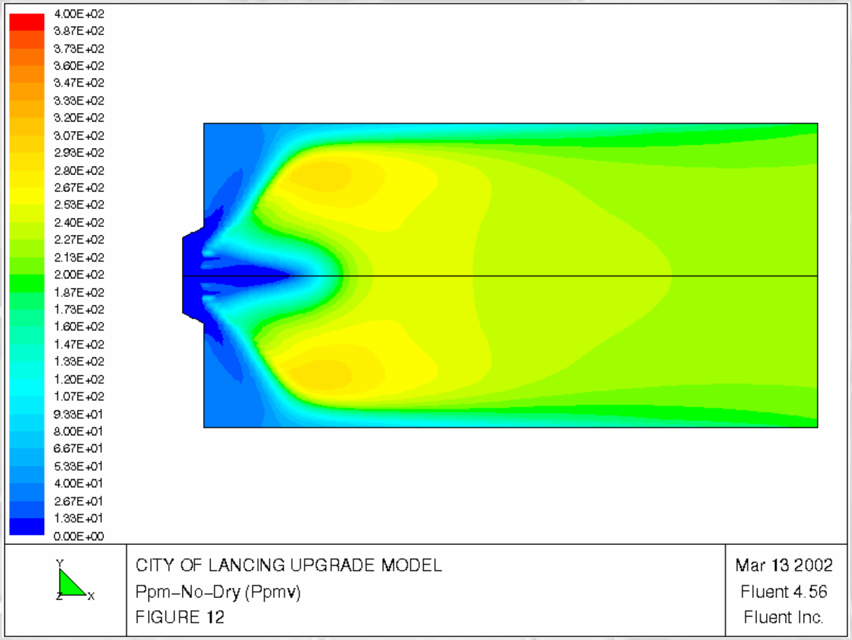
ACT

NOx Formation

Baseline Case



Upgrade Case



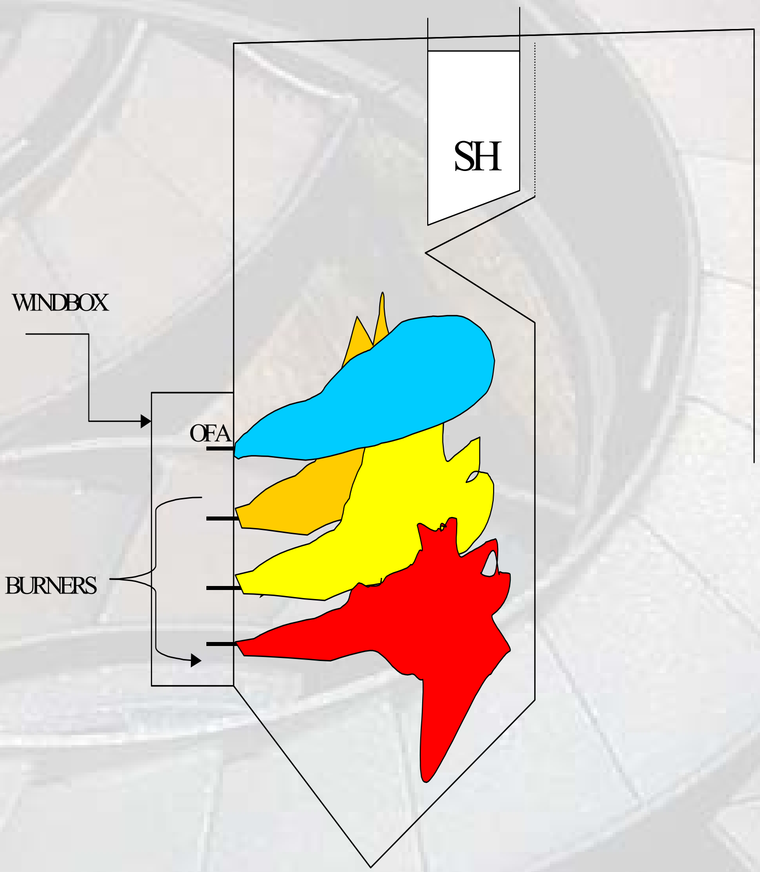
ACT

OVER-FIRE AIR (OFA)

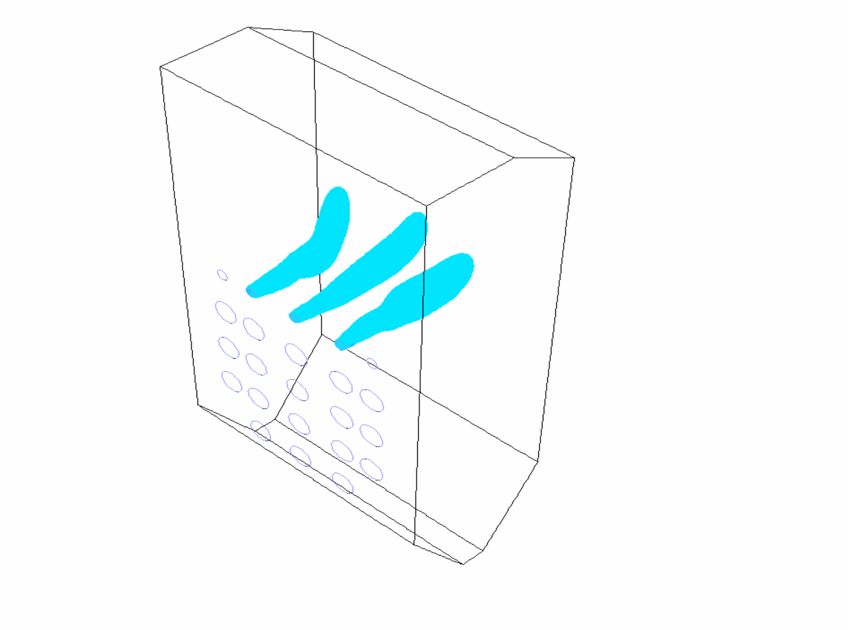
第三□　燃□□系□

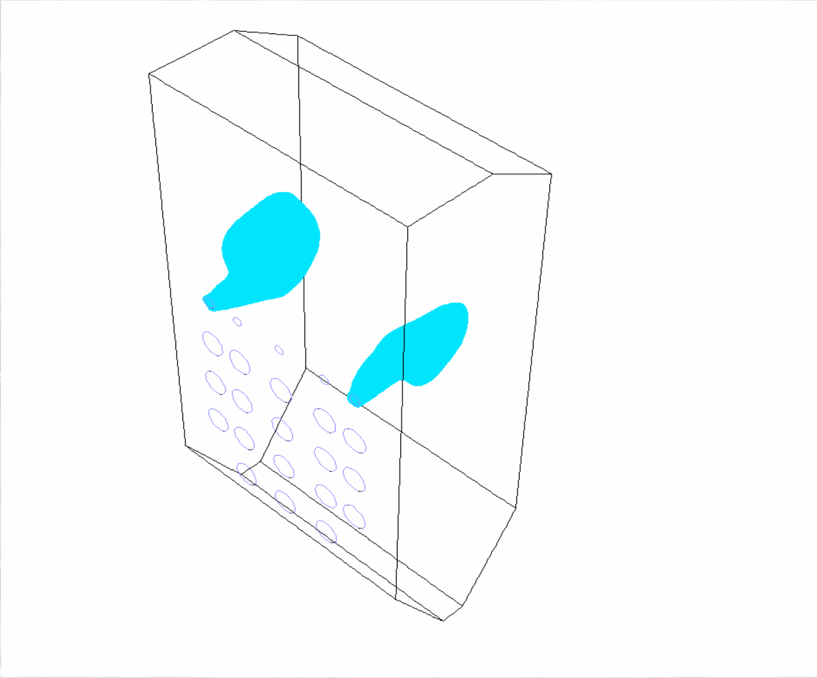
OVER-FIRE AIR (OFA) PROCESS

- Burner CFD model inputs into furnace model
- Mixing must be complete before the gases exit the furnace
- NOx reduction can be limited by LOI and CO



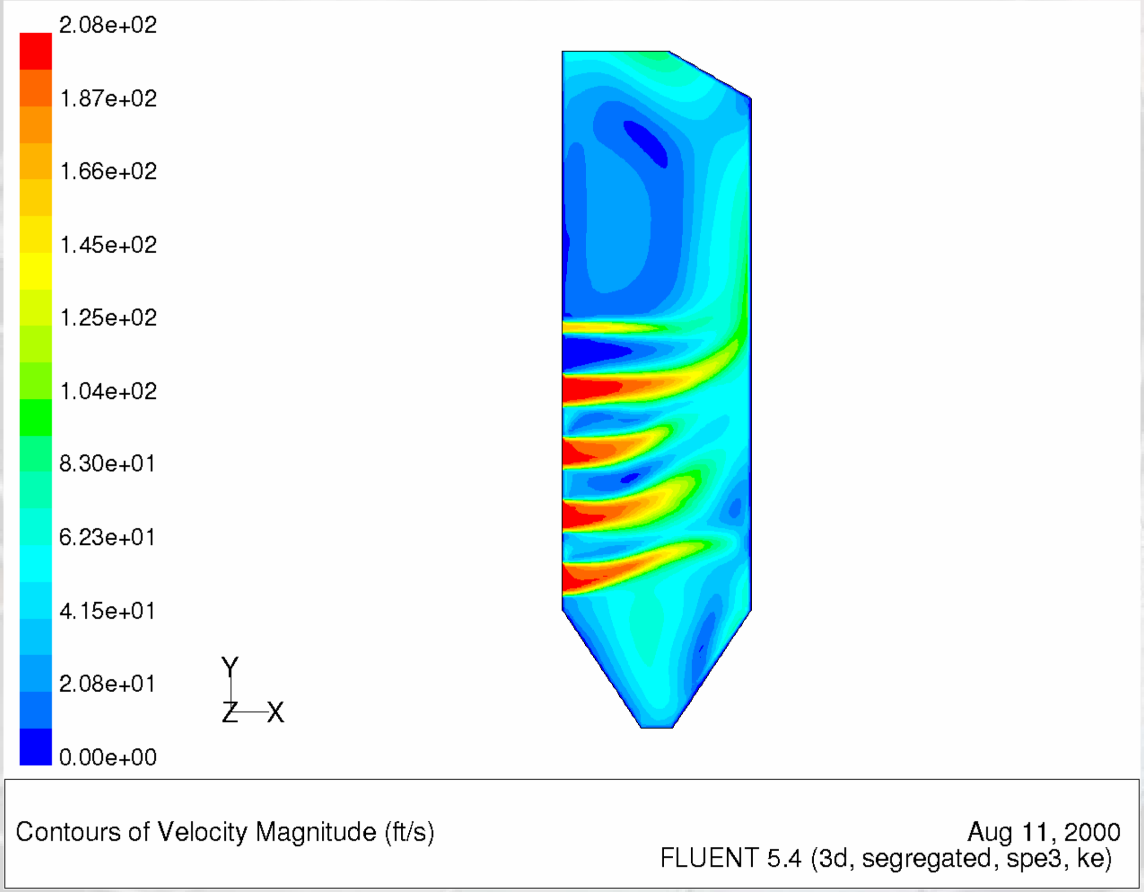
OFA Process





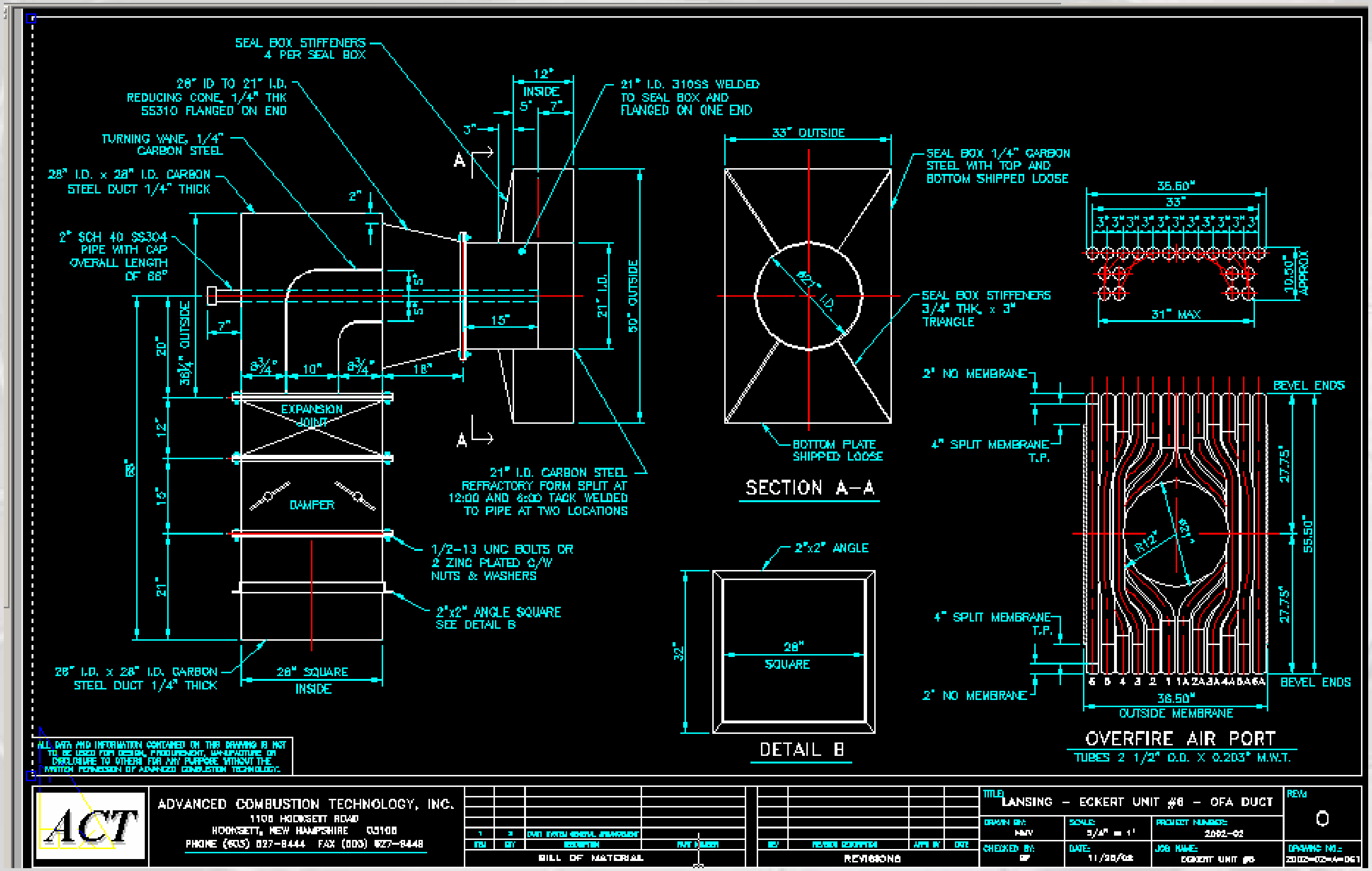
Penetration/Mixing Optimization

OFA Process


2.08e+02
1.87e+02
1.66e+02
1.45e+02
1.25e+02
1.04e+02
8.30e+01
6.23e+01
4.15e+01
2.08e+01
0.00e+00
Y
Z
X
Contours of Velocity Magnitude (ft/s)
Aug 11, 2000
FLUENT 5.4 (3d, segregated, spe3, ke)

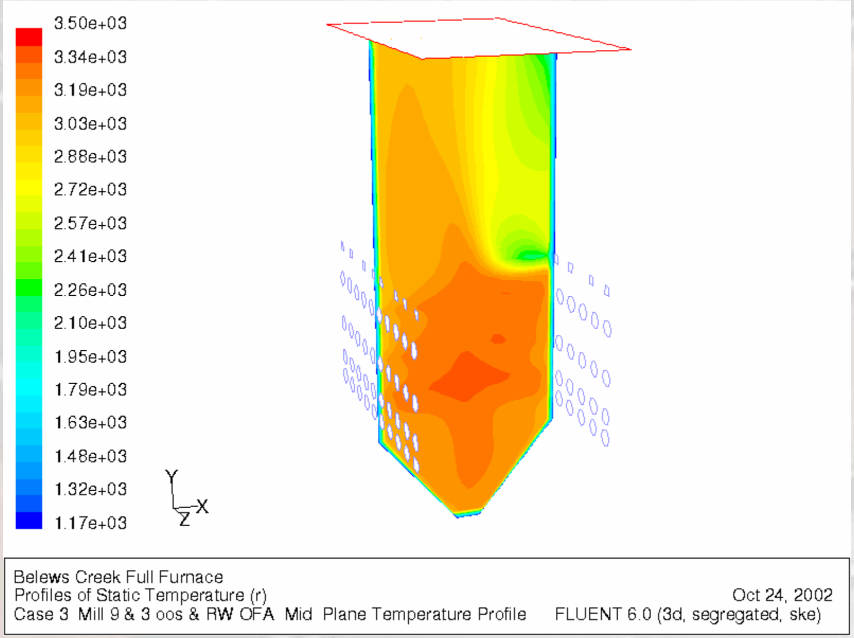
ACT

OFA Design

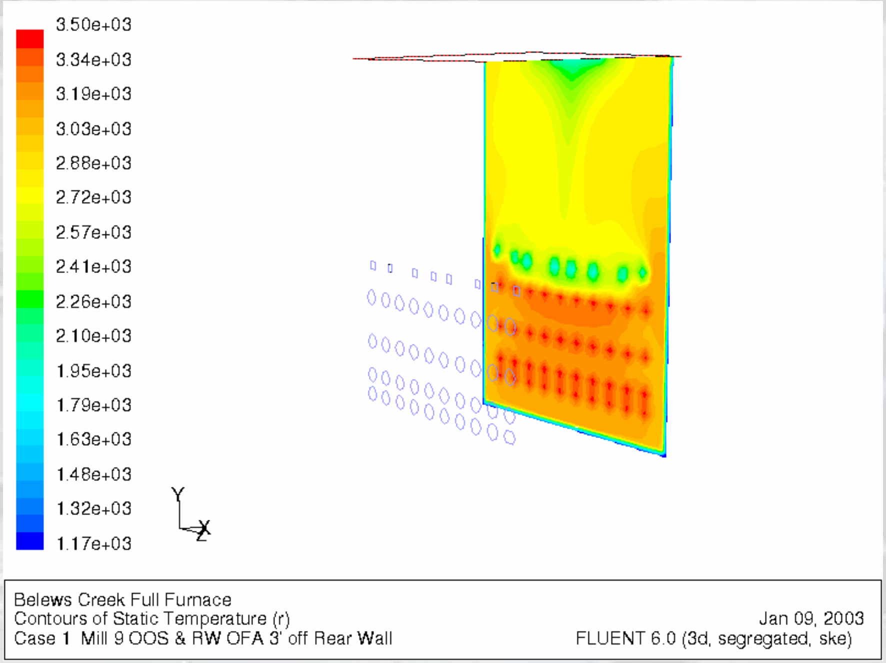


Furnace Model – OFA
□例

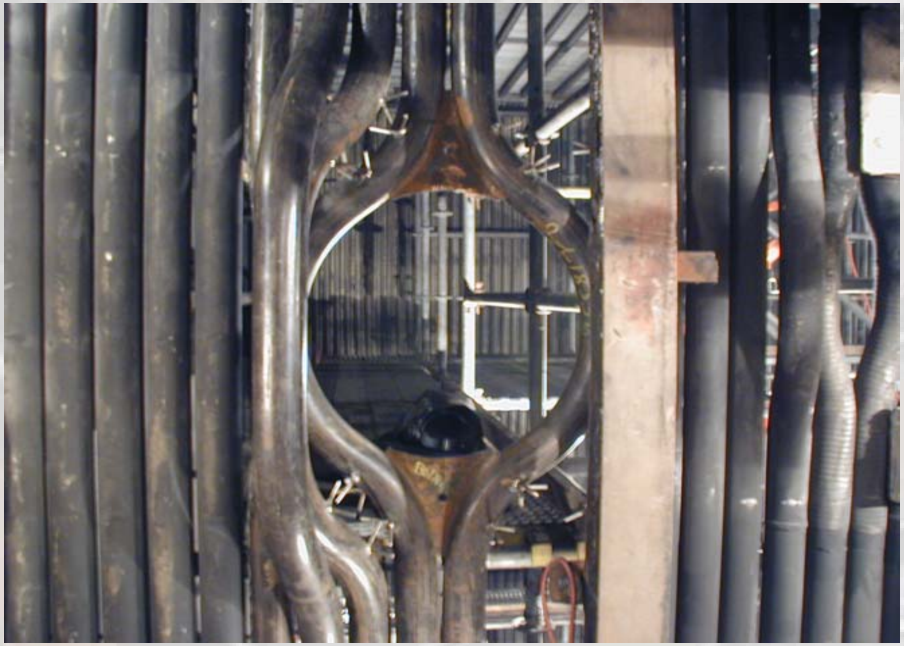
Before Modification



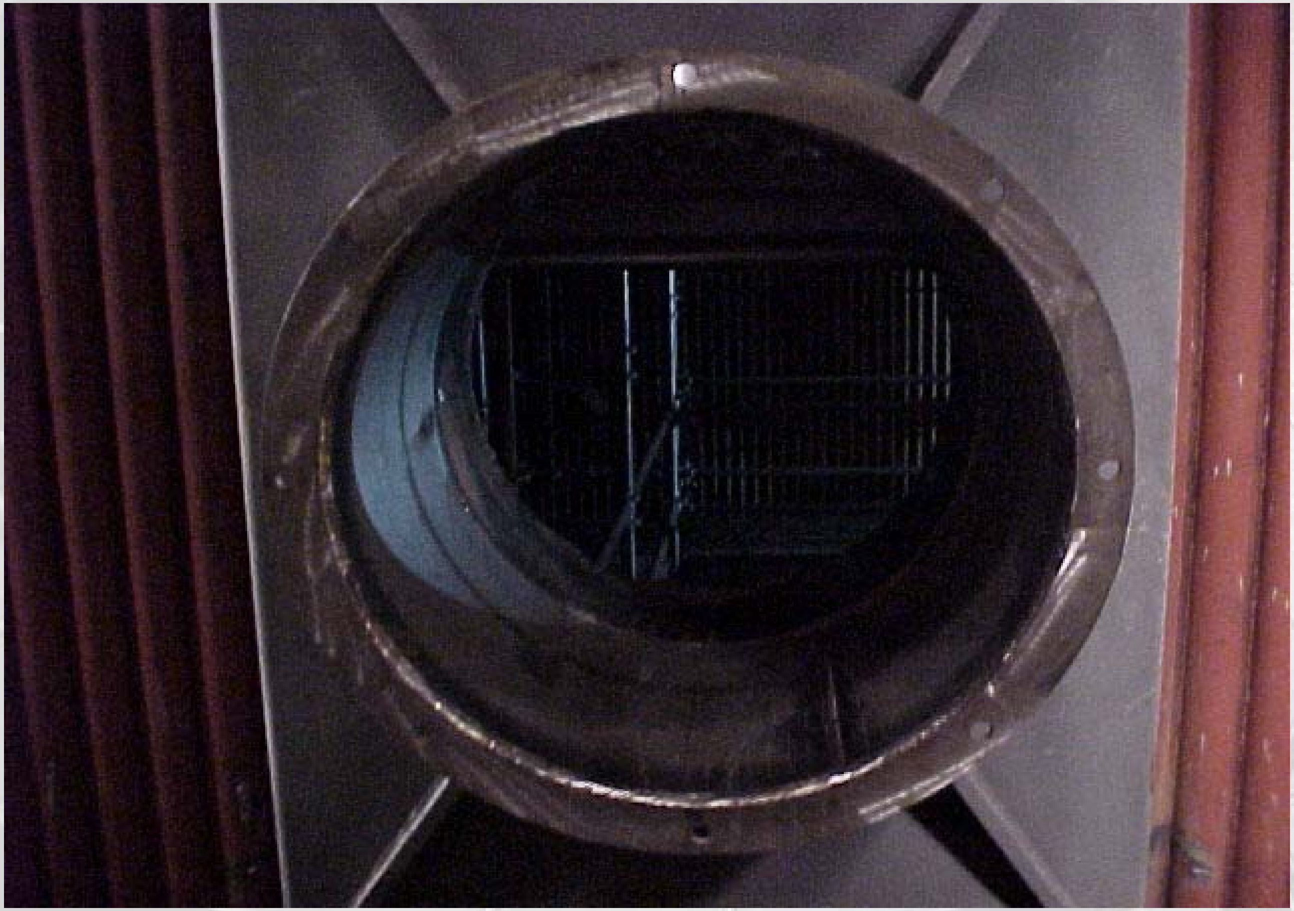
After Modification



OFA System Port Design



OFA System Port Design



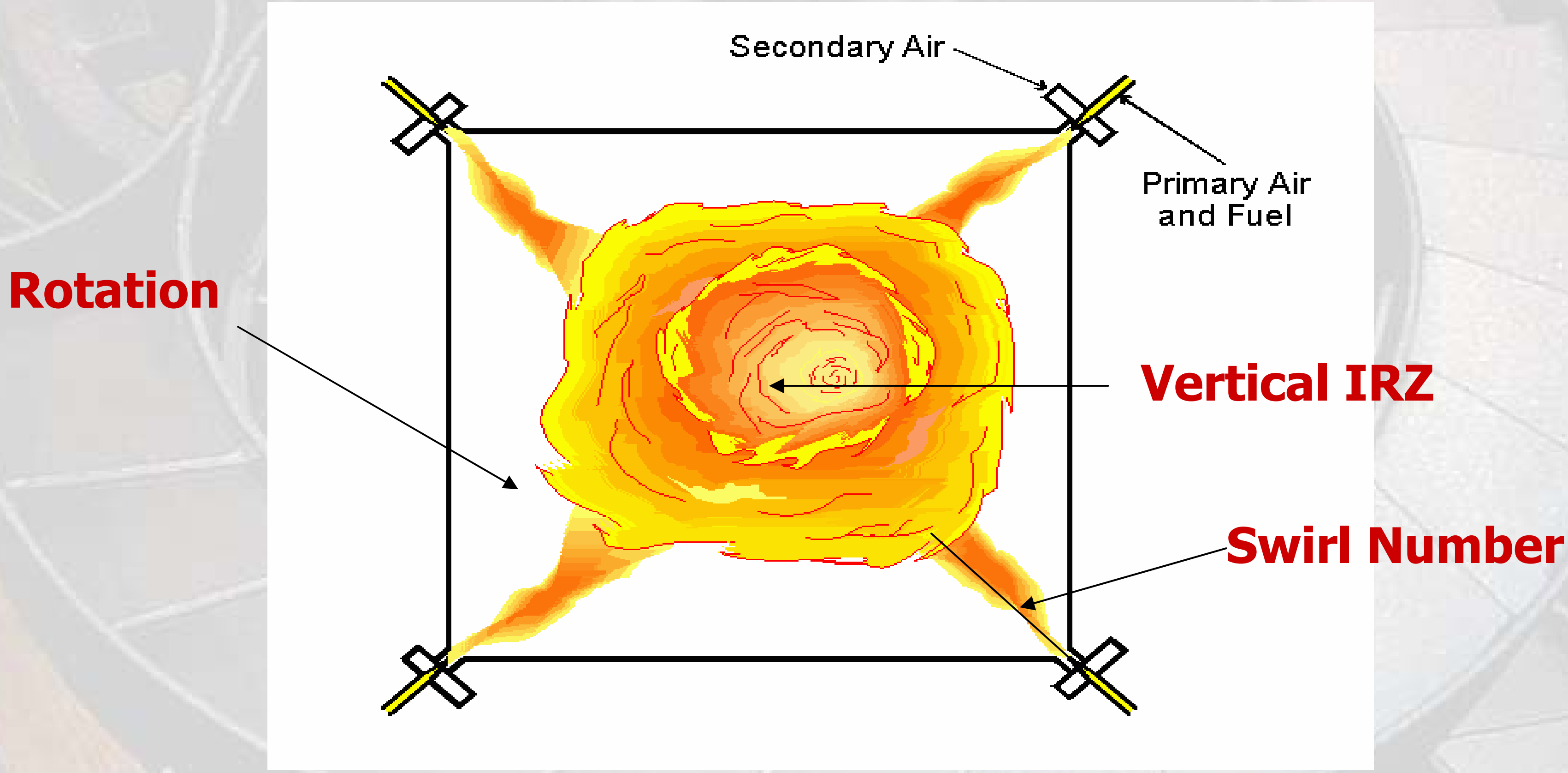
OFA System

T-FIRED BOILER

ACT

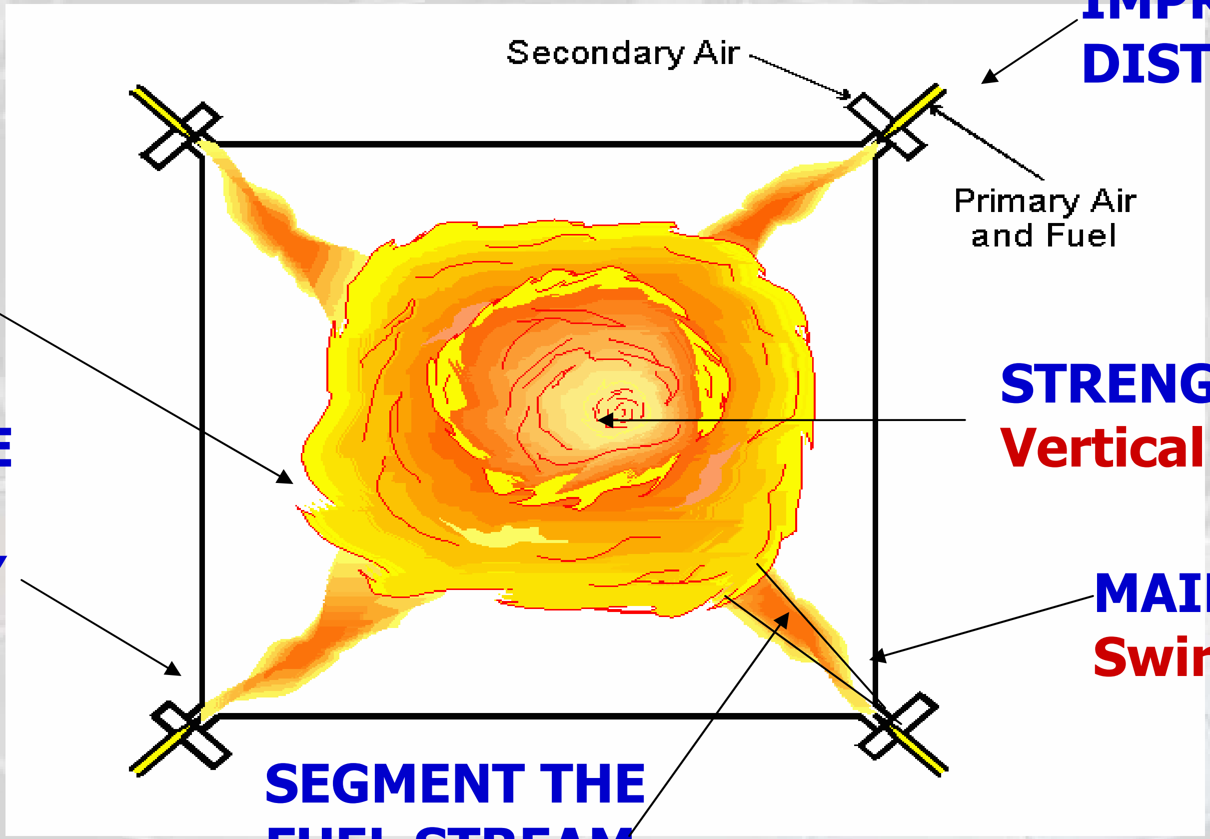
Coal Burner Dynamics

T-fired - Swirl Number (sn), Rotation & IRZ



Low NOx Dynamics

T-fired – NOx Reduction Techniques



IMPROVE COAL DISTRIBUTION

Rotation

INCREASE COAL VELOCITY

STRENGTHEN Vertical IRZ

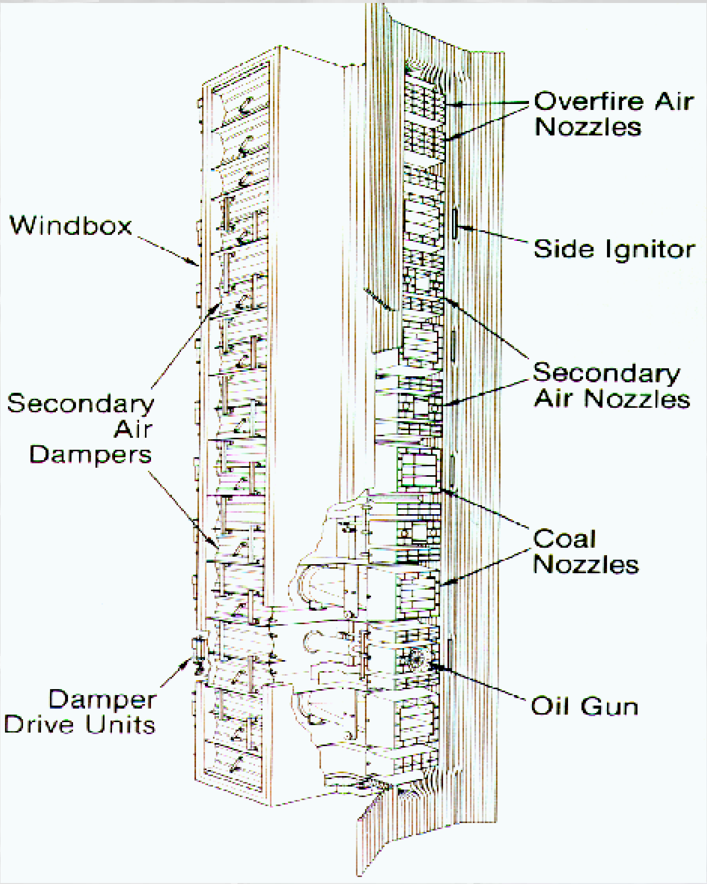
MAINTAIN Swirl Number

SEGMENT THE FUEL STREAM

ACT T-fired Boiler Burner Upgrade

- Coal Flow Distributor
- Coal Pipe Tip Insert
  - Increase Coal Injection Velocity
- New Fuel Bucket
  - Segmentation Of Fuel Stream

Typical T-fired Burner Corner

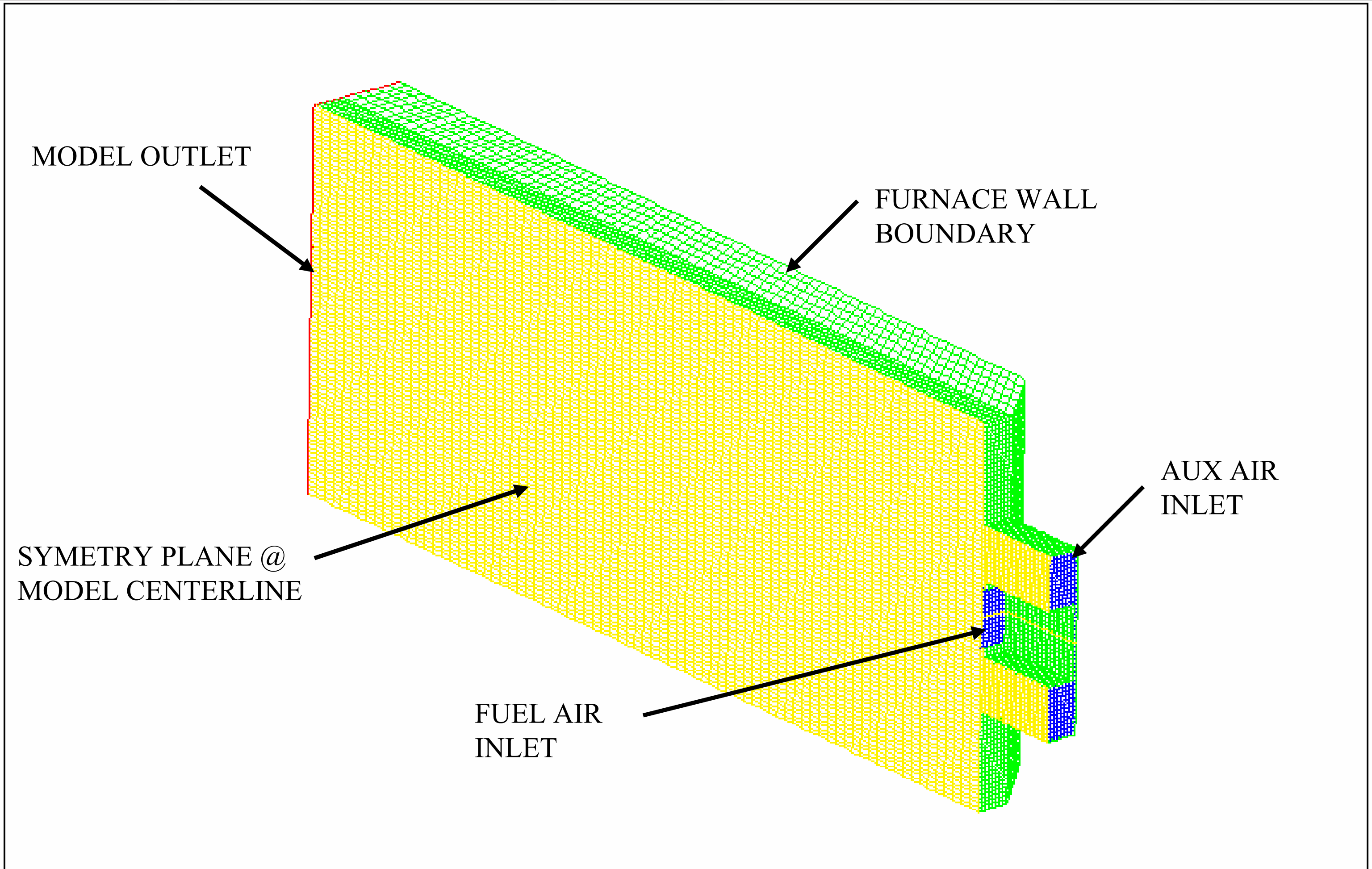


ACT T-fired Burner Upgrade & SOFA Addition

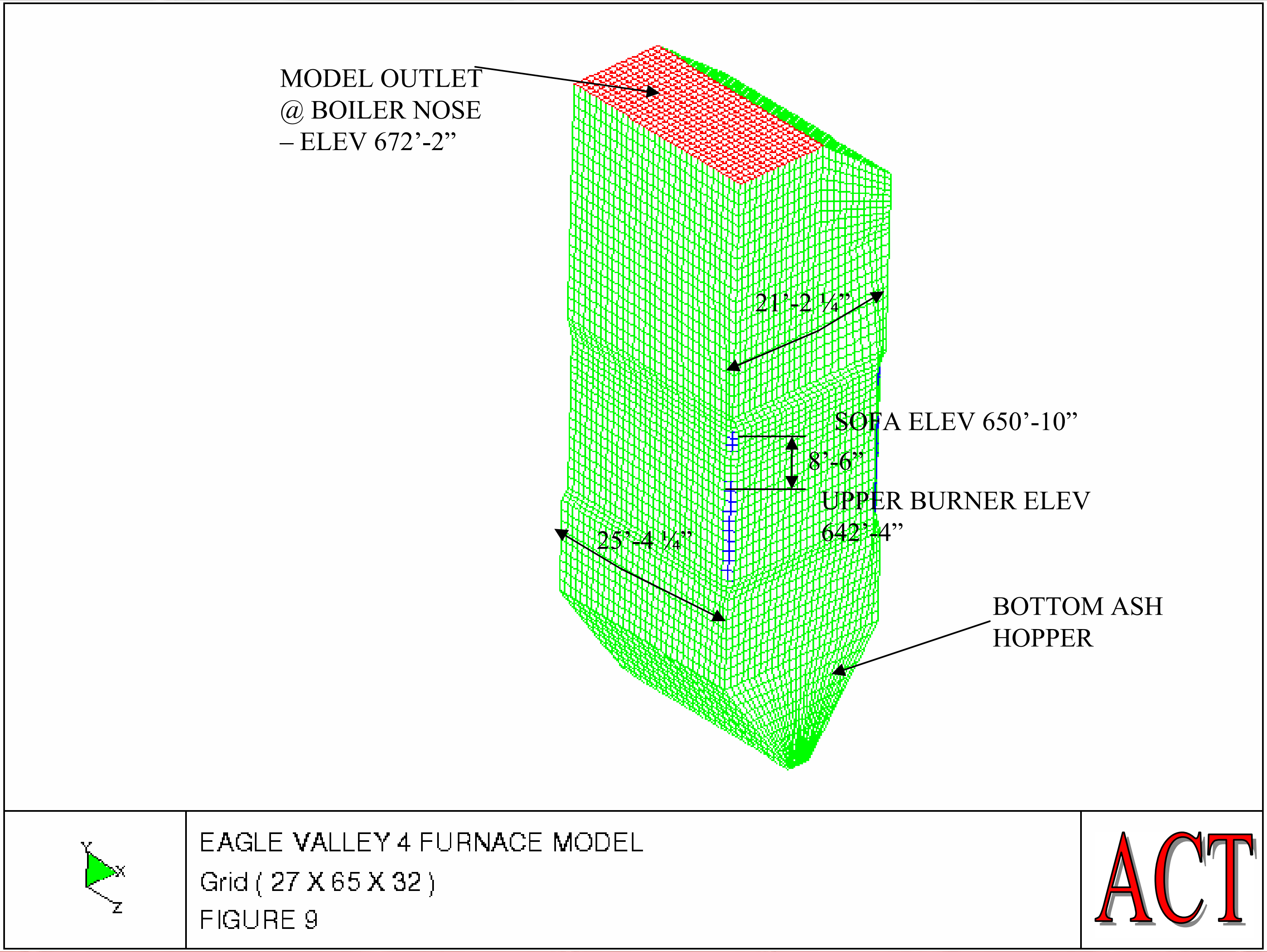
TYPICAL NOx REDUCTION

50 to 60% Burner Mods & OFA

Virtually No Change In LOI



Y X Z	EAGLE VALLEY UNIT 4 BURNER MODEL Grid (14 X 47 X 105) FIGURE 2	Jan 05 2004 Fluent 4.56 Fluent Inc.

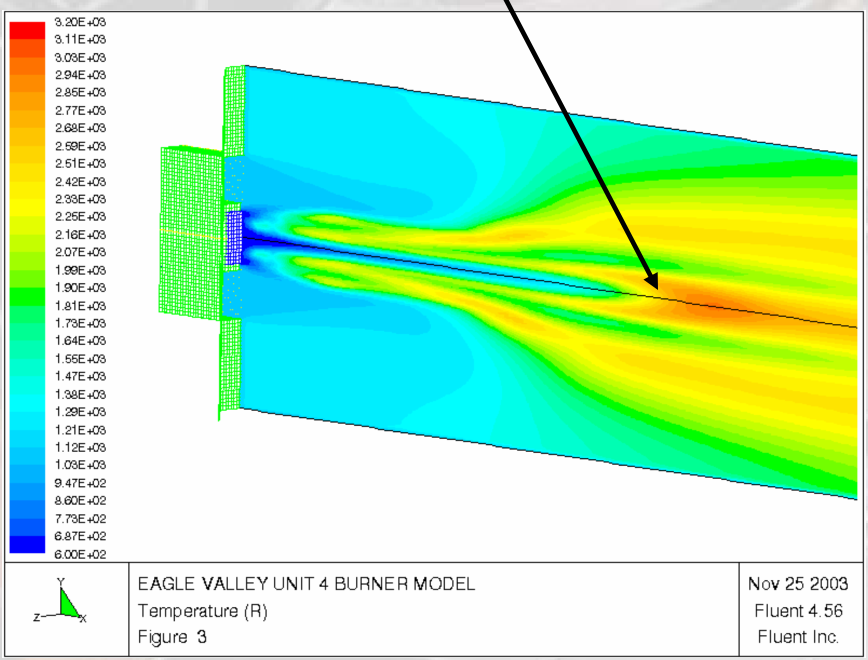

MODEL OUTLET
@ BOILER NOSE
– ELEV 672’-2”
21’-2 ¼”
SOFA ELEV 650’-10”
8’-6”
UPPER BURNER ELEV
642’-4”
25’-4 ¼”
BOTTOM ASH
HOPPER
EAGLE VALLEY 4 FURNACE MODEL
Grid (27 X 65 X 32)
FIGURE 9
ACT

ACT

Temperature Contour

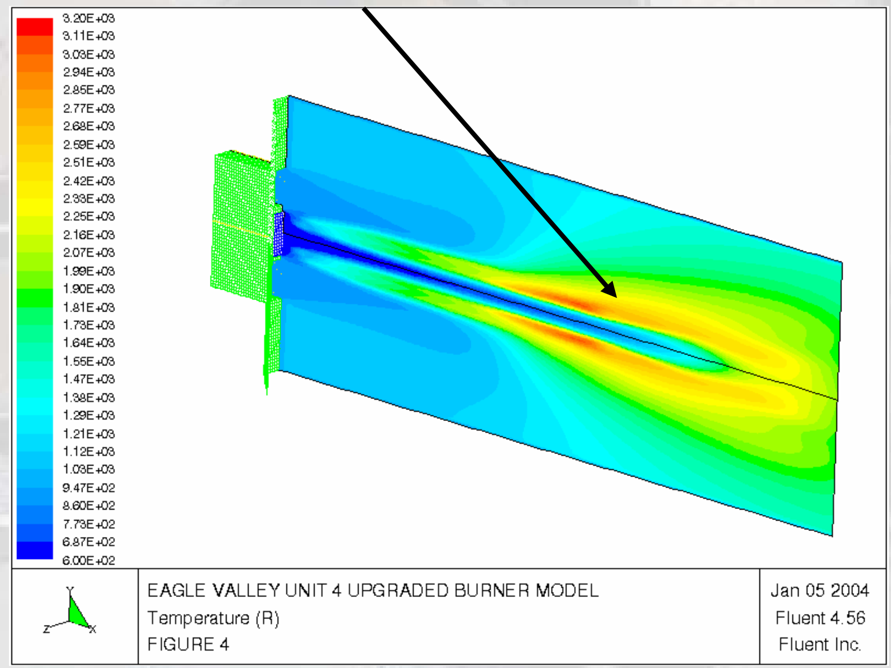
Baseline

PEAK TEMPERATURE ZONE



Upgraded

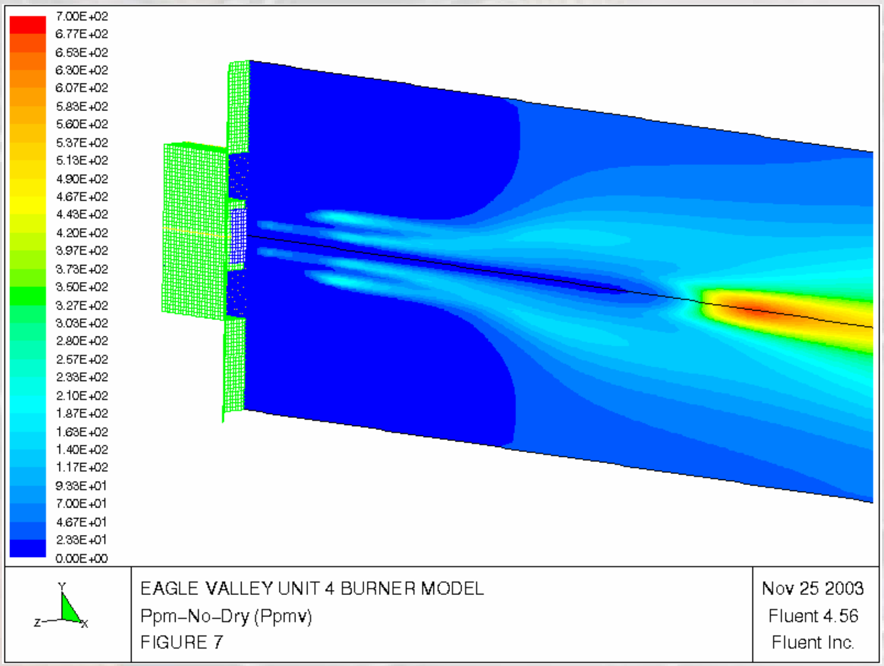
PEAK TEMPERATURE ZONE REDUCED



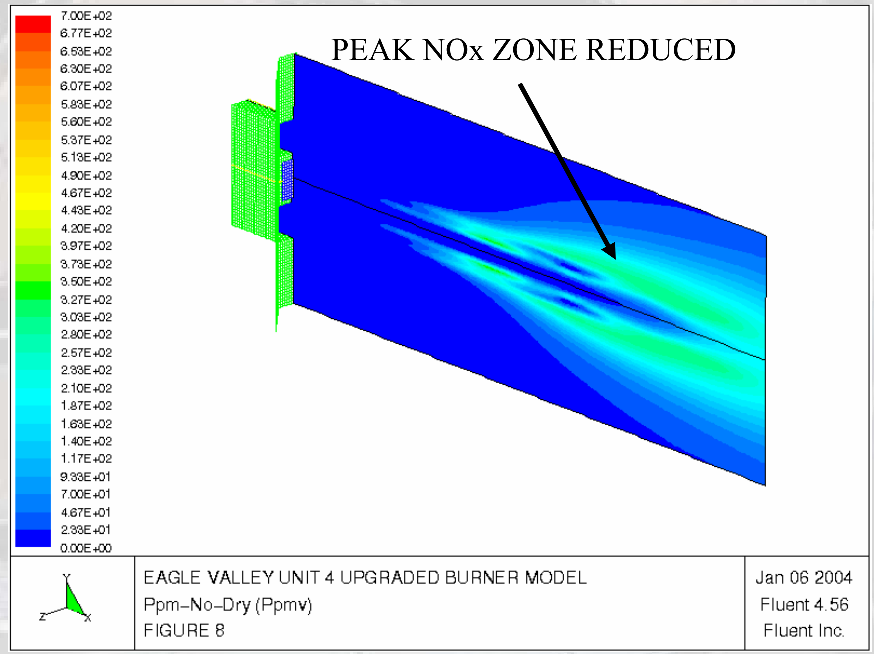
ACT

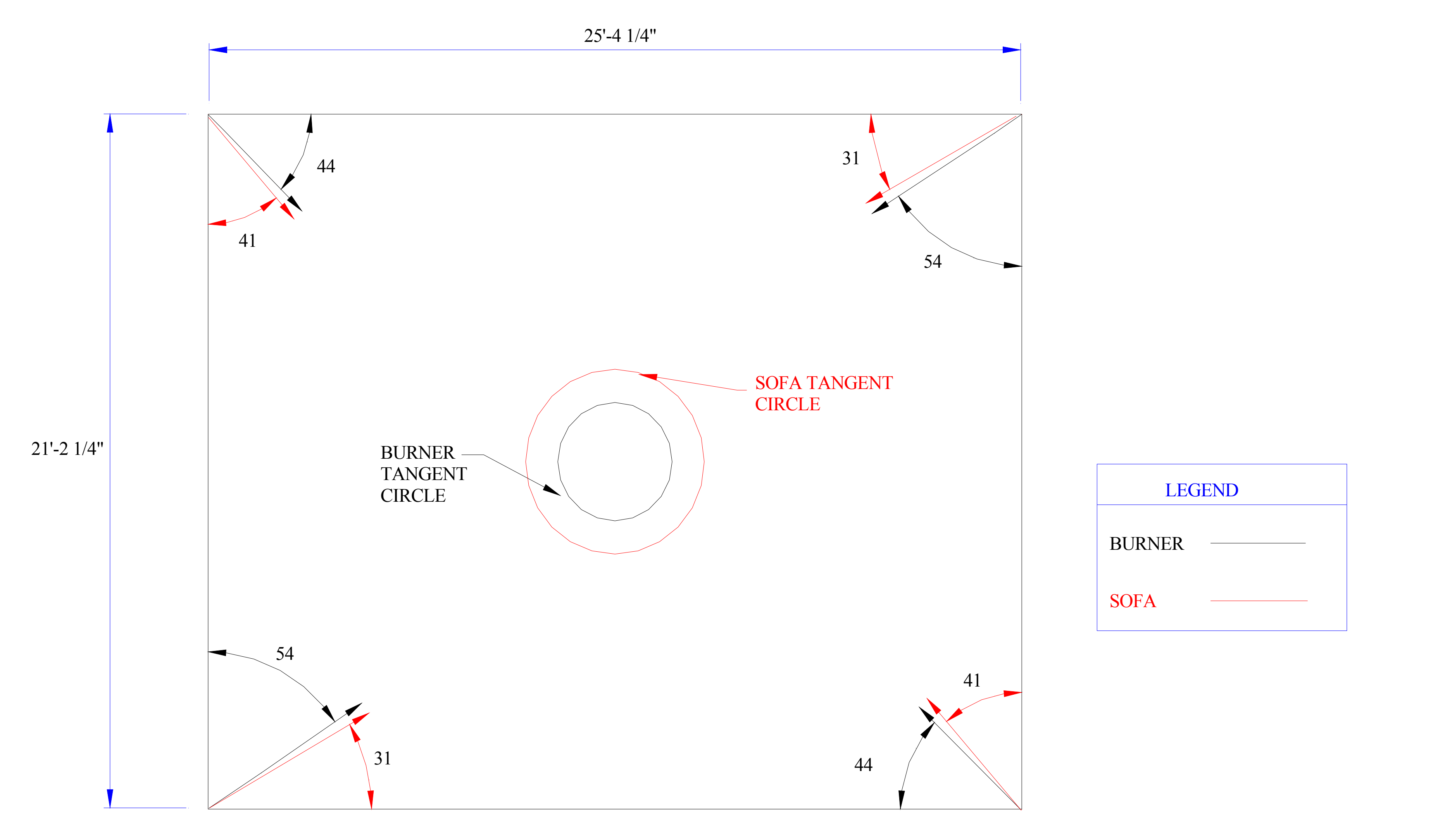
NOx Formation

Baseline Case

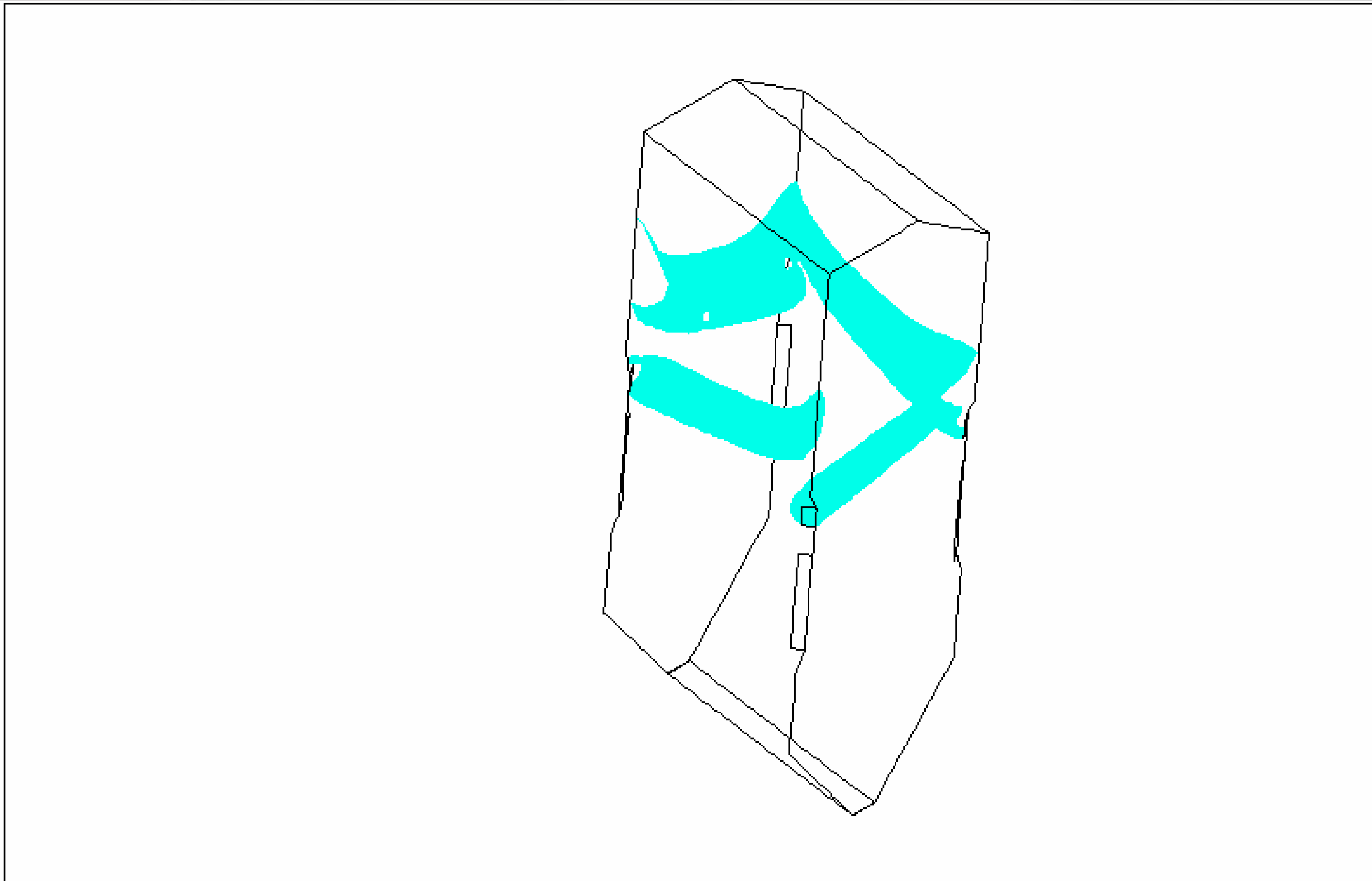


Upgrade Case



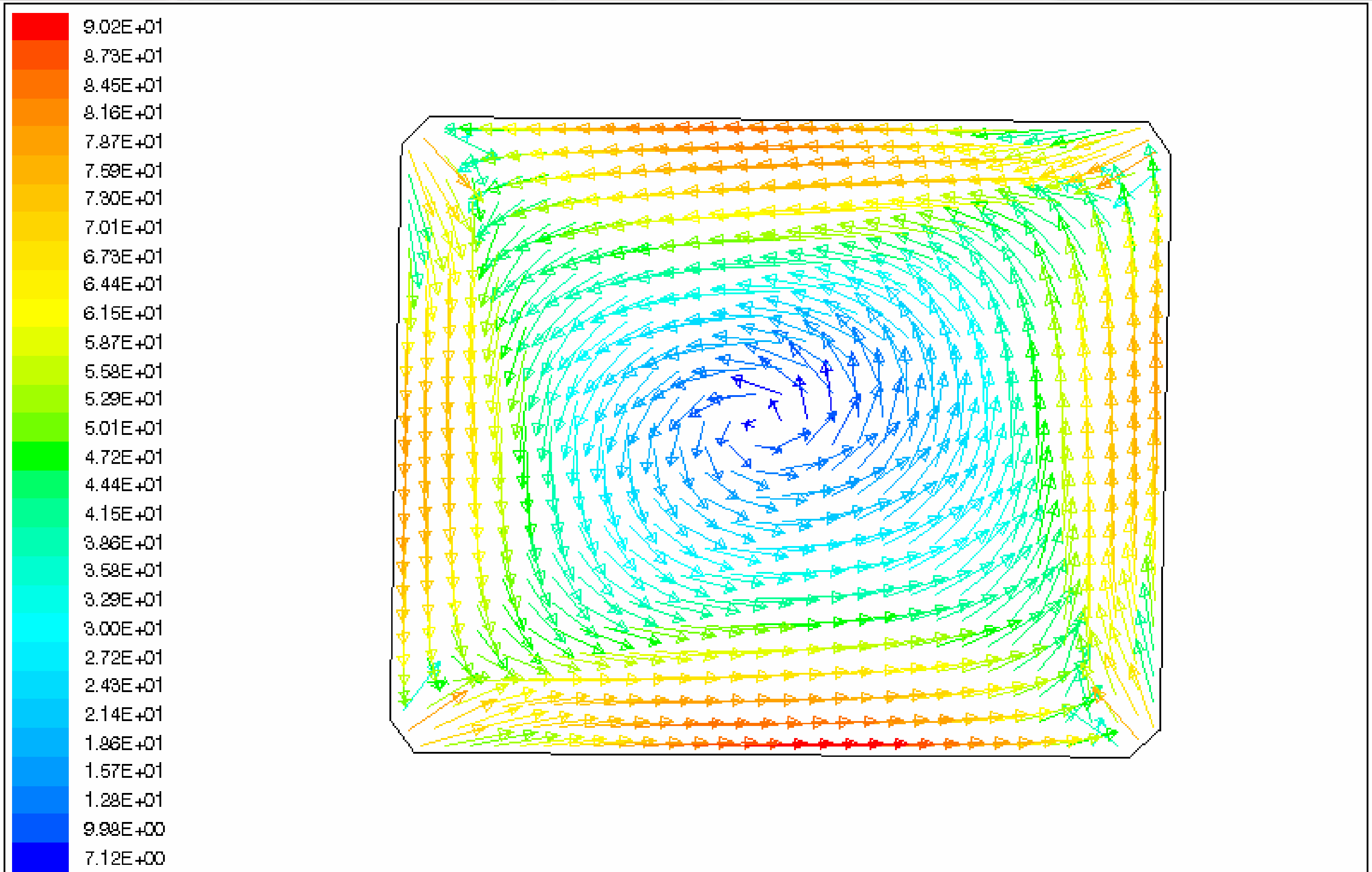


EAGLE VALLEY UNIT 4 FIRING CIRCLE



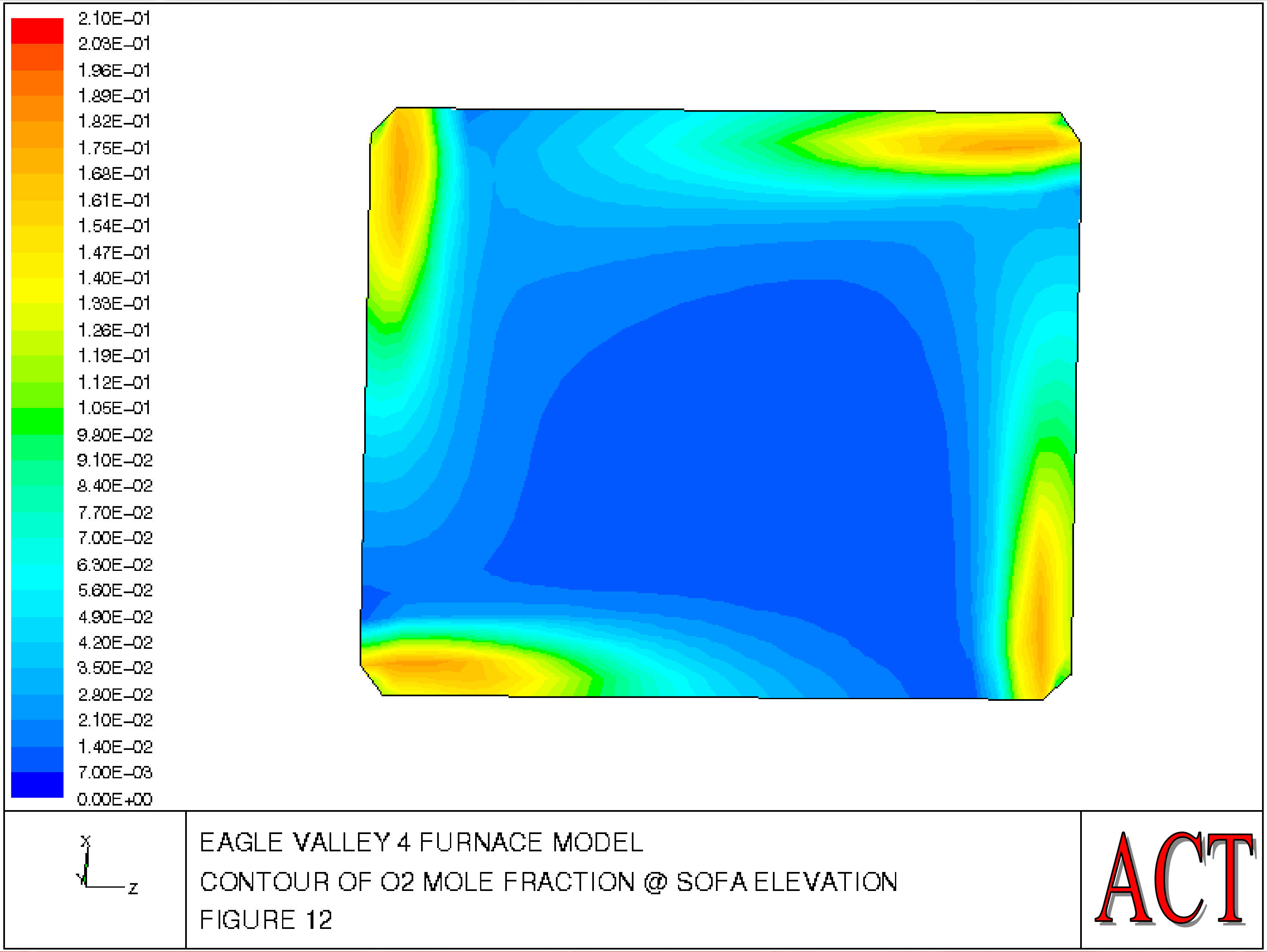
EAGLE VALLEY 4 FURNACE MODEL
Surface Of Constant 30% OFA Mole Fraction
FIGURE 10

ACT



EAGLE VALLEY 4 FURNACE MODEL
Velocity Vectors (Ft/S) @ SOFA Elevation
FIGURE 11

ACT

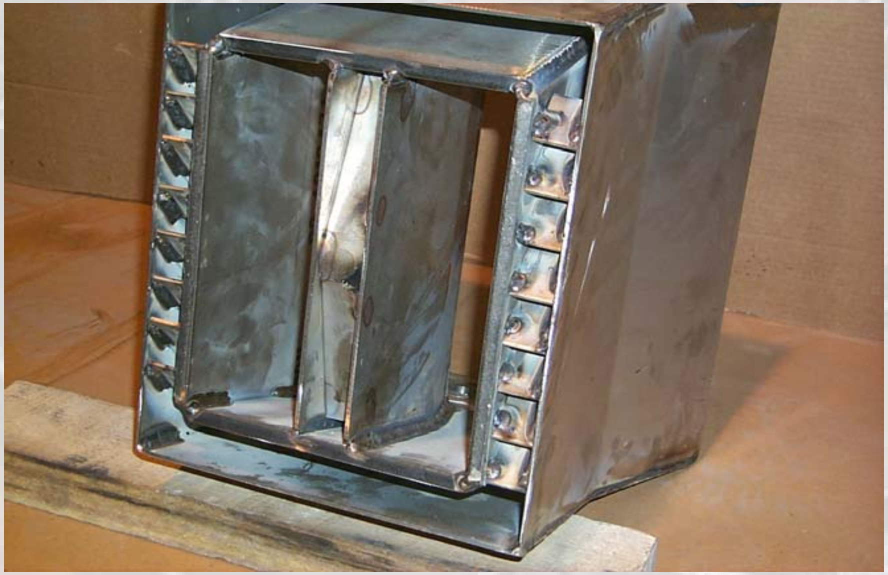


Confidential

ACT

ACT Low NOx T-Fired Fuel Bucket

Designed To Mate With Existing Coal Pipe And Sealing Arrangement



Coal Pipe

ACT Rope Breaker positioned inside existing coal pipe

ACT Coal Pipe Inserts positioned inside existing coal pipe

ACT Low NOx Burner Upgrade

ACT

Advanced Overfire Air

Advanced Overfire Air

OFA System Port Design

ACT

Advanced Overfire Air

OFA System Port Design

ACT

Advanced Overfire Air

OFA System Port Design

ACT

Typical NOx Reductions Coal Firing - Burner

- Wall Fired Boilers
  - 45% - 65%
- Opposed Fired Boilers
  - 40% - 55%
- Tangentially Fired Boilers
  - 45% - 60%

Low NOx Coal Burners

(Engineering and Design Summary)

- Baseline Testing
- CFD Modeling
- Hardware Design
- Hardware Manufacturing
- Hardware Installation
- Air And Coal Flow Testing
- Optimization

ACT

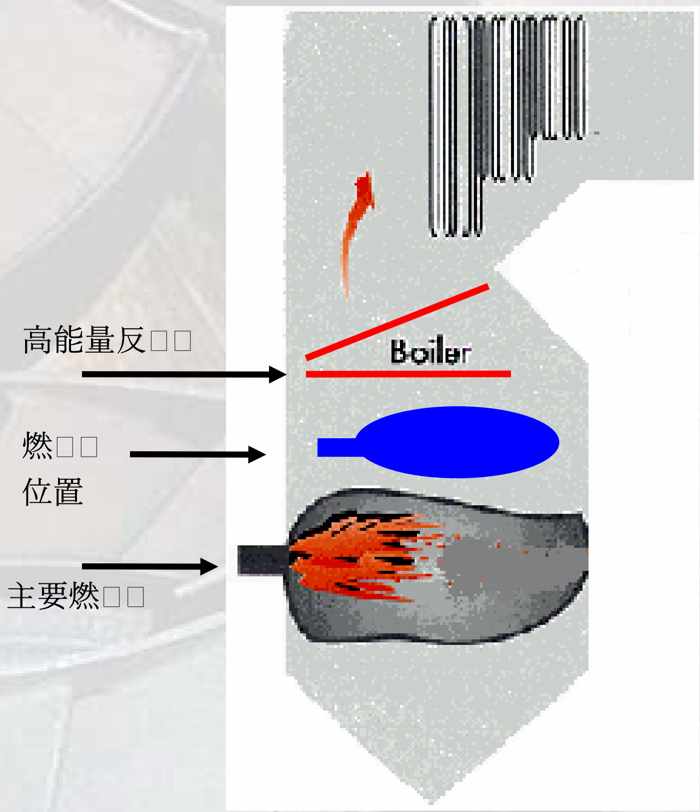
HIGH ENERGY REAGENT TECHNOLOGY (HERT)

第四□ 高能量反□□技□

ACT

HERT- ADVANCED SNCR

- Over Fire Air (OFA) is coupled with Urea or Ammonia injection to control nitrogen oxide emissions.   Up to 65% NOx reductions achievable.
- OFA reduces NOx by staging combustion. Urea breaks down to NH_3 and reacts with NOx in the proper temperature window, 1600 F to 2100 F, to form H_2O and N_2. Multi-level injection scheme controls NH_3 slip below 5 ppm.
- Fewer injectors are required than a typical SNCR system.
- CFD modeling is used in conjunction with test data to design the OFA system and predict NOx reduction potential and NH_3 slip levels.



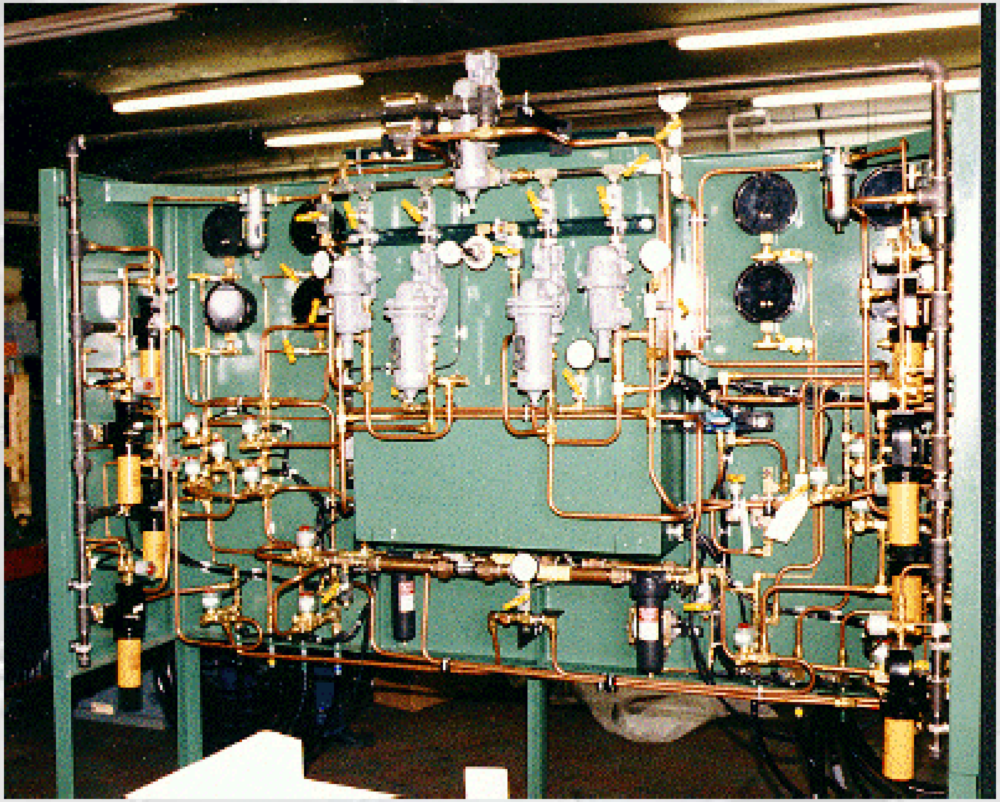
HERT – Advanced SNCR

OFA Port & Wall Injector

Large wall injectors coupled with a high momentum OFA injection stage combustion and produce an optimum chemical agent coverage at the furnace outlet.

HERT – Advanced SNCR
Injection Skid

The skid mounted control system meters urea from storage tank to injectors throughout the load range. Optimum chemical usage with minimal ammonia slip is maintained.



EXPERIENCES AND CASES

ACT

EXPERIENCE SUMMARY

- Over 100 boilers (25 to 1100 MW) upgraded or replaced with new burners
- 45 coal fired boilers (36 coal fired boiler in the past four years)
- 24 OFA systems (17 OFA systems in the past four years)
- Over 1000 burners supplied
- Over 500 coal fired burners

Low NOx Upgrades & OFA Experience
Coal Fired Boilers (2001-2004)

Utility/Station Location	Boiler MFG	Firing	# of Burner	MW	Steam Flow Klb/hr	Baseline NOx lb/mmBtu	LNB NOx lb/mmBtu	OFA NOx lb/mmBtu
Project 1 Pekin, IL	CE	Front	6	30	300	0.8	0.32	---
Project 2 Austell, GA	B&W	Front	6	25	250	0.6	0.34	0.26
Project 3 Blue Asheville, NC	CE	Tang	12	40	400	0.7	0.48	0.28
Project 4 Tuscola, IL	CE	Front	4	20	200	0.90	0.40	0.30
Project 5 Hamilton, OH	CE	Tang	12	55	550	0.70	0.50	0.30
Project 6 Lansing, MI	B&W	Front	9	65	650	0.35	0.23	0.18
Project 7 Lansing, MI	B&W	Front	9	65	650	0.35	0.23	0.18
Project 8 Lansing, MI	CE	Tang	12	40	400	0.3	0.25	0.17
Project 9 Lansing, MI	B&W	Front	6	35	350	0.6	0.24	0.18
Project 10 Colorado Springs, CO	B&W	Front	12	150	1300	0.8	0.35	---
Project 11 Colorado Springs, CO	B&W	Front	9	90	750	0.8	0.35	---
Project 12 Colorado Springs, CO	B&W	Front	6	50	500	0.75	0.4	---
Project 13 Colorado Springs, CO	B&W	Opposed	21	300	2,100	0.65	0.25	---
Project 14 Litchfield, MI	B&W	Front	6	55	550	0.6	0.34	0.22

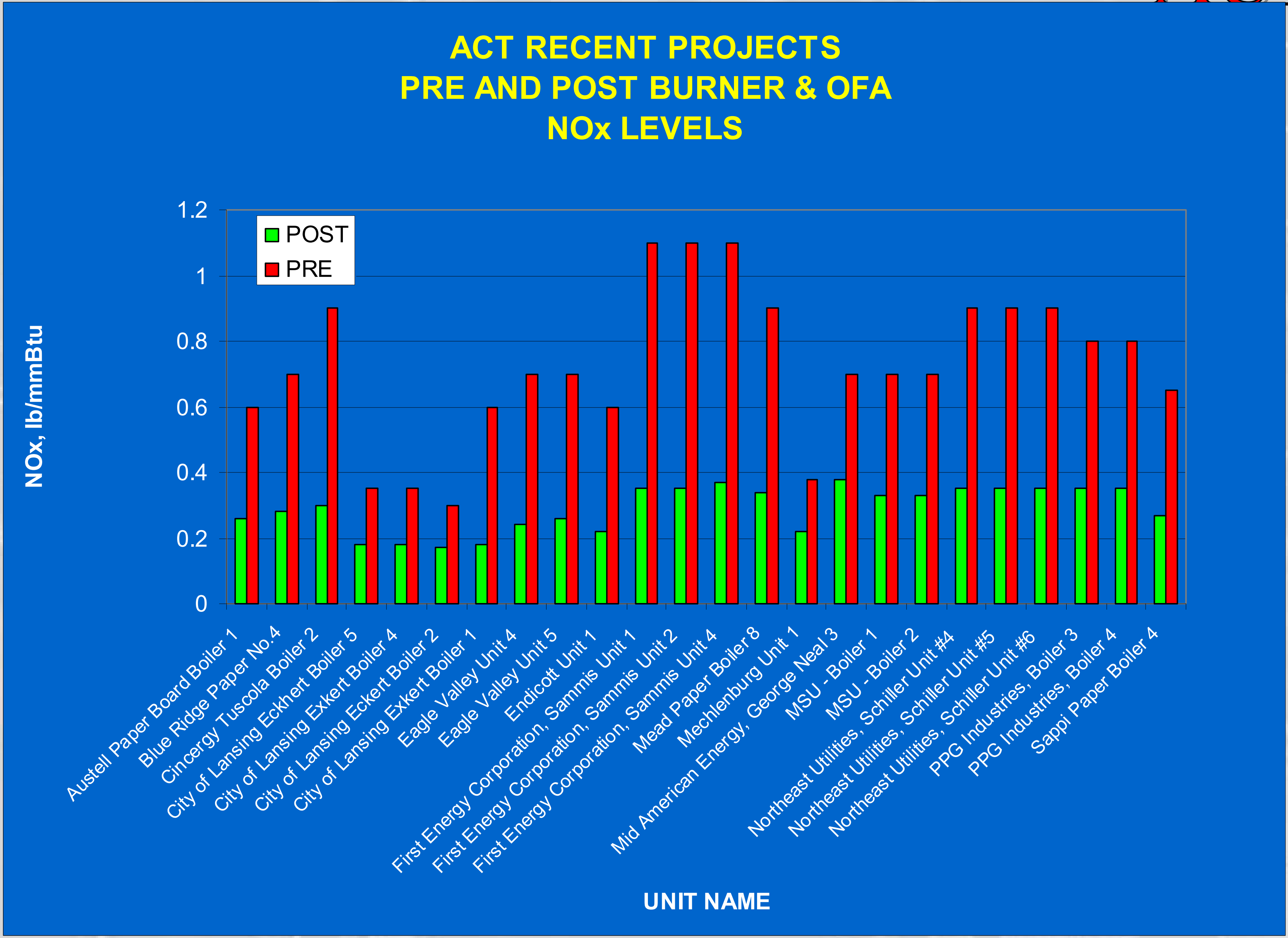
Low NOx Upgrades & OFA Experience
Coal Fired Boilers (2001-2004)

Utility/Station Location	Boiler MFG	Firing	# of Burner	MW	Steam Flow Klb/hr	Baseline NOx lb/mmBtu	LNB NOx lb/mmBtu	OFA NOx lb/mmBtu
Project 15 Stratton, OH	FW	Front	15	180	1,500	1.1	0.42	0.35
Project 16 Stratton, OH	FW	Front	15	180	1,500	1.1	0.42	0.37
Project 17 Martinsville, IN	CE	Tang	16	60	600	0.7	0.5	0.3
Project 18 Martinsville, IN	CE	Tang	16	60	600	0.7	0.5	0.3
Project 19 Chillicothe, OH	CE	Front	4	36	360	0.9	0.42	0.34
Project 20 Salix, IA	FW	Front	16	550	2,800	0.7	0.45	0.38
Project 21 Lansing, MI	Riley	Front	4	25	250	0.7	0.4	0.33
Project 22 Lansing, MI	Riley	Front	4	25	250	0.7	0.4	0.33
Project 23 Minneapolis, MN	B&W	Oppos ed	70	900	6,150	0.6	0.35	---
Project 24 Portsmouth, NH	FW	Front	6	40	400	0.90	0.42	0.35
Project 25 Portsmouth, NH	FW	Front	6	40	400	0.90	0.42	0.35
Project 26 Portsmouth, NH	FW	Front	6	40	400	0.90	0.42	0.35
Project 27 New Martinsville, WV	Riley	Front	6	20	200	0.80	0.42	0.35
Project 28 New Martinsville, WV	Riley	Front	6	35	350	0.80	0.45	0.35

Advanced Combustion Technology, Inc.
Low NOx Upgrades & OFA Experience
Coal Fired Boilers (2001-2004)

Utility/Station Location	Boiler MFG	Firing	# of Burner	MW	Steam Flow Klb/hr	Baseline NOx lb/mmBtu	LNB NOx lb/mmBtu	OFA NOx lb/mmBtu
Project 29 Muskegon, MI	CE	Tang	8	28	275	0.70	0.5	0.3
Project 30 Muskegon, MI	CE	Tang	12	35	350	0.50	0.4	0.28
Project 31 Syracuse, NY	B&W	Front	4	25	250	0.6	0.35	---
Project 32 Syracuse, NY	B&W	Front	4	25	250	0.6	0.35	---
Project 33 Syracuse, NY	B&W	Front	4	25	250	0.6	0.35	---
Project 34 Syracuse, NY	B&W	Front	4	25	250	0.6	0.35	---
Project 35 Syracuse, NY	B&W	Front	4	25	250	0.6	0.35	---
Project 36 Monticello, TX	B&W	Opposed	70	850	6500	0.29	0.19	0.16
Project 37 Toronto, Ontario	B&W	Front	24	300	2000	0.99	0.45	---
Project 38 Toronto, Ontario	B&W	Front	24	300	2000	0.99	0.45	---
Project 39 Toronto, Ontario	B&W	Front	18	300	2000	0.99	0.45	---
Project 40 Toronto, Ontario	B&W	Front	18	300	2000	0.99	0.45	---

ACT


ACT RECENT PROJECTS
PRE AND POST BURNER & OFA
NOx LEVELS
NOx, lb/mmBtu
UNIT NAME
POST
PRE
1.2
1
0.8
0.6
0.4
0.2
0
Austell Paper Board Boiler 1
Blue Ridge Paper No.4
Cincergy Tuscola Boiler 2
City of Lansing Eckhert Boiler 5
City of Lansing Exkert Boiler 4
City of Lansing Eckert Boiler 2
City of Lansing Exkert Boiler 1
Eagle Valley Unit 4
Eagle Valley Unit 5
Endicott Unit 1
First Energy Corporation, Sammis Unit 1
First Energy Corporation, Sammis Unit 2
First Energy Corporation, Sammis Unit 4
Mead Paper Boiler 8
Mechlenburg Unit 1
Mid American Energy, George Neal 3
MSU - Boiler 1
MSU - Boiler 2
Northeast Utilities, Schiller Unit #4
Northeast Utilities, Schiller Unit #5
Northeast Utilities, Schiller Unit #6
PPG Industries, Boiler 3
PPG Industries, Boiler 4
Sappi Paper Boiler 4

ACT

Case Example 1

Austell Coal Fired Boiler – Austell, GA

PROJECT SCOPE:

Engineer, model, supply and start-up burner upgrades and Overfire Air to reduce NOx emissions 53% to 0.26 lb/mmBtu.

DESCRIPTION AND PERFORMANCE:

•Secondary airflow was balanced utilizing ACT's combustion air testing technology. Burner upgrades included the addition of a Low NOx Swirler, Coal Nozzle, Coal Flow Distributor and Burner Barrel. Two (2) Over Fire Air ports (OFA), one (1) over each column of burners was added.

•NOx emissions were reduced to less than 0.36 lb/mmBtu at full load conditions with the burner upgrades and less than 0.26 lb/mmBtu with the OFA. Flyash Loss-On-Ignition, (LOI) decreased significantly from "Pre Upgrade" level of 37% to the "Post Upgrade" level of 15%.

ACT

Case Example 2

PLANT NAME: Michigan South Central Power Agency (MSCPA) – Boiler 1

APPLICATION: A 550,000 lb/hr Babcock & Wilcox Wall Fired Boiler required NOx reduction under the EPA Section 126 petition.

PROJECT SCOPE: Engineer, model, supply and start-up burner optimizations and modifications to reduce NOx emissions to 0.22 lb/mmBtu.

BOILER DATA

• Manufacturer	B&W
• Type	Natural Circulation Boiler
• Capacity	550,000lb/hr
• Steam Conditions	1,800 PSIG, 950 °F SH
• Fuels	Eastern Bituminous Coal
• Burners	8 B&W circular register
• Firing Arrangement	Front Fired 2 wide x 4 high
• Baseline NOx	0.65 lb/mmBtu
• Final NOx	0.22 lb/mmBtu

ACT

Case Example 2
Description And Performance

- MSCPA owns and operates a wall fired coal boiler. As part of Petition 126, they needed to reduce NOx to the lowest possible level. Baseline NOx was 0.65 lb/mmBtu with flyash LOI of 6%.

- The project was performed in two (2) stages. In the first stage ACT upgraded burners. NOx was reduced to less than 0.34 lb/mmBtu.

- ACT performed the OFA system addition in the second phase to reduce NOx to less than 0.22 lb/mmBtu. Flyash Loss-On-Ignition following the two (2) phases increased slightly to 8%.

- Burner upgrades included the addition of a Low NOx Swirler, Coal Nozzle, Coal Flow Distributor and Coal Barrel. The OFA system included, flow control dampers, ductwork, expansion joints, seal boxes and nozzles.

Case Example 3

PLANT NAME Monroe Unit 2 – Combustion Tuning - Post Burner Upgrade

APPLICATION 840 MWg boiler with 28 coal fired burners upgraded for enhanced NOx control.

PROJECT SCOPE Tune upgraded burners for optimum combustion and Low NOx performance

BOILER DATA

Manufacturer	Babcock & Wilcox
Type	UP Boiler
Capacity	5,900,000 lb/hr
Steam Conditions	3,500 psig and 1,000 F
Fuels	Coal Blend with Opportunity Fuels
Burners	28 Cell Burners
Baseline NOx	0.55 lb/mmBtu
Final NOx	0.35 lb/mmBtu
CO, ppm	<200 ppm
Opacity	14% - 16%
Upper NOx Ports - % Open (N-S)	100/100/50 50/100/100
Lower NOx Ports 5-4, 7-1, 1-1	100/100/40

DESCRIPTION AND PERFORMANCE

DTE's Monroe Unit 2 was upgraded with ACT low NOx burner components. Tuning was performed to optimize combustion and reduce NOx to the lowest possible level. A third party test crew to determine the emission performance conducted testing. An initial setup was performed for low NOx performance. CO emission was maintained below 200 ppm.

Table 1
Monroe Unit 2
Low NOx Test Run
(750 MWn, 60/40 Coal Blend)

Parameter	North Duct	South Duct	Unit Average
NOx, lb/mmBtu	.37	.31	.34
CO, ppm	129	124	127

Tuning was conducted to reduce CO to the lowest possible level and maintain acceptable NOx emissions. These results are illustrated in Table 2.

Table 2
Monroe Unit 2
Low CO Test Run
(700 MWn, 65/35 Coal Blend)

Parameter	North Duct	South Duct	Unit Average
NOx, lb/mmBtu	.37	.34	.355
CO, ppm	16	7	12

Case Example 4

CLIENT ***COLORADO***

PLANT NAME Unit 1

APPLICATION One (1) 2,000,000 lb/hr Babcock and Wilcox Coal Fired Boiler

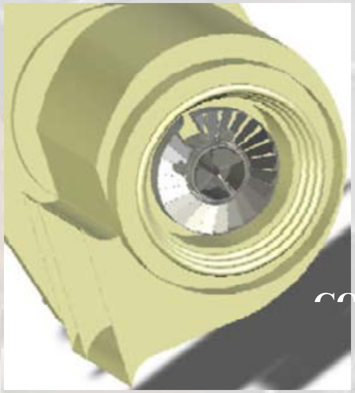
PROJECT SCOPE Engineer, model, supply and start-up ACT designed Low NOx burners to reduce NOx emissions from 0.40 lb/mmBtu to less than 0.26 lb/mmBtu

BOILER DATA

Manufacturer	Babcock & Wilcox
Type	Natural Circulation Boiler
Capacity	2,000,000 lb/hr
Steam Conditions	1800 PSIG, 950°F SH
Fuels	Western Sub Bit Coal
Burners	21 opposed fired circular register
Baseline NOx	0.40 lb/mmBtu
Final NOx	0.25 lb/mmBtu

DESCRIPTION AND PERFORMANCE

CSU owns and operates Nixon Boiler 1, in order to operate the Front Range combined cycle unit NOx needed to be reduced. The boiler was retrofitted several years earlier with Eagle Air burners. Following the retrofit NOx was 0.40 lb/mmBtu with high CO and severe slagging. To further reduce NOx, ACT's low NOx burners were selected as the most cost effective technology. Baseline testing determined the flyash LOI was 2% at the full load condition. The design was required to limit flyash to less than 2% with no impact on unit opacity.



Secondary airflow was balanced utilizing ACT's combustion air testing technology. The existing secondary air dampers were set to balance airflow to each burner to within +-5% of boiler mean.

NOx emissions were reduced to less than 0.25 lb/mmBtu at full load conditions. Flyash LOI was less than 2.0% and Opacity was not impacted

ACT

HERT (ADVANCED SNCR) EXPERIENCE

Utility/Station Location	Boiler MFG	Firing	# of Burner	MW	Steam Flow Klb/hr	Baseline NOx lb/mmBtu	LNB NOx lb/mmBtu	OFA NOx lb/mmBtu	HERT NOx lb/mmBtu	Total NOx Reduction (%)
Project 1 Asheville, NC	CE	Tang	12	40	400	0.7	0.48	0.28	0.12	83%
Project 2 Litchfield, MI	B&W	Front	6	55	550	0.6	0.34	0.22	0.15	75%
Project 3 Stratton, OH	FW	Front	15	180	1,500	1.1	0.42	0.35	0.21	81%
Project 4 Stratton, OH	FW	Front	15	180	1,500	1.1	0.42	0.35	0.25	77%
Project 5 Stratton, OH	FW	Front	15	180	1,500	1.1	0.42	0.37	0.22	80%
Project 6 Portsmouth, NH	FW	Front	6	40	400	0.90	0.42	0.35	0.25	72%
Project 7 West Pittsburg, PA	B&W	Front	16	135	1,350	0.83	0.45	0.38	0.26	69%

ACT

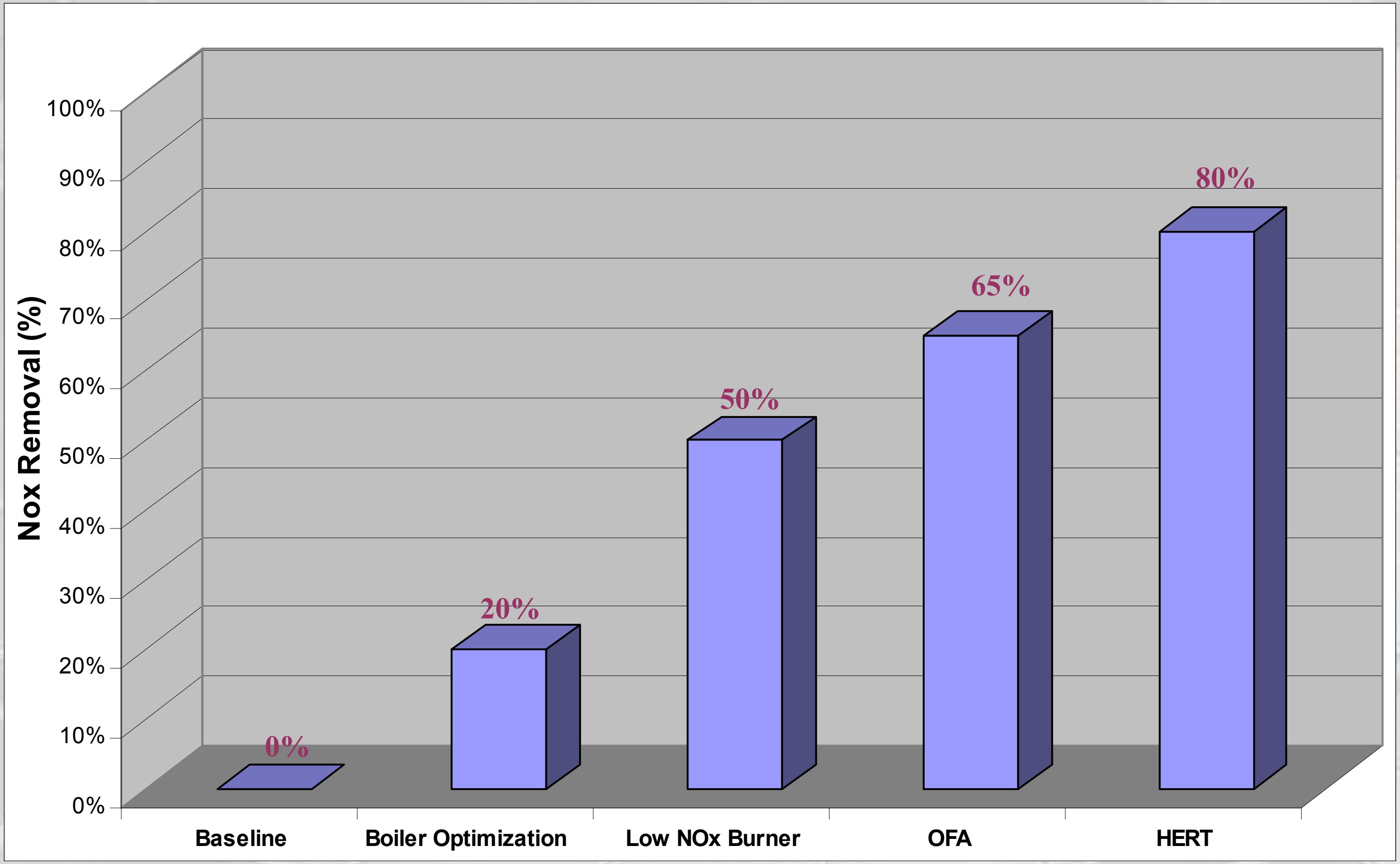
ACT LAYERED APPROCH SUMMARY

Layer	Technologies	NOx Reduction (%)
Layer 1	Combustion Optimization	10-20%
Layer 2	Low NOx Burner	45%-60%
Layer 3	Over Fire Air (OFA)	25-40%
Layer 4	HERT (Advanced SNCR)	35-50%
Layer 2+3	Low NOx Burner + OFA	55-65%
Layer 3+4	OFA + HERT	65%
Layer 2+3+4	Low NOx Burner + OFA + HERT	80%

ACT

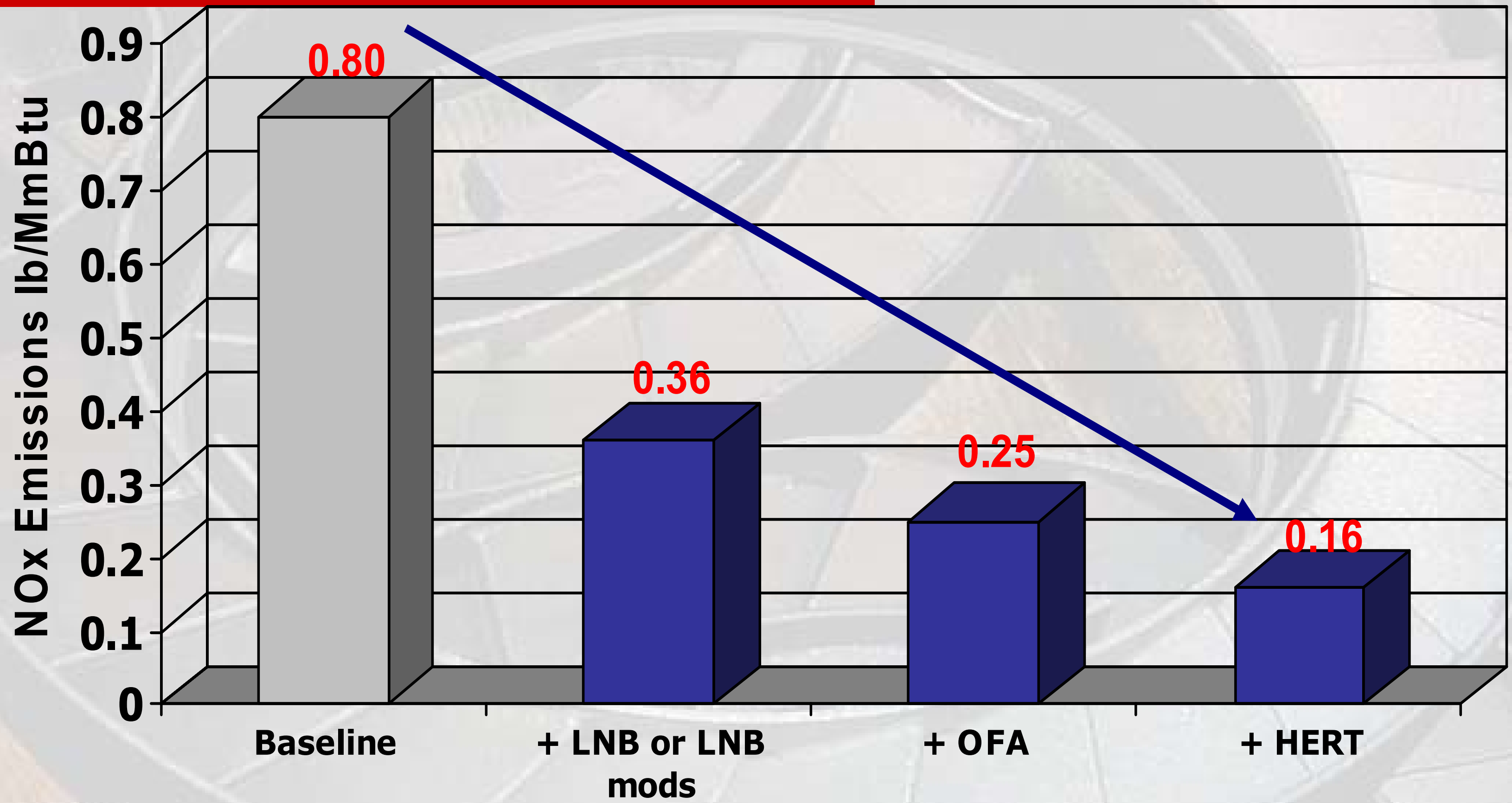
ACT Layered NOx Reduction Approach

80%+NOx reduction at the lowest cost/ton (以最低价位□到80%以上□□率)



ACT

ACT's Layered NOx Reduction Process



ACT

WHAT ARE YOU LOOKING FOR?

		NOx Reduction	Cost (□用)
ACT NOx 分□控制系□	Boiler Optimization? Modified Burners? New Low NOx Burners? Overfire Air? HERT (Advanced–SNCR)?	80%+	Low（低）
	Traditional SNCR?	35%	High（高）
	SCR?	90%	Extremely High（很高）

ANSWER：
ACT Best Value NOx Reduction

ACT

HERE IS YOUR SOLUTION

- Custom Fit
- Minimize Operational Impact （Shorter Plant Outages）
- Lowest Urea Consumption
- No Catalyst Required
- Select Only the Performance You Need （Flexibility)
- Lower Capital Cost
- Lowest O&M Cost

The ACT Layered NOx Reduction Process
80%+NOx reduction at the lowest cost/ton
(以最低价位□到80%以上□□率)

ACT

THANK YOU

Comments of NRG Energy, Inc.
on the Draft Report
"Reducing Emissions in Connecticut on High Electric Demand Days (HEDD)"

Introduction

On June 17, 2008, the Connecticut Department of Environmental Protection ("Department" or "DEP") made available for public comment the draft report prepared by Synapse Energy Economics, Inc. ("Synapse") entitled "Reducing Emissions in Connecticut on High Electric Demand Days (HEDD)" (the "Report").

As stated in the Report (at page 10), DEP asked Synapse to complete three tasks to analyze electricity demand during peak demand:

- project Connecticut electricity demand for the period from 2005 to 2020;
- project generation and transmission from load; and
- project emissions and prepare a report that will be used as part of Connecticut's SIP to demonstrate attainment with the federal eight-hour ozone standard.

On behalf of its operating companies in Connecticut,[1] NRG Energy, Inc. ("NRG") hereby submits its comments on the Report. NRG's comments focus on the following issues:

1. the cost recovery method for the installation of controls on units that are covered by a Reliability Must Run contract ("RMR units"),
2. the Report's use of year 2005 operations as the baseline for its projections;
3. the omission of new planned generation in the state;
4. the omission of potential controls on combustion turbines as a means for HEDD reductions;
5. the need for a CO2 adder;
6. the limited options presented by the Report to meet the HEDD commitment; and
7. the use of the 12 highest demand days to determine HEDD emissions.

Cost Recovery Method for Installation of Controls on RMR Units

The Report states (at page 4) that:

> [i]nstalling controls on affected sources also will add costs. These costs will be passed along to Connecticut ratepayers through existing cost recovery mechanisms available through the CT Department of Public Utility Control (DPUC), and through higher hourly clearing prices in the [ISO New England Inc.] electricity market.

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[1] NRG's Connecticut companies are Connecticut Jet Power LLC, Devon Power LLC, Middletown Power LLC, Montville Power LLC and Norwalk Power LLC.

For RMR units, a cost recovery mechanism may not be available. Under the RMR contracts for NRG's Middletown Station ("MD"), Montville Station ("MV"), and Norwalk Harbor Station ("NH") the MD, MV, and NH units' contracts are scheduled to expire upon the start of the Forward Capacity Market ("FCM") in June 2010. On these dates, the MD and MV NRG units at must recover their costs solely through the energy and capacity markets or in the case of NH, under terms determined to be just and reasonable by the FERC until June 2011. An HEDD program that mandates reductions from the present RMR units must take into account that the owners of such generation will have to give serious consideration as to whether project economics can support additional investment for environmental compliance. All options including plant shutdown and unit de-rates will have to be considered as alternatives to continued operation. The Department should not assume that there is full recovery of HEDD costs through the market or other contractual means.

The Report's Use of Year 2005 Operations as a Baseline for Projections

The Report uses year 2005 operations as the baseline for its projections. Using a one year period as the basis for projecting future demand, generating unit operations or NOx emissions may yield non-representative results. At a minimum, a one-year period may not properly capture fuel price volatility or unusual weather variations. Both fuel price volatility and weather conditions can alter both demand and the resulting generating levels for each generating unit. For these reasons, NRG asserts that a three year period should be used as the baseline for the Report's projections

Synapse partially recognized these potential issues when reviewing the year 2005 data and excluded from the analysis two data sets. Demand and generating information for the "cold snap" period of January 18 – 30, 2005 were excluded because the lack of natural gas for generation altered the generation mix normally expected. Second, the Report omitted periods when the congestion charge for southwest Connecticut ("SWCT") exceeded $20. The Report concluded that, at this congestion level, units within SWCT were dispatched even if they were not economic and, given the transmission upgrades currently being completed, this level of congestion is unlikely to continue in the future.

However, even with the exclusion of this data, the year 2005 operating, demand and NOx emissions data are not good indicators for the projections that would result from the analysis.

A. Projecting Future Operations

In particular, year 2005 generating units' operations are not a good basis to predict future operations for several reasons. NRG has collated the individual unit generation for the five year period of 2003 – 2007 for each of the NRG-owned generating boilers. Depicted in Figure 1, the data clearly shows a spike in year 2005 generation. (The generating data are presented in tabular form in Table 1.) NRG does not have access to the operating records for the units not owned by NRG, but the data suggests that circumstances likely caused a spike, not only in NRG's generation, but also perhaps in others' generation. Conversely, some generating units potentially experienced lower than expected operations for the same year.

In 2005, oil and natural gas prices varied throughout the year. The period following Hurricanes Katrina and Rita saw abnormal spikes in gas prices, which, in turn, caused a usually high level of oil usage during a period when natural gas is typically the less expensive fuel. The NRG-owned generating units are either oil-fired or dual fuel (gas and oil) fired. Hence, their ability to fire oil during high gas price periods could explain some of the spike in their generation. On the other hand, units fired solely by gas likely experienced lower than normal operations.

Additionally, specific to NRG's generating units, in Spring 2005 the cable that connects the AES Thames plant ("AES")[2] to the transmission system experienced problems that continued through mid-Fall 2005. NRG believes that one reason for the sharp increase in generation at MV during 2005 was due partly to the issue associated with the AES transmission cable.

B. Projecting NOx Emissions

The Report also uses the NOx emissions data from 2005 to project future emissions levels. However, year 2005 emissions data is not an accurate reflection of the current NOx emission rate from three of NRG's units: MD Unit 2 ("MD2") and Norwalk Harbor Units 1 and 2 ("NH1&2"). The Report concentrates on NOx reductions that are possible from units with an RMR contract. The RMR units noted in the Report amount to approximately 1,900 MW of installed capacity. MD2 and NH1&2 are about 465 MW of this capacity. To over-estimate the NOx emissions from 25% of the capacity covered by the Report will overestimate projected NOx emissions.

During the Summer of 2007, NRG added a high energy reagent technology ("HERT") system for the control of NOx emissions to MD2.[3] MD2 has been operated on a limited basis since the HERT system became operational, but, based on this limited operation, NRG expects the NOx rate to be no greater than 0.14 lb/MMBTU across the load range, which is lower than the NOx rate for MD2 in year 2005 assumed as the basis from Synapse's projections.

Additionally, throughout 2005 NRG experienced operational issues associated with the selective non-catalytic reduction ("SNCR") system for NH1&2. NH1&2 are each approximately 165 MW oil fired units. The SNCR issue was associated with the hardness of the water used in the urea system. This caused injector plugging, resulting in a NOx rate higher than expected but in compliance with the regulatory daily NOx rate limit. The issue was resolved in early 2006, and the NOx rate for NH1&2 is now lower than in year 2005 across the load range.

<u>Omission of New Planned Generation in Connecticut</u>

Section 3 of the Report includes the tasks and assumptions that were used in the analysis. The assumptions include the load growth, future energy efficiency programs in the state, the elimination of congestion in southwest Connecticut due to the completion of new transmission lines, nuclear unit operations, and the energy efficiency load shape.

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2 AES is a base loaded coal plant, rated at approximately 200 MW. This plant is located less than ¼ mile from MV and is interconnected to the same transmission line as MV.

3 MD2 is a dual fuel-fired 120 MW unit.

The Report makes the assumption that, once future demand is determined, if demand is greater than available generation, then the demand will be met with new gas-fired generation. While this may be true, the Report omits from its analysis planned new generation within the state. Approximately 1,460 MW of new generation is planned for the state within the next five years, pursuant to two, separate procurement proceedings conducted by the DPUC. [4] The addition of such a large amount of generation will affect future operations of all existing resources, and therefore their NOx emissions. Given the substantial addition of new generation, operation of the existing generation at full load conditions on all HEDD events is highly unlikely. Accordingly, the Report's analysis should incorporate the projected commercial in-service dates for all of the new generation and estimate the resulting NOx emissions on the HEDD events.

Omission of Potential Controls on Combustion Turbines

The Report concentrates on RMR units and ignores potential NOx emission reductions by non-RMR units during HEDD events,[5] concluding that:

> Connecticut DEP can meet the OTC MOU commitment to reduce NOx emissions through a combination of reducing emissions from the RMR units and continuing to have sustained performance from the state's energy efficiency programs. Achieving the second phase, with NOx emissions decreasing a total of 50% from 2005 levels, will require additional reductions from the RMR units and ramping up energy efficiency programs to levels higher than 2008 in order to achieve these levels by 2020.

However, where technically and economically feasible, the addition of water injection to the older combustion turbines ("CTs") also provides an effective means to lower HEDD NOx emissions.

On April 16, 2008, the Department issued an analysis of an alternate baseline for the HEDD emissions, based on data from 20 CTs on three days, July 27, 2005 and August 1 and 2, 2006. The analysis assumed a 40% reduction in NOx emissions from the older CTs in the state, and showed elimination of between two and six tons per day of NOx emissions based on this level of reduction.

Recently, NRG installed water injection on three existing CTs at its Cos Cob site. The pre-controlled NOx rate was 0.8 lb/MMBTU (the Full Load Emission Rate listed in the NOx Trading Order). While NRG has not completed the stack testing of the units, NRG expects that the

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4 Under the Energy Independence Act, the DPUC selected four projects for development for a total of 787 MW of incremental capacity will be added to the grid, with 782 MW being from three generating resources: a 620 MW base loaded natural gas-fired, combined cycle plant, a 66 MW oil-fired peaking facility, and a 96 MW natural gas-fired, peaking facility. The 66 MW facility is currently operational while the other two generating facilities will be operational no later than 2011. The final five MW will be procured from statewide energy efficiency projects. Additionally, the DPUC recently selected 678 MW of peaking generation, comprised of three projects proposed for construction within the state: 360 MW at site in Bridgeport with an in-service date of December 2010, 194 MW at a site in Milford with an in-service date of June 2010, and 130 MW at a site in New Haven with an in-service date of June 2012.

5 The non-RMR units include Bridgeport Harbor Units 2 and 4, as well as the statewide fleet of older combustion turbines.

controlled NOx rate will be approximately 0.22 lb/MMBTU, or equal to a 70% reduction in the NOx rate.

Clearly, the installation of the water injection system at Cos Cob provides an effective means to achieve part of the HEDD commitment. However, the Report does not assume controls on these units, with perhaps the exception of Middletown Unit 10 and Norwalk Harbor Unit 10 ("NH10"), which are listed in the Report as RMR units[6]. The assumption that NOx controls can be added to NH10 has not been technically proven.

Need for a CO2 Adder

The Report does not indicate whether Synapse included a CO2 allowance cost "adder" to a generating unit's dispatch price in arriving at its prediction of future operations. With the scheduled implementation in the state of the Regional Greenhouse Gas Initiative ("RGGI") on January 1, 2009, generating resources will be required to obtain CO2 allowances equal to their CO2 emissions. The majority of the allowances will be auctioned and, therefore, the resources will incur an additional operating cost. All generating resources affected by RGGI are expected to include the cost of the allowances in their dispatch price bids.

The CO2 emissions rates of oil-fired units differs from natural gas fired units, with the natural gas fired units' emissions rates being about 30% lower. Depending on the predicted cost of a RGGI allowance, the use of natural gas firing may increase, because the cost of CO2 emissions may be high enough to make a natural gas-fired unit more economical than an oil-fired unit. Moreover, a shift to a higher percent of gas firing over oil firing will lower NOx emissions, because the NOx rate from the generating units is lower when firing gas than when firing oil. Accordingly, the Report should reflect the cost of RGGI CO2 allowances and analyze what impact implementation of RGGI will have on NOx emissions.

Limited Options to Meet HEDD Commitment

The Memorandum of Understanding ("MOU") on the HEDD commitment states that "each state shall select the strategy or combination of strategies that provides both maximum certainty and appropriate flexibility for that state and its electric generators." Yet the Report's conclusion focuses on only two strategies as the means to reduce NOx emissions on HEDDs: an increase in energy efficiency programs and lowering NOx emissions from RMR units.[7]

Other compliance methods that may be employed and that are listed in the MOU, include state/generator HEDD partnership agreements, demand response programs (provided that such programs reduce or preclude the installation or use of distributed generation with unacceptable high emissions), regulatory standards or controls for behind-the-meter generators, and effective adjustment of the NOx retirement ratio to provide reductions on HEDD. These other compliance methods should not be ignored when the DEP issues its draft regulations for the HEDD program. All of them provide the means to meet the HEDD commitment and, therefore, their inclusion as

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6 It should be noted that Norwalk Harbor Unit 10 is not an RMR unit.

7 The Report states that, at the operator's discretion, RMR units could install controls or reduce the full load output from the unit in order to reduce NOx emissions.

compliance options provides generators with maximum flexibility to achieving reductions at the lowest cost. In addition, the Department must also look to the non-RMR units to provide NOx emission reductions, because their emissions were included in the analysis establishing the Baseline HEDD NOx emissions under the MOU.

NRG disagrees with the Report's position on the use of a NOx retirement ratio, namely that "if such a program was implemented anyway, even a few high electric demand days would require surrender of a large portion of Connecticut's emissions budget, leaving little for the remaining days. This would likely lead to temporarily shutting down fossil fuel generation for many days if not weeks, and electricity would have to be imported from elsewhere, at higher costs, into Connecticut."[8] This conclusion appears to be based on a HEDD program where only NOx allowances allocated to a Connecticut site could be used as a means of compliance under the HEDD program. The NOx allowances that could be used are those allocated under the Clean Air Interstate Rule ("CAIR"). Twenty-eight states are covered by CAIR, of which only three are not part of the Ozone Season NOx program. Since CAIR is a regional cap-and-trade program to aid in the attainment of the Ozone standard, it only stands to reason that the use of CAIR NOx allowances independent of the state of origin should be allowed as a compliance option in a HEDD program. The Report's conclusion on the use of CAIR allowances should be re-evaluated based on the entire universe of CAIR allowances.

Use of 12 Highest Demand Days to Determine HEDD Emissions

It is unclear why the Report uses the 12 highest demand days as part of the basis for its analysis. NRG disagrees that the single day listed in the MOU -- July 26, 2005 -- should be used as the baseline day to determine the baseline HEDD emissions. NRG has demonstrated in previous submittals to the Department that the use of a three-day average is the more appropriate method than the single day for determining the baseline emissions.

Using the analysis in the Report, rather than a single day or even the NRG proposed three-day average, yields different results regarding the need for a HEDD program, at least for the NRG units. As shown in Table 2 below, operations of the NRG units exceeded the proposed HEDD cap for these units on only four of the 12 highest demand days in year 2005. The HEDD cap for the NRG units was calculated using the ratio of the NOx emissions from the NRG units to the NOx emissions for all HEDD units included in the NOx analysis for July 26, 2005. The 25% reduction in the baseline emissions relates to an overall HEDD "cap" of 29.25 tons per day for the NRG HEDD units (or a 9.7 ton per day reduction).

In fact, the 12-day average NOx emissions from the NRG units are 27.12 tons per day, which is below the HEDD cap. This suggests either that a HEDD program is not needed or that other units, rather than the NRG RMR units, must reduce their NOx emissions.

If the Department elects to use the 12 highest days to determine the HEDD baseline, then the committed tons per day of 11.7 tons must be recalculated based on the committed 25% reduction in the MOU. This in turn, will reduce the daily NOx commitment for individual units or companies covered by the HEDD program.

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8 See page 9 of the Report

Conclusion

The Report presents a good starting point to develop a HEDD program in Connecticut. However, in its current form, the Report should not be used as the basis for the HEDD program. The Report's analysis should be modified as follows:

1. include the new planned generation within the state;
2. use a three-year average for demand, generation and NOx emission rates as the basis for projections rather than relying only on year 2005 data;
3. consider the NOx reductions that could be achieved from the installation of controls on non-RMR units; and
4. incorporate a CO2 allowance adder to reflect the costs of implementation of RGGI within the state.

TABLE 1
YEARS 2003 – 2007 GROSS GENERATION DATA
NRG STEAM ELECTRIC BOILERS

Year	Middletown 2	Middletown 3	Middletown 4	Montville 5	Montville 6	Norwalk 1	Norwalk 2
2003	60,250	335,896	74,104	48,592	209,636	151,344	159,349
2004	207,818	198,791	81,965	34,527	130,504	145,322	197,871
2005	**331,505**	**377,153**	**272,120**	**139,111**	**431,873**	**242,535**	**358,188**
2006	163,347	253,447	120,386	36,523	131,906	165,307	230,534
2007	177,175	270,197	75,135	41,746	60,478	126,524	187,294

Notes:
1. Data are gross megawatt-hours (MWh) for each unit for each year.
2. Middletown 2 is a 120 MW natural gas and No. 6 oil fired unit
3. Middletown 3 is a 235 MW natural gas and No. 6 oil fired unit
4. Middletown 4 is a 400 MW No. 6 oil fired unit
5. Montville 5 is an 80 MW natural gas and No. 6 oil fired unit
6. Montville 6 is a 400 MW No. 6 oil fired unit
7. Norwalk 1 is a 170 MW No. 6 oil fired unit
8. Norwalk 2 is a 170 MW No. 6 oil fired unit

TABLE 2
NRG HEDD UNITS HISTORIC EMISSIONS
12 HIGHEST DEMAND DAYS IN 2005

Date	MW Load	NOx tons	HEDD Limit	Delta
July 27	26,420	39.41	29.25	10.16
July 19	26,230	24.12	29.25	-5.13
August 5	25,400	29.93	29.25	0.68
July 26	25,020	38.22	29.25	8.97
August 11	24,760	30.94	29.25	1.69
July 20	24,540	17.54	29.25	-11.71
July 22	24,440	26,55	29.25	-2.7
August 10	24,240	24.74	29.25	-4.51
August 3	24,040	27.85	29.25	-1.4
August 8	23,950	25.29	29.25	-3.96
June 27	23,940	16.23	29.25	-13.02
August 4	23,900	24.76	29.25	-4.49
Average	24,740	27.13	29.25	-2.12

Notes:

1. Baseline NRG tons are 39 tons
2. HEDD limit is 25% reduction from baseline or 29.95 tons
3. Data do not include emissions from Devon Units 11 – 14 because they have water injection for the control of NOx.
4. Data do not contain Montville Units 10 and 11 because they were not considered HEDD units in the MOU.

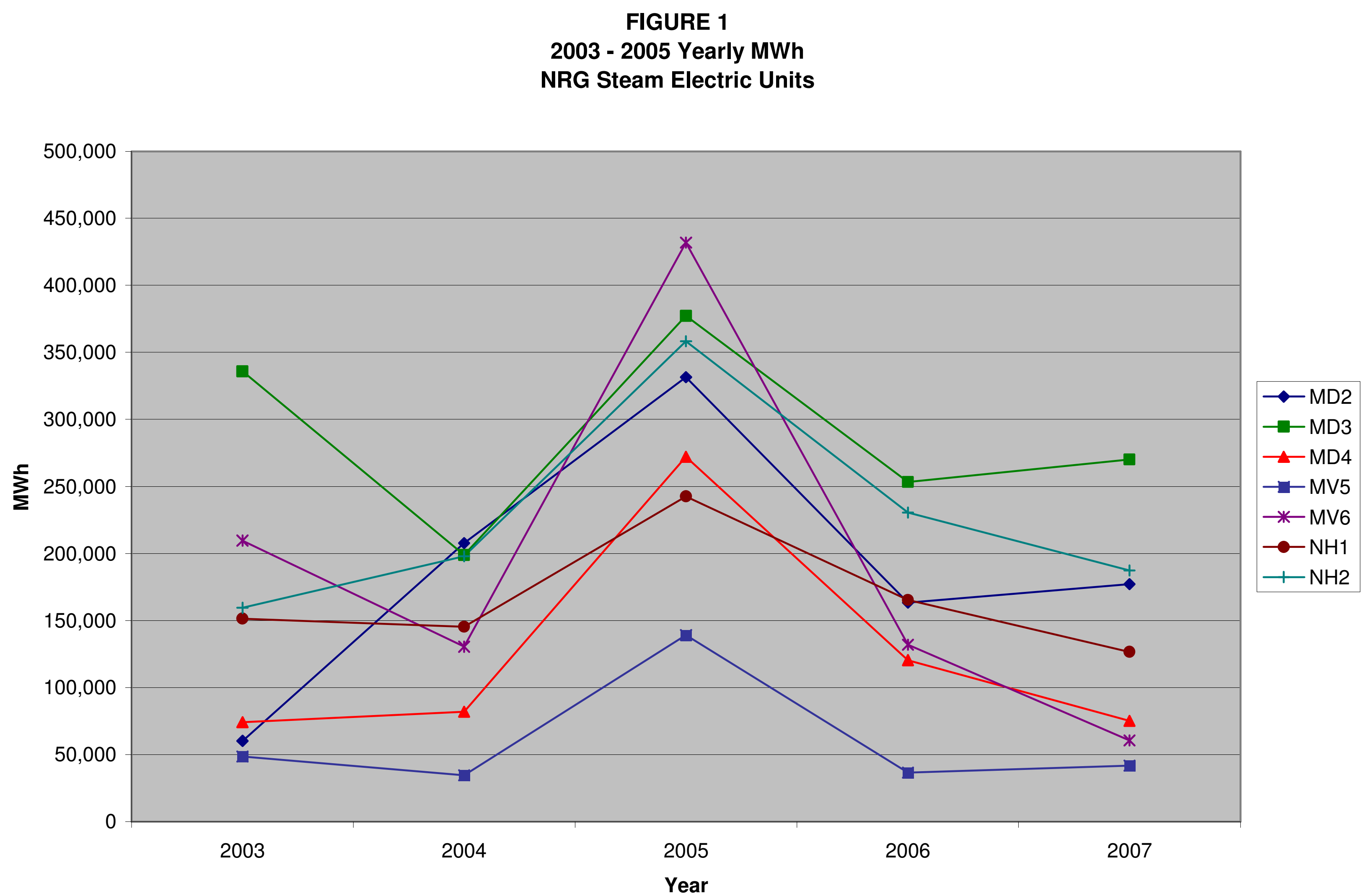


FIGURE 1
2003 - 2005 Yearly MWh
NRG Steam Electric Units
500,000
450,000
400,000
350,000
300,000
250,000
200,000
150,000
100,000
50,000
0
MWh
2003
2004
2005
2006
2007
Year
MD2
MD3
MD4
MV5
MV6
NH1
NH2

EPRI | ELECTRIC POWER RESEARCH INSTITUTE

Memorandum

Date 6/16/2008

TO: 2008 Post-Combustion NOx Control Program

FROM: Alex Jimenez, *EPRI*

SUBJECT: **REVIEW OF ACT'S HERT POST COMBUSTION NOx CONTROL TECHNOLOGY**

Process Description

Advanced Combustion Technology, Inc (ACT) has developed and patented High Energy Reagent Technology (HERT), a process that couples Overfire Air (OFA) with Selective Non-Catalytic Reduction (SNCR). ACT claims HERT can achieve up to 65% NO_x reductions while maintaining NH_3 slip below 5 ppm on boilers without existing OFA systems.

The HERT system is comprised of multi-level SNCR injection where urea is injected both through wall injectors in the upper furnace, as well as into the OFA system. The basis of the HERT system is that injecting into the OFA stream allows for improved mixing and urea distribution in the upper furnace, thereby reducing the number of injectors as compared to traditional SNCR systems. The HERT reagent injectors utilize mechanical atomizers to create droplets that range between 1 and 40 microns in diameter, resulting in vaporization times of about 0.01 seconds. ACT claims that the instantaneous vaporization of reagent in the OFA streams contributes to enhanced reagent mixing, resulting in less urea usage. Furthermore, ACT also claims that the technology can function in a temperature window beyond typical SNCR to eliminate NH_3 slip. ACT claims that HERT has the following potentials for NO_x reduction (e.g. OFA + SNCR):

- Wall Fired: 40-60%
- Cyclones: 55-65%
- T-Fired: 45-65%

ACT predetermines injector designs and locations prior to fabrication and installation through the use of Computational Fluid Dynamics (CFD) modeling and actual boiler test data, such as temperature and emissions profiles.

ACT holds the following patent: *Method and Apparatus for Adding Reducing Agent to Secondary Overfire Air Stream*, Marx, et al – U.S. Patents 6,988,454 B2, January 24, 2006. The process is somewhat similar to two other OFA-reagent injection systems: one developed and patented by GE Energy & Environmental Research Corp. (GE EER) (US Patent No 6,280,695 and No 6,865,994), and the other by Nalco Mobotec for the ROTAMIX® system.

The original GE EER patent (US Patent No 6,280,695) was for the injection of reagent in the form of large droplets (50 to 1000 microns) into the OFA, such that the droplets' lifetime was greater than the OFA mixing time with the combustion flue gas (0.1 to 5 seconds). The purpose of these larger droplets was to prevent the reagent from reacting with CO in the combustion zone, and allow the reagent to react with NOx in the upper furnace in the appropriate temperature window. The technology focused on the perceived need for the ability to install SNCR in boilers where it was difficult or impossible to install an injection system in the upper furnace. The technology required more reagent than a standard SNCR system, and the design of the large droplets to achieve the necessary residence times was difficult and often resulted in increased NH_3 slip and conversion of NH_3 to additional NOx.

The second GE EER patent (US Patent No 6,865,994) still emphasized the large-scale mixing created by injecting reagent into the OFA system, but also enhanced the small-scale mixing at the OFA jet. The technology used a step-diffuser at the injector outlet to induce vigorous air/flue gas mixing near the injector outlet which was claimed to decrease CO and improve overall OFA performance. As the CO is reduced in the reagent injection zone, smaller droplets could be used for SNCR, which decreased the overall reagent usage.

The Nalco Mobotec ROTAMIX™ system uses their ROFA™ system to inject SNCR reagent into the upper furnace. The ROFA™ (Rotating Overfire Air) system works to decrease furnace exit gas temperatures through increased mixing between the OFA and flue gas. The increased mixing is achieved through incorporation of a booster fan (e.g. 600 hp – 1200 hp for 150 MW boiler) to increase the OFA velocity introduced into the boiler. Unlike conventional OFA systems which rely upon windbox air pressures of 4 – 6 inches water column (iwc), the ROFA system generates boosted pressures in excess of 30 iwc. Mobotec claims that injection of SNCR reagent into the boosted pressure ROFA flow creates a greater degree of mixing and the potential for increased chemical utilization.

Principles of Operation

The HERT system is comprised of two common methods for NOx control: Overfire Air (OFA) and SNCR. Each mechanism is described separately below.

<u>Overfire Air</u>

Overfire air (OFA) is a method of staged combustion, where a portion of the burner air is removed to reduce oxygen availability during the initial combustion process, and re-introduced later in the combustion process to allow for complete burn-out. NOx emission reductions with OFA are a direct function of the burner zone stoichiometric ratio (e.g. actual air to coal ratio relative to the theoretical air to coal ratio required to achieve complete burnout). Introduction of combustion air into the upper furnace reduces the oxygen partial pressure within the burner zone, as well as the level of fuel nitrogen conversion to NOx. In addition, the delay in coal combustion suppresses peak flame temperatures and the formation of thermal NOx. OFA is especially effective in tangentially-fired boilers, with typical NOx reductions ranging up to 50%, depending upon achievable lower furnace stoichiometry, coal sulfur content, and fly ash unburned carbon levels.

Selective Non-Catalytic Reduction

Selective Non-Catalytic Reduction (SNCR) is a post-combustion method for NOx reduction, utilizing the injection of urea reagent into the upper furnace. For urea-based SNCR, it is postulated that the urea compound [$CO(NH_2)_2$] decomposes as shown below:

$NH_2CONH_2 \Rightarrow NH_3 + HNCO$ Equation 1

The NOx reduction reactions then proceed as follows:

$NH_3 + OH \Rightarrow NH_2 + H_2O$ Equation 2
$HNCO + H \Rightarrow NH_2 + CO$ Equation 3
$HNCO + OH \Rightarrow NCO + H_2O$ Equation 4
$NH_2 + NO \Rightarrow N_2 + H_2O$ Equation 5
$NCO + NO \Rightarrow N_2O + CO$ Equation 6
$N_2O + M \Rightarrow N_2 + \ldots.$ Equation 7

The above set of chemical reactions determines the temperature sensitivity of the SNCR process. Equations 2 to 4 represent the initial decomposition of urea due to reaction with H or OH radical species that are short-lived and only present in sufficient concentrations at flue gas temperatures in excess of 1700 F (927 C). Without these radical species, NH_2 is not formed and NH_3 and HNCO can pass though the boiler and convective pass unreacted.

On the high temperature side of the SNCR process temperature window (i.e. > 2000 F (1093 C)), radical species concentrations can become too great, resulting in continued oxidation of nitrogen intermediates to form additional NO. As can also be seen in the sequence above, Equation 6 provides a path for the formation of N_2O and CO.

There are a number of factors which determine the amount of NOx reduction achievable with SNCR, chiefly the effectiveness of the injectors to adequately mix the reagent in the flue gas, adequate residence time for the reduction reactions to occur, and a proper temperature window as indicated above (1700 to 2000°F (927 to 1093°C)). Under ideal conditions, NOx reductions in full scale utility boilers of up to 40% are achievable; however, 25-35% reductions are more typical. Reagent distribution becomes more difficult in large coal-fire boilers because of the large distances required to cover the cross section of the boiler. Conventional SNCR systems use multiple levels of reagent injectors to follow temperature changes caused by boiler load changes. It should be noted, however, that EPRI has successfully demonstrated the SNCR Trim concept where a single level of injectors can be used to reduce NOx over the entire load range by tailoring the reagent drop size distribution to the furnace exit gas temperature and quench rate.

Low energy injection systems can be used to delay the release of urea when injected at high flue gas temperatures though the use of dilute urea solutions (e.g. 5% - 10% by weight) and large drop size distributions. Table 1 presents calculated water droplet evaporation times as a function of temperature and drop size. This characteristic typically allows the use of a lower capital cost, low-energy injection system that relies on droplet momentum and bulk furnace turbulence for reagent mixing.

Table 1
Calculated Water Droplet Evaporation Time

Temperature (^{o}F)	Drop Size 400 micron	Drop Size 500 microns	Drop Size 600 micron
2000	0.72 s	1.13 s	1.58 s
2200	0.65 s	1.02 s	1.46 s
2400	0.59 s	0.92 s	1.33 s

<u>HERT</u>

The HERT systems combine SNCR with OFA by installing wall injectors in the upper furnace and high momentum OFA injectors in the OFA ports. ACT uses Computational Fluid Dynamics (CFD) in conjunction with test data to design the OFA system and predict flue gas conditions. A multi-level injection scheme is designed to inject urea in a mixed flue gas and overfire air temperature window that is between 1600 ^{o}F and 2100 ^{o}F. The HERT system OFA injectors mechanically atomize the reagent into droplets ranging from 1 to 40 microns in diameter, which ACT claims will result in instantaneous vaporization (about 0.01 seconds), allowing for improved distribution and mixing over conventional SNCR systems. They also claim that this immediate vaporization allows for better utilization of reagent compared to other SNCR installations. ACT claims that other commercial systems which inject reagent into the OFA tend to create larger droplets, which don't evaporate until after the combustion gases have finished mixing with the OFA gas, leading to the need for higher reagent injection rates. However, in making this claim, ACT appears to be referring to the original GE EER patent which did use larger reagent droplets, but was focused on making SNCR available for boilers that were unable to install upper furnace wall injectors.

Performance and Experience Base

Table 2 lists the HERT systems installed and their performance, as reported by ACT. HERT has been installed in boilers with different firing configurations and range between 40 MW to 255 MW in size. In addition to the 14 installations listed, HERT demonstrations were conducted at Gulf Power's Plant Smith Units 1 and 2, in October, 2007.

Additional details available on select installations are discussed below.

Blue Ridge Paper Unit 4

Blue Ridge Paper Products Boiler 4 is a 40 MW, Tangentially-fired, CE boiler that burns eastern bituminous coal. ACT designed and implemented a layered NOx control strategy that consisted of low NOx burners (LNBs), separated overfire air (SOFA) and HERT. The original uncontrolled NOx was 0.70 lb/MBtu. LNB's reduced the NOx to 0.48 lb/MBtu; SOFA reduced it

Table 2. HERT Installations

Station Utility	Boiler Mfg	Firing	# of Burners	Fuel	MW	Steam Flow, klb/hr	Baseline NOx, lb/Mbtu	Urea Flow, gph	HERT NOx, lb/Mbtu	dNOx, %
Blue Ridge Paper Unit 4 Blue Ridge Paper Company	CE	Tang	12	Coal	40	400	0.3	28	0.15	50%
Clinch River Unit 3 AEP	B&W	Roof	14	Coal	255	2200	0.3	66	0.2	33%
James River Unit 1 City Utilities of Springfield	CE	Tang	8	Coal	25	200	0.35	12	0.2	43%
James River Unit 2 City Utilities of Springfield	CE	Tang	8	Coal	25	200	0.35	12	0.2	43%
James River Unit 3 City Utilities of Springfield	Riley	Wall	6	Coal	46	450	0.18	15	0.1	44%
James River Unit 4 City Utilities of Springfield	Riley	Wall	6	Coal	60	550	0.2	20	0.12	40%
James River Unit 5 City Utilities of Springfield	Riley	Wall	8	Coal	105	890	0.22	25	0.15	32%
John Sevier Unit 2 TVA	CE	Tang	16	Coal	180	1500	0.35	60	0.19	46%
Johnsonville Unit 4 TVA	CE	Tang	16	Coal	135	100	0.39	50	0.15	62%
Middletown Unit 2 NRG	Riley	Wall	12	Oil/Gas	123	960	0.23	27	0.15	35%
Philip Sporn Unit 3 AEP	B&W	Roof	10	Coal	155	1450	0.32	52	0.2	38%
Schiller Unit 4 Northeast Utilities	FW	Front	6	Coal	50	400	0.35	15	0.25	29%
Schiller Unit 6 Northeast Utilities	FW	Front	6	Coal	50	400	0.35	15	0.25	29%
Tanner Creek Unit 3 AEP	B&W	Roof	10	Coal	155	1450	0.28	49	0.18	36%

further to 0.28 lb/MBtu, and HERT system brought it down to 0.15 lb/MBtu. All three systems were supplied and installed for $25 per kW.

The LNBs and SOFA system were installed first, in 2001, to meet the initial goal of 0.34 lb/MBtu, and were able to achieve reductions down to 0.28 lb/MBtu. However, a future goal of 0.15 lb/MBtu was desired, but studies determined that traditional SNCR would only reduce NOx to 0.22 lb/MBtu. As a result, ACT determined that by maximizing the interaction of the three technologies, NOx could be reduced to 0.15 lb/MBtu.

Prior to installation, ACT performed CFD modeling to simulate the performance of each system. Additionally, a field demonstration was performed with ACT's portable HERT skid, shown in Figure 1, prior to completing the final design. The final HERT system utilized only four reagent injectors, one in each of the SOFA ports, and was able to achieve a 50% reduction in NOx over the load ranges of 50% to 100%, while maintaining less than 2 ppm ammonia slip at the air heater inlet.

Figure 1: ACT's Portable HERT Test Skid (presented at 2006 Environmental Controls Conference)

Data from the US EPA EDR database does confirm that Blue Ridge Paper Boiler 4 was able to achieve reductions in NOx levels from 0.3 lb/MBtu to 0.16 lb/MBtu in third quarter, 2005, as shown in Figure 2 versus time and Figure 3 versus load. In 2006, shown in Figure 4 versus load, second quarter NOx averaged 0.18 lb/MBtu, and third quarter averaged 0.17 lb/MBtu (first and fourth quarter data are unavailable). However, in 2007, the second and third quarter NOx averages rose to 0.27 lb/MBtu and 0.28 lb/MBtu, respectively (Figure 5). It appears as though Blue Ridge did not utilize the HERT system for at least those two quarters in 2007, which may be attributable to NOx allowance prices less than the operating cost of urea during this time period.

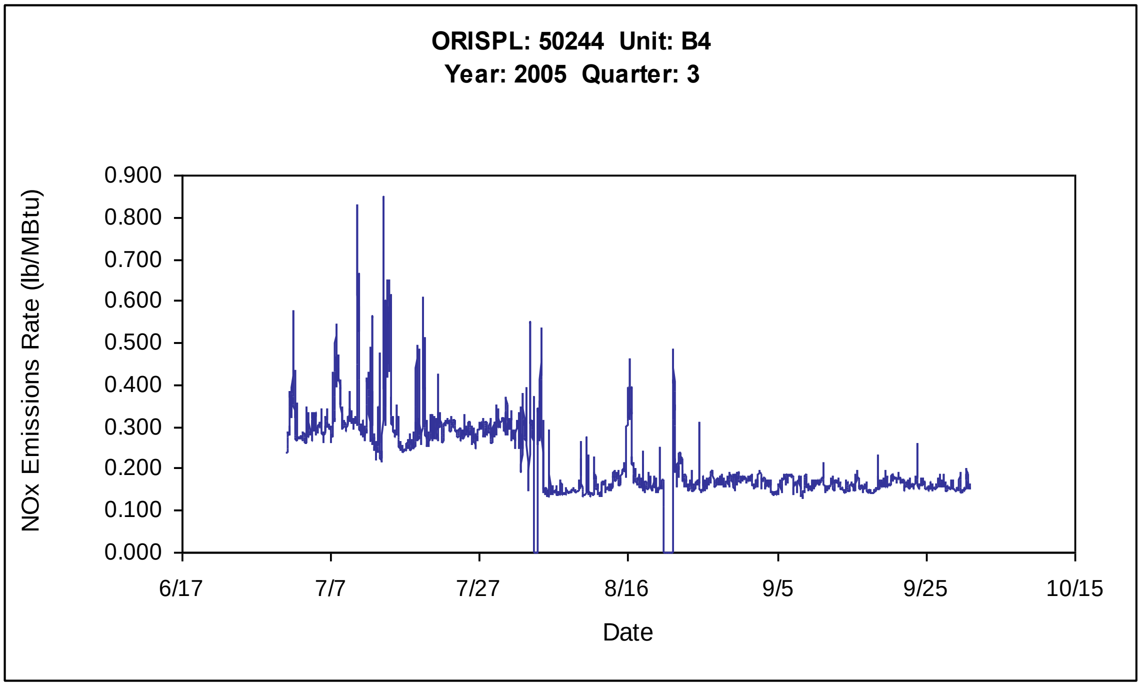


Figure 2: Blue Ridge Paper Boiler 4: NOx EDR Data, Third Quarter, 2005

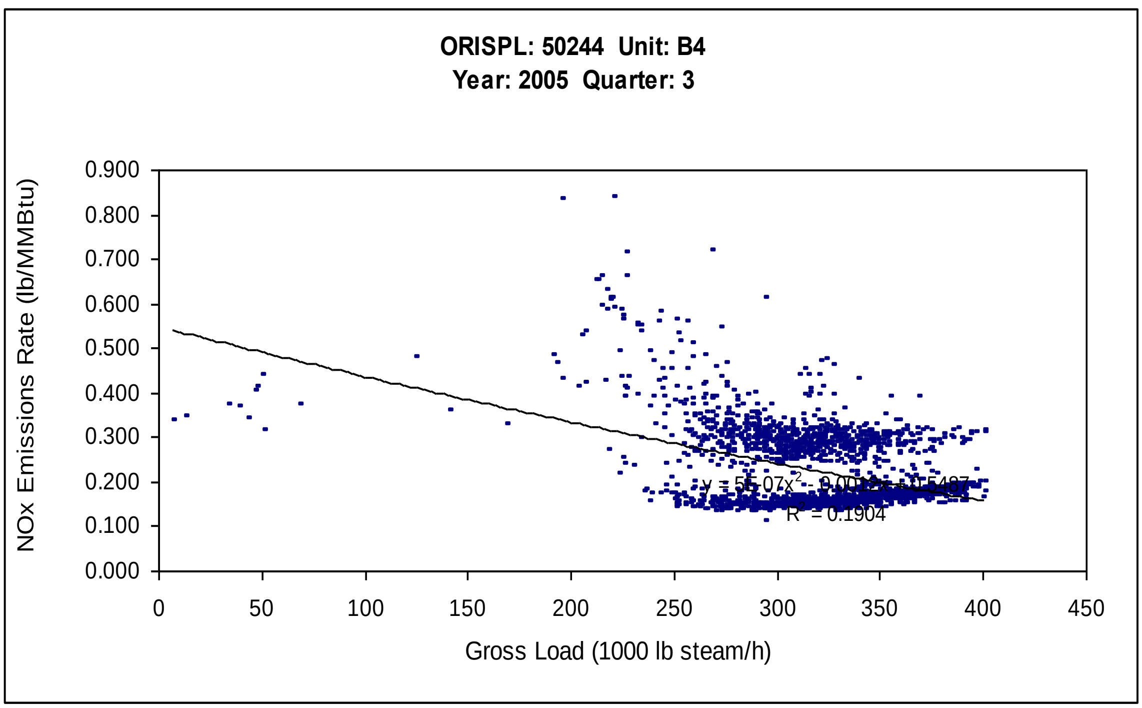
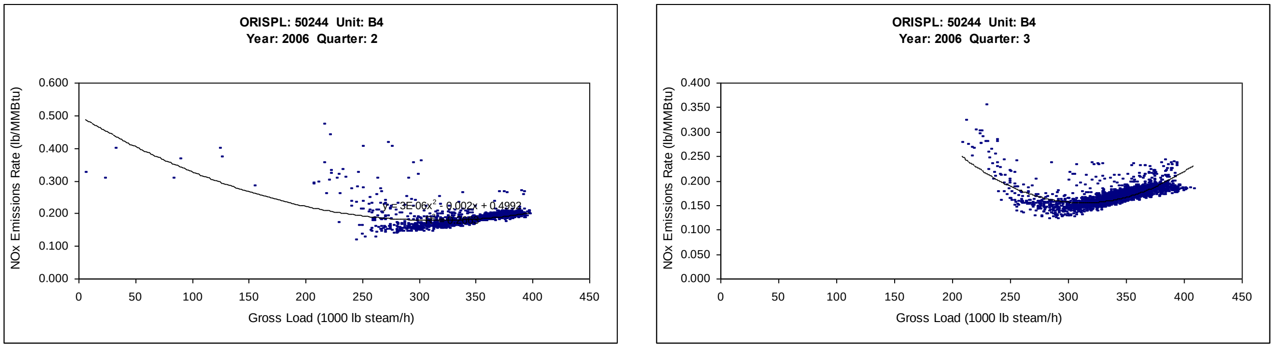
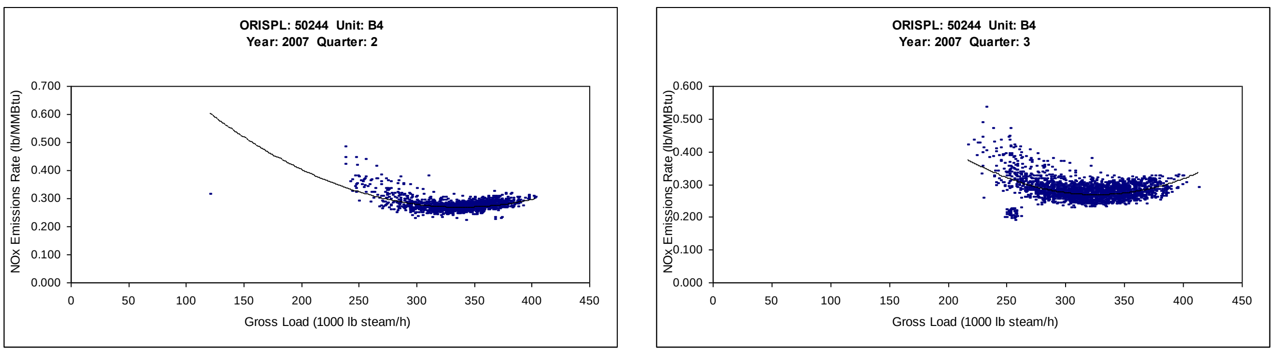


Figure 3: Blue Ridge Paper Boiler 4: NOx versus Load EDR Data, Third Quarter, 2005



a) NOx EDR Data, Second Quarter, 2006 b) NOx EDR Data, Third Quarter, 2006

Figure 4: Blue Ridge Paper Boiler 4, NOx versus Load EDR Data, Second and Third Quarters, 2006



a) NOx EDR Data, Second Quarter, 2007 b) NOx EDR Data, Third Quarter, 2007

Figure 5: Blue Ridge Paper Boiler 4, NOx versus Load EDR Data, Second and Third Quarters, 2007

NRG Middletown Unit 2

NRG Middletown Power, LLC Unit 2 is a 125MW, wall-fired, Riley boiler that burns #6 oil and natural gas. Similar to the Blue Ridge Paper installation, ACT designed and implemented a layered technology strategy that was comprised of LNBs, SOFA and HERT.

The uncontrolled baseline NO_x, when oil-fired, was 0.39 lb/MBtu. With ACT's LNBs and optimized SOFA, the NO_x was reduced to 0.19 to 0.22 lb/MBtu, with opacity below 7%. Initial HERT testing reduced NO_x further to less than 0.12 lb/MBtu, while maintaining ammonia slip less than 6.5 ppm. The HERT system utilized only two SOFA reagent injectors.

It is estimated that the installed capital cost of all three technologies at Middletown was \$7 to \$10 per kW.

US EPA EDR data for fourth quarter, 2007, reports that the average NO_x was 0.12 lb/MBtu, as shown in Figure 6 versus load.

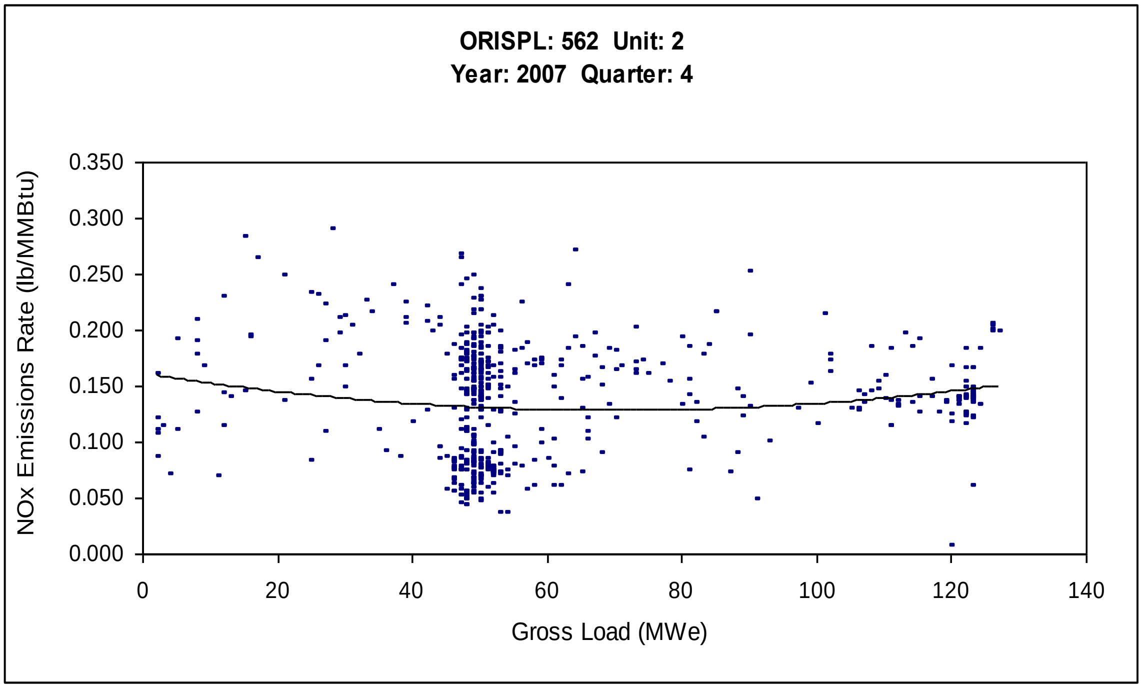


Figure 6: NRG Middletown Unit 2, NOx versus Load EDR Data, Fourth Quarter, 2007

TVA John Sevier Unit 1

TVA John Sevier Unit 1 is a 180 MW, tangentially-fired, CE boiler that burns Central Appalachian Coal. Unit 1 is a twin furnace design, with a superheat and reheat furnace. Prior to the HERT installation in spring of 2007, Unit 1 was already equipped with LNBs and OFA.

The HERT system utilizes a total of 10 SNCR injectors per furnace (20 total). Figures 7 and 8 depict installed injectors at the furnace wall and OFA system. Eight of the injectors are distributed over two upper furnace elevations, while the remaining two injectors are at the OFA level, as shown in Figure 9. The placement of these injectors was based on the results of the CFD modeling that ACT performed in 2006.

The dilution water and metering skid, the individual injector isolation valves, and the injector blower skid were all installed on the second floor of the powerhouse. The dilution water skid supplies water to both the superheat and reheat lances; the blower skid supplies air only to the upper furnace injectors, not the OFA injectors. The urea recirculation building, including the 25,000 gallon, double-walled, unheated storage tank, was installed in the yard near the loading dock. Feedforward control of the HERT system was accomplished with the installation of NOx CEMS units on both superheat and reheat ducts.

Based on the 2006 CFD modeling, ACT guaranteed 35.4% NOx removal, averaged from tests at three loads, while maintaining ammonia slip of 5 ppm or less. The three loads tested during the performance testing were 180 MW, 140 MW, and 100 MW.

Table 3 summarizes the results of the performance tests.

Table 3: John Sevier Unit 1, HERT Performance Test Results

Load MW	Baseline NO_x lb/MBtu	NO_x Removal %	NSR	NH_3 Slip ppm, dry	Urea Utilization %
180	0.33-0.35	40-46%	0.8-1.0	1.4	45-49%
140	0.33-0.40	38-42%	0.9-1.0	1.7-2.5	41-42%
100	0.34-0.36	33-36%	1.1-1.3	0.16-0.13	27-30%

As seen in Table 3, the HERT system achieved the predicted design goals. Plant personnel have reported that periodic checks on the system while in Automatic Generation Control indicate NO_x removal in the mid 30% to low 40% range.

US EPA EDR data is unavailable for John Sevier Unit 1, as it is a combined stack.

Figure 7: HERT Wall Injector
Presented at EPRI SNCR Interest Group Meeting

Figure 8: **HERT OFA injector**
Presented at EPRI SNCR Interest Group Meeting

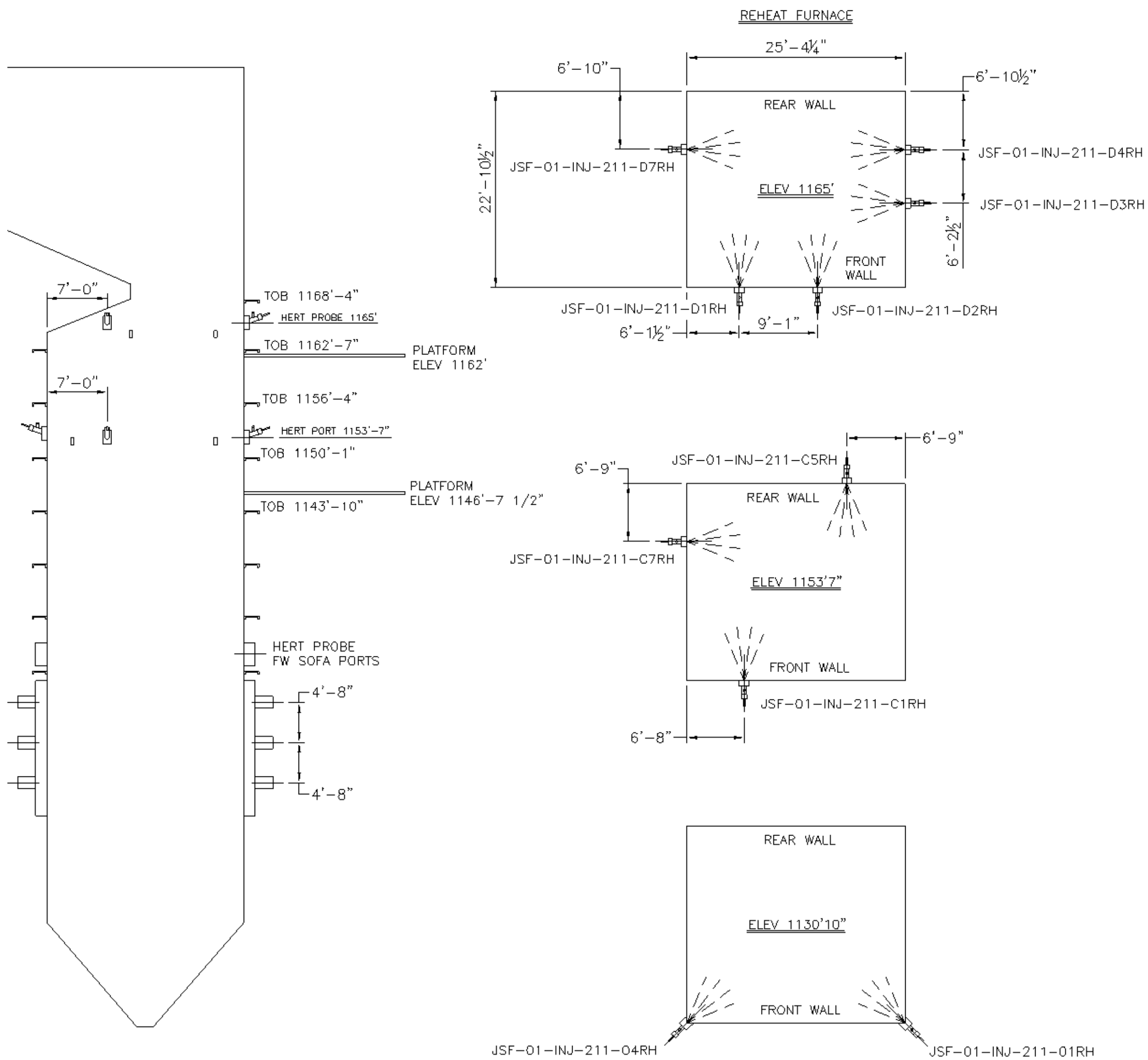


Figure 9: TVA John Sevier Unit 1, HERT Injector Locations

TVA Johnsonville Unit 4

TVA Johnsonville Unit 4 is a 120 MW, tangentially-fired, CE boiler that burns various blends of Colorado, PRB, and Illinois Basin coal. The ACT installation included both an OFA system and the SNCR HERT system. The OFA system reduced the NO_x from 0.32-0.40 lb/MBtu to 0.20-0.24 lb/MBtu. The unit does not have LNBs.

The installation at Johnsonville Unit 4 is similar to the John Sevier Unit 1 system, with some exceptions. The Johnsonville HERT system has a total of 9 SNCR injectors; five injectors were installed at a single upper furnace elevation, while the remaining four were at the OFA level (Figure 10). The placement of the injectors was based on the results of CFD modeling performed by ACT in 2006. Furthermore, the Johnsonville system does not have individual injector isolation valves, as each level is operated at the water dilution skid. An existing Fuel Tech urea recirculation skid in the yard was used for the ACT system.

ACT's performance guarantee specified 54% NO_x removal, averaged from tests at three loads, while maintaining ammonia slip of 5 ppm or less. The NO_x removal was to be calculated for both the OFA and HERT systems combined. The three loads tested during the performance testing were 120 MW, 100 MW, and 85 MW.

Table 4 summarizes the results of the performance tests

Table 4: Johnsonville Unit 4, Performance Test Results

Load MW	Baseline NO_x lb/MBtu	NO_x Removal %	NSR	NH_3 Slip ppm, dry	Urea Utilization %
120	0.37	55-61%	1.3-1.6	1.5-2.9	14-23%
100	0.33	57-59%	1.2	1.6-2.1	25-27%
85	0.36	60%	1.1	3.2	28%

As seen in Table 4 the OFA and HERT system achieved the predicted design goals. Plant personnel have reported that periodic checks on the system while in Automatic Generation Control indicate combined OFA + SNCR NO_x removals in the 51-56% range, using 0.34 lb/MBtu as the uncontrolled baseline value. US EPA EDR data is unavailable for Johnsonville Unit 4, as it is a combined stack.

The Johnsonville HERT installation provided a chance to compare HERT to a typical Fuel Tech SNCR system installed on Unit 1. The HERT system had fewer injectors (i.e. 9 injectors on Unit 4) than the Fuel Tech system (i.e. 19 injectors on Unit 1). Additionally, the HERT system used approximately 25-30% less urea than the Fuel Tech SNCR. The HERT system used 100 scfm of blower air at 3-4 iwc from a newly installed blower, while the Fuel Tech system used 370 scfm of 130 psig compressed air from the plant supply. The HERT control system was reported to be simpler than the Fuel Tech system, with only feedforward control; however TVA has indicated that the ability to control trim with feedback on the Fuel Tech system does offer some advantages. Finally, the overall HERT installed cost was reported to be less than that associated with the Fuel Tech system.

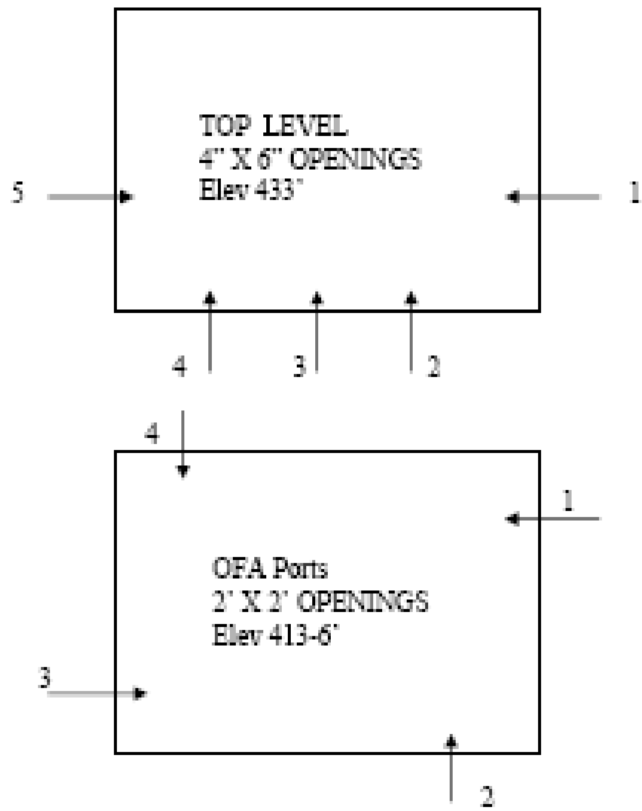


Figure 10: TVA Johnsonville Unit 4, HERT Injector Locations

Gulf Power Company Plant Smith Units 1 and 2

Gulf Power Plant Smith Unit 1 is a 180 MW, tangentially-fired, CE boiler, with baseline NO_x of approximately 0.45 – 0.50 lb/MBtu. Unit 2 is a 210 MW, tangentially-fired CE boiler, with baseline NO_x of approximately 0.35 - 0.45 lb/MBtu. The main objective of the Phase I testing was to demonstrate that the HERT system was capable of reducing NO_x by 30% over the load range, and to gather data which would be used to validate the CFD model for determining the optimal injection locations.

The Phase I work was performed with the ACT portable HERT skid in October, 2007. Injectors were inserted through existing observation doors on the 7^{th} and 8^{th} floors. The load ranges tested were as follows:

- Unit 1 – 173 MW, 125 MW, and 73 MW
- Unit 2 – 205 MW, 135 MW, and 73 MW

Unit 1 averaged 40% NO_x reduction over the three loads tested, while Unit 2 averaged 30% NO_x over the three loads tested. Both units utilized six injectors. NO_x reductions at full load averaged in the 20% to 25% range, while reductions at lower loads approached 50% to 60%.

Estimated Capital and O&M Cost

ACT reports that a typical cost for a HERT installation, including engineering design, ranges from $600,000 to $850,000. This cost takes into account the installation of wall injectors and OFA injectors, a reagent skid and transport and control system, and reagent storage tank. The difference in cost is due to differences in reagent storage tank size. The cost also assumes that the boiler already has an OFA system in place. The average unit size of the current installations listed in Table2 is 100 MW, which translates to a cost of $6 to $8.5 per kW. In addition to the capital costs, the HERT systems have an ongoing operating cost for the reagent.

By comparison, the capital cost for a Mobotec ROFA® installation has been reported to range between $25/kW - $50/kW, with the ROTAMIX® system costing an additional $5/kW- $10/kW, depending upon unit size. A typical SNCR system can be expected to cost between $2,000,000 to $4,000,000, or $7 - $13 per kW for a 300 MW unit. Adjusted for a 100 MW unit, this translates to approximately $15 to $20 per kW.

Potential Operational Issues

The HERT technology combines SNCR technology with OFA. As ACT, in the majority of installations, is retrofitting the SNCR HERT system to a boiler with an existing OFA system, the potential operating issues associated with OFA are not discussed here.

SNCR systems typically suffer from equipment issues, which include heating the urea solution to prevent precipitation and keeping the injectors clean. In terms of the actual SNCR chemistry, the combustion gas temperature is a key parameter, as at lower flue gas temperatures excess unreacted reagent in the form of ammonia slip can combine with SO_3 to form ammonium bisulfates, which can foul air heaters. Additionally, excess ammonia slip can combine with acidic fly ash, thereby affecting its salability. For situations where injected urea is released at high flue gas temperatures (e.g. 2000 F (1093 C)), the reagent can actually react with O_2 to form NOx.

Actual operation of the HERT system at TVA's John Sevier Unit 1 revealed problems with using filtered river water to create dilute urea solution. The solution formed a calcium precipitate that plugged the system after two weeks of operation. The short term solution was to use gland seal water instead of the river water. Additionally, use of the HERT system resulted in a drop in steam temperatures in the reheat furnace to below acceptable levels, creating the potential for condensation of water vapor to result in particle erosion in the reheat turbine. Their current solution is to shut down the reheat portion of the HERT system when the load drops below 130 MW. Finally, an ammonia smell was reported when the fly ash was mixed with water for dry stacking.

The HERT system at TVA's Johnsonville Unit 4 also suffered from system pluggage from calcium precipitate resulting from the use of filtered river water and unstabilized urea. The short term solution was to use stabilized urea, but the long term solution is likely to be the use of demineralized water.

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www.advancedcombustion.net
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Petermarx2@yahoo.com

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Prepared for:
Arizona Public Service – Four Corners Power Plant
Fruitland, New Mexico

BART Visibility Modeling Report for the Arizona Public Service Four Corners Power Plant

ENSR Corporation
January 2008
Document No.: 00494-021-300

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January 2008
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Executive Summary

The Arizona Public Service Company (APS) operates the Four Corners Power Plant ("FCPP"), a privately owned and operated coal-fired power plant located in Navajo Indian Reservation, about 25 miles west of Farmington, New Mexico. The Best Available Retrofit Technology (BART) analysis for Four Corners is under the jurisdiction of EPA Region 9.

During 2004 and 2005, FCPP undertook a testing program to increase the plant's SO_2 control level from 72% to 85%. This test program was undertaken with the concurrence of the US EPA Region IX, the National Park Service (NPS), the Navajo Nation EPA, and several environmental interest groups. The testing demonstrated that the plant could actually increase its SO_2 control to 88% on an annual average basis. Based on that finding, FCPP voluntarily agreed to accept that level of SO_2 controls as an enforceable emission control level for the Plant. This new control level reduced the Plant's annual emissions of SO_2 by about 25,000 tons per year. A Federal Implementation Plan (FIP) for the FCPP (published in the May 7, 2007 issue of the Federal Register), concluded that 88% SO_2 control level on an annual basis was equivalent to BART level for the FCPP.

The large Units 4 and 5 at FCPP have state-of-the-art particulate baghouse controls, while the smaller Units 1-3 have venturi scrubber controls for PM_{10}.

One PM_{10} BART control case for Units 1-3 and three BART NO_x control cases were modeled using CALPUFF for each of three meteorological years (2001-2003) and several nearby Class I areas. The BART control options were as follows:

PM_{10} Control Option 1: fabric filter (baghouse) controls on Units 1-3.

NO_x Control Option 1: Advanced combustion controls (low NO_x burners (LNB) on all units and overfire furnace air (OFA) on Units 3-5).

NO_x Control Option 2: Advanced combustion controls (LNB/OFA) on Units 1-5 in combination with High Energy Reagent Technology (HERT) on Units 1-3 and in combination with selective non-catalytic reduction (SNCR) on Units 4-5.

NO_x Control Option 3: Advanced combustion controls (LNB/OFA) in combination with selective catalytic reduction (SCR) on Units 1-5.

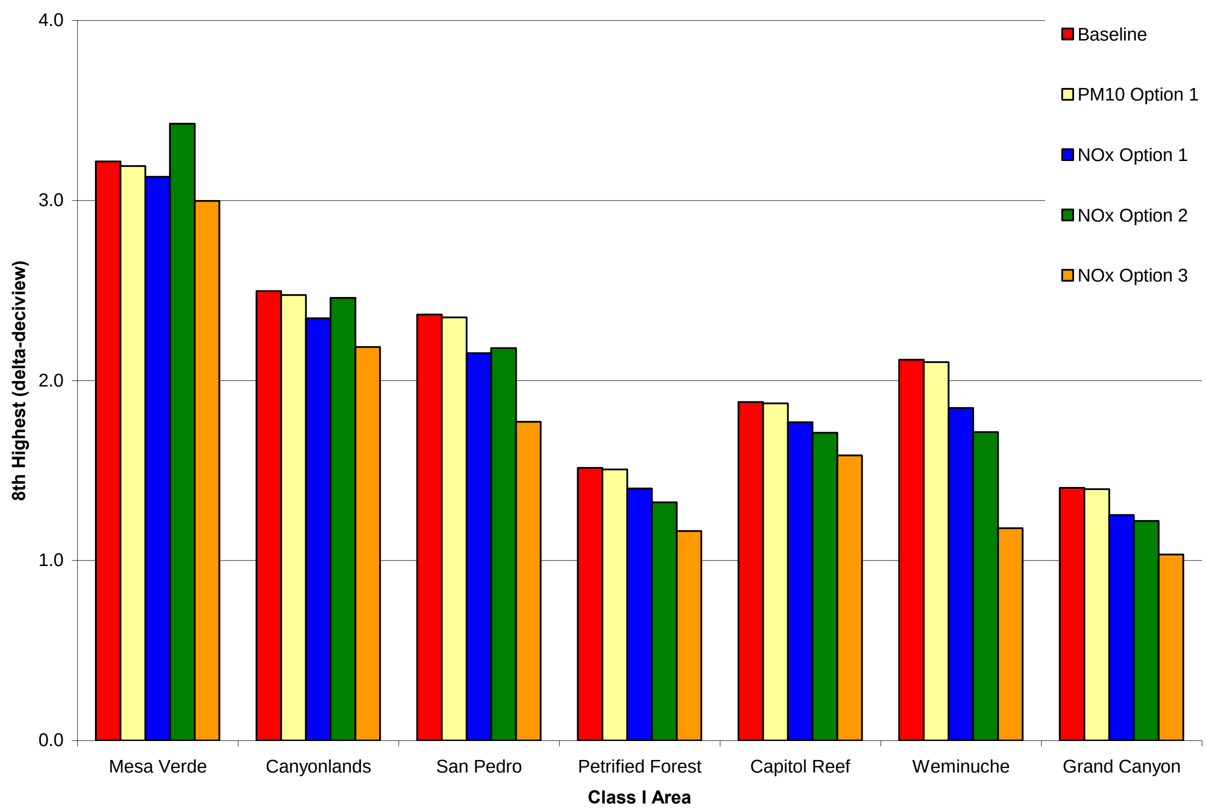
Modeling results were obtained for each of the 16 PSD Class I areas within 300 km of the FCPP. The highest impacts occur at the closest Class I areas in various directions, so modeling results are also reported for the closest 7 Class I areas. For only PM_{10} controls, the results show that the regional haze impacts averaged over the closest 7 Class I areas may improve visibility by an average of only 0.01 delta-dv (relative to the baseline case), so this control option is not cost effective.

NO_x presumptive BART limits apply to FCPP Units 3-4-5 (0.39 lb/MMBtu for Unit 3 and 0.40 lb/MMBtu for Units 4-5) since the plant capacity exceeds 750 MW, and these units all exceed 200 MW. NO_x presumptive BART limits do not apply to Units 1-2 since they do not exceed 200 MW.

NO_x control option 1 will result in NO_x emission rates below the presumptive limit for Units 3-4-5. For NO_x Control Option 1, the visibility improvement averaged over the 7 closest Class I areas is 0.16 delta-dv (relative to the baseline case). Addition of SNCR (NO_x control option 2) shows visibility degradation at Mesa Verde National Park (the closest Class I area) due to additional ammonia emissions, and only a slight (0.14 delta-dv) regional haze improvement when averaged over the closest seven Class I areas – a smaller average visibility improvement than that projected for NOx Control Option 1. This poor performance under Option 2 reflects the fact that SNCR operations can increase the ambient ammonia concentration by about 0.2 ppb and result in additional sulfate and nitrate particulate formation. Therefore, this NO_x control option is not effective in improving visibility.

Addition of SCR (NO_x control option 3) may improve visibility by about 0.44 delta-dv (averaged over the seven closest Class I Areas) from the baseline case. The incremental improvement of option 3 over option 1 is only about 0.28 delta-dv. This change is small compared to the deciview change that is perceptible by humans (about 1-2 delta deciviews) and is less than the “contribution” threshold of 0.5 delta-dv. The relatively small incremental improvement in visibility is due in part to the small role that nitrates play in the total regional haze contribution, especially in summer. In addition, the installation of SCR would create new emissions of primary sulfates (H_2SO_4) and excess ammonia, partially offsetting any available NO_x reduction benefit to visibility. This is especially true during the high visitation period of the warm weather months, when nitrates have a minimal contribution to visibility impairment, but sulfates have an important role. Therefore, NO_x emission controls involving SCR are relatively ineffective in this case, especially taking into account the high cost of the controls. Figure ES-1 shows the changes in visibility impact among the NO_x control cases for each of the closest 7 PSD Class I areas.

Figure ES-1 8th Highest Regional Haze Impacts Averaged Over 3-Years Due to Baseline and BART Control Emissions



1.0 Introduction

1.1 Source Description

The Arizona Public Service Company (APS) operates the Four Corners Power Plant ("Four Corners" or "FCPP"), a privately owned and operated coal-fired power plant located on the Navajo Nation, about 25 miles west of Farmington, New Mexico. The facility consists of five generating units, with a total capacity of approximately 2,060 megawatts.

The BART analysis for Four Corners is under the jurisdiction of EPA Region 9, and the analysis will be reviewed and approved by EPA Region 9.

1.2 History of Emission Reductions at FCPP

FCPP Units 1-5 were constructed between 1962 and 1970. An SO_2 removal efficiency of 50% was obtained for Units 1-2-3 in the early 80s by retrofitting the venturi particulate scrubbers with lime injection. Lime spray towers were added to Units 4-5 and SO_2 removal was increased to 72% Plant-wide in the mid 80s.

In the late 1990s, APS initiated a dialog with four environmental interest groups involved in environmental issues in the western United States: Environmental Defense, the Grand Canyon Trust, Western Resource Advocates and the New Mexico Citizens for Clean Air and Water. The dialog focused on the issue of visibility in the western United States. The dialog focused on improved SO_2 control primarily because that pollutant had much higher visibility impact than NO_x emissions. In 2003, APS and these environmental groups agreed on a proposal geared to further reduce sulfur dioxide emissions at the Four Corners plant utilizing an 18-month test program. The test program involved certain phased operational changes and scrubber chemical process changes to increase annual sulfur dioxide control levels from 72% to 85% without triggering operational problems. APS and the environmental groups jointly presented that proposal to the EPA, the Navajo EPA and the National Park Service. With the support of these groups, APS initiated the test program in early 2004. The test program was completed during the summer of 2005. APS prepared a report concluding that the plant was not only able to meet the goal set in the proposal, but could also improve the annual average sulfur dioxide controls to an 88% removal efficiency. At that elevated control level, the plant was able to cut its annual sulfur dioxide emissions by more than 55 percent, compared to the pre-test level.

After the testing program, the Navajo Nation and the stakeholders group requested that EPA include these negotiated, additional SO_2 emissions reductions into a source-specific Federal Implementation Plan (FIP) for the FCCP. FCPP agreed to increase the amount of SO_2 emissions it was eliminating from its exhaust stream from 72% to 88%, thereby reducing its annual emissions of SO_2 to the atmosphere by about 25,000 tons per year. APS and the environmental groups then worked with the reviewing agencies to incorporate the higher sulfur dioxide control level as an enforceable emission limit for the plant through the FIP.

The FIP, published in the May 7, 2007 issue of the Federal Register, provides EPA's policy on whether the agreed-upon SO_2 controls are BART equivalent, with excerpts provided here:

"As noted in the preamble to the proposed FIP, the level of control in the FIP for FCPP is "close to or the equivalent" of BART for this source. EPA agrees that if the Agency were to undertake a case-by-case BART analysis, BART could potentially be determined to be a greater level of control than 88% SO_2 removal. However, any case-by-case BART analysis would be subject to the timeframes needed to implement such controls. EPA has the discretion to promulgate FIPs, as necessary or appropriate, within reasonable timeframes to protect air quality in Indian country. In today's rulemaking EPA is exercising its discretion under 40 CFR 49.11 to find that it is neither necessary or appropriate at this time to undertake a BART determination for SO_2 for FCPP given the timing of the substantial SO_2 reductions resulting from this FIP.

Moreover, as explained in the preamble to the 2006 proposed FIP, there are only two major sources of SO_2 on the Navajo Reservation that are potentially subject to the BART requirements--Navajo Generating Station and FCPP. 71 FR at 53632. EPA determined previously that the SO_2 emission limits in the 1991 FIP for the Navajo Generating Station provide for greater reasonable progress toward the national visibility goal than would BART. 71 FR at 53633. As explained above, given that the SO_2 controls for FCPP immediately achieve significant reductions in SO_2 comparable to what could ultimately be achieved through a formal BART determination, EPA believes that it will not be necessary or appropriate to develop a regional haze plan to address SO_2 for the Navajo Nation in the near term."

The dialog with these environmental groups also dealt with NO_x emissions. APS, in consultation with the environmental groups, hired an independent consultant charged with assessing the potential for reducing the plant's NO_x emissions, through additional combustion controls. The consultant's report concluded there was little room for improving combustion controls at the three smaller units, although further detailed evaluations were needed to assess potential combustion controls for the two larger units. APS has continued to study such control options as part of the Best Available Retrofit Technology program.

The large Units 4 and 5 at FCPP have state-of-the-art particulate baghouse controls, while the smaller Units 1-3 have venturi scrubber controls. One of the BART control options tested considers the expected visibility improvement if baghouse controls were to also be installed on Units 1-3.

1.3 BART Requirements

Federal regulations under 40 CFR Part 51, Appendix Y provide guidance for conducting a visibility impairment analysis for designated eligible sources. The program requires the evaluation of the Best Available Retrofit Technology (BART) for existing eligible sources and corresponding visibility impacts, in order to help meet the targets for visibility improvement at designated Class I areas.

Four Corners has been identified as a source that is eligible for consideration of BART controls for NO_x and particulate, as discussed in Section 1.2. ENSR conducted BART exemption modeling of Units 1-5, and the results indicated that these units are subject to BART review because the predicted visibility impacts with baseline emissions exceed 0.5 delta deciviews in at least one Class I area.

This BART analysis report discusses CALPUFF modeling results of the baseline case and the BART control options that were modeled.

1.4 Overview of BART Modeling Analysis

The site-specific BART visibility improvement analysis provided in this report includes the following components:

- A list of candidate retrofit controls that are being considered;
- A discussion of the control effectiveness and resulting emission rates for each feasible retrofit technology that is considered as BART;
- An evaluation of the impacts of each site-specific BART option, including
  - An estimate of the annualized cost for each of the BART options;
  - An evaluation of the impacts on visibility for each of the BART options; and
  - The visibility improvement for each control option in terms of dollar per deciview improvement.

1.5 Report Outline

Section 2 of this protocol describes meteorological and monitoring data. Section 3 discusses CALPUFF modeling parameters and technical options used in the modeling. Section 4 describes the formation of sulfates and nitrates and their effect on emission controls. BART eligibility analysis and the baseline emissions modeling results are discussed in Section 5. Section 6 describes BART control options and the modeling results. References are provided in Section 7.

2.0 Meteorological and Monitoring Data

For the refined CALPUFF modeling, FCPP followed the Western Regional Air Partnership (WRAP) common BART modeling protocol with the exception of the model version and a few refinements to CALMET settings. These differences are discussed below in Section 2.2.

2.1 WRAP CALMET Database

The WRAP has developed six 4-km CALMET meteorological databases for three years (2001-2003). The CALMET modeling domains are strategically designed to cover all potential BART eligible sources within WRAP states and all PSD Class I areas within 300 km of those sources. The extents of the six domains are shown in Figure 3-1a through Figure 3-1f of the WRAP common BART modeling protocol, available at http://pah.cert.ucr.edu/aqm/308/bart/WRAP_RMC_BART_Protocol_Aug15_2006.pdf. The BART modeling for Four Corners was done using the New Mexico domain, as shown in Figure 2-1 of this report. The WRAP CALMET meteorological inputs, technical options, and processing steps are described in Sections 2 and 3 of the WRAP protocol.

USGS 3 arc-second Digital Elevation Model (DEM) files were used by WRAP to generate the terrain data at 4-km resolution for input to the six CALMET runs. Likewise, the Composite Theme Grid format (CTG) files using Level I USGS land use categories were used by WRAP to generate the land use data at 4-km resolution for input to the six CALMET runs. See Sections 3.1.1.3 and 3.1.1.4 of the WRAP common BART modeling protocol for more details on the data processing.

Three years of 36-km MM5 data (2001-2003) were used by WRAP to generate the 4-km sub-regional meteorological datasets. Section 2 of the WRAP protocol discusses MM5 data extraction. The BART CALPUFF modeling for FCPP was done using the New Mexico 4-km CALMET database with application-specific modifications described in the next section of the report. CALMET meteorological inputs, technical options, and processing steps were identical to those specified in the WRAP common BART modeling protocol with the exception of only R1, R2, and RMAX1, and the model version. These differences are listed in Table 2-1 and are further discussed below.

Figure 2-1 WRAP CALMET Modeling Domain for New Mexico

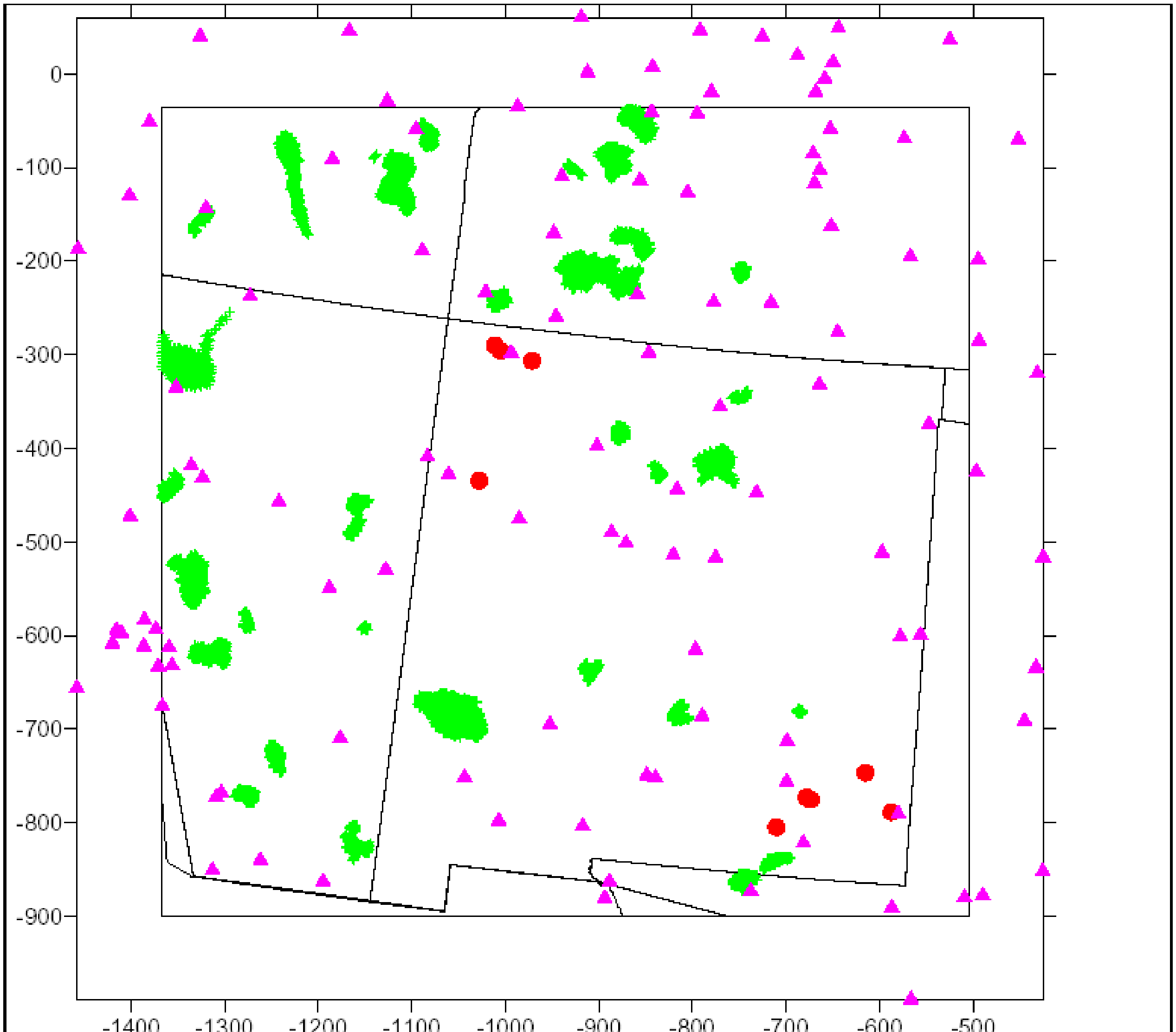


Figure 3-1c. Proposed CALMET/CALPUFF modeling domain, Class I area receptors (green), observed surface meteorological sites (purple triangles) and potential BART-eligible source locations (red circles) for New Mexico.

2.2 Enhancements to the CALMET Processing

ENSR made two refinements to the 4-km New Mexico CALMET WRAP database. They are as follows:

1. <u>Weighting Factors for Modifying the Step 1 Wind Field.</u> The 4-km New Mexico CALMET database has been produced by ENSR using the downloaded CALMET inputs from the WRAP website http://pah.cert.ucr.edu/aqm/308/bart/calpuff/calmet_inputs/nm/. ENSR initially ran CALMET with the setting suggested in the WRAP BART modeling protocol. As part of ENSR's internal quality assurance procedure, we displayed and examined the 4-km New Mexico WRAP CALMET wind fields in the visualization software CALDESK. Figure 2-2 graphically shows wind fields with the WRAP settings for a typical hour. Arrows represent wind direction and wind speed for that hour at a 10-meter height. Circular areas in these figures with common winds and abrupt transitions at the edge of the circles indicate a radius of influence of surface stations, R1, which was set to 100 km, as suggested in the WRAP BART protocol. The R1 value was coupled with R1MAX = 50 km, so that the influence of the surface stations is established out to 50 km and then it abruptly ends beyond that distance. Setting R1 and R1MAX to such high values is not recommended by the model developer and Federal Land Managers, especially with MM5 data resolution of 36 km with areas of complex terrain. Typically, R1 is set to a fairly small value, generally not exceeding half of the MM5 data resolution (18 km), according to recent guidance on multiple PSD projects involving CALPUFF modeling in the WRAP region from John Notar of the National Park Service (personal correspondence between John Notar of the NPS and Bob Paine of ENSR). A large R1 value results in wind fields surrounding surface stations that overwrite the MM5 wind fields, which do have terrain influences incorporated into them. In many instances, the extended extrapolation of the surface station data with an abrupt transition at 50 km produces opposing wind directions in adjacent grid squares at the 50 km distance.

To avoid this problematic wind field result, ENSR used a smaller R1 value of 18 km and R1MAX value of 30 km. The resulting wind fields for the same hour and height are depicted in Figure 2-3. The adjusted R1 and R1MAX values blend the surface observations into the MM5 observations much better, creating a more uniform wind field throughout the domain. Therefore, ENSR used the smaller R1 and R1MAX values to be more consistent with FLM guidance and due to the better performance in the wind field depiction associated with the smaller values.

2. <u>Official EPA CALPUFF Version.</u> When rerunning CALMET, ENSR used the latest EPA-approved version of the CALPUFF modeling system CALMET (Version 5.8, Level 070623) instead of Version 6.211 that was used by WRAP, available at http://www.src.com/calpuff/download/download.htm#EPA_VERSION. CALPUFF version 6 is basically equivalent to the VISTAS version of CALPUFF, Version 5.756. At the time of the WRAP BART protocol development process, the VISTAS version and Version 6 were generally acknowledged to be the latest and best versions available. However, EPA's deliberate attempt to review the nature of the changes between the previous official version (5.711a) and the VISTAS version (and Version 6) uncovered a number of issues that were of concern to EPA. These issues were discussed in a presentation by Mr. Dennis Atkinson of EPA's Office of Air Quality Planning and Standards at the 2007 annual modelers workshop (see http://www.cleanairinfo.com/regionalstatelocalmodelingworkshop/agenda.htm; "CALPUFF_status_update.pdf"). The basic issues of concern with the VISTAS version (and equivalent Version 6) are as follows:

- There were unexplained and unresolved large differences between Versions 5.711a and 5.756.
- Incomplete model documentation has been a problem with the last model users guides now 7 years old.
- The VISTAS code changes went beyond just fixing coding errors in Version 5.711a, contrary to what TRC, the model developer, asserted.
- EPA's annotated in-code documentation identified several categories of changes, including:

- Bug fixes
- Non-optional technical enhancements
- Optional technical enhancements
- Non-technical enhancements
- Enhancement adjustments
- Coordinate conversion fixes

- EPA had serious technical concerns regarding how the optional technical enhancements, e.g., for mixing height, were implemented in CALMET.

The new approved Version 5.8 disables some of the VISTAS “optional technical enhancements”. Therefore, use of Version 5.756 or Version 6 of CALPUFF would appear to be inconsistent with the current EPA approved version. Default values of technical options specified in the newly approved version were adopted by ENSR.

Table 2-1 CALMET Options Comparison

Variable	Description	WRAP Value	ENSR Value
RMAX1	Maximum radius of influence over land in the surface layer	50	30
R1	Relative weighting of the first-guess field and observations in the surface layer	100	18
R2	Relative weighting of the first-guess field and observations in the layers aloft	200	20

Figure 2-2 CALMET Wind Fields with WRAP Settings

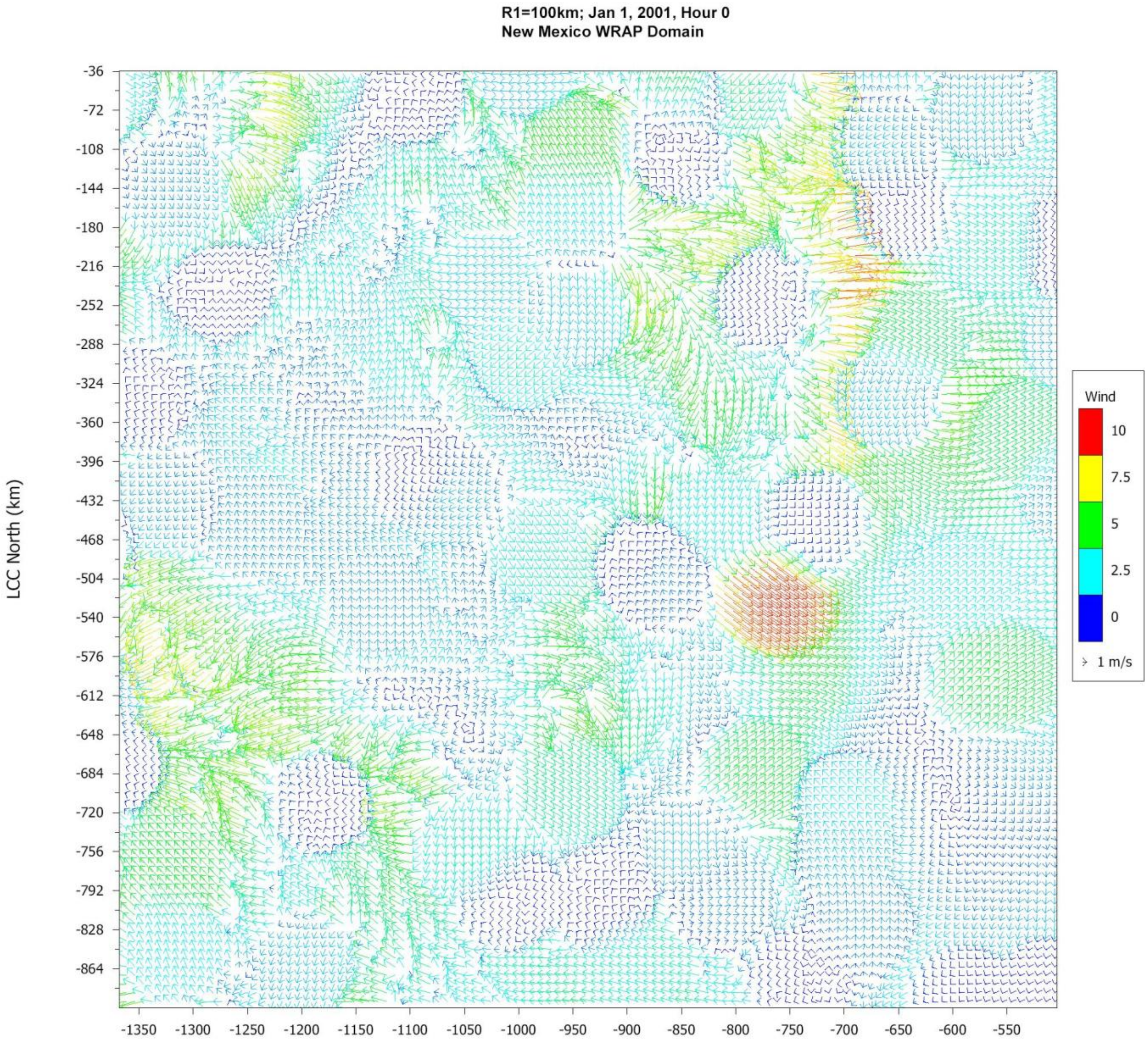
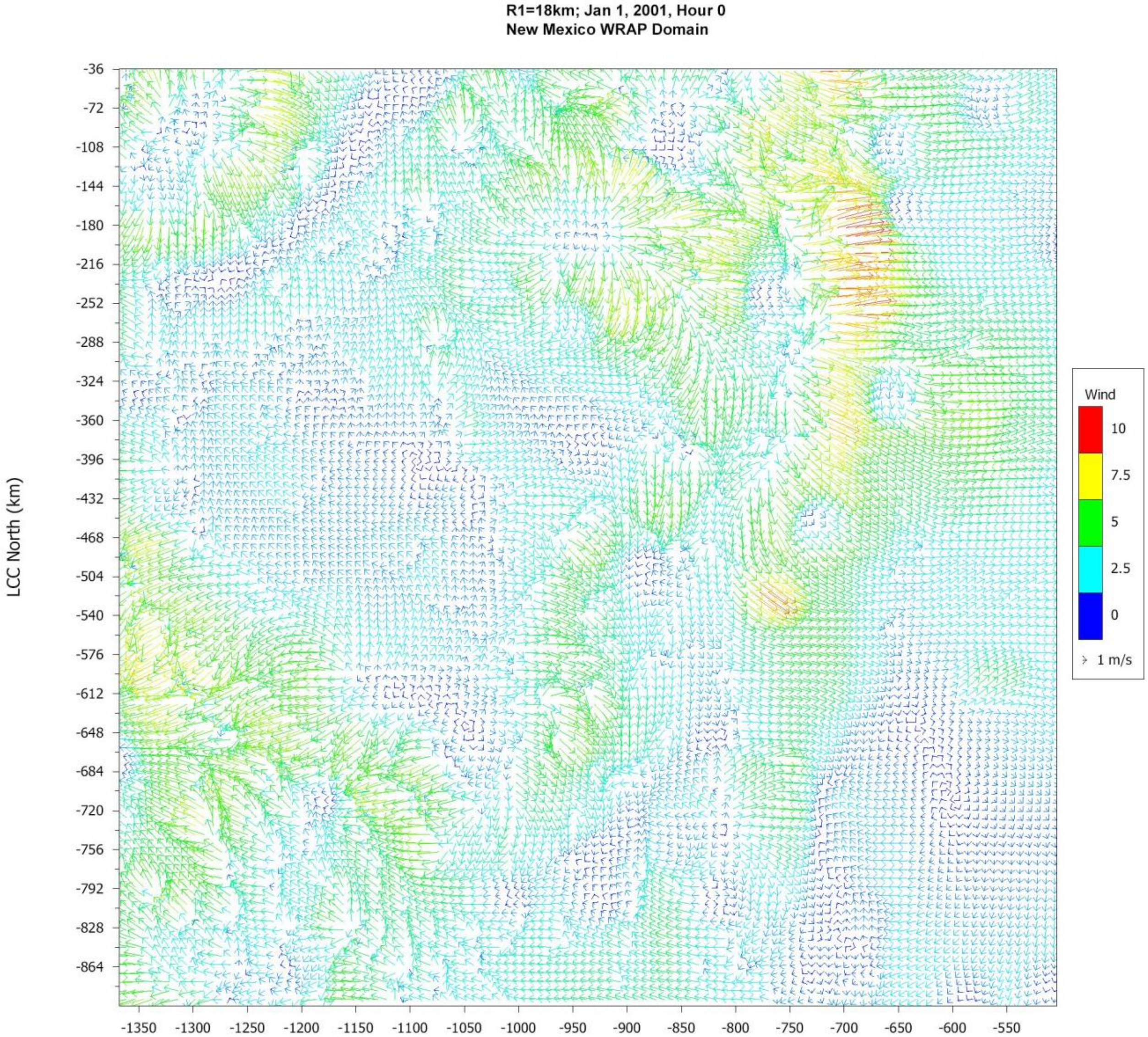


Figure 2-3 CALMET Wind Fields with ENSR Settings

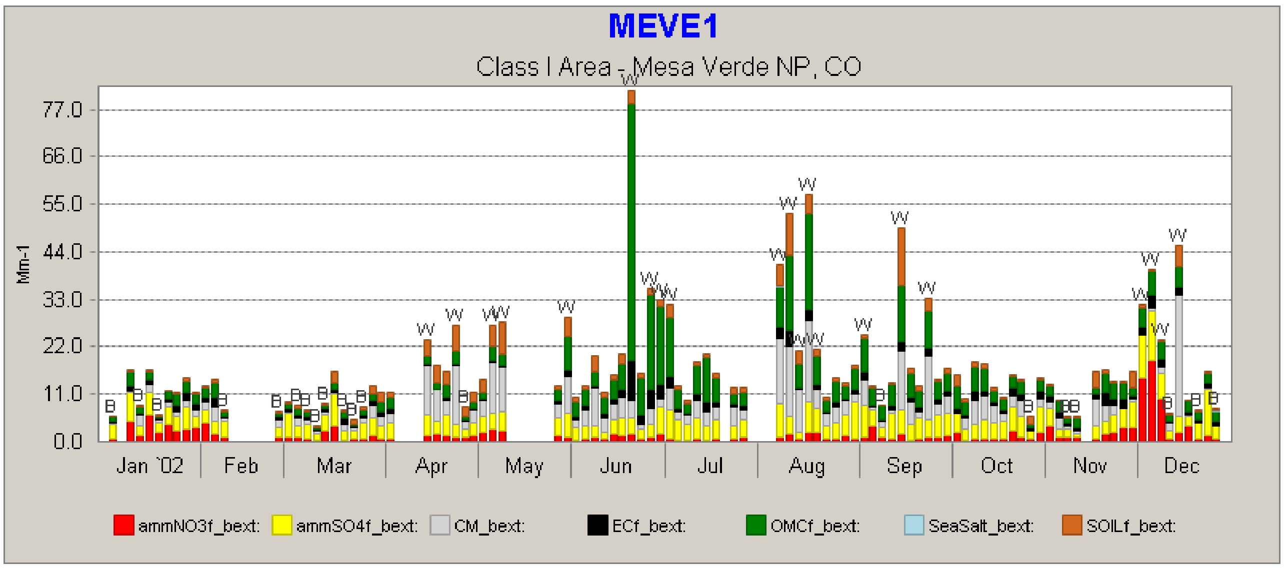


2.3 IMPROVE Monitoring Network

The Visibility Information Exchange Web System (VIEWS) is an online database of air quality data designed to understand the effects of air pollution on visibility and to support the Regional Haze Rule enacted by the USEPA to reduce regional haze and improve visibility in national parks and wilderness areas (http://vista.cira.colostate.edu/views/).

The VIEWS database contains annual summary of Class I area-specific charts of visibility-degrading pollutants. Bar charts depict seasonal patterns of pollution and pie charts show the average composition for the 20% best and 20% worst pollution days. An example of a bar and pie chart for Mesa Verde National Park is shown in Figure 2-4. Mesa Verde is the closest Class I area to FCPP. Bar and pie charts for the modeled sixteen Class I areas for year 2002 are presented in Appendix A. Year 2002 was chosen because it is the year for which WRAP has established the baseline emissions inventory.

Figure 2-4 Plot of Measured Visibility-Degrading Pollutants in Mesa Verde NP, Year 2002



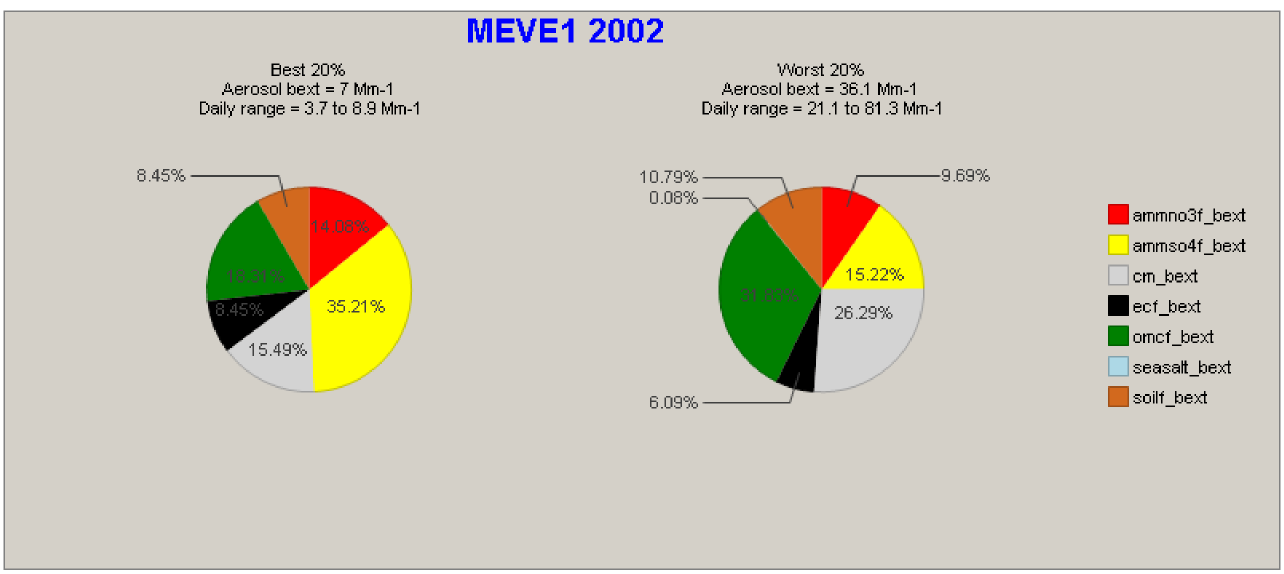


Figure 2-4 shows visibility degradation expressed as extinction in units of inverse megameters. Visibility is often described with two metrics: 1) visual range (the greatest distance that a large, dark object can be seen) or 2) light extinction coefficient (the attenuation of light per unit distance due to scattering and absorption by gases and particles in the atmosphere). Extinction coefficient (expressed in inverse distance units such as inverse megameters) can easily be apportioned into contributions by various particulate species, as is shown in Figure 2-4. The relationship between measured species concentrations and the extinction coefficient is known as the "IMPROVE equation". One drawback of visual range and extinction coefficient is that neither of them is linearly related to perceived visual scene changes caused by uniform haze. Therefore, a newly-developed visibility index, the deciview, or dv (Pitchford and Malm, 1994), has a scale that is linear to humanly-perceived changes in visual air quality. A one dv change is approximately a 10% change in the extinction coefficient, which is a small, but possibly perceptible scenic change (the threshold for perceived change is between 1 and 2 dv). In terms of extinction coefficient (bext) and visual range (vr), the deciview is:

$$\textbf{haziness } (\textbf{\textit{dv}}) = \textbf{10 ln (bext/0.01 km}^{-1}\textbf{) = 10 ln (391 km/vr)}$$

Figure 2-4 shows that organic aerosols (probably associated with forest fires for peak impacts) contribute about 32% and coarse particulate matter (due to wind-blown dust) contributes about 26% on the worst 20% days to the visibility extinction at Mesa Verde National Park. On the other hand, ammonium nitrate contributes only 10% and ammonium sulfate contributes 15% to the visibility extinction at the park, and these particles are due to emissions from all sources surrounding the park (including non-USA sources), not just from any individual source. Furthermore, the nitrate impacts were virtually nonexistent during the warm period of April-October (during the period of the heaviest park visitation), while sulfate impacts were generally present throughout the entire year. This pattern is generally present in all of the Class I areas, as can be seen in the composition plots shown in Appendix A. Due to this fact, NO_x emission controls are not very effective in improving regional haze. Moreover, certain NO_x emission controls, such as SCR and SNCR, create excess ammonia and primary sulfate emissions (H_2SO_4) that are both visibility-degrading, especially in the warm months when nitrates are a very small contributor to regional haze relative to sulfates.

3.0 CALPUFF Modeling Parameters

This section provides a summary of the modeling procedures that were used for the refined CALPUFF analysis conducted for the Four Corners Power Plant.

3.1 CALPUFF Modeling Domain and Receptors

The Four Corners Power Plant used the EPA-approved version of CALPUFF (Version 5.8, Level 070623) that has been posted at http://www.src.com/calpuff/download/download.htm#EPA_VERSION. Although the WRAP BART protocol mentions the use of CALPUFF version 6, the EPA's Office of Air Quality Planning and Standards has clearly stated that the use of a version other than the official EPA version is a non-guideline application that must obtain regional EPA approval on a case-by-case basis. It is clear from the discussion provided in Section 2.2 that CALPUFF version 6 is not approvable by EPA at this time without a significant effort to show that it is technically superior. To avoid the need for the justification and documentation required to use a non-guideline version of the model, ENSR used the official EPA version.

The extents of the 4-km WRAP domain for New Mexico are shown in Figure 3-1. The BART CALPUFF modeling for Four Corners was done using a smaller computational grid within the WRAP domain to minimize computation time and output file size. Four Corners computational grid domain is shown in Figure 3-1. This domain includes sixteen Class I areas within 300 km of the source, plus a 50-km buffer around each Class I area and a 100-km buffer around the source to assure puffs recirculation. The receptors used for each of the Class I areas are based on the National Park Service database of Class I receptors. For Grand Canyon and Maroon Bells Snowmass, only the receptors within the computational grid were included in CALPUFF modeling.

3.2 Technical Options Used in the Modeling

For CALPUFF model technical options, inputs and processing steps, APS followed the WRAP common BART protocol with the exception of the model version.

Due to the large distance to the nearest Class I area, building downwash effects were not included in the CALPUFF modeling.

WRAP has developed an hourly ozone measurements files for three years (2001-2003), available at http://pah.cert.ucr.edu/aqm/308/bart/calpuff/ozone_dat/. Data collection and processing are described in Section 3.1.2.7 of the WRAP protocol. These ozone data files were used as input to CALPUFF.

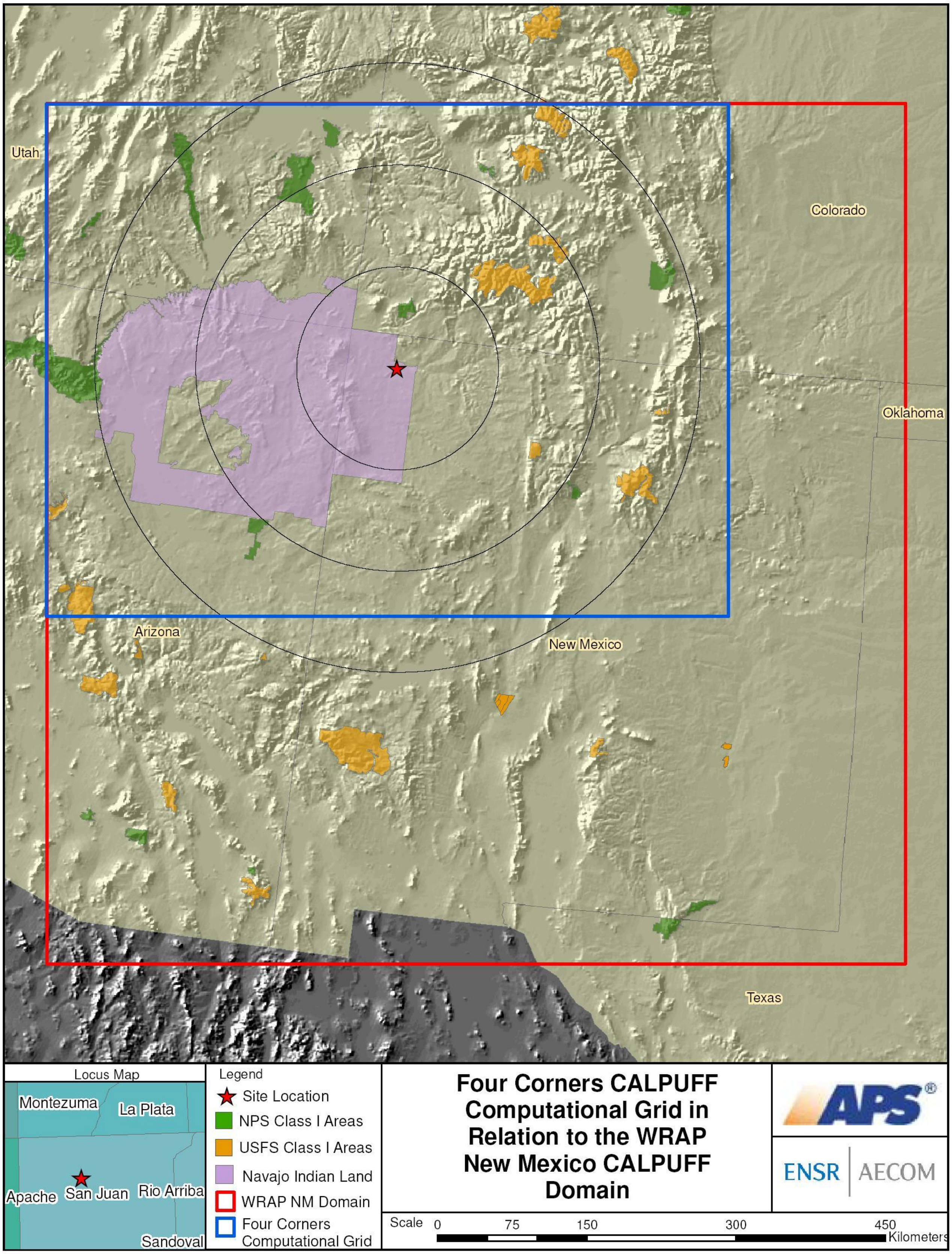
The POSTUTIL utility program was used to repartition HNO_3 and NO_3 using appropriate ammonia background values that were approved by the Federal Land Managers for the nearby Desert Rock Energy Facility (DREF) PSD permit application. For that project, located nearby in northwestern New Mexico, it was realized that the likely overprediction by CALPUFF of nitrates in winter can be partially addressed by using a monthly variation of background ammonia concentrations, with guidance from actual ammonia measurements, some of which were taken in the Grand Canyon. The default value of 1.0 ppb for arid lands as referenced in the IWAQM Phase 2 document is valid at 20 deg C, but the same document cites a strong dependence with ambient temperature, with variations of a factor of 3-4. This same dependence is seen at the CASTNET monitor at Bondville, Illinois (see page 5 at http://www.ladco.org/tech/monitoring/docs_gifs/NH3proposal-revised3.pdf). In addition, a study of light-affecting particles in SW Wyoming indicated that nitrates were overpredicted by a factor of 3 for a constant ammonia concentration of 1.0 ppb, and by a factor of 2 for an ammonia concentration of 0.5 ppb (see slide 57 at http://www.air.dnr.state.ga.us/airpermit/psd/dockets/longleaf/facilitydocs/050711_CALPUFF_eval.pdf). Since there are no large sources of ammonia due to agricultural activities near the Class I areas being analyzed (see Figure 1 in http://www.ladco.org/tech/monitoring/docs_gifs/ammonia_role_midwest_haze.pdf), it is appropriate to introduce a monthly varying ammonia background concentration to the CALPUFF modeling. Table 3-1 lists the values that were used in CALPUFF and have been agreed to by the National Park Service for DREF. Note that these values were used only for modeling the baseline and BART NOx Control Option 1 emissions. A refined set of ammonia background values was developed for modeling BART NOx Control Option 2 and 3 and further discussed in Section 4.3.

Table 3-1 Ambient Ammonia Background Concentration

Month	Ambient Ammonia Background Concentration (ppb)
January – February	0.2
March – April	0.5
May – September	1.0
October – November	0.5
December	0.2

These proposed values are consistent with the CMAQ modeled values provided in Appendix A of www.vistas-sesarm.org/BART/CMAQ2002_evaluation_Dec31_2005.pdf.

Figure 3-1 Four Corners CALPUFF Computational Grid in Relation to the WRAP NM Domain



3.3 Natural Conditions and Monthly f(RH) at Class I Areas

Sixteen Class I areas were modeled for the Four Corners Power Plant. For these Class I areas, natural background conditions must be established in order to determine a change in natural conditions related to a source's emissions. For the modeling described in this document, APS used the natural background light extinctions shown in Table 3-2, modified as noted below with site-specific considerations, and corresponding to the annual average (EPA 2003, Appendix B), consistent with the July 19, 2006 EPA guidance to Region 4 on this issue ("Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations", Joseph W. Paise/ EPA OAQPS to Kay Prince/Branch Chief).

Table 3-2 Background concentrations of soil used as input to CALPOST

Class I Area	Natural Background Concentrations (deciviews)	Natural Background non-Rayleigh Extinction (Mm^{-1})
Arches National Park	4.43	5.57
Bandelier Wilderness	4.46	5.62
Black Canyon of the Gunnison Wilderness	4.50	5.68
Canyonlands National Park	4.45	5.60
Capitol Reef National Park	4.47	5.64
Grand Canyon National Park	4.39	5.51
Great Sand Dunes National Monument	4.54	5.75
La Garita Wilderness	4.5	5.68
Maroon Bells Snowmass Wilderness	4.51	5.70
Mesa Verde National Park	4.53	5.73
Pecos Wilderness	4.48	5.65
Petrified Forest National Park	4.41	5.54
San Pedro Parks Wilderness	4.47	5.64
West Elk Wilderness	4.51	5.70
Weminuche Wilderness	4.5	5.68
Wheeler Peak Wilderness	4.51	5.70

To determine the input to CALPOST, it is first necessary to convert the deciviews to extinction using the equation:

Extinction (Mm^{-1}) = 10 exp(deciviews/10).

For example, for Bandelier, 4.46 deciviews is equivalent to an extinction of 5.62 inverse megameters (Mm^{-1}); this extinction excludes the default 10 Mm^{-1} for Rayleigh scattering. This remaining extinction is due to naturally occurring particles, and is held constant for the entire year's simulation. Therefore, the data provided to CALPOST for Bandelier would be the total natural background extinction minus 10 (expressed in Mm^{-1}), or 5.62. This is most easily input as a fine soil concentration of 5.62 $\mu g/m^3$ in CALPOST, since the extinction efficiency of soil (PM-fine) is 1.0 and there is no f(RH) component. The concentration entries for all other particle constituents would be set to zero, and the fine soil concentration would be kept the same for each month of the year.

The monthly values for f(RH) that CALPOST needs were taken from "Guidance for Tracking Progress Under the Regional Haze Rule" (EPA, 2003) Appendix A, Table A-3.

3.4 Light Extinction and Haze Impact Calculations

The CALPOST postprocessor was used for the calculation of the impact from the modeled source's primary and secondary particulate matter concentrations on light extinction. The formula that is used is the existing IMPROVE/EPA formula, which is applied to determine a change in light extinction due to increases in the particulate matter component concentrations. Using the notation of CALPOST, the formula is the following:

$$b_{ext} = 3\ f(RH)\ [(NH_4)2SO_4] + 3\ f(RH)\ [NH_4NO_3] + 4[OC] + 1[Soil] + 0.6[Coarse\ Mass] + 10[EC] + b_{Ray}$$

The concentrations, in square brackets, are in $\mu g/m^3$ and b_{ext} is in units of Mm^{-1}. The Rayleigh scattering term (b_{Ray}) has a default value of 10 Mm^{-1}, as recommended in EPA guidance for tracking reasonable progress (EPA, 2003a).

For assessment of visibility impacts at the Class I areas we used CALPOST Method 6. Each hour's source-caused extinction is calculated by first using the hygroscopic components of the source-caused concentrations, due to ammonium sulfate and nitrate, and monthly Class I area-specific f(RH) values. The contribution to the total source-caused extinction from ammonium sulfate and nitrate is then added to the other, non-hygroscopic components of the particulate concentration (from coarse and fine soil, secondary organic aerosols, and from elemental carbon) to yield the total hourly source-caused extinction.

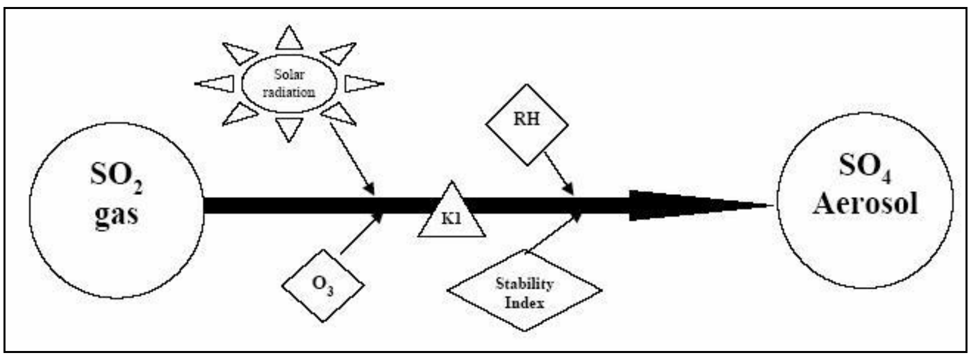
4.0 Factors Influencing Pollutant Emissions' Effects on Visibility

Secondary pollutants such as nitrates and sulfates are significant contributors to the visibility extinction in Class I areas. The CALPUFF model was used to determine the effect of these pollutants on Class I areas, associated with BART control options. CALPUFF uses the EPA-approved MESOPUFF II chemical reaction mechanism to convert SO_2 and NO_x emissions to secondary sulfates and nitrates. The discussion below describes how the secondary pollutants are formed and the factors affecting their formation.

4.1 Formation of Sulfates

The rate of transformation of gaseous SO_2 to ammonium sulfate $(NH_4)_2SO_4$ aerosol is dependent upon solar radiation, ambient ozone concentration, atmospheric stability, and relative humidity, as shown in Figure 4-1 (taken from the CALPUFF users guide, 2000). Homogeneous gas phase reaction is the dominant SO_2 oxidation pathway during clear, dry conditions (Calvert et al., 1978). CALPUFF assumes that the sulfate reacts preferentially with ammonia (NH_3) to form ammonium sulfate and that any remaining ammonia is available to form ammonium nitrate (NH_4NO_3).

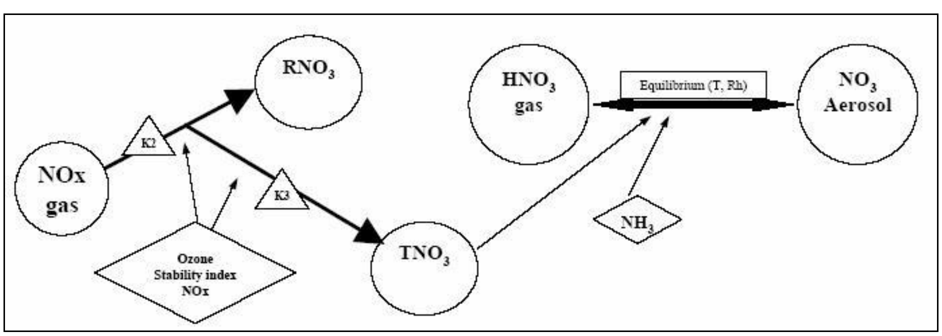
Figure 4-1 MESOPUFF II SO_2 Oxidation



4.2 Formation of Nitrates

The oxidation of NO_x to nitric acid (HNO_3) depends on the NO_x concentration, ambient ozone concentration, and atmospheric stability. Some of the nitric acid is then combined with available ammonia in the atmosphere to form ammonium nitrate aerosol in an equilibrium state that is a function of temperature, relative humidity, and ambient ammonia concentration, as shown in Figure 4-2 (from the CALPUFF users guide).

Figure 4-2 MESOPUFF II NO_x Oxidation

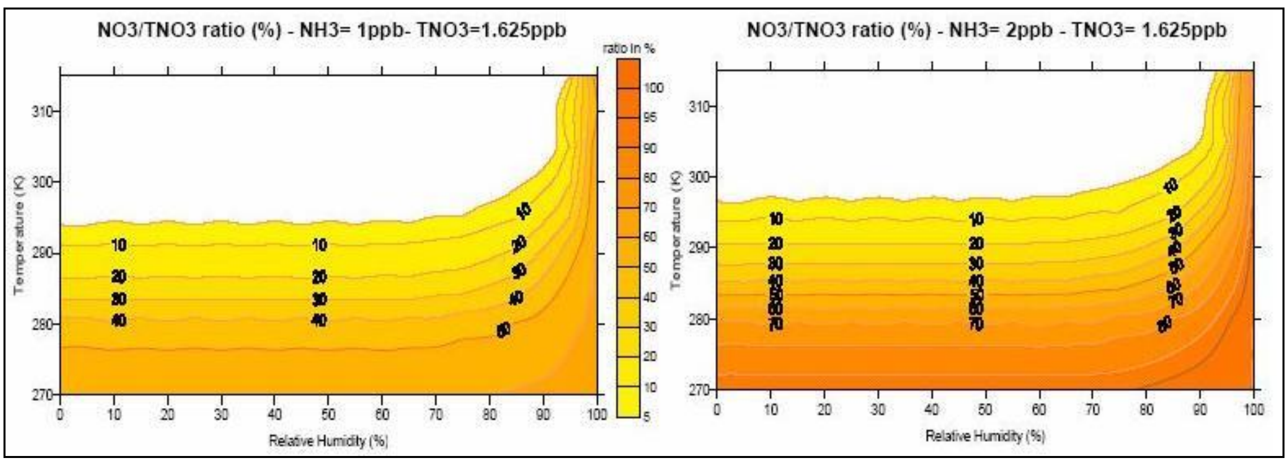


In CALPUFF, total nitrate ($TNO_3 = HNO_3 + NO_3$) is partitioned into each species according to the equilibrium relationship between gaseous HNO_3 and NO_3 aerosol. This equilibrium is a function of ambient temperature and relative humidity. Moreover, the formation of nitrate strongly depends on availability of NH_3 to form ammonium nitrate, as shown in Figure 4-3 (from CALPUFF courses given by TRC). The figure on the left shows that with 1 ppb of available ammonia and fixed temperature and humidity (for example, 275 deg K and 80% humidity), only 50% of the total nitrate forms particulate matter. When the available ammonia is increased to 2 ppb, as shown in the figure on the right, as much as 80% of the total nitrate is in the particulate form. Figure 4-3 also shows that colder temperatures and higher relative humidity significantly favor nitrate formation and vice versa. A summary of the conditions affecting nitrate formation are listed below:

- Colder temperature and higher relative humidity create favorable conditions to form nitrate particulate matter, and therefore <u>more</u> ammonium nitrate is formed;
- Warm temperatures and lower relative humidity create less favorable conditions to form nitrate particulate matter, and therefore <u>less</u> ammonium nitrate is formed;
- Sulfate preferentially scavenges ammonia over nitrates. In areas where sulfate concentrations are high and ambient ammonia concentrations are low, there is less ammonia available to react with nitrate, and therefore <u>less</u> ammonium nitrate is formed.

For this BART analysis, the effects of temperature and background ammonia concentrations on the nitrate formation are the key to understanding the effects of various NO_x control options. For parts of the country where sulfate concentrations are relatively high and ammonia emissions are quite low, the atmosphere is likely to be in an ammonia-limited regime relative to nitrate formation. Therefore, NO_x emission controls are not very effective in improving regional haze, especially if there is very little ambient ammonia available.

Figure 4-3 NO_3/HNO_3 Equilibrium Dependency on Temperature and Humidity



4.3 Refined Ambient Ammonia Background Concentrations

As discussed in Section 4.2, the formation of nitrate is highly sensitive to availability of ammonia to form ammonium nitrate. Ammonium nitrate is a visibility-degrading pollutant. For the purpose of evaluating NO_x emissions control options, the ambient ammonia background concentrations were refined to factor in excess ammonia emission increases associated with SNCR and SCR operations. Moreover, the installation of SCR creates primary sulfate emissions (H_2SO_4) that are also visibility-degrading.

Excess ammonia emissions associated with SNCR and SCR operations were modeled in CALPUFF to determine the 24-hour ammonia concentration at Mesa Verde National Park as well as the other Class I areas associated with a peak predicted impact from FCPP. Predicted excess ammonia concentrations associated with SNCR and SCR operation are listed in Table 4-1. For simplicity in the post-processing, the predicted values of additional ambient ammonia concentrations were allocated to three specific values covering the range of the CALPUFF predictions. It is noteworthy from a review of the values listed in Table 4-1 that the highest additional ammonia concentration occurs at Mesa Verde National Park, while substantially lower concentrations are added at the more distant Class I areas.

The resultant ammonia concentrations for the peak daily impact at the Class I areas (corresponding to a peak regional haze event) were added to the monthly ambient background values, as shown in Table 4-1. Then POSTUTIL program (CALPUFF post-processor) was used to re-compute regional haze impacts with the adjusted ammonia background at each Class I areas.

Table 4-1 Refined Ambient Ammonia Background Concentration

Class I Area	SNCR	SCR
	ppb	ppb
These NH_3 values were predicted at each Class I area		
Arches National Park	0.05	0.02
Bandelier Wilderness	0.04	0.01
Black Canyon of the Gunnison Wilderness	0.02	0.01
Canyonlands National Park	0.08	0.03
Capitol Reef National Park	0.03	0.01
Grand Canyon National Park	0.02	0.01
Great Sand Dunes National Monument	0.02	0.01
La Garita Wilderness	0.02	0.01
Mesa Verde National Park	0.19	0.08
Pecos Wilderness	0.03	0.01
Petrified Forest National Park	0.03	0.01
San Pedro Parks Wilderness	0.08	0.03
West Elk Wilderness	0.02	0.01
Weminuche Wilderness	0.06	0.02
Wheeler Peak Wilderness	0.02	0.01
Maroon Bells Snowmass Wilderness	0.01	0.004
Color-coded NH_3 values were averaged and then added to the monthly ambient NH_3 concentrations		
Mesa Verde National Park	0.19	0.08
Arches National Park	0.06	0.01
Bandelier Wilderness		
Canyonlands National Park		
San Pedro Parks Wilderness		
Weminuche Wilderness		
Black Canyon of the Gunnison Wilderness	0.02	
Capitol Reef National Park		
Grand Canyon National Park		
Great Sand Dunes National Monument		
La Garita Wilderness		
Pecos Wilderness		
Petrified Forest National Park		
West Elk Wilderness		
Wheeler Peak Wilderness		
Maroon Bells Snowmass Wilderness		
Excess NH_3 Emission Rate (lb/hr)	70.71	28.28

5.0 BART Eligibility Analysis

5.1 BART-Eligible Requirements

The BART-affected emission units at the Four Corners plant are Units 1 through 5. Each of the units were in existence on August 7, 1977 and had not been in operation for more than 15 years as of that date. Therefore, they fall into the time period addressed by the Regional Haze BART Rule published on July 6, 2005. In addition, the units meet the other criteria for BART eligibility. All five units burn western bituminous coal. NO_x presumptive BART limits apply to FCPP Units 3-4-5 (0.39 lb/MMBtu for Unit 3 and 0.40 lb/MMBtu for Units 4-5) since the plant capacity exceeds 750 MW, and these units all exceed 200 MW. NO_x presumptive BART limits do not apply to Units 1-2 since they do not exceed 200 MW.

5.2 Existing Control Equipment and Emission Rates

The air emissions data used to assess the visibility impacts associated with the Four Corners Power Plant at the selected Class I areas are discussed in this section. The SO_2, NO_x and PM_{10} baseline emissions were provided by APS for the baseline calendar years, 2002 through 2006. The baseline emissions were based on the highest daily emission rates of these pollutants and highest daily heat input rates for the baseline period.

Baseline SO_2 emissions were based on the highest daily emission rates and highest daily heat input rates compiled by the continuous emissions monitoring system (CEMS) during 2005 through 2006, since the plant operations were changed during 2004 to incorporate a higher level of removal of SO_2 emissions. Based on a review of the CEMS data, the highest daily SO_2 emissions were determined by excluding a few days for which there were documented startups, shutdowns, or malfunctions that affected the SO_2 emission rates. Baseline NO_x emissions were based on the highest daily emission rates and highest daily heat input rates compiled by the CEMS during 2002 through 2006, since the plant operations relative to NO_x emissions have not recently changed. No data were excluded due to startups, shutdowns, and malfunctions from the determination of baseline NO_x emissions. Due to the assumption of these worst-case emissions for each day of the 3-year simulation, the modeling approach prescribed by EPA's BART rule is very conservative, and will likely result in an overprediction of the 98th percentile impact.

Baseline PM emissions were based on the highest filterable PM emissions determined by annual stack testing and highest daily heat input rates compiled by the CEMS during 2002 through 2006. Because various components of PM_{10} emissions have different visibility extinction efficiencies, the PM_{10} emissions are divided or "speciated" into several components. Four Corners is using, where available, source-specific emission and speciation factors. Otherwise, default values from EPA's AP-42 reference document are used to determine emissions and speciation.

Units 1 through 3 at the Four Corners Power Plant are wall-fired, dry-bottom pulverized coal-fired boilers equipped with venturi scrubbers for PM and SO_2 control, while Units 4 and 5 are cell burner, pulverized coal-fired boilers equipped with lime spray towers and baghouses for SO_2 and PM control. The exhaust gases from Units 1 and 2 and Units 4 and 5 are ducted into two separate stacks each containing two flues. The Unit 3 exhaust gas is ducted into a separate stack. Table 5-1 summarizes exhaust stack parameters that were used to model the baseline conditions and the BART control options. Table 5-2 summarizes baseline emissions.

Total PM_{10} is comprised of filterable and condensable emissions. The PM_{10} emissions and speciation approach to be used for the modeling described in this protocol is presented below.

- Baseline filterable PM emissions (units of lb/hr) were based on the source-specific emission factors (units of lb/MMBtu) derived from annual stack tests and the maximum daily heat input recorded by the CEMS during the 2002 through 2006 period.

- Based on AP-42 Table 1.1-6 (September 1998), 71% of filterable PM is PM_{10} and 51% is fine PM_{10} for a dry-bottom boiler firing pulverized coal with a scrubber for PM control (Units 1, 2 and 3). In addition, 92% of filterable PM is PM_{10} and 53% of fine PM_{10} for a dry-bottom boiler firing pulverized coal with a fabric filter for PM control (Units 4 and 5).
- Elemental carbon is 3.7% of fine PM based on the best estimate for electric utility coal combustion in Table 6 of “Catalog of Global Emissions Inventories and Emission Inventory Tools for Black Carbon”, William Battye and Kathy Boyer, EPA Contract No. 68-D-98-046, January 2002.
- Total condensable PM_{10} is the sum of H_2SO_4 and organic condensable PM_{10} emissions.
- H_2SO_4 emissions are based on "Estimating Total Sulfuric Acid Emissions from Stationary Power Plants," EPRI, Technical Update, March 2007. For coal-fired boilers, H_2SO_4 emissions are determined from "(Q)(98.06/64.04)(F1)(F2)" where Q is the uncontrolled SO_2 emission rate (lb/hr), F1 is the fuel factor (0.00111 for western bituminous coal), and F2 is the control factor (0.56 for an air preheater and 0.65 for a venturi scrubber).
- Based on AP-42, Table1.1-5 (September 1998), organic condensable PM_{10} is 0.004 lb/MMBtu for boilers firing pulverized coal with FGD for SO_2 control.

Table 5-1 Modeling Exhaust Stack Parameters

	Units	Units 1-2 Merged Stacks	Unit 3 Single Stack	Units 4-5 Merged Stacks
UTM-X, Zone 12, NAD83	Meters	724966.054	724966.045	725349.264
UTM-Y, Zone 12, NAD83	Meters	4063508.296	4063433.039	4063085.953
Stack Height	Meters	75.90	76.20	93.73
Base Elevation	Meters	1625.50	1625.27	1631.29
Effective Diameter	Meters	6.47	4.57	12.28
Gas Exit Velocity	m/s	20.73	23.77	19.21
Stack Gas Exit Temperature	deg K	323.15	323.15	325.93

Table 5-2 Baseline Emission Rates

Unit	Description	Max. Heat Input	Higher Heating Value	Fuel Sulfur Content	Maximum NOx Emissions		Maximum SO2 Emissions		Maximum Filterable PM Emissions			Filterable PM10					Condensable PM10			Total PM10
												total	coarse	Fine			total	SO4	organic	
														fine total	fine soil	EC				
		MMBtu/hr (a)	Btu/lb (b)	% wt. (b)	lb/MMBtu (c)	lb/hr	lb/MMBtu (c)	lb/hr	lb/MMBtu (c)	lb/hr	Basis	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr
1	Bituminous Coal, 190 MW, PC Wall-Fired, Dry Bottom, Venturi Scrubber, Wet FGD	2,087	8,880	0.772	0.882	1,841.37	0.222	464.17	0.030	62.60	Stack Test	44.45 (d)	12.52	31.9 (d)	30.74	1.18 (f)	10.59	2.24 (g)	8.35 (i)	55.03
2	Bituminous Coal, 190 MW, PC Wall-Fired, Dry Bottom, Venturi Scrubber, Wet FGD	2,352	8,880	0.772	0.666	1,567.66	0.262	615.12	0.041	97.46	Stack Test	69.20 (d)	19.49	49.7 (d)	47.87	1.84 (f)	11.94	2.53 (g)	9.41 (i)	81.13
3	Bituminous Coal, 253 MW, PC Wall-Fired, Dry Bottom, Venturi Scrubber, Wet FGD	2,896	8,880	0.772	0.665	1,926.23	0.344	995.26	0.037	107.72	Stack Test	76.48 (d)	21.54	54.9 (d)	52.90	2.03 (f)	14.69	3.11 (g)	11.58 (i)	91.17
4	Bituminous Coal, 818 MW, PC Cell Burner, Dry Bottom, Fabric Filter, Semi-Dry FGD	8,000	8,880	0.772	0.627	5,015.98	0.253	2,026.10	0.025	197.75	Stack Test	181.926 (e)	77.12	104.81 (e)	100.93	3.88 (f)	32.60	0.60 (h)	32.00 (i)	214.53
5	Bituminous Coal, 818 MW, PC Cell Burner, Dry Bottom, Fabric Filter, Semi-Dry FGD	8,047	8,880	0.772	0.552	4,444.04	0.265	2,130.76	0.012	94.04	Stack Test	86.515 (e)	36.67	49.84 (e)	48.00	1.84 (f)	32.79	0.61 (h)	32.19 (i)	119.31

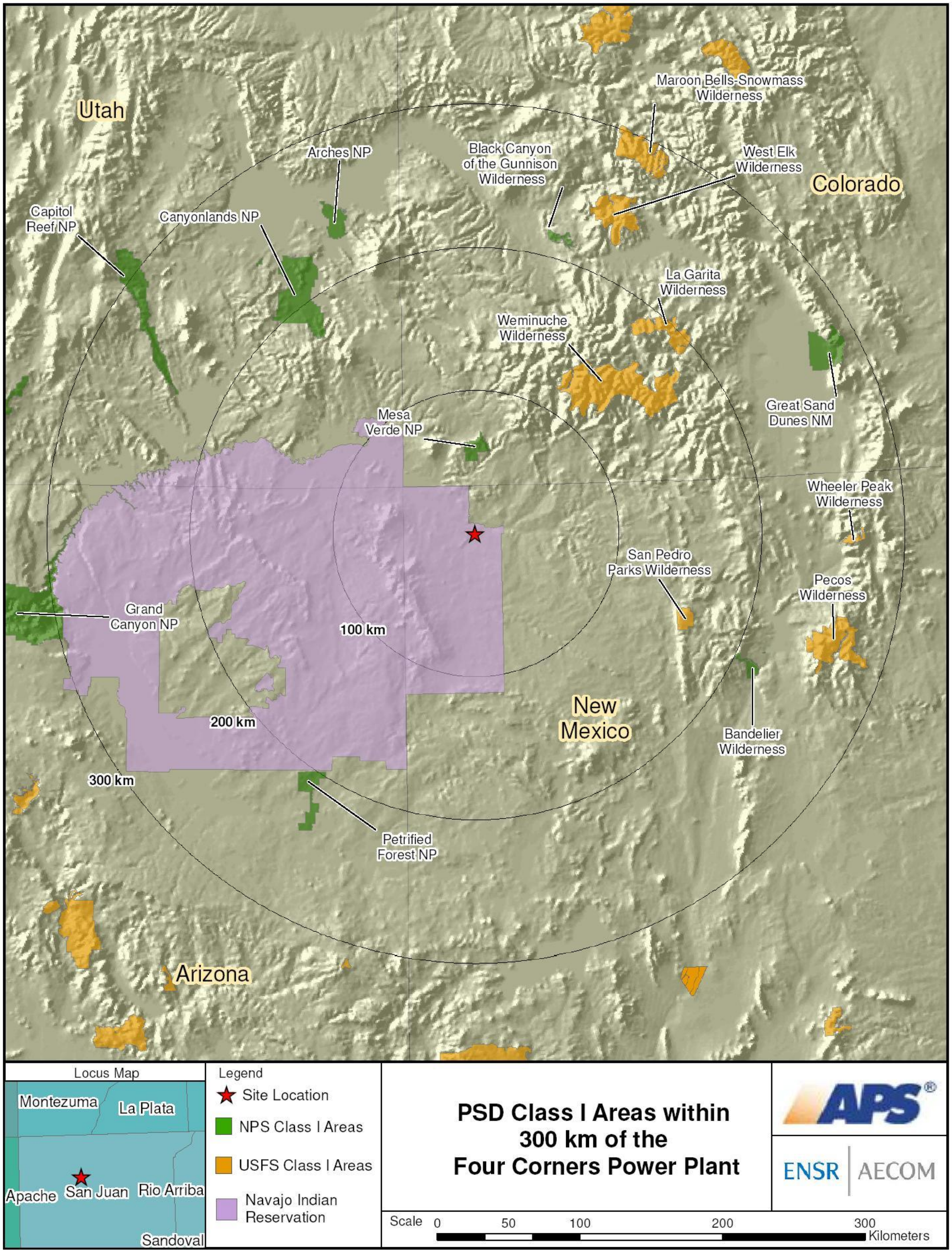
(a) Maximum heat input rate are based worst-case daily emissions for calendar years 2002 through 2006.
(b) Higher heating values and sulfur content are based on the average values for calendar years 2002 through 2006.
(c) Baseline NOx, SO2 and filterable PM emissions are based worst-case daily emissions received on March 2, 2007 and revised April 26, 2007.
(d) For a dry bottom boiler fired with bituminous coal and equipped with a scrubber, total filterable PM10 is 71% of filterable PM and fine filterable PM10 is 51% of filterable PM based on AP-42, Table 1.1-6.
(e) For a dry bottom boiler fired with bituminous coal and equipped with a bagouse, total filterable PM10 is 92% of filterable PM and fine filterable PM10 is 53% of filterable PM based on AP-42, Table 1.1-6.
(f) Elemental carbon is 3.7% of fine PM based on the best estimate for electric utility coal combustion in Table 6 of "Catalog of Global Emissions Inventories and Emission Inventory Tools for Black Carbon", William Battye and Kathy Boyer, EPA Contract No. 68-D-98-046, January 2002.
(g) H2SO4 emissions are based on "Estimating Total Sulfuric Acid Emissions from Stationary Power Plants," EPRI, Technical Update, March 2007. For coal-fired boilers, H2SO4 emissions are determined from "(Q)(98.06/64.04)(F1)(F2)" where Q is the uncontrolled SO2 emission rate (lb/hr), F1 is the fuel factor (0.00111 for western bituminous coal), and F2 is the control factor (0.56 for an air preheater and 0.65 for a venturi scrubber).
(h) H2SO4 emissions are based on "Estimating Total Sulfuric Acid Emissions from Stationary Power Plants," EPRI, Technical Update, March 2007. For coal-fired boilers, H2SO4 emissions are determined from "(Q)(98.06/64.04)(F1+S2)(F2)" where Q is the uncontrolled SO2 emission rate (lb/hr), F1 is the fuel factor (0.00111 for western bituminous coal), and F2 is the control factor (0.56 for an air preheater, 0.40 for a wet spray tower, and 0.10 for a baghouse).
(i) For pulverized coal-fired boilers with an FGD system, total condensable organic PM10 emissions factor is 0.004 lb/MMBtu based on AP-42, Table 1.1-5.

5.3 Affected Class I Areas

Figure 5-1 shows a plot of the Four Corners Power Plant relative to nearby Class I areas. There are sixteen Class I areas within 300 km of the plant. They are:

1. Arches National Park
2. Bandelier Wilderness
3. Black Canyon of the Gunnison Wilderness
4. Canyonlands National Park
5. Capitol Reef National Park
6. Grand Canyon National Park
7. Great Sand Dunes National Monument
8. La Garita Wilderness
9. Maroon Bells Snowmass Wilderness
10. Mesa Verde National Park
11. Pecos Wilderness
12. Petrified Forest National Park
13. San Pedro Parks Wilderness
14. West Elk Wilderness
15. Weminuche Wilderness
16. Wheeler Peak Wilderness

Figure 5-1 Location of Class I Areas in Relation to the Four Corners Power Plant



5.4 Baseline CALPUFF Modeling Results

CALPUFF modeling results of the baseline emissions at sixteen Class I areas are presented in Table 5-3 and graphically plotted in Figure 5-2. Modeling was conducted for all three years of CALMET meteorological data (2001-2003).

For each Class I area and year, Table 5-3 lists the 8^{th} highest delta-deciview. Figure 5-2 shows the total 8^{th} highest deciview impacts. The figure indicates that the higher visibility impacts generally occur at Mesa Verde National Park, San Pedro Parks Wilderness, and Canyonlands National Park. Higher impacts at these Class I areas are due to their proximity to FCPP.

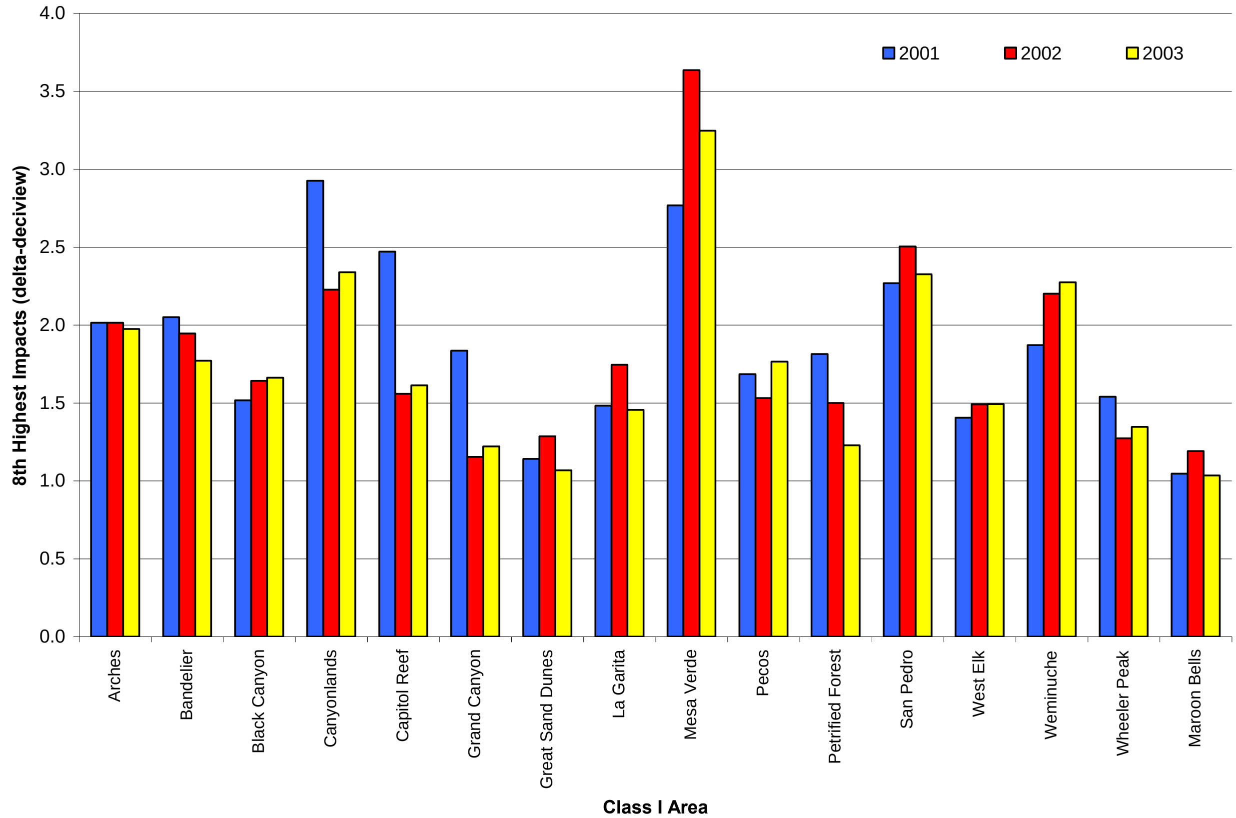
EPA recommends in their BART rule that the 98^{th} percentile value of the modeling results should be compared to the threshold of 0.5 deciviews to determine if a source contributes to visibility impairment. This statistic is also recommended for comparing visibility improvements due to BART control options. On an annual basis, this implies the 8^{th} highest day at each modeled Class I area.

The results of the baseline emissions indicate that Four Corners units are subject to BART review because the predicted visibility impacts exceed 0.5 deciviews in at least one Class I area. Therefore, BART determination modeling was conducted for specific NO_x and PM control options discussed in Section 6. The results of the modeling are discussed in Section 6.2.

Table 5-3 Regional Haze Impacts Due to Baseline Emissions

Class I Area	Met Year 2001	Met Year 2002	Met Year 2003
	8th Highest Δ dv	8th Highest Δ dv	8th Highest Δ dv
Arches National Park	2.02	2.01	1.97
Bandelier Wilderness	2.05	1.95	1.77
Black Canyon of the Gunnison Wilderness	1.52	1.64	1.66
Canyonlands National Park	2.93	2.23	2.34
Capitol Reef National Park	2.47	1.56	1.61
Grand Canyon National Park	1.84	1.15	1.22
Great Sand Dunes National Monument	1.14	1.29	1.07
La Garita Wilderness	1.48	1.75	1.46
Mesa Verde National Park	2.77	3.64	3.25
Pecos Wilderness	1.68	1.53	1.76
Petrified Forest National Park	1.81	1.50	1.23
San Pedro Parks Wilderness	2.27	2.50	2.33
West Elk Wilderness	1.41	1.49	1.49
Weminuche Wilderness	1.87	2.20	2.27
Wheeler Peak Wilderness	1.54	1.27	1.35
Maroon Bells Snowmass Wilderness	1.05	1.19	1.03

Figure 5-2 8th Highest Regional Haze Impacts for Each Modeled Year Due to Baseline Emissions



6.0 BART Control Options Modeling Analysis

This section provides a summary of the modeled visibility improvement as a result of installing BART control options on FCPP Units 1 - 5.

6.1 Modeled Control Scenarios

One PM_{10} and three NO_x BART control scenarios were modeled for each meteorological year (2001-2003) and the seven closest Class I areas (considered here due to their proximity to the FCPP). The BART control options are listed below.

PM_{10} Control Option 1: fabric filter (baghouse) controls on units 1, 2, and 3. Table 6-1 lists emission rates associated with these PM_{10} controls.

NO_x Control Option 1: Advanced combustion controls, such as low NO_x burners (LNB) on Units 1-5 and overfire furnace air (OFA) on Units 3-5.

- Overfire Furnace Air (OFA) technology involves the introduction of combustion air that is separated into primary and secondary flow sections to achieve complete burnout and to encourage the formation of N_2 rather than NO_x.
- Low NO_x burners (LNB) are designed to control fuel and air mixing at each burner in order to create larger and more branched flames. This internal combustion staging reduces peak flame temperature and results in less NO_x formation.

Table 6-2 lists emission rates associated with these NO_x controls.

NO_x Control Option 2: Advanced combustion controls (LNB/OFA) on Units 1-5 in combination with High Energy Reagent Technology (HERT) on Units 1-3 and selective non-catalytic reduction (SNCR) on Units 4-5.

- HERT technology involves OFA coupled with reagent injection to control nitrogen oxide emissions. The OFA system stages combustion for an initial reduction and a high energy chemical agent follows the OFA into the proper temperature window to optimize the NO_x conversion. The advantage of HERT over SNCR is that fewer injectors are required than for a typical SNCR system.
- SNCR is based on a gas-phase homogeneous reaction that involves the injection of an amine-based compound into the flue gas within an appropriate temperature for reduction of NO_x.

Table 6-3 lists emission rates associated with these NO_x controls.

NO_x Control Option 3: Advanced combustion controls (LNB/OFA) in combination with selective catalytic reduction (SCR) on Units 1-5.

- SCR reduction is a process that involves post-combustion removal of NO_x from flue gas utilizing a catalytic reactor. In the SCR process, ammonia injected into the flue gas reacts with nitrogen oxides and oxygen to form nitrogen and water vapor.

Table 6-4 lists emission rates associated with these NO_x controls.

Table 6-1 PM10 BART Control Option 1

Unit	Description	New BART Controls	Percent NOx Control	Percent PM Control	Max. Heat Input	Higher Heating Value	Fuel Sulfur Content	Maximum NOx Emissions		Maximum SO2 Emissions		Maximum Filterable PM Emissions			Filterable PM10					Condensable PM10			Total PM10
															total	coarse	Fine						
																	fine total	fine soil	EC	total	SO4	organic	
					MMBtu/hr (a)	Btu/lb (b)	% wt. (b)	lb/MMBtu (c)	lb/hr	lb/MMBtu (c)	lb/hr	lb/MMBtu (c)	lb/hr	Basis	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr
1	Bituminous Coal, 190 MW, PC Wall-Fired, Dry Bottom, FF, Venturi Scrubber, Wet FGD	FF	0%	52%	2,087	8,880	0.772	0.882	1,841.37	0.222	464.17	0.014	30.05	Stack Test	27.64 (d)	11.72	15.9 (d)	15.34	0.59 (f)	8.57	0.22 (g)	8.35 (i)	36.21
2	Bituminous Coal, 190 MW, PC Wall-Fired, Dry Bottom, FF, Venturi Scrubber, Wet FGD	FF	0%	59%	2,352	8,880	0.772	0.666	1,567.66	0.262	615.12	0.017	39.96	Stack Test	36.76 (d)	15.58	21.2 (d)	20.39	0.78 (f)	9.66	0.25 (g)	9.41 (i)	46.42
3	Bituminous Coal, 253 MW, PC Wall-Fired, Dry Bottom, FF, Venturi Scrubber, Wet FGD	FF	0%	59%	2,896	8,880	0.772	0.665	1,926.23	0.344	995.26	0.015	44.16	Stack Test	40.63 (d)	17.22	23.4 (d)	22.54	0.87 (f)	11.89	0.31 (g)	11.58 (i)	52.52
4	Bituminous Coal, 818 MW, PC Cell Burner, Dry Bottom, Fabric Filter, Semi-Dry FGD	None	0%	0%	8,000	8,880	0.772	0.627	5,015.98	0.253	2,026.10	0.025	197.75	Stack Test	181.926 (e)	77.12	104.81 (e)	100.93	3.88 (f)	32.60	0.60 (h)	32.00 (i)	214.53
5	Bituminous Coal, 818 MW, PC Cell Burner, Dry Bottom, Fabric Filter, Semi-Dry FGD	None	0%	0%	8,047	8,880	0.772	0.552	4,444.04	0.265	2,130.76	0.012	94.04	Stack Test	86.515 (e)	36.67	49.84 (e)	48.00	1.84 (f)	32.79	0.61 (h)	32.19 (i)	119.31

(a) Maximum heat input rate are based worst-case daily emissions for calendar years 2002 through 2006.
(b) Higher heating values and sulfur content are based on the average values for calendar years 2002 through 2006.
(c) Baseline NOx, SO2 and filterable PM emissions are based worst-case daily emissions received on March 2, 2007 and revised April 26, 2007.
(d) For a dry bottom boiler fired with bituminous coal and equipped with a scrubber, total filterable PM10 is 71% of filterable PM and fine filterable PM10 is 51% of filterable PM based on AP-42, Table 1.1-6.
(e) For a dry bottom boiler fired with bituminous coal and equipped with a bagouse, total filterable PM10 is 92% of filterable PM and fine filterable PM10 is 53% of filterable PM based on AP-42, Table 1.1-6.
(f) Elemental carbon is 3.7% of fine PM based on the best estimate for electric utility coal combustion in Table 6 of "Catalog of Global Emissions Inventories and Emission Inventory Tools for Black Carbon", William Battye and Kathy Boyer, EPA Contract No. 68-D-98-046, January 2002.
(g) H2SO4 emissions are based on "Estimating Total Sulfuric Acid Emissions from Stationary Power Plants," EPRI, Technical Update, March 2007. For coal-fired boilers, H2SO4 emissions are determined from "(Q)(98.06/64.04)(F1+S2)(F2)" where Q is the uncontrolled SO2 emission rate (lb/hr), F1 is the fuel factor (0.00111 for western bituminous coal), and F2 is the control factor (0.56 for an air preheater,0.65 for a venturi scrubber, and 0.10 for a bahouse).
(h) H2SO4 emissions are based on "Estimating Total Sulfuric Acid Emissions from Stationary Power Plants," EPRI, Technical Update, March 2007. For coal-fired boilers, H2SO4 emissions are determined from "(Q)(98.06/64.04)(F1+S2)(F2)" where Q is the uncontrolled SO2 emission rate (lb/hr), F1 is the fuel factor (0.00111 for western bituminous coal), and F2 is the control factor (0.56 for an air preheater, 0.40 for a wet spray tower, and 0.10 for a baghouse).
(i) For pulverized coal-fired boilers with an FGD system, total condensable organic PM10 emissions factor is 0.004 lb/MMBtu based on AP-42, Table 1.1-5.

Table 6-2 NO_x BART Control Option 1 (OFA/LNB)

Unit	Description	New NOx BART Controls	Percent NOx Control	Max. Heat Input	Higher Heating Value	Fuel Sulfur Content	Maximum NOx Emissions		Maximum SO2 Emissions		Maximum Filterable PM Emissions			Filterable PM10					Condensable PM10			Total PM10
														total	coarse	Fine						
																fine total	fine soil	EC	total	SO4	organic	
				MMBtu/hr (a)	Btu/lb (b)	% wt. (b)	lb/MMBtu (c)	lb/hr	lb/MMBtu (c)	lb/hr	lb/MMBtu (c)	lb/hr	Basis	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr
1	Bituminous Coal, 190 MW, PC Wall-Fired, Dry Bottom, Venturi Scrubber, Wet FGD	LNB	45%	2,087	8,880	0.772	0.484	1,010.91	0.222	464.17	0.030	62.60	Stack Test	44.45 (d)	12.52	31.9 (d)	30.74	1.18 (f)	10.59	2.24 (g)	8.35 (i)	55.03
2	Bituminous Coal, 190 MW, PC Wall-Fired, Dry Bottom, Venturi Scrubber, Wet FGD	LNB	33%	2,352	8,880	0.772	0.447	1,051.90	0.262	615.12	0.041	97.46	Stack Test	69.20 (d)	19.49	49.7 (d)	47.87	1.84 (f)	11.94	2.53 (g)	9.41 (i)	81.13
3	Bituminous Coal, 253 MW, PC Wall-Fired, Dry Bottom, Venturi Scrubber, Wet FGD	LNB, OFA	44%	2,896	8,880	0.772	0.373	1,078.69	0.344	995.26	0.037	107.72	Stack Test	76.48 (d)	21.54	54.9 (d)	52.90	2.03 (f)	14.69	3.11 (g)	11.58 (i)	91.17
4	Bituminous Coal, 818 MW, PC Cell Burner, Dry Bottom, Fabric Filter, Semi-Dry FGD	LNB, OFA	29%	8,000	8,880	0.772	0.445	3,561.35	0.253	2,026.10	0.025	197.75	Stack Test	181.926 (e)	77.12	104.81 (e)	100.93	3.88 (f)	32.60	0.60 (h)	32.00 (i)	214.53
5	Bituminous Coal, 818 MW, PC Cell Burner, Dry Bottom, Fabric Filter, Semi-Dry FGD	LNB, OFA	29%	8,047	8,880	0.772	0.392	3,155.27	0.265	2,130.76	0.012	94.04	Stack Test	86.515 (e)	36.67	49.84 (e)	48.00	1.84 (f)	32.79	0.61 (h)	32.19 (i)	119.31

(a) Maximum heat input rate are based worst-case daily emissions for calendar years 2002 through 2006.
(b) Higher heating values and sulfur content are based on the average values for calendar years 2002 through 2006.
(c) Baseline NOx, SO2 and filterable PM emissions are based worst-case daily emissions received on March 2, 2007 and revised April 26, 2007.
(d) For a dry bottom boiler fired with bituminous coal and equipped with a scrubber, total filterable PM10 is 71% of filterable PM and fine filterable PM10 is 51% of filterable PM based on AP-42, Table 1.1-6.
(e) For a dry bottom boiler fired with bituminous coal and equipped with a bagouse, total filterable PM10 is 92% of filterable PM and fine filterable PM10 is 53% of filterable PM based on AP-42, Table 1.1-6.
(f) Elemental carbon is 3.7% of fine PM based on the best estimate for electric utility coal combustion in Table 6 of "Catalog of Global Emissions Inventories and Emission Inventory Tools for Black Carbon", William Battye and Kathy Boyer, EPA Contract No. 68-D-98-046, January 2002.
(g) H2SO4 emissions are based on "Estimating Total Sulfuric Acid Emissions from Stationary Power Plants," EPRI, Technical Update, March 2007. For coal-fired boilers, H2SO4 emissions are determined from "(Q)(98.06/64.04)(F1+S2)(F2)" where Q is the uncontrolled SO2 emission rate (lb/hr), F1 is the fuel factor (0.00111 for western bituminous coal), and F2 is the control factor (0.56 for an air preheater and 0.65 for a venturi scrubber).
(h) H2SO4 emissions are based on "Estimating Total Sulfuric Acid Emissions from Stationary Power Plants," EPRI, Technical Update, March 2007. For coal-fired boilers, H2SO4 emissions are determined from "(Q)(98.06/64.04)(F1+S2)(F2)" where Q is the uncontrolled SO2 emission rate (lb/hr), F1 is the fuel factor (0.00111 for western bituminous coal), and F2 is the control factor (0.56 for an air preheater, 0.40 for a wet spray tower, and 0.10 for a baghouse).
(i) For pulverized coal-fired boilers with an FGD system, total condensable organic PM10 emissions factor is 0.004 lb/MMBtu based on AP-42, Table 1.1-5.

Table 6-3 NO_x BART Control Option 2 (OFA/LNB/HERT/SNCR)

Unit	Description	New NOx BART Controls	Percent NOx Control	Max. Heat Input	Higher Heating Value	Fuel Sulfur Content	Maximum NOx Emissions		Maximum SO2 Emissions		Maximum Filterable PM Emissions			Filterable PM10					Condensable PM10			Total PM10	NH3 Slip
														total	coarse	Fine							
																fine total	fine soil	EC	total	SO4	organic		
				MMBtu/hr (a)	Btu/lb (b)	% wt. (b)	lb/MMBtu (c)	lb/hr	lb/MMBtu (c)	lb/hr	lb/MMBtu (c)	lb/hr	Basis	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr
1	Bituminous Coal, 190 MW, PC Wall-Fired, Dry Bottom, Venturi Scrubber, Wet FGD	LNB, OFA, HERT	74%	2,087	8,880	0.772	0.229	478.76	0.222	464.17	0.030	62.60	Stack Test	44.45 (d)	12.52	31.9 (d)	30.74	1.18 (f)	10.59	2.24 (g)	8.35 (i)	55.03	6.31 (j)
2	Bituminous Coal, 190 MW, PC Wall-Fired, Dry Bottom, Venturi Scrubber, Wet FGD	LNB, OFA, HERT	69%	2,352	8,880	0.772	0.207	485.98	0.262	615.12	0.041	97.46	Stack Test	69.20 (d)	19.49	49.7 (d)	47.87	1.84 (f)	11.94	2.53 (g)	9.41 (i)	81.13	7.11 (j)
3	Bituminous Coal, 253 MW, PC Wall-Fired, Dry Bottom, Venturi Scrubber, Wet FGD	LNB, OFA, HERT	66%	2,896	8,880	0.772	0.226	654.92	0.344	995.26	0.037	107.72	Stack Test	76.48 (d)	21.54	54.9 (d)	52.90	2.03 (f)	14.69	3.11 (g)	11.58 (i)	91.17	8.76 (j)
4	Bituminous Coal, 818 MW, PC Cell Burner, Dry Bottom, Fabric Filter, Semi-Dry FGD	LNB, OFA, SNCR	47%	8,000	8,880	0.772	0.332	2,658.47	0.253	2,026.10	0.025	197.75	Stack Test	181.926 (e)	77.12	104.81 (e)	100.93	3.88 (f)	32.60	0.60 (h)	32.00 (i)	214.53	24.19 (j)
5	Bituminous Coal, 818 MW, PC Cell Burner, Dry Bottom, Fabric Filter, Semi-Dry FGD	LNB, OFA, SNCR	47%	8,047	8,880	0.772	0.293	2,355.34	0.265	2,130.76	0.012	94.04	Stack Test	86.515 (e)	36.67	49.84 (e)	48.00	1.84 (f)	32.79	0.61 (h)	32.19 (i)	119.31	24.33 (j)

(a) Maximum heat input rate are based worst-case daily emissions for calendar years 2002 through 2006.
(b) Higher heating values and sulfur content are based on the average values for calendar years 2002 through 2006.
(c) Baseline NOx, SO2 and filterable PM emissions are based worst-case daily emissions received on March 2, 2007 and revised April 26, 2007.
(d) For a dry bottom boiler fired with bituminous coal and equipped with a scrubber, total filterable PM10 is 71% of filterable PM and fine filterable PM10 is 51% of filterable PM based on AP-42, Table 1.1-6.
(e) For a dry bottom boiler fired with bituminous coal and equipped with a bagouse, total filterable PM10 is 92% of filterable PM and fine filterable PM10 is 53% of filterable PM based on AP-42, Table 1.1-6.
(f) Elemental carbon is 3.7% of fine PM based on the best estimate for electric utility coal combustion in Table 6 of "Catalog of Global Emissions Inventories and Emission Inventory Tools for Black Carbon", William Battye and Kathy Boyer, EPA Contract No. 68-D-98-046, January 2002.
(g) H2SO4 emissions are based on "Estimating Total Sulfuric Acid Emissions from Stationary Power Plants," EPRI, Technical Update, March 2007. For coal-fired boilers, H2SO4 emissions are determined from "(Q)(98.06/64.04)(F1)(F2)" where Q is the uncontrolled SO2 emission rate (lb/hr), F1 is the fuel factor (0.00111 for western bituminous coal), and F2 is the control factor (0.56 for an air preheater and 0.65 for a venturi scrubber).
(h) H2SO4 emissions are based on "Estimating Total Sulfuric Acid Emissions from Stationary Power Plants," EPRI, Technical Update, March 2007. For coal-fired boilers, H2SO4 emissions are determined from "(Q)(98.06/64.04)(F1)(F2)" where Q is the uncontrolled SO2 emission rate (lb/hr), F1 is the fuel factor (0.00111 for western bituminous coal), and F2 is the control factor (0.56 for an air preheater, 0.40 for a wet spray tower, and 0.10 for a baghouse).
(i) For pulverized coal-fired boilers with an FGD system, total condensable organic PM10 emissions factor is 0.004 lb/MMBtu based on AP-42, Table 1.1-5.
(j) Ammonia slip is 5.00 ppmvd at 6% O2 for SNCR.

Table 6-4 NO_x BART Control Option 3 (OFA/LNB/SCR)

Unit	Description	New NOx BART Controls	Percent NOx Control	Max. Heat Input MMBtu/hr (a)	Higher Heating Value Btu/lb (b)	Fuel Sulfur Content % wt. (b)	Maximum NOx Emissions lb/MMBtu (c)	Maximum NOx Emissions lb/hr	Maximum SO2 Emissions lb/MMBtu (c)	Maximum SO2 Emissions lb/hr	Maximum Filterable PM Emissions lb/MMBtu (c)	Maximum Filterable PM Emissions lb/hr	Maximum Filterable PM Emissions Basis	Filterable PM10 total lb/hr	Filterable PM10 coarse lb/hr	Filterable PM10 Fine fine total lb/hr	Filterable PM10 Fine fine soil lb/hr	Filterable PM10 Fine EC lb/hr	Condensable PM10 total lb/hr	Condensable PM10 SO4 lb/hr	Condensable PM10 organic lb/hr	Total PM10 lb/hr	NH3 Slip lb/hr
1	Bituminous Coal, 190 MW, PC Wall-Fired, Dry Bottom, Venturi Scrubber, Wet FGD	LNB, OFA, SCR	92%	2,087	8,880	0.772	0.071	147.31	0.222	464.17	0.030	62.60	Stack Test	44.45 (d)	12.52	31.9 (d)	30.74	1.18 (f)	20.69	12.34 (g)	8.35 (i)	65.13	2.52 (j)
2	Bituminous Coal, 190 MW, PC Wall-Fired, Dry Bottom, Venturi Scrubber, Wet FGD	LNB, OFA, SCR	91%	2,352	8,880	0.772	0.060	141.09	0.262	615.12	0.041	97.46	Stack Test	69.20 (d)	19.49	49.7 (d)	47.87	1.84 (f)	23.32	13.91 (g)	9.41 (i)	92.52	2.85 (j)
3	Bituminous Coal, 253 MW, PC Wall-Fired, Dry Bottom, Venturi Scrubber, Wet FGD	LNB, OFA, SCR	90%	2,896	8,880	0.772	0.067	192.62	0.344	995.26	0.037	107.72	Stack Test	76.48 (d)	21.54	54.9 (d)	52.90	2.03 (f)	28.71	17.13 (g)	11.58 (i)	105.19	3.50 (j)
4	Bituminous Coal, 818 MW, PC Cell Burner, Dry Bottom, Fabric Filter, Semi-Dry FGD	LNB, OFA, SCR	88%	8,000	8,880	0.772	0.075	601.92	0.253	2,026.10	0.025	197.75	Stack Test	181.926 (e)	77.12	104.81 (e)	100.93	3.88 (f)	35.32	3.32 (h)	32.00 (i)	217.24	9.68 (j)
5	Bituminous Coal, 818 MW, PC Cell Burner, Dry Bottom, Fabric Filter, Semi-Dry FGD	LNB, OFA, SCR	88%	8,047	8,880	0.772	0.066	533.29	0.265	2,130.76	0.012	94.04	Stack Test	86.515 (e)	36.67	49.84 (e)	48.00	1.84 (f)	35.52	3.34 (h)	32.19 (i)	122.04	9.73 (j)

(a) Maximum heat input rate are based worst-case daily emissions for calendar years 2002 through 2006.
(b) Higher heating values and sulfur content are based on the average values for calendar years 2002 through 2006.
(c) Baseline NOx, SO2 and filterable PM emissions are based worst-case daily emissions received on March 2, 2007 and revised April 26, 2007.
(d) For a dry bottom boiler fired with bituminous coal and equipped with a scrubber, total filterable PM10 is 71% of filterable PM and fine filterable PM10 is 51% of filterable PM based on AP-42, Table 1.1-6.
(e) For a dry bottom boiler fired with bituminous coal and equipped with a bagouse, total filterable PM10 is 92% of filterable PM and fine filterable PM10 is 53% of filterable PM based on AP-42, Table 1.1-6.
(f) Elemental carbon is 3.7% of fine PM based on the best estimate for electric utility coal combustion in Table 6 of "Catalog of Global Emissions Inventories and Emission Inventory Tools for Black Carbon", William Battye and Kathy Boyer, EPA Contract No. 68-D-98-046, January 2002.
(g) H2SO4 emissions are based on "Estimating Total Sulfuric Acid Emissions from Stationary Power Plants," EPRI, Technical Update, March 2007. For coal-fired boilers equipped with SCR, H2SO4 emissions are determined from "(Q)(98.06/64.04)(F1+S2)(F2)" where Q is the uncontrolled SO2 emission rate (lb/hr), F1 is the fuel factor (0.00111 for western bituminous coal), S2 is the SCR catalyst SO2 oxidation rate (0.5% for western bituminous coal), and F2 is the control factor (0.56 for an air preheater and 0.65 for a venturi scrubber).
(h) H2SO4 emissions are based on "Estimating Total Sulfuric Acid Emissions from Stationary Power Plants," EPRI, Technical Update, March 2007. For coal-fired boilers equipped with SCR, H2SO4 emissions are determined from "(Q)(98.06/64.04)(F1+S2)(F2)" where Q is the uncontrolled SO2 emission rate (lb/hr), F1 is the fuel factor (0.00111 for western bituminous coal), S2 is the SCR catalyst SO2 oxidation rate (0.5% for western bituminous coal), and F2 is the control factor (0.56 for an air preheater, 0.40 for a wet spray tower, and 0.10 for a baghouse).
(i) For pulverized coal-fired boilers with an FGD system, total condensable organic PM10 emissions factor is 0.004 lb/MMBtu based on AP-42, Table 1.1-5.
(j) Ammonia slip is 2.00 ppmvd at 6% O2 for SCR.

6.2 CALPUFF Results and Visibility Improvement Analysis

The results of the BART control options modeling are presented in Tables 6-5 and 6-6 for PM_{10} and NO_x controls. Results are also plotted in Figure 6-1. Table 6-5 presents overall summaries, averaged over the seven closest Class I areas and the three modeled years, of the regional haze improvements and degradation due to installation of the BART controls on FCPP units. Table 6-6 show detailed regional haze impacts of the PM_{10} and NO_x BART control options for each modeled Class I area and meteorological year.

Table 6-5 indicates that the fabric filter controls for Units 1-3 would have very little visibility benefit (an average of 0.01 dv over the 7 closest Class I areas), but at a substantial cost. As expected, the addition of the fabric filter controls for PM emissions provides very little improvement, because direct PM emissions are not substantially contributing to regional haze.

Tables 6-5 and 6-6 indicate that the BART NO_x controls result in visibility benefits as well as some visibility degradation in some cases (shown in red in Table 6-6). The results show that the regional haze impacts may improve visibility by an average of 0.16 delta-dv (relative to the baseline case) with the installation of LNB on Units 1-2 and LNB/OFA on Units 3-4-5 (NOx Control Option 1).

Addition of SNCR (NOx Control Option 2) actually shows a regional haze degradation (0.21 delta-dv) at Mesa Verde National Park and a slight regional haze improvement (0.14 delta-dv) when averaged over the seven closest Class I areas. The visibility degradation in some areas is a result of excess ammonia emissions associated with the SNCR operations which increase the ambient ammonia concentration by about 0.2 ppb and result in additional sulfate and nitrate particulate formation. Therefore, NO_x BART control option 2 is not effective in improving visibility.

Addition of SCR (NOx Control Option 3) is projected to improve visibility by about 0.44 delta-dv from the baseline case, and only about 0.28 delta-dv from NO_x BART control option 1, but at a very substantial cost. The relatively small incremental improvement in visibility is due in part to the small role that nitrates play in the total regional haze contribution. In addition, the installation of SCR would create new emissions of primary sulfates (H_2SO_4) and excess ammonia, partially offsetting any available NO_x reduction benefit to visibility. This is especially true during the high visitation period of the warm weather months, when nitrates have minimal contribution to visibility impairment, but sulfates have an important role. Therefore, NO_x emission controls involving SCR are relatively ineffective in this case, especially taking into account the high cost of the controls.

Table 6-5 Regional Haze Impact of BART Controls

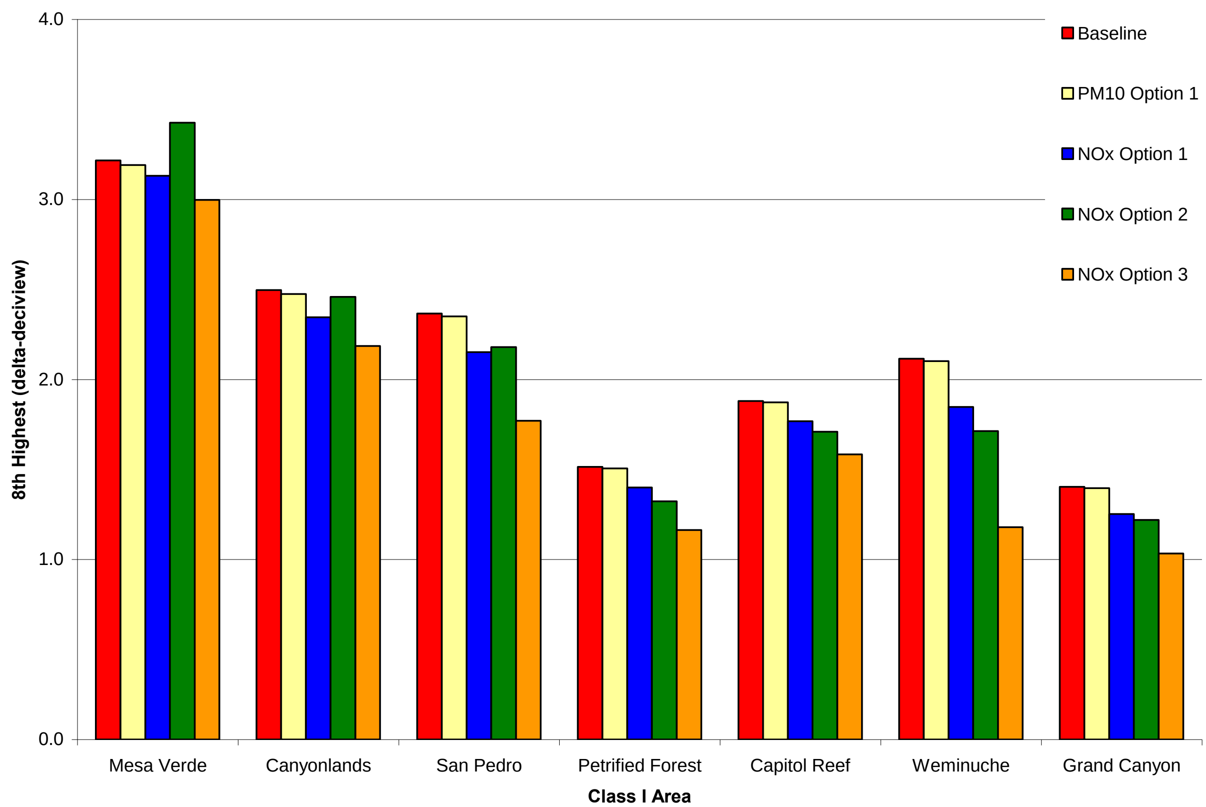
Class I Area	Option	BART Controls	2001	2002	2003	2001-2003 Ave	Benefit of Controls from Baseline, delta-dv
			8th Highest dv Δ B_{ext}				
Average of 7 Class I Areas (1)	Baseline	None	2.28	2.11	2.04	2.14	**0.00**
	NOx Option 1	LNB (1-2) LNB/OFA (3-5)	2.11	1.98	1.86	1.99	**0.16**
	NOx Option 2	LNB/OFA/HERT (1-3) LNB/OFA/SNCR (4-5)	2.17	1.98	1.87	2.00	**0.14**
	NOx Option 3	LNB/OFA/SCR (1-5)	1.87	1.66	1.57	1.70	**0.44**
	PM10 Option 1	FF (1-3)	2.26	2.10	2.02	2.13	**0.01**

(1) Seven Class I areas are: Grand Canyon, Capitol Reef, Canyonlands, Mesa Verde, Petrified Forest, Weminuche, San Pedro.

Table 6-6 Regional Haze Results of BART Controls on Each Class I Areas

Class I Area	Option	BART Controls	Met Year 2001	Met Year 2002	Met Year 2003	Ave 01-03	Change from Baseline, dv
			8^{th} Highest Δ dv	8^{th} Highest Δ dv	8^{th} Highest Δ dv	8^{th} Highest Δ dv	
Mesa Verde	Baseline	None	2.77	3.64	3.25	3.22	0.00
	NOx Option 1	LNB (1-2) LNB/OFA (3-5)	2.74	3.61	3.05	3.13	0.09
	NOx Option 2	LNB/OFA/HERT (1-3) LNB/OFA/SNCR (4-5)	3.26	3.66	3.35	3.43	-0.21
	NOx Option 3	LNB/OFA/SCR (1-5)	2.89	3.18	2.92	3.00	0.22
	PM10 Option 1	FF (1-3)	2.75	3.60	3.22	3.19	0.03
Canyonlands	Baseline	None	2.93	2.23	2.34	2.50	0.00
	NOx Option 1	LNB (1-2) LNB/OFA (3-5)	2.68	2.13	2.23	2.35	0.15
	NOx Option 2	LNB/OFA/HERT (1-3) LNB/OFA/SNCR (4-5)	2.85	2.34	2.19	2.46	0.04
	NOx Option 3	LNB/OFA/SCR (1-5)	2.68	1.94	1.94	2.19	0.31
	PM10 Option 1	FF (1-3)	2.89	2.22	2.31	2.47	0.02
San Pedro	Baseline	None	2.27	2.50	2.33	2.37	0.00
	NOx Option 1	LNB (1-2) LNB/OFA (3-5)	2.13	2.26	2.06	2.15	0.21
	NOx Option 2	LNB/OFA/HERT (1-3) LNB/OFA/SNCR (4-5)	2.19	2.23	2.11	2.18	0.19
	NOx Option 3	LNB/OFA/SCR (1-5)	1.74	1.83	1.74	1.77	0.60
	PM10 Option 1	FF (1-3)	2.25	2.48	2.32	2.35	0.02
Petrified Forest	Baseline	None	1.81	1.50	1.23	1.51	0.00
	NOx Option 1	LNB (1-2) LNB/OFA (3-5)	1.62	1.40	1.17	1.40	0.11
	NOx Option 2	LNB/OFA/HERT (1-3) LNB/OFA/SNCR (4-5)	1.48	1.39	1.10	1.32	0.19
	NOx Option 3	LNB/OFA/SCR (1-5)	1.24	1.19	1.06	1.16	0.35
	PM10 Option 1	FF (1-3)	1.81	1.49	1.22	1.51	0.01
Capitol Reef	Baseline	None	2.47	1.56	1.61	1.88	0.00
	NOx Option 1	LNB (1-2) LNB/OFA (3-5)	2.29	1.48	1.53	1.77	0.11
	NOx Option 2	LNB/OFA/HERT (1-3) LNB/OFA/SNCR (4-5)	2.16	1.47	1.50	1.71	0.17
	NOx Option 3	LNB/OFA/SCR (1-5)	1.95	1.42	1.38	1.58	0.30
	PM10 Option 1	FF (1-3)	2.46	1.55	1.61	1.87	0.01
Weminuche	Baseline	None	1.87	2.20	2.27	2.12	0.00
	NOx Option 1	LNB (1-2) LNB/OFA (3-5)	1.69	1.94	1.91	1.85	0.27
	NOx Option 2	LNB/OFA/HERT (1-3) LNB/OFA/SNCR (4-5)	1.62	1.74	1.78	1.71	0.40
	NOx Option 3	LNB/OFA/SCR (1-5)	1.23	1.24	1.06	1.18	0.94
	PM10 Option 1	FF (1-3)	1.86	2.20	2.25	2.10	0.01
Grand Canyon	Baseline	None	1.84	1.15	1.22	1.40	0.00
	NOx Option 1	LNB (1-2) LNB/OFA (3-5)	1.63	1.04	1.09	1.25	0.15
	NOx Option 2	LNB/OFA/HERT (1-3) LNB/OFA/SNCR (4-5)	1.60	1.03	1.03	1.22	0.18
	NOx Option 3	LNB/OFA/SCR (1-5)	1.34	0.84	0.92	1.03	0.37
	PM10 Option 1	FF (1-3)	1.83	1.15	1.21	1.40	0.01
Average of 7 Class I Areas	Baseline	None	2.28	2.11	2.04	2.14	0.00
	NOx Option 1	LNB (1-2) LNB/OFA (3-5)	2.11	1.98	1.86	1.99	0.16
	NOx Option 2	LNB/OFA/HERT (1-3) LNB/OFA/SNCR (4-5)	2.17	1.98	1.87	2.00	0.14
	NOx Option 3	LNB/OFA/SCR (1-5)	1.87	1.66	1.57	1.70	0.44
	PM10 Option 1	FF (1-3)	2.26	2.10	2.02	2.13	0.01

Figure 6-1 8th Highest Regional Haze Impacts Averaged Over 3 Years For Baseline and BART Control Emissions



6.3 Effectiveness of BART Control Options

Tables 6-7 and 6-8 summarize the annualized control cost that is the product of the $/ton removed and the number of tons of PM_{10} and NO_x, respectively, removed by each control strategy. The tables also include an incremental computation of each control option's visibility improvement/degradation effectiveness and cost. The visibility results in these tables are based on the average of the three years and the seven modeled Class I areas. Figures 6-2 and 6-3 show graphs of visibility improvements/degradation as a function of the cost for each control option for PM_{10} and NO_x, respectively. BART options associated with incremental improvements in visibility relative to a previous beneficial control option are connected with a blue line. The table and the figure both show a very large increase in the cost per deciview improvement slope for the only PM_{10} control option. A large cost per unit visibility improvement is also evident beyond BART NO_x Control Option 1 (combustion controls), indicating that post-combustion NO_x controls are not cost-effective for improving visibility, and that the visibility improvement for SCR controls would be below half of the detection limit and would therefore be imperceptible.

Table 6-7 Visibility Improvement and Annual Costs for PM_{10} Control Options

Option	BART Controls	Annualized Cost	8th Highest Ave over 3 Years in 7 Class I Areas	Incremental Deciview Reduction (Relative to the Previous Case)	Incremental Cost Effectiveness (Relative to the Previous Case)
		($/Year)	(delta-dv)	(delta-dv))	($/delta-dv)
Baseline	None	$0	2.14	0.00	$0
PM_{10} Option 1	FF (1-3)	$44,990,000	2.13	0.014	$3,118,118,812

Table 6-8 Visibility Improvement and Annual Costs for NO_x Control Options

Option	BART Controls	Annualized Cost	8th Highest Ave over 3 Years in 7 Class I Areas	Incremental Deciview Reduction (Relative to the Previous Case)	Incremental Cost Effectiveness (Relative to the Previous Case)
		($/Year)	(delta-dv)	(delta-dv))	($/delta-dv)
Baseline	None	$0	2.14	0.000	$0
NO_x Option 1	LNB Units 1-5 OFA Units 3-4-5	$8,709,000	1.99	0.157	$55,640,097
NO_x Option 2	LNB/OFA/SNCR	$23,765,000	2.00	-0.019	Not effective, visibility degrades
NO_x Option 3	LNB/OFA/SCR	$161,892,000	1.70	0.303	$456,366,740

Figure 6-2 Annualized Control Cost for PM_{10} BART Control Option vs. Visibility Impairment

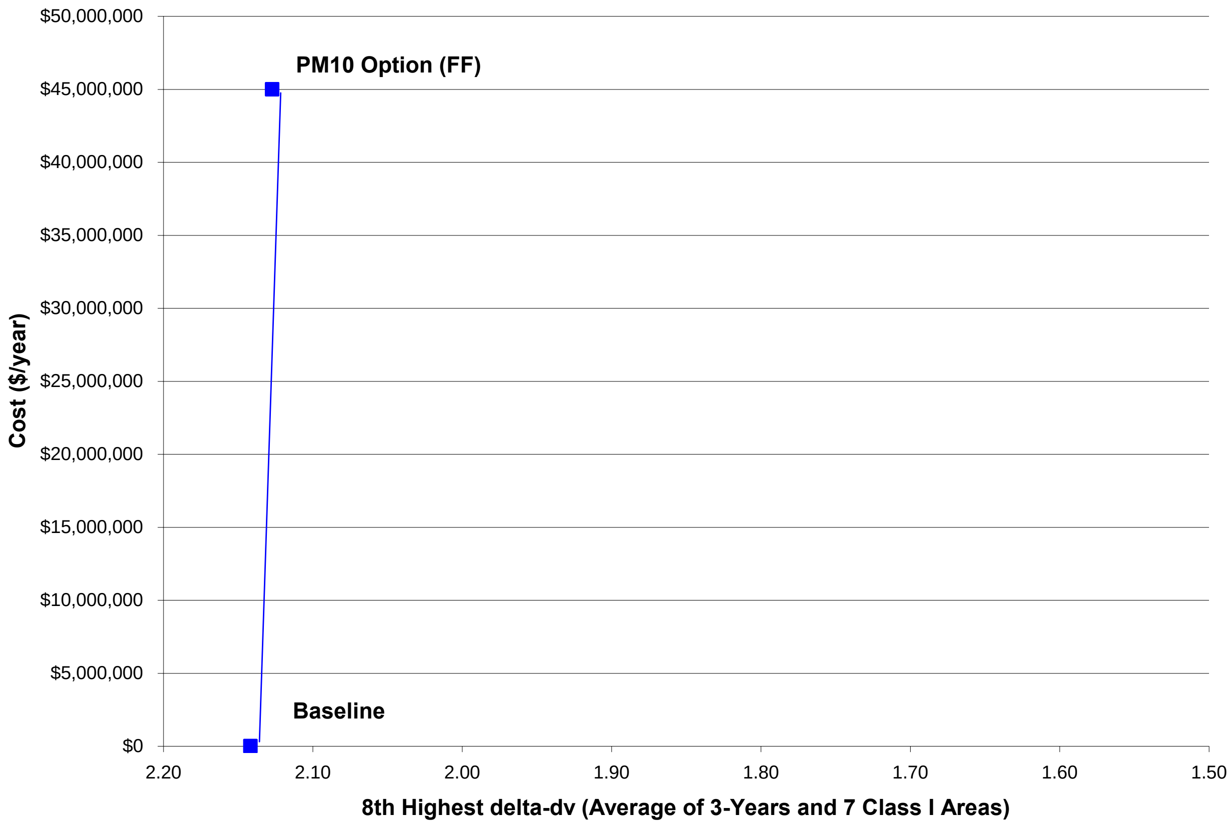
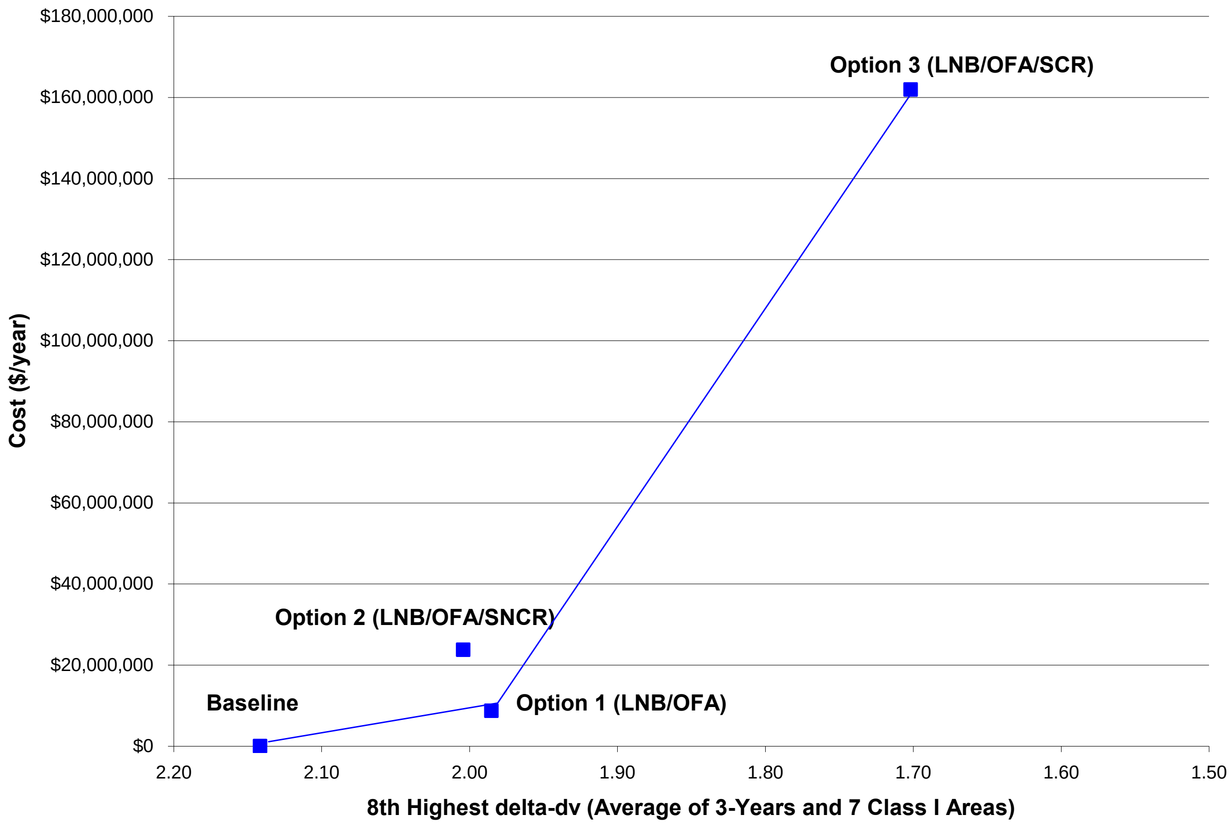


Figure 6-3 Annualized Control Cost for NO_x BART Control Options vs. Visibility Impairment



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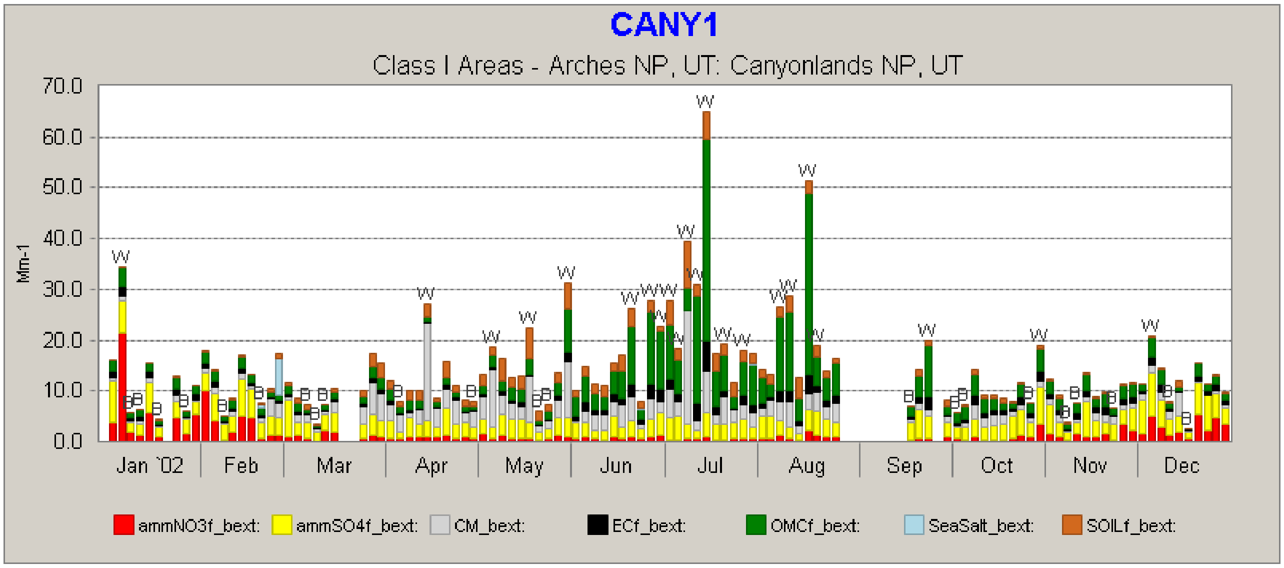
Appendix A

IMPROVE Monitoring Data

Figure A-1 Plot of Measured Visibility-Degrading Pollutants in Arches NP and Canyonlands NP, Year 2002



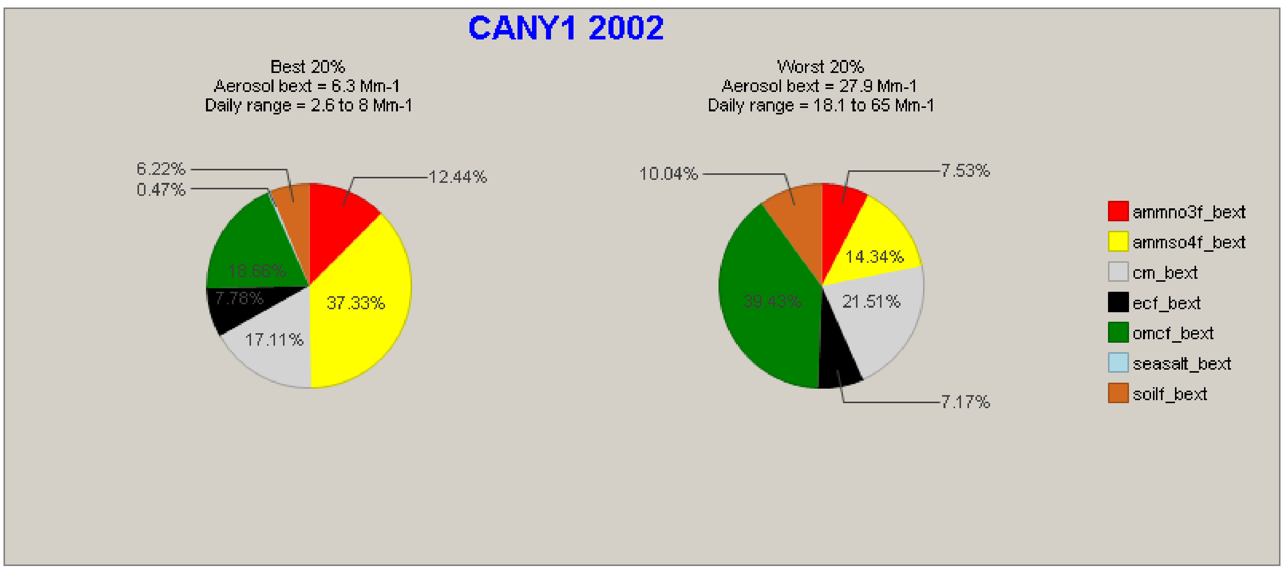
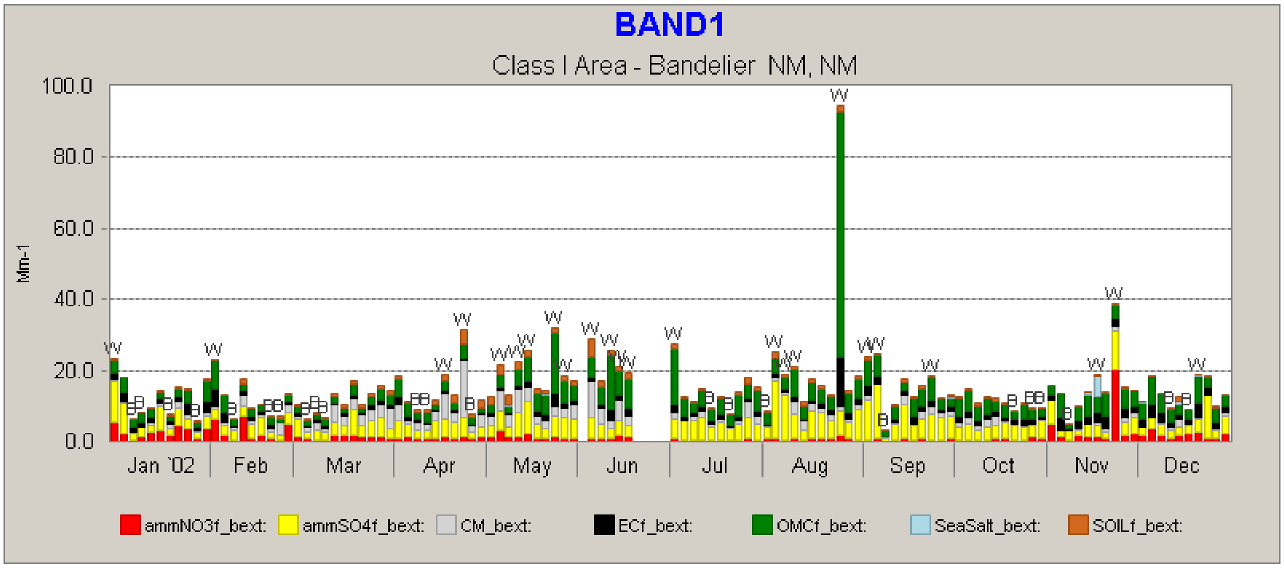


Figure A-2 Plot of Measured Visibility-Degrading Pollutants in Bandelier W, Year 2002



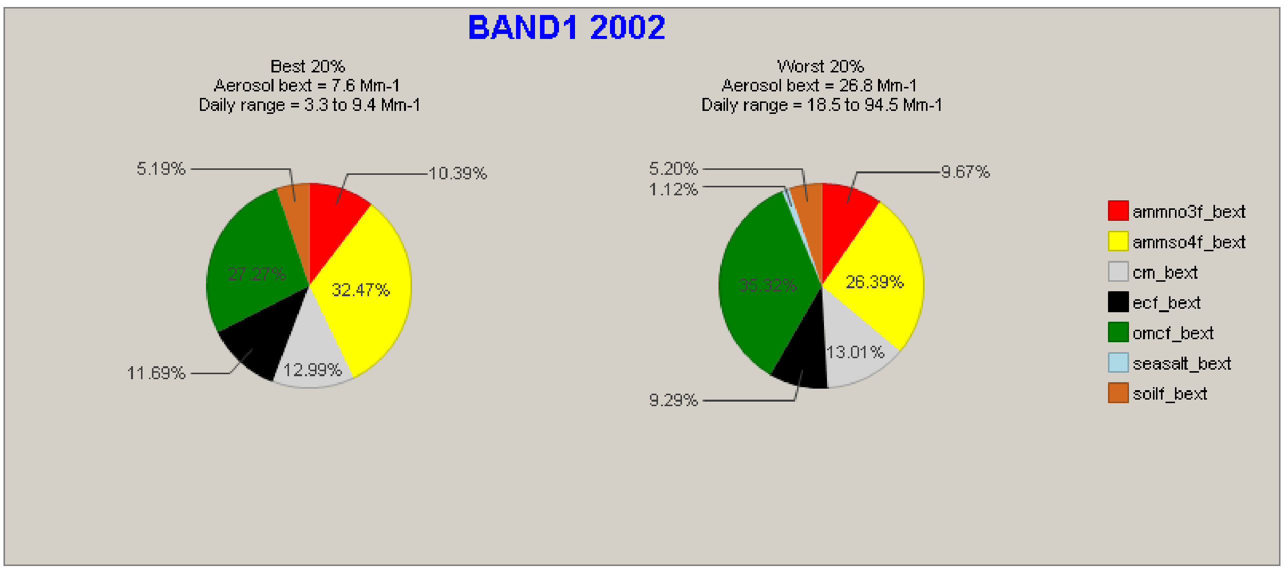
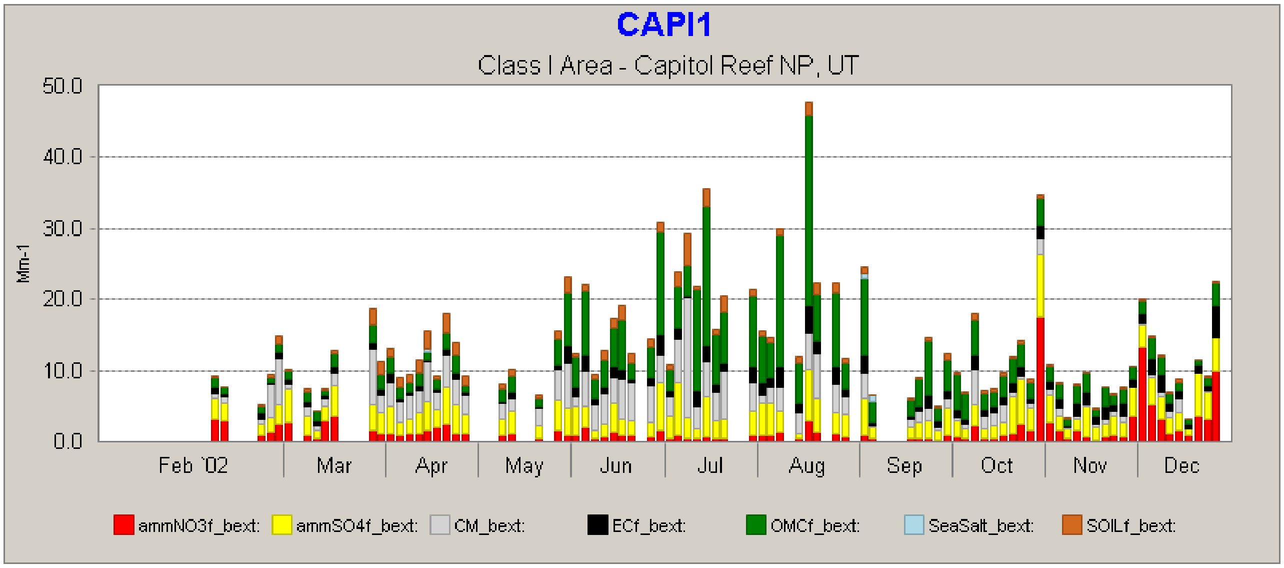
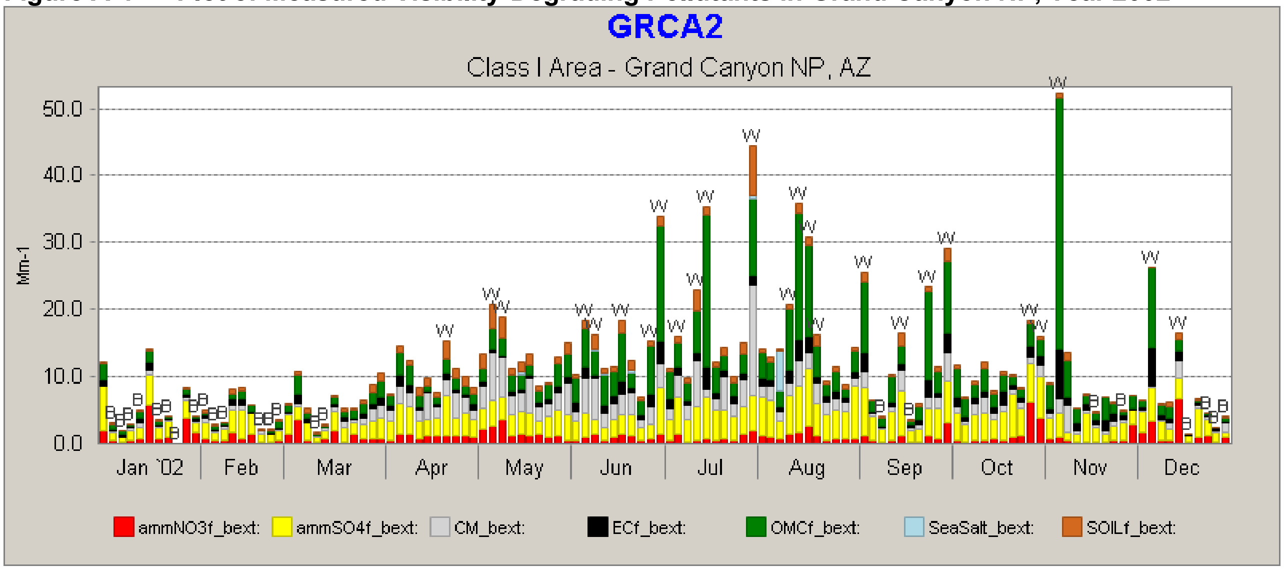


Figure A-3 Plot of Measured Visibility-Degrading Pollutants in Capitol Reef NP, Year 2002



Pie chart for Capitol Reef NP is not available.

Figure A-4 Plot of Measured Visibility-Degrading Pollutants in Grand Canyon NP, Year 2002



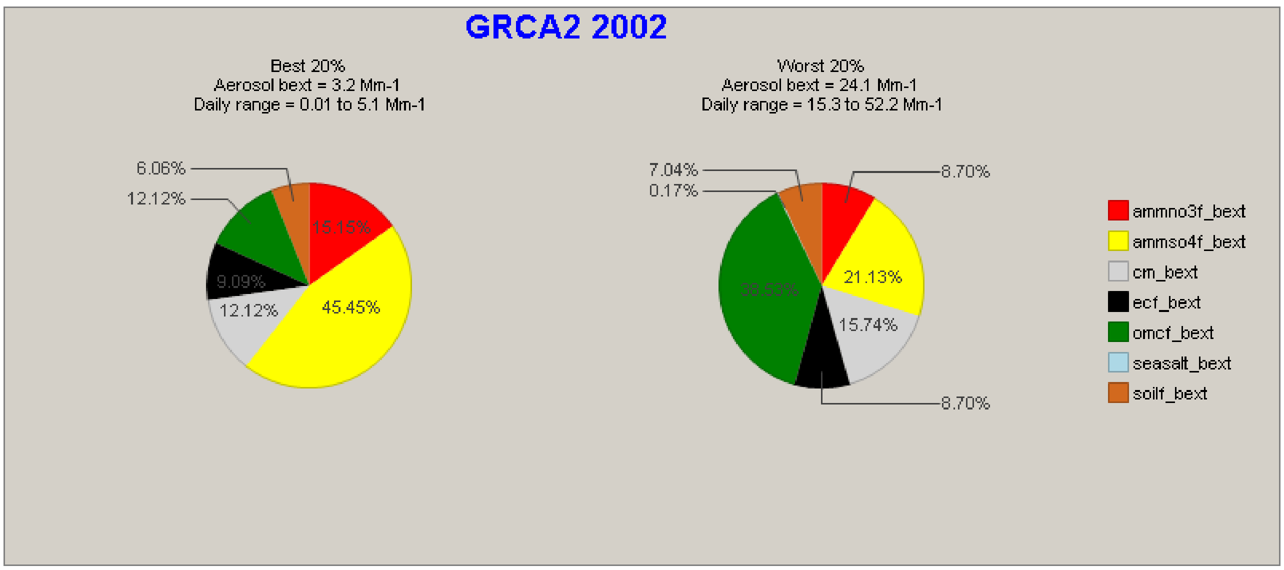
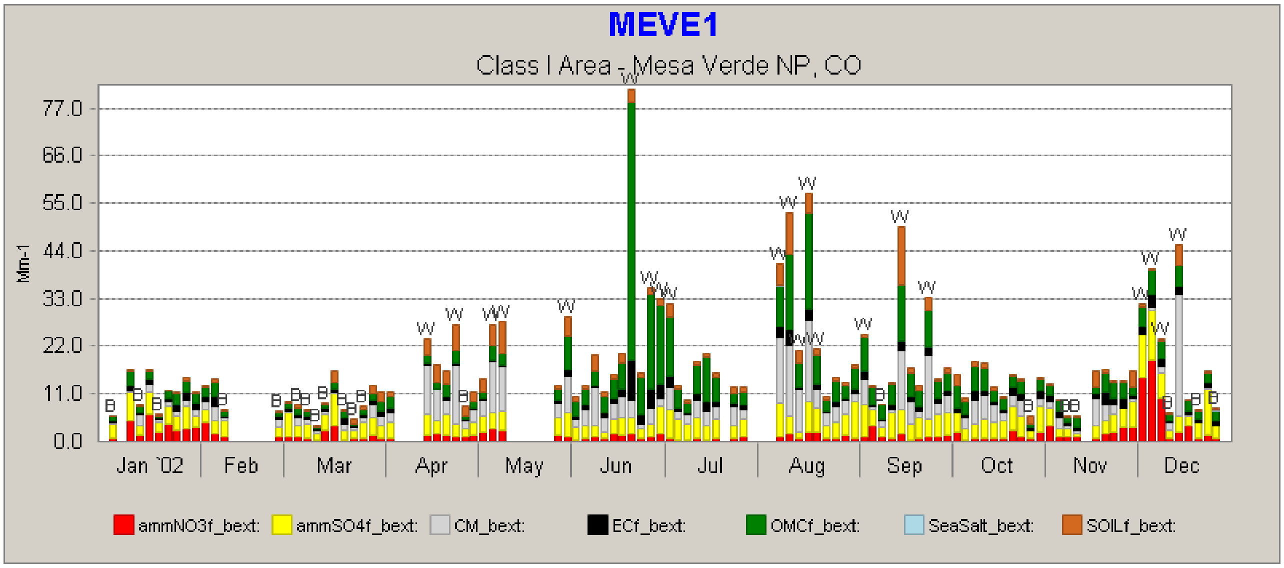


Figure A-5 Plot of Measured Visibility-Degrading Pollutants in Mesa Verde NP, Year 2002



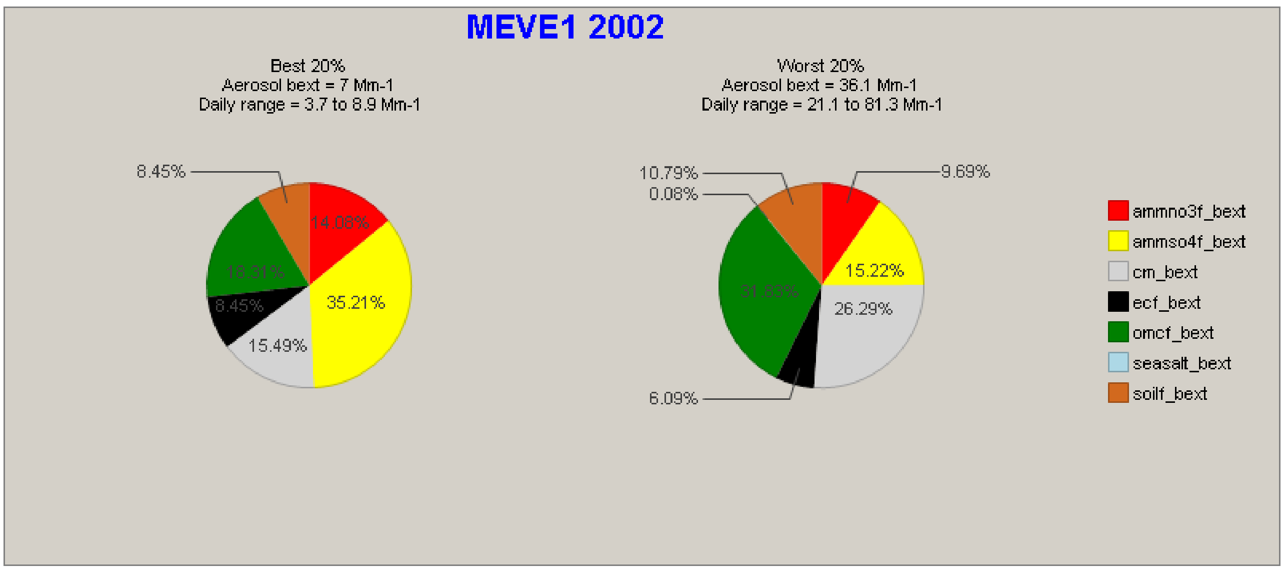
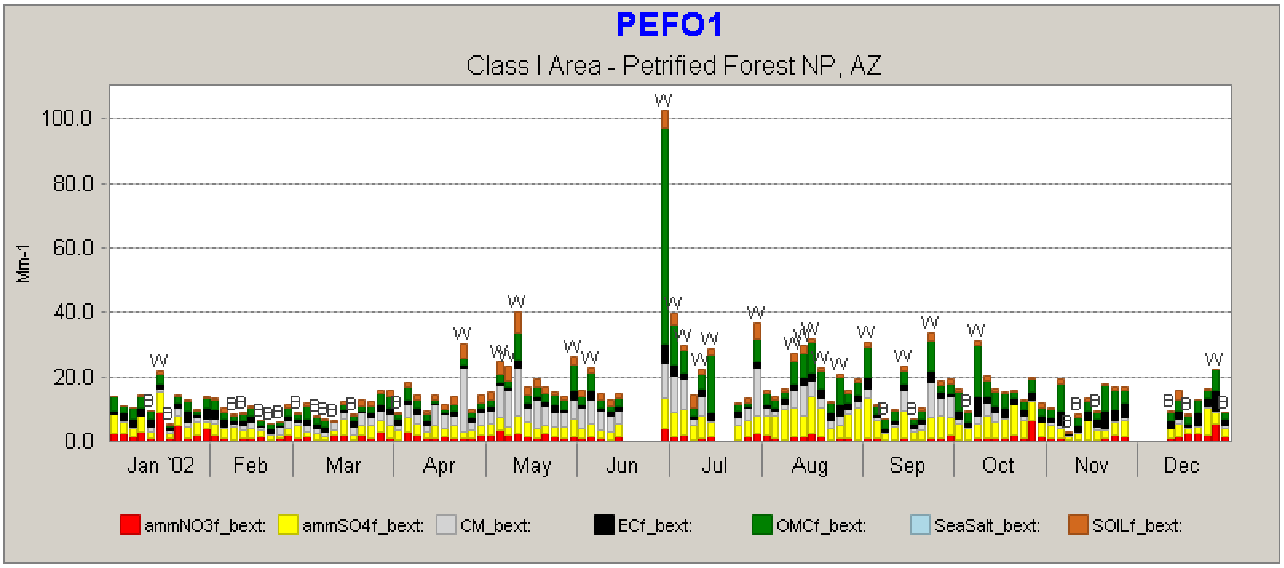


Figure A-6 Plot of Measured Visibility-Degrading Pollutants in Petrified Forest NP, Year 2002



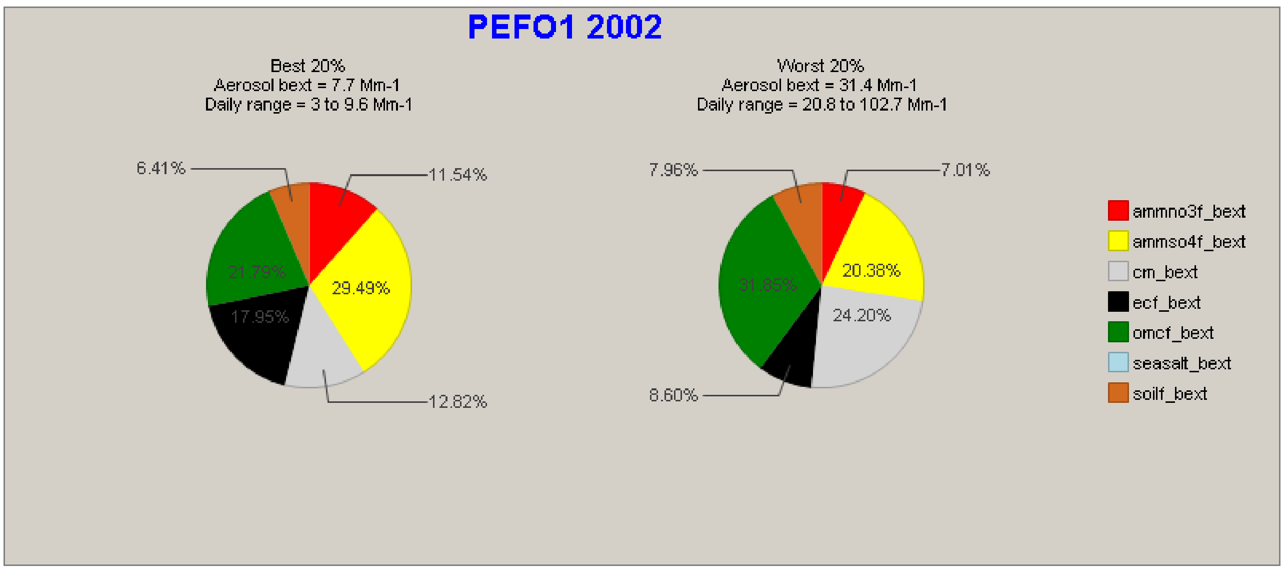
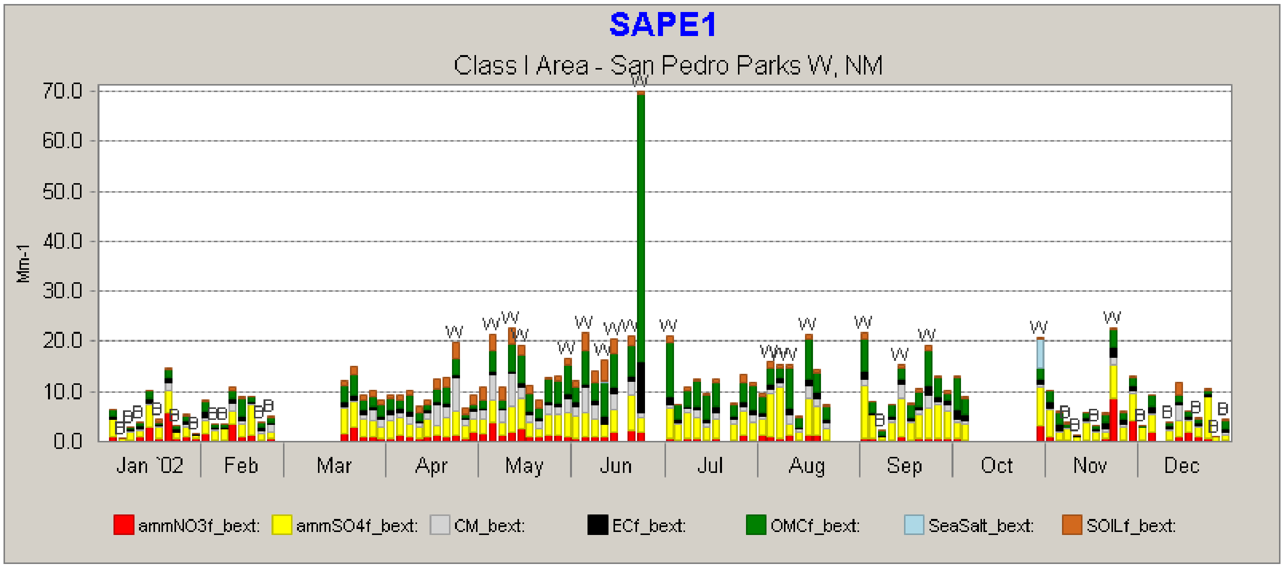


Figure A-7 Plot of Measured Visibility-Degrading Pollutants in San Pedro W, Year 2002



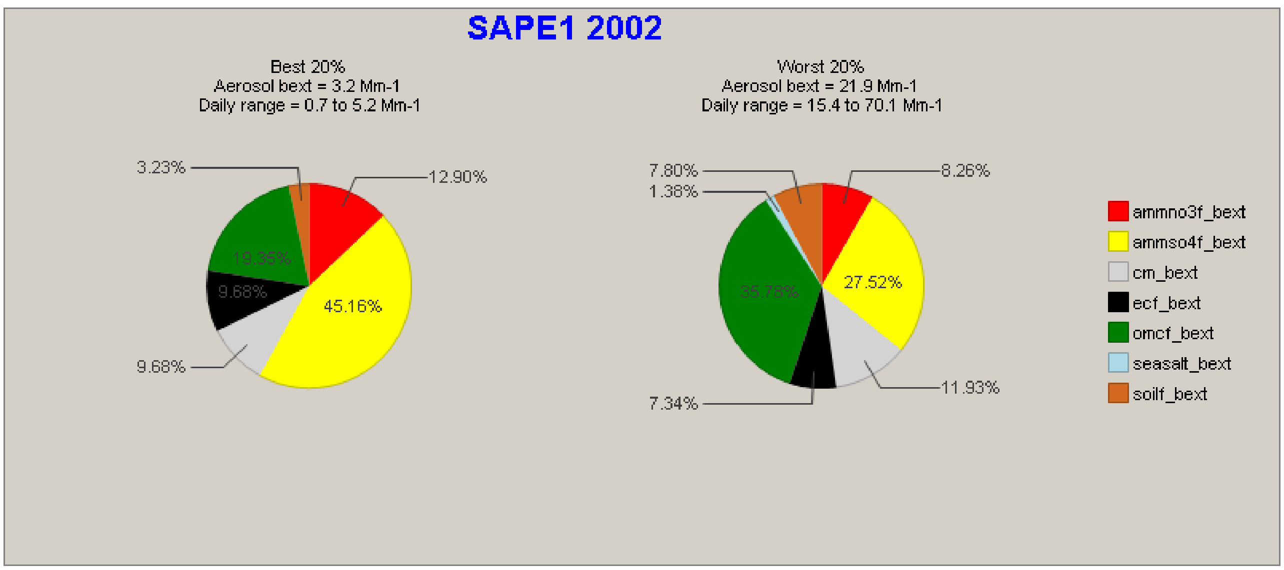
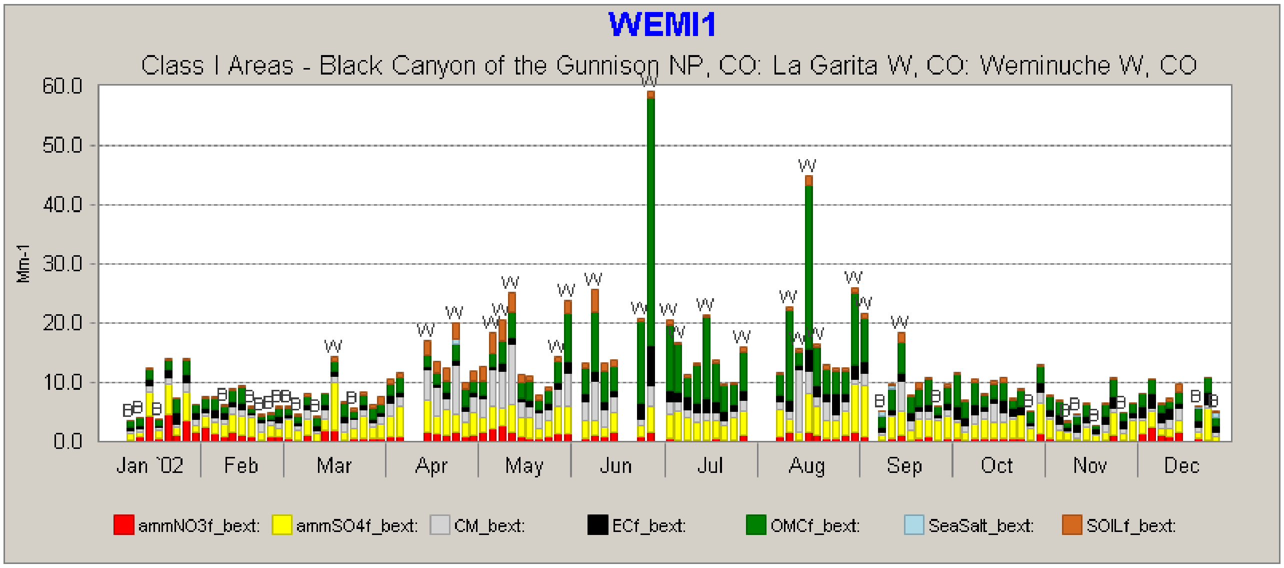


Figure A-8 Plot of Measured Visibility-Degrading Pollutants in Weminuche W, La Garita W, Black Canyon of the Gunnison W, Year 2002



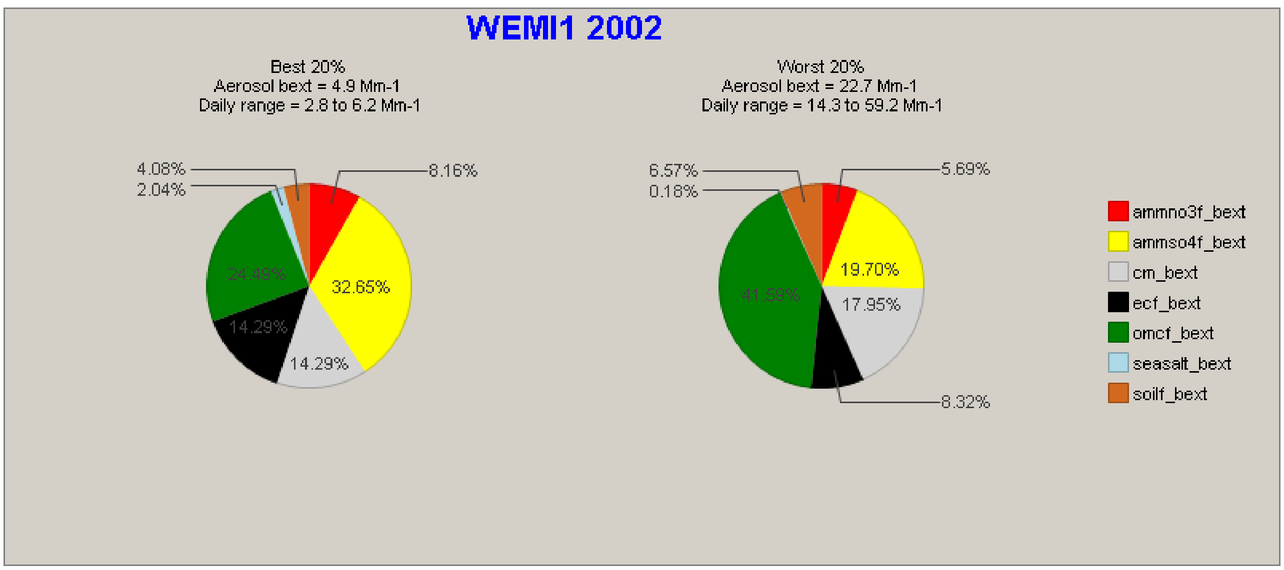
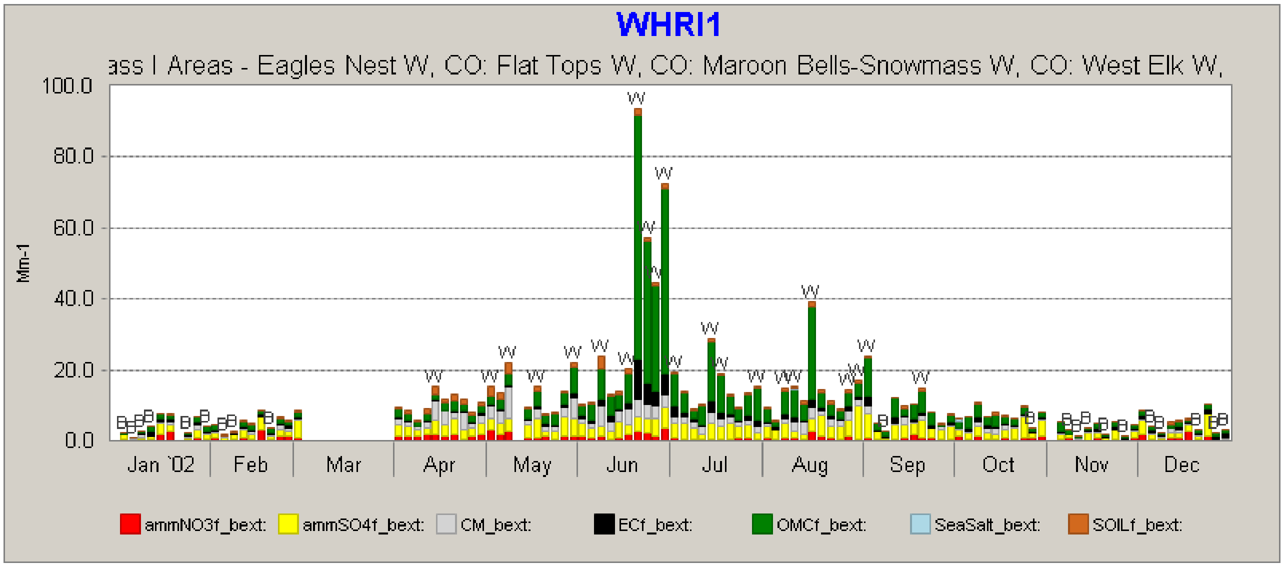


Figure A-9 Plot of Measured Visibility-Degrading Pollutants in Maroon Bells W and West Elk W, Year 2002



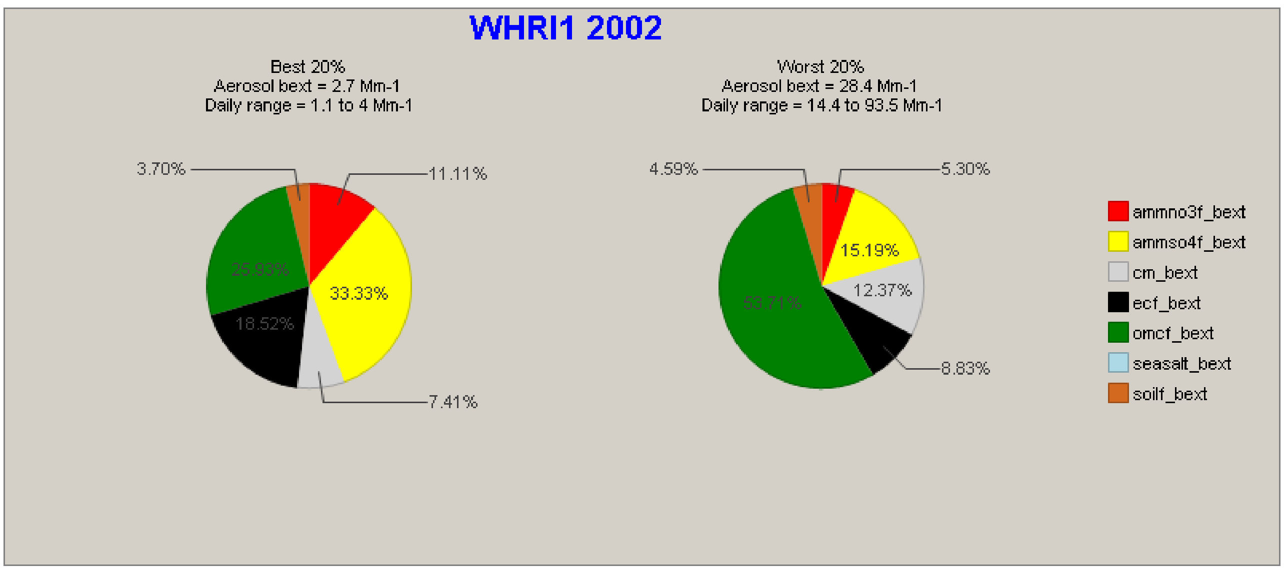
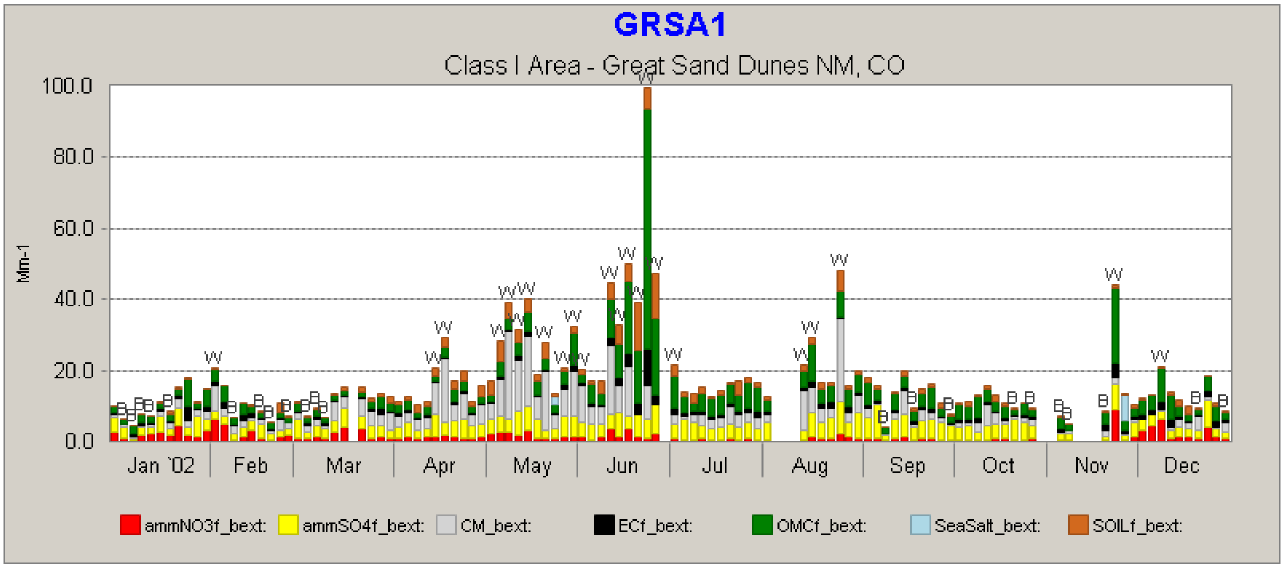


Figure A-10 Plot of Measured Visibility-Degrading Pollutants in Great Sand Dunes W, Year 2002



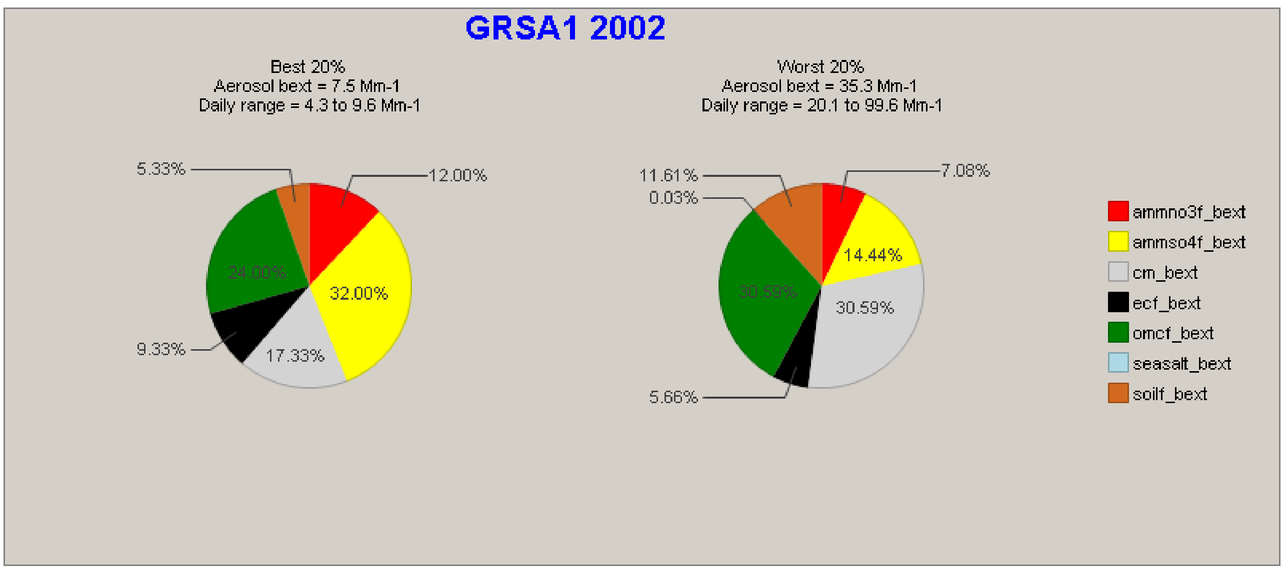
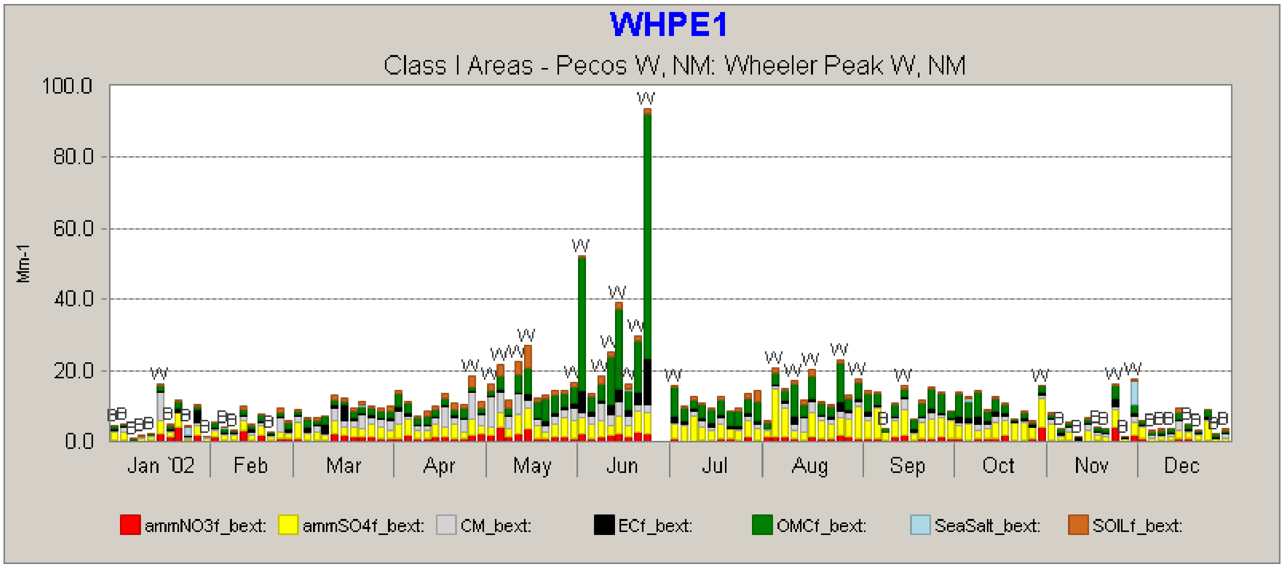
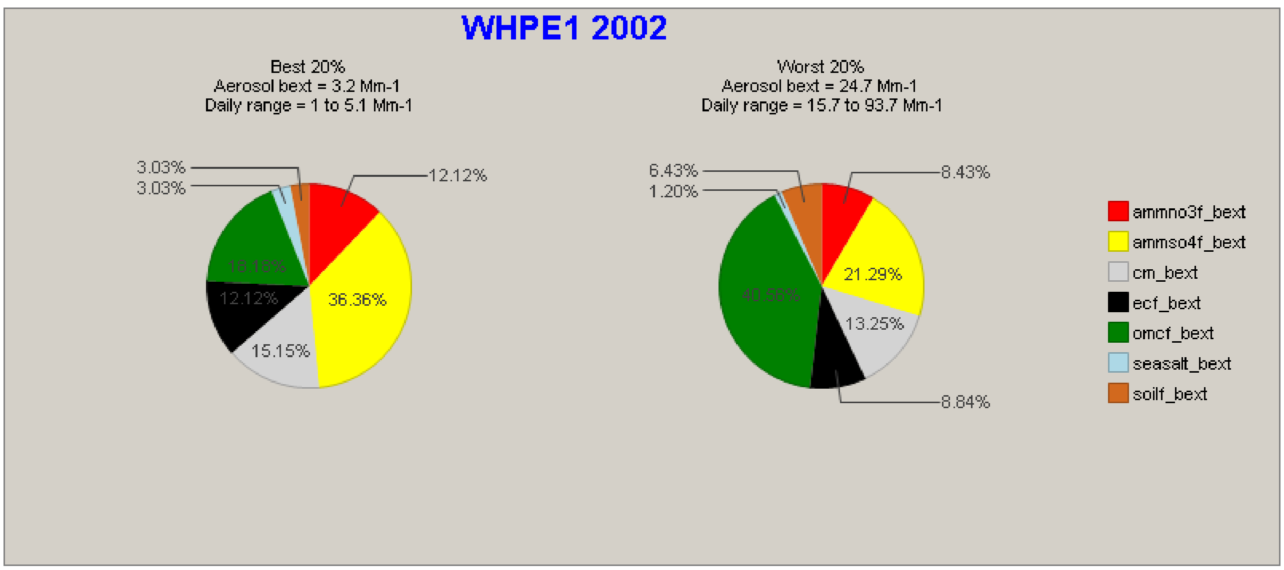


Figure A-11 Plot of Measured Visibility-Degrading Pollutants in Pecos W and Wheeler Peak W, Year 2002





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November 21, 2012

Via Electronic
and U.S. Mail

Mr. Terry O'Clair
Director, Division of Air Quality
North Dakota Department of Health
918 E. Divide Ave.
Bismarck, ND 58501-1947

RE: Coal Creek Supplemental NOx BART Analysis: Response to Comments

Dear Mr. O'Clair:

Great River Energy ("GRE") has reviewed the letters sent to the North Dakota Department of Health ("NDDH") by entities commenting on the NDDH's September 2012 Supplemental Evaluation of NOx BART Determination for Coal Creek Station Units 1 and 2 ("Supplemental BART Determination"). GRE hereby provides a response to those comments for NDDH's consideration.

1. LaFarge North America's October 16, 2012 Comments

Lafarge accurately describes the key issues attendant with the use of Selective Non-Catalytic Reduction ("SNCR"), the resulting fly ash contamination, and the unique non-air environmental and economic impacts that contamination would have on North Dakota. The use of SNCR will result in some fly ash being lost, and the negative environmental consequences of disposing of that fly ash and replacing it with cement (to the extent cement is even available in North Dakota) are well known. This factor is entitled to as much weight as any of the others identified by Congress (e.g., cost-effectiveness and improvements in visibility), and GRE encourages the NDDH to continue to account for it in the agency's BART determination.

2. Martin R. Schock's October 22, 2012 Comments

Mr. Schock's comments regarding NDDH's modeling technique could and should have been raised when NDDH's Regional Haze State Implementation Plan ("SIP") was circulated for public comments over two years ago or, at the latest, when it was being reviewed by the U.S. Environmental Protection Agency earlier this year. In any event, this comment highlights the NDDH's conservative approach for determining the Best

Available Retrofit Technology ("BART") for Coal Creek Station's NOx emissions by utilizing the modeling results that showed the greatest improvements to visibility as a result of the emissions limits under consideration. Although GRE believes this approach may exaggerate the improvement to visibility resulting from these emissions limits, GRE concedes the NDDH's conservative approach strengthens the NDDH's overall analysis.

3. U.S. DOI Fish and Wildlife Service's October 29, 2012 Comments

The U.S. Department of Interior Fish and Wildlife Service ("FWS") submitted multiple comments that essentially repeat its earlier October 2009 comments to NDDH. NDDH has already responded to those comments and the deadline to seek judicial review on those issues has expired. GRE agrees with FWS's statement that the Supplemental BART Determination is more robust than NDDH's prior analysis, which was itself more than adequate. GRE further agrees with the FWS's conclusion that NDDH's technical findings on such issues as the volume of fly ash likely to be ruined by SNCR, urea usage rates, and the control efficiency of SNCR are reasonable.

Although GRE disagrees with most of the FWS's remaining legal and factual assertions, GRE's and NDDH's prior submissions, along with those of other commenters, refute those assertions and need not be repeated here. GRE nonetheless notes that FWS's statements regarding Coal Creek Station's actual emissions rate and the proper retrofit factor for SNCR are not supported by any technical evidence, while GRE's numbers are based upon reported emissions data and a widely-recognized expert in installing pollution controls at power plants. Likewise, the FWS is incorrect to suggest that NDDH's ultimate conclusion regarding controls at Coal Creek Units 1 and 2 should have been different due to NDDH's finding that SNCR was BART for NOx at other units. First, BART is developed based upon the individual plant configuration and none of the plants listed in the FWS comments are currently employing DryFining™ technology, which complicates the layout of a facility and increases the cost of retrofitting it. Second, based upon the EPA Acid Rain database for 2011 and through September 2012, Coal Creek Units 1 and 2 have consistently had the lowest baseline NOx emissions rate in the state. *See* Graph of EPA Acid Rain Data, 2011-2012 (Attachment A). It is therefore more difficult to obtain cost-effective NOx reductions from Coal Creek Units 1 and 2 than at other, higher-emitting units. The fact that a given deciview improvement may be achieved at one facility in a cost-effective manner says nothing about whether that same deciview improvement can be cost-effectively achieved at another facility.

4. NPCA and Sierra Club's October 30, 2012 Comments

The National Parks Conservation Association and Sierra Club (collectively, "NPCA") also submitted comments that generally repeat legal arguments made during the earlier comment period. Again, general comments about NDDH's BART determination process could and should have been made earlier. NPCA also submitted comments from Dr. Ranajit Sahu that contain several inaccurate and unsupported assumptions.

a. Coal Creek's Baseline Emissions

Dr. Sahu asserts that GRE's NOx baseline emissions rate of 0.201 lb/MMBtu is not supported by emissions data. Dr. Sahu's error is likely due to his ignorance of GRE's proprietary DryFining™ technology and the timeline for its installation. Although operational in 2009, the technology requires fine-tuning and, once tuned, is able to maintain that level of performance. Optimization of the DryFining™ system was completed in June of 2010, and emissions reflected this optimization as of July 2010. As such, GRE utilized the period from July 2010 through October 2011 (when GRE's supplemental NOx analysis was performed) as a baseline because it represented routine operations for Coal Creek and was representative of expected future operations. Further, Sahu provides no explanation why such a minor change could or should result in any changes in the overall cost-effectiveness of SNCR or the lack of visibility improvements resulting therefrom.

b. High-Energy Reagent Technology (HERT®)

Dr. Sahu also asserts that GRE should have considered SNCR utilizing a specific process sold by FuelTech called High-Energy Reagent Technology (HERT®). HERT® is a patented injection process regulating the reagent delivery into the furnace. FuelTech Presentation, *SNCR Operation Workshop*, pp. 24, 60 (Feb. 7, 2011) ("FuelTech 2011 Presentation") (Attachment B). FuelTech recommends that SNCR using HERT® be coupled with over-fire air ("OFA") to introduce the reagent into the furnace or a source may utilize a separate blower to deliver reagent. *Id*. at 58. Per EPA's 2005 BART Determination Guidelines, 70 Fed. Reg. 39,164 n. 12 (July 6, 2005), GRE looked at the best-performing SNCR controls in use under "similar conditions," i.e., at facilities similar to Coal Creek Station. *See* 70 Fed. Reg. 39,165/1. Coal Creek Units 1 and 2 are identical, tangentially-fired Combustion Engineering designed boilers burning Ft. Union Lignite coal. The two electrical generators combined are over 1100 MW. In the course of its review, GRE included all types of SNCR, such as HERT®, to the extent they were best performing for sources similar to Coal Creek Station Units 1 and 2.

URS's recommendations were used to determine a control efficiency of 20% for SNCR and corresponding 0.15 lb/MMBtu NOx emissions rate appropriate for Coal Creek's size, firing configuration and existing NOx control strategy. Although EPA took issue with these figures, even EPA argued for only a 25% efficiency of SNCR in addition to existing controls and an emissions rate of 0.13 lb/MMBtu. *See, e.g.*, 77 Fed. Reg. 20,919 (April 6, 2012). URS's position is further supported by EPA's evaluation of the best performing utility furnaces with SNCR based upon EPA's Title IV Data (Attachment C). These SNCR-controlled utility units have an average NOx emission rate of 0.142 lb/MMBtu, but the list includes multiple supercritical units, which have a distinct design advantage that makes them inherently lower emitting than subcritical units such as GRE's Coal Creek Unit 1 and Unit 2.[1] Thus, the data confirm URS's determination that 0.15

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[1] For a subcritical boiler (standard operational design consistent with Coal Creek Units 1 and 2), steam to power the turbine is derived by heating liquid water to its saturation

lb/MMBtu was a realistic assessment of how the best-performing SNCR would do at a utility furnace similar to those at Coal Creek. While EPA argued that the best-performing SNCR could perform slightly better, it was not by a significant margin.

Dr. Sahu's error arises from his assumption that the advertising material upon which he bases his entire argument describes a new technology. Had Dr. Sahu performed an independent investigation, he would have learned that HERT® is FuelTech's brand name for an SNCR injection system (similar to ROTAMIX® patented by Nalco Mobotech).[2] FuelTech 2011 Presentation at 24. FuelTech lists HERT® as one of its two SNCR technology options with the other being NOxOUT®. FuelTech's predecessor, which developed HERT®, similarly described HERT® as nothing more than "Advanced" SNCR. Advanced Combustion Control Presentation, *New Coal Burners and Low NOx Control Technologies*, p. 82 (Aug. 3, 2005) ("2005 ACT Presentation") (Attachment D).

Consistent with this, EPA's RACT/BACT/LAER Clearinghouse database does not have a listing for HERT® under any of the determinations; only SNCR is listed. So long as a source considers the best performing SNCR, as GRE and EPA did, there is no need to look at every possible variation of SNCR; by definition, the best-performing SNCR for units similar to Coal Creek Units 1 and 2 is the best performing regardless of the vendor, the marketing label used to sell the technology, or variations in how the injection process operates.

Dr. Sahu also failed to realize that HERT® is a well-understood type of SNCR injection process and has never been considered available or applicable to the larger pulverized coal boilers at Coal Creek Units 1 and 2. FuelTech obtained HERT® from Advanced Combustion Technology (ACT), who had installed HERT® in seven non-utility units by 2005. Since then, a variety of other commercial and industrial users have also employed SNCR systems with HERT®, although none of them resembles Coal Creek Units 1 and 2. An overview of various publicly-available documents confirms that HERT® has been in use for years but not at large utility boilers and not with the success claimed by Dr. Sahu:

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point and then isothermally heating the system, thereby causing the phase change from liquid water to steam (boiling). In contrast, a supercritical steam generating unit operates at such a high pressure that liquid water does not boil and is instead converted to a supercritical fluid, an intermediate fluid having properties of both liquid water and steam. Operation of supercritical units is typically more thermally efficient than operation of subcritical units, resulting in less fuel combusted for the same energy output and, consequently, a lower lb/MMBtu emissions rate (although not necessarily a lower overall emissions rate in tons).

[2] *See* FuelTech's March 5, 2012 10-K, Table of Defined Terms, available at http://www.sec.gov/Archives/edgar/
data/846913/000119312512096880/d309745d10k.htm (last visited November 8, 2012).

- As of 2005, the five largest units (the largest being 180 MW) using HERT®/OFA only reduced NOx emissions to 0.21 lb/MMBtu. 2005 ACT Presentation, p. 81. At the time, ACT advertised that SCNR (HERT®)/OFA could reduce NOx emissions rates to 0.16 lb/MMBtu although ACT's only examples were from very small boilers. 2005 ACT Presentation, p. 84. None of these listed units are remotely similar to Coal Creek Units 1 and 2 in size, coal type, configuration, and baseline NOx emissions.
- In the summer of 2007, a power company reported to regulators that HERT® installed on a 120 MW unit had reduced NOx emissions to 0.14 lb/MMBtu. Comments of NRG Energy, Inc. on the Draft Report "Reducing Emissions in Connecticut on High Electric Demand Days (HEDD)," p. 3 (Attachment E). This involved an oil-fired/natural gas unit, EPRI Memorandum, *Review of ACT's HERT Post Combustion NOx Control Technology,* p. 2-9 (June 16, 2008) ("EPRI Memo.") (Attachment F). It thus has no bearing on units like Coal Creek Units 1 and 2, which are well-controlled and burn lignite coal.
- An ENSR BART analysis from January 2008 considered HERT® for use on several medium-sized boilers. Although the report distinguishes between HERT® and SNCR, a close reading confirms that HERT® was being used with OFA as a de facto SNCR/OFA combination. ENSR Corp., *BART Visibility Modeling Report for the Arizona Public Service Four Corners Power Plant*, p. 6-1 (Jan. 2008) ("ENSR Report") (Attachment G). For boilers of 190 and 253 MW, the HERT®/OFA controls were expected to reduce NOx emissions down to 0.207-0.229 lb/MMBtu. ENSR Report, Table 6-3. ENSR rejected the HERT®-based option because the resulting excess ammonia emissions were expected to degrade visibility. As with prior examples, Coal Creek Units 1 and 2 already achieve emissions rates better than these units expected to achieve with HERT®. ENSR Report, p. 6-6.
- An EPRI memorandum from June 2008 identifies 14 commercial installations and 2 demonstrations of HERT®, and the results of those installations were consistent with prior results. EPRI Memo. at 4, Table 2.
    - The largest boiler using HERT was 255 MW and was achieving emissions rates of 0.200 lb/MMBtu. HERT®'s performance generally improved as boilers got smaller with the best performance (0.100 lb/MMBtu) being at a 46 MW unit. EPRI Memo at Table 2.
    - Testing one of the 180 MW demonstration units confirmed that HERT®'s performance was susceptible to degrading rapidly as the unit went to full power. EPRI reported that "NOx reductions at full load averaged in the 20% to 25% range, while reductions at lower loads approached 50% to 60%." EPRI Memo. at 14.
- FuelTech's 2011 presentation confirms these earlier findings. It describes the application of HERT® at multiple demonstration units and several

small commercial units and obtaining results in-line with those reported in earlier documents. For example:

- o FuelTech's SNCR performs notably worse at well-controlled sources. FuelTech's 2011 Presentation, p. 48.
- o FuelTech never claims HERT® can achieve an emissions rate of 0.1 lb/MMBtu at industrial or utility pulverized coal furnaces; FuelTech cites only limited experience, none of which purports to be applicable to a large-scale utility furnace. FuelTech's 2011 Presentation, pp. 64, 66.
- o FuelTech's sole utility example is a biomass-fired, circulating fluidized-bed boiler, which has no relevance to Coal Creek Units 1 and 2 given the well-understood technical differences between controlling NOx at the two types of boilers and fuel types. FuelTech's 2011 Presentation, p. 69.

This foregoing material confirms several key technical points:

- Neither ACT nor FuelTech have ever claimed that HERT® can reduce NOx emissions to 0.10 lb/MMBtu (or anything close) at a source similar to Coal Creek Units 1 and 2, i.e., a large (>500 MW) utility furnace; FuelTech confirms HERT® performs worse at utility boilers than it does at industrial boilers; FuelTech 2011 Presentation, p. 24; FuelTech is willing to guarantee that its SNCR systems can only obtain about half the reductions in utility boilers that it gets from industrial boilers; FuelTech 2011 Presentation, p. 27;[3]
- HERT® has only achieved 0.1 lb/MMBtu emissions rates from small (<200 MW) furnaces, at a small circulating fluidized bed boiler, and during isolated demonstrations.

GRE undertook a thorough search of publicly available data on the internet as well as publicly available data through EPRI for the use of HERT®. The data provided in the

[3] It is well-understood in the industry that "[a]t larger boilers sizes, the capability to uniformly distribute a chemical reagent, urea, or NH_3, throughout the furnace volume may diminish, which therefore, may negatively impact NOx removal efficiency." Srivastava, R. et al., *Nitrogen Oxides Emission Control Options for Coal-Fired Electric Utility Boilers*, 55 J. Air & Waste Manage. Assoc. 1367, 1374 (Sept. 2005). This paper goes on to confirm that SNCR's performance declines by as much as 50% as boilers get larger. *Id*. EPA's Control Cost Manual agrees that "SNCR systems applied to large combustion units (greater than 3,000 MMBtu/hr) typically have lower NOx reduction efficiencies (less than 40%) due to mixing limitations." EPA, *EPA Air Pollution Control Cost Manual, EPA/452/B-02-001*, Section 4.2, 1-3 (6th ed. Jan. 2002). Thus, SNCR's results from small sources cannot be extrapolated to large units without discounting the SNCR's expected performance.

following table are a compilation of these data sources. Table 1 does not present an exhaustive list of all HERT® installations, but rather a summary of the two primary publicly available data sources identified by GRE that cite HERT® installations. These two sources along with supplemental database references used to identify specific coal types and historical emissions are included as references to Table 1. As illustrated in Table 1 below, in practice, HERT® has tended to obtain emissions rates of roughly 0.2 lb/MMBtu at medium-sized boilers (~200 MW). Coal Creek Station Units 1 and 2 achieve these emissions levels already. GRE's analysis assumed SNCR/OFA could further reduce emissions to 0.15 lb/MMBtu, which is far superior to what HERT® has obtained in the real world.

Table 1

Stations/Unit Identification	Firing Type	# of Burners	Fuel [1]	Unit Size, MW	Baseline NOx, lb/MMBtu	HERT NOx, lb/MMBtu	NOx Min, lb/MMBtu [2]	NOx Max, lb/MMBtu [2]	Ref.
James River Unit 1 City Utilities of Springfield	T-Fired	8	Subbituminous Coal	25	0.35	0.20	--	--	[3], [7]
James River Unit 2 City Utilities of Springfield	T-Fired	8	Subbituminous Coal	25	0.350	0.20	--	--	[3], [7]
Blue Ridge Paper Unit 4 Blue Ridge Paper Company	T-Fired	12	Eastern Bituminous Coal	40	0.300	0.15	--	--	[3], [7]
Johnsonville Unit 4 TVA	T-Fired	16	Subbituminous Coal	135	0.390	0.15	0.176	0.302	[3], [5]
John Sevier Unit 2 TVA	T-Fired	16	Bituminous Coal	180	0.350	0.19	0.231	0.276	[3], [5]
Coal Creek Station Unit 1 GRE	T-Fired	64	Lignite Coal	590	0.201	NA	0.175	0.223	[6]
Coal Creek Station Unit 2 GRE	T-Fired	64	Lignite Coal	590	0.153	NA	0.140	0.168	[6]
Schiller Unit 4 Northeast Utilities	Front	6	Bituminous Coal or Fuel Oil	50	0.350	0.25	0.143	0.304	[3]
Schiller Unit 6 Northeast Utilities	Front	6	Bituminous Coal or Fuel Oil	50	0.350	0.25	0.187	0.312	[3]
Endicott Generating Station	Front	6	Bituminous Coal	55	0.600	0.15	0.185	0.256	[4], [5]
GenOn Energy New Castle Plant	Front	16	Bituminous Coal, Diesel	135	0.830	0.26	0.314	0.493	[4], [5]

Stations/Unit Identification	Firing Type	# of Burners	Fuel [1]	Unit Size, MW	Baseline NOx, lb/MMBtu	HERT NOx, lb/MMBtu	NOx Min, lb/MMBtu [2]	NOx Max, lb/MMBtu [2]	Ref.
W.H. Sammis Power Plant Unit 1	Front	15	Bituminous Coal	180	1.100	0.21	0.196	0.272	[4]
W.H. Sammis Power Plant Unit 2	Front	15	Bituminous Coal	180	1.100	0.25	0.185	0.243	[4]
W.H. Sammis Power Plant Unit 3	Front	15	Bituminous Coal	180	1.100	0.22	0.200	0.239	[4]
Clinch River Unit 3 AEP	Roof	14	Bituminous Coal	255	0.300	0.20	0.151	0.227	[3]
Philip Sporn Unit 3 AEP	Roof	10	Subbituminous Coal	155	0.320	0.20	0.213	0.299	[3]
James River Unit 3 City Utilities of Springfield	Wall-Fired	6	Subbituminous Coal	46	0.180	0.10	0.181	0.229	[3], [5]
James River Unit 4 City Utilities of Springfield	Wall-Fired	6	Subbituminous Coal	60	0.200	0.12	0.123	0.291	[3], [5]
James River Unit 5 City Utilities of Springfield	Wall-Fired	8	Subbituminous Coal	105	0.220	0.15	0.134	0.251	[3]

References

[1] http://www.eia.gov/electricity/data/eia860/

[2] Data from January 2011 September 2012 are the monthly averages. Only 12 possible values per unit. The monthly value is representative of a 30 day rolling average. http://ampd.epa.gov/ampd/

[3] EPRI Memo, "Review of ACT'S HERT Post Combustion NOx Control Technology," 6/16/2008

[4] http://www.netl.doe.gov/publications/proceedings/05/NOx_SO2/De-%20NOx%20workshop/ACT_2005.pdf

[5] Unclear whether unit continues to operate with SNCR.

[6] HERT not installed, units listed to demonstrate differences in size and baseline emission rates.

[7] Unit not included in the Acid Rain Program; emission data not available in Acid Rain database.

- The publicly-available percent reduction results for HERT® arise from installation of the technology at previously uncontrolled sources. There is no evidence regarding HERT®'s performance at already well-controlled, large utility sources.
- In reviewing FuelTech's website, there is no indication that they are a "leading" vendor as Mr. Sahu states in his comments (p. 9). They have several press releases for projects being sold, primarily overseas, but no mention of any recently completed projects, and notably no mention of any pulverized-coal-fired boiler projects achieving <0.15 lb/MMBtu. Further, few of the FuelTech announcements include any more than a mention of HERT®, suggesting that it is specialized technology with limited application to small, commercial units. This would explain why GRE was able to find so few examples of HERT® in use despite it being available for years and there being tens of thousands of boilers required by state and federal law to have NOx emission controls.

GRE was unable to find any evidence of HERT® installations on Coal Creek Station-sized utility boilers (>500 MW). We have no reason to believe that there are any successful applications of HERT® in similar-sized units. Dr. Sahu provides no evidence to the contrary. To the extent there have been any such installations, then they would likely be part of EPA's database for SNCR-controlled units and GRE and EPA already looked at the best performing sources using SNCR-type controls.

In any event, evaluation of HERT® would require additional engineering. FuelTech's online brochure concerning HERT® identifies that the necessary evaluation to get to the vendor's specification would involve Computational Fluid Dynamics/Chemical Kinetic Modeling (CFD/CKM), which would be a costly evaluation for screening a control option. GRE would need to make a significant additional investment to cover the cost of modeling. Based on EPA's BART Guidelines, sources are not required to obtain a vendor guarantee for each control, particularly for familiar controls such as OFA and SNCR where the Control Cost Manual includes data. Likewise, sources are not required to perform engineering studies to confirm that controls that have not been used on similar sources also would not work at their own source. Thus, even if HERT® was a discrete control option, which it is not, and if HERT were available and applicable, which it is not, then the 2005 BART Guidelines still did not require GRE to look more closely at HERT® given the engineering requirements necessary to do so.

Collectively, this material confirms that HERT® is a well-understood SNCR injection process that obtains good emissions reductions when used with previously uncontrolled, small commercial and industrial furnaces (although many other SNCR technologies do, as well). It is not unique, and there is no evidence that it should be expected to outperform the best-performing SNCR/OFA controls in-use at large, pulverized coal utilities. In fact, the available evidence suggests it cannot. In the event HERT® was considered separate from SNCR (and there is no reason it should be), there is no evidence suggesting it is either available or applicable for sources similar to Coal Creek Units 1 or 2.

Finally, GRE notes that Dr. Sahu's opinion that it should be assumed that HERT® could obtain an emissions rate of 0.1 lb/MMBtu is completely unsupported. Dr. Sahu does not mention a single utility using HERT® to obtain the emissions he assumes could be achieved at Coal Creek Station Units 1 and 2. Dr. Sahu does not discuss how HERT® would work (or indeed if it could work) with Coal Creek's unique boilers and existing controls. Dr. Sahu does not claim to have any experience with installation or operation of HERT®. Indeed, Dr. Sahu's failure to recognize the methodological flaws in extrapolating limited commercial and demonstration emissions results to a large-scale utility furnace undermines his claim to expertise in this area. No expert in SNCR controls at utilities would make such a claim; and if they did, they would include numerous caveats for the size and firing method of the boiler, existing NOx control strategies, and the type of fuel. Dr. Sahu failed to differentiate between the annual rate in FuelTech's promotional material versus the 30-day rate for BART limits.[4] In short, Dr. Sahu has offered nothing more than an unsupported, non-expert opinion, and the NDDH should weight it accordingly.

Please do not hesitate to call me if you have any questions.

Sincerely,

Mary Jo Roth

Mary Jo Roth
Manager, Environmental Services

Attachments:

- Attachment A – Graph of NOx performance for all ND units
- Attachment B – FuelTech Presentation, SNCR Operation Workshop (Feb. 7, 2011)
- Attachment C – EPA Title IV Data relied upon by EPA in Docket No. EPA-R08-OAR-2010-0406
- Attachment D – Advanced Combustion Control Presentation, New Coal Burners and Low NOx Control Technologies (Aug. 3, 2005)
- Attachment E – Comments of NRG Energy, Inc. on the Draft Report "Reducing Emissions in Connecticut on High Electric Demand Days (HEDD)"
- Attachment F – EPRI Memorandum, Review of ACT's HERT Post Combustion NOx Control Technology (June 16, 2008)
- Attachment G – ENSR Corp., BART Visibility Modeling Report for the Arizona Public Service Four Corners Power Plant, Table 6-3 (Jan. 2008)

c: Tom Bachman, NDDH
Deb Nelson, GRE

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[4] EPA believes 30-day BART limits should generally be 5-15% greater than an annual rate. *See* 77 Fed. Reg. 20,919. According to EPA, a 0.10 lb/MMBtu annual rate would therefore be the equivalent of a 0.11-0.12 lb/MMBtu 30-day BART limit. Dr. Sahu did not even recognize this flaw in his purported expert opinion.

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BART Supplement - NOx Emission Control Cost Analysis

Update Key

Update Key
Change related to utilization (non-outage scale up)
Change related to update in baseline for Unit 2 (0.201 lb/MMBtu)

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Table A-1: Cost Summary

NO_x Control Cost Summary - Unit 1

Case	Control Technology [1]	Annual Designed Emissions lb/MMBtu	Control Eff % from Baseline [3]	Controlled Emissions T/yr	Emission Reduction T/yr	Installed Capital Cost MM$	Annualized Control Cost MM$/yr	Pollution Control Cost $/ton	Annual Incremental Cost $/ton [4]	See Table XX for additional information
3 [2]	SNCR + LNC3+ - 100% Lost Ash Sales	0.122	39%	3,085.6	1,994.3	$17.873	$8.879	$4,452	$10,457	A-4, A-10
	SNCR + LNC3+ - 30% Lost Ash Sales						$6.604	$3,311	$7,524	A-4, A-9
	SNCR + LNC3+ - No Ash Impacts						*$4.385*	*$2,199*	*$4,666*	*A-4, A-8*
2	SNCR - 100% Lost Ash Sales	0.151	25%	3,809.9	1,270.0	$12.176	$9.101	$7,167	NA - Inferior Control	A-7
	SNCR - 30% Lost Ash Sales						$6.826	$5,375	NA - Inferior Control	A-6
	SNCR - No Ash Impacts						*$4.608*	*$3,628*	*NA - Inferior Control*	*A-5*
1	LNC3+	0.153	24%	3,861.6	1,218.2	$6.079	$0.764	$627	$627	A-4
0	Baseline Control - Standard LNC3	0.201	NA-Base	5,079.9	NA-Base	NA-Base	NA-Base	NA-Base	NA-Base	A-3

NO_x Control Cost Summary - Unit 2

Case	Control Technology [1]	Annual Designed Emissions lb/MMBtu	Control Eff % from Baseline [3]	Controlled Emissions T/yr	Emission Reduction T/yr	Installed Capital Cost MM$	Annualized Control Cost MM$/yr	Pollution Control Cost $/ton	Annual Incremental Cost $/ton [4]	See Table XX for additional information
2 [5]	SNCR + LNC3+ - 100% Lost Ash Sales	0.122	39%	3,089.2	1996.6	$17.873	$8.879	$4,447	$10,444	A-4, A-10
	SNCR + LNC3+ - 30% Lost Ash Sales						$6.604	$3,307	$7,516	A-4, A-9
	SNCR + LNC3+ - No Ash Impacts						*$4.385*	*$2,196*	*$4,661*	*A-4, A-8*
1	LNC3+	0.153	24%	3,866.1	1,219.6	$6.079	$0.764	$627	$627	A-4
0	Baseline Control - LNC3	0.201	NA-Base	5,085.8	NA-Base	NA-Base	NA-Base	NA-Base	NA-Base	A-3

[1] Ash impact scenarios align with November 2011 Golder report.
No Ash Impacts - Golder Scenario A; *Scenario provided for reference only and does not represent a feasible outcome*
30% Lost Ash Sales - Golder Scenario C
100% Lost Ash Sales - Golder Scenario B

[2] Capital costs for combined control scenario on Unit 1 are calculated using LNC3+ costs for Unit 1 (scenario 1) and SNCR costs for Unit 2, as unit 2 presently has LNC3+ installed.

[3] Calculated on a mass basis.

[4] Incremental costs calculated as the difference in annualized operating cost divided by the difference in emission reduction for the next lowest level of dominant control.

[5] Scenario represents incremental imprevement from the LNC3+ controls already installed on Unit 1. Design emissions rely on inlet of 0.153 lb/MMBtu NOx.

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BART Supplement - NOx Emission Control Cost Analysis

Table A-2: Emission Inventory Data / Baseline Emission Rate for BART Control Cost Analysis

Scaled to Unit 2 operating hours to reflect non-outage year for Unit 1 | Scaled to Unit 1 to reflect higher baseline emissions for Unit 2

Equipment Information: GRE Coal Creek Unit I				6015	MMBtu/hr	**Baseline Emis**	
Year (12-Month Avg. Period)	Jul 2010 - Jun 2011	Aug 2010 - Jul 2011	Sep 2010 - Aug 2011	Oct 2010 - Sep 2011	Nov 2010 -Oct 2011	**Unit 1**	**Unit 2**
Hours of Operation	7,700	7,700	7,635	7,599	7,629	8,410	8,410
Fuels Used:							
Quanity of Lignite - Tons	3,356,248	3,352,605	3,296,938	3,268,966	3,282,270	3,638,972	3,688,805
Percent Sulfur in Coal (Average)	0.64%	0.65%	0.65%	0.66%	0.61%	0.64%	0.64%
BTU per Unit of Coal (Average)	6,415	6,448	6,482	6,517	6,003	6,373	6,373
Heat Input	4.410E+07	4.422E+07	4.356E+07	4.320E+07	4.346E+07	48,032,232	47,761,077
MMBtu/hr	5,727	5,743	5,705	5,685	5,697	5,712	5,679
% of Capacity	95.2%	95.5%	94.8%	94.5%	94.7%	95.0%	95.0%
NOx lb/MMBtu	0.200	0.200	0.199	0.200	0.203	0.200	0.201 [1]
Total Stack Emissions:							
NOx Emitted Tons Per Year:	4,416.3	4,412.0	4,333.1	4,330.2	4,402.3	4,811.9	4,791.6
NOx Emitted Lb Per Hour:	1,204.8	1,200.3	1,196.7	1,205.8	1,218.5	1204.6	1199.5
Stack Emissions --- Lignite:							
NOX CEM Annual Average lb/MMBtu	0.201	0.200	0.200	0.201	0.203	0.201	0.153 [1]

Equipment Information: GRE Coal Creek Unit II				6022	MMBtu/hr
Year	Jul 2010 - Jun 2011	Aug 2010 - Jul 2011	Sep 2010 - Aug 2011	Oct 2010 - Sep 2011	Nov 2010 -Oct 2011
Hours of Operation	8,430	8,430	8,397	8,401	8,390
Fuels Used:					
Quanity of Lignite - Tons	3,730,674	3,718,253	3,676,481	3,672,436	3,646,178
Percent Sulfur in Coal (Average)	0.64%	0.65%	0.65%	0.66%	0.61%
BTU per Unit of Coal (Average)	6,415	6,448	6,482	6,517	6,003
Heat Input	4.810E+07	4.799E+07	4.757E+07	4.764E+07	4.751E+07
MMBtu/hr	5,706	5,692	5,665	5,671	5,662
% of Capacity	94.9%	94.6%	94.2%	94.3%	94.1%
NOx lb/MMBtu [1]	0.152	0.153	0.152	0.152	0.153
Total Stack Emissions:					
NOx Emitted Tons Per Year:	3,662.4	3,666.8	3,610.4	3,626.8	3,646.1
Stack Emissions --- Lignite:					
NOX CEM Annual Average lb/MMBtu [1]	0.152	0.153	0.152	0.153	0.154

[1] Although Unit 2's actual 2010-2011 NOx emissions were 0.152-0.153, the pre-LNC3+ emissions rate was the 0.201 which is used in this analysis.

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BART Supplement - NOx Emission Control Cost Analysis

Table A-3: Summary of Utility, Chemical and Supply Costs

Operating Unit: Unit 1 or 2 **Study Year** 2011

From Golder Report

Item	**Unit Cost**	**Units**	**Reference Cost**	**Year**	**Data Source**	**Notes**
Operating Labor	37.00	$/hr	25.86	2002	Stone & Webster 2002 Cost Estimate; confirmed by GRE	
Maintenance Labor	37.00	$/hr	26.25	2002	Stone & Webster 2002 Cost Estimate; confirmed by GRE	
Electricity	0.0604	$/kwh	0.049	2004	DOE Average Retail Price of Industrial Electricity, 2004	http://www.eia.doe.gov/emeu/aer/txt/ptb0810.html
Water	0.31	$/kgal	0.79	2002	Stone & Webster 2002 Cost Estimate; confirmed by GRE	
Cooling Water	0.32	$kgal	0.23	1999	EPA Air Pollution Control Cost Manual, 6th ed. Section 3.1 Ch 1	Ch 1 Carbon Adsorbers, 1999 $0.15 - $0.30 Avg of 22.5 and 7 yrs and 3% inflation
Compressed Air	0.37	$/kscf	0.25	1998	EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1	Example problem; Dried & Filtered, Ch 1.6 '98 cost adjusted for 3% inflation
Wastewater Disposal Neutralization	1.96	$/kgal	1.50	2002	EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 2 Chapter 2.5.5.5	Section 2 lists $1- $2/1000 gal. Cost adjusted for 3% inflation Sec 6 Ch 3 lists $1.30 - $2.15/1,000 gal
Wastewater Disposal Bio-Treat	4.96	$/kgal	3.80	2002	EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 5.2 Chapter 1	Ch 1 lists $1.00 - $6.00 for municipal treatment, $3.80 is average. Cost adjusted for 3% inflation
Solid Waste Disposal - No Impact	0.000	$/ton	0.00	2011	Assume no chang in GRE landfill cost for ash	Fly ash disposal of 0 net tons
Solid Waste Disposal - 30% Lost	5.438	$/ton	5.438	2011	Golder Fly Ash Management Evaluation - Nov. 2011	Cost per ton of $13.91/ ton for 234,500 tons less existing cost of $18.06/tons for 110,000 tons
Solid Waste Disposal - 100% Lost	7.396	$/ton	7.396	2011	Golder Fly Ash Management Evaluation - Nov. 2011	Cost per ton of $11.18/ ton for 525,000 tons less existing cost of $18.06/tons for 110,000 tons
Hazardous Waste Disposal	326.19	$/ton	250.00	2002	EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 2 Chapter 2.5.5.5	Section 2 lists $200 - $300/ton Used $250/ton. Cost adjusted for 3% inflation
Waste Transport	0.65	$/ton-mi	0.500	2002	EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 3	Example problem. Cost adjusted for 3% inflation
Ash Sales	12.300	$/ton	12.300	2011	Golder Fly Ash Management Evaluation - Nov. 2011	$/ton received for sale of ash; this amount is lost if ash cannot be sold
Ammonia Mitigation	5.610	$/ton	5.610	2011	Golder Fly Ash Management Evaluation - Nov. 2011	
Chemicals & Supplies						
Lime	90.00	$/ton	72.19	2005	GRE per Diane Stockdill 12/6/05 email	Cost adjusted for 3% inflation
Caustic	364	$/ton	305.21	2005	GRE per Diane Stockdill 12/6/05 email	Cost adjusted for 3% inflation
Urea	500	$/ton	500	2011	URS SNCR Report - November 2011	
Oxygen	17.91	kscf	15.00	2005	Get cost from Air Prod Website	Cost adjusted for 3% inflation
EPA Urea	179.1	$/ton				
Ammonia	1	$/lb	0.92	2005	GRE per Diane Stockdill	Cost adjusted for 3% inflation
Other						
Sales Tax	0	%			GRE per Diane Stockdill 12/6/05 email	
Interest Rate	5.50%	%			GRE per Diane Stockdill 12/6/05 email	Estimated prime rate plus 3%

Please note, for units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal

Future Operating Scenario for BART Cost Analysis

Operating Information	**Unit 1**	**Unit 2**			Data Source	Notes
Annual Op. Hrs	8,409.6	8,409.6	Hours		July 2010 to October 2011 Coal Creek Emission Data	
Utilization Rate	100.0%	100.0%			GRE per Diane Stockdill 12/6/05 email	
Equipment Life	20	20	yrs			Engineering Estimate
Coal Ash	11.70	11.70	wt % ash		2010 Coal Creek Emission Inventory	
Coal Sulfur	0.64	0.64	% Coal Sulfur Content		July 2010 to October 2011 Coal Creek Emission Data	
Coal Heating Value	6,373	6,373	Btu/lb of coal		July 2010 to October 2011 Coal Creek Emission Data	
Design Capacity	6,015	6,022	MMBtu/hr			
ID Fan Flow Rates	Assumes coal drying with DryFining™					
Standardized Flow Rate	866293.7	866293.7	scfm @ 32º F			
Temperature	330.0	330.0	Deg F		GRE per G. Riveland 4/5/06 email	
Moisture Content	13.3%	13.3%			GRE per G. Riveland 4/5/06 email	
Actual Flow Rate	2,234,300	2,234,300	acfm		GRE per G. Riveland 4/5/06 email	
Standardized Flow Rate	1,391,000	1,391,000	scfm @ 330º F		GRE per G. Riveland 4/5/06 email	
Dry Std Flow Rate	1,205,997	1,205,997	dscfm @ 330º F			
NOx Pollutant Data						
Max Emis (lb/hr)	1,208.1	1,209.5			Calculated using baseline emission rate and design capacities	
Max Emis (tpy)	5,079.9	5,085.8			Calculated	
Baseline Emiss (lb/MMBtu)	0.201	0.201			Unit 1 average prior to LNC3+ installation	

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Table A-4: Unit 1 NOx Control - Foster Wheeler LNC3+

Operating Unit: **Unit 1**

Emission Unit Number	EU-1		Stack/Vent Number	SV-1		CEPCI	
Desgin Capacity	6,015	MMBtu/hr	Standardized Flow Rate	866,294	scfm @ 32º F	2005	468.2
Expected Utiliztion Rate	100%		Temperature	330	Deg F	2011	588.9
Expected Annual Hours of Operation	8,409.6	Hours	Moisture Content	13.3%		Inflation Factor	1.26
Annual Interest Rate	5.5%		Actual Flow Rate	2,234,300	acfm		
Expected Equipment Life	20	yrs	Standardized Flow Rate	1,391,000	scfm @ 330º F		
Baseline NOx	0.201	lb/MMBtu	Dry Std Flow Rate	1,205,997	dscfm @ 330º F		

CONTROL EQUIPMENT COSTS

Capital Costs								
Direct Capital Costs								
Purchased Equipment (A)								1,257,796
Purchased Equipment Total (B)								**1,958,057**
Installation - Standard Costs								1,958,057
Installation - Site Specific Costs								NA
Installation Total								3,729,632
Total Direct Capital Cost, DC								5,687,689
Total Indirect Capital Costs, IC								391,611
Total Capital Investment (TCI) = DC + IC								**6,079,300**
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.						7,779
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost						756,551
Total Annual Cost (Annualized Capital Cost + Operating Cost)								**764,330**

Emission Control Cost Calculation

Pollutant	**Max Emis Lb/Hr**	**Pre-control Annual T/Yr**	**Cont Eff %**	**Exit Conc**	**Conc Units**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
Nitrogen Oxides (NOx)	1,208.1	5,079.9	24%			3861.6	1,218.2	627

Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 2 (Used PM Scrubber which has lowest installed cost multiplier)

Notes & Assumptions

1. Sept 2005 Cost Estimate from Foster Wheeler, Option 2, inflated to 2011 dollars. Ratio based on actual cost for Unit 2 instalaltion.
2. Total capital investment reflects actual installed costs for Unit 2 installation, infllated to 2011 dollars.
3. Assumed 0.1 hr/shift operatior and maintenance labor for LNB
4. Process, emissions and cost data listed above is for one unit.
5. For units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal

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Table A-4: Unit 1 NOx Control - Foster Wheeler LNC3+

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CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) (1)			**1,257,796**
Instrumentation			
Sales Taxes			
Freight			
Purchased Equipment Total (B)			**1,958,057**
Installation			
Foundations & supports			
Handling & erection			
Electrical			
Piping			
Insulation			
Painting			
Installation Subtotal Standard Expenses (1)			**1,958,057**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Site Specific - Other		Site Specific	NA
Total Site Specific Costs			NA
Installation Total			**3,729,632**
Total Direct Capital Cost, DC			**5,687,689**
Indirect Capital Costs			
Engineering, supervision	5%	of purchased equip cost (B)	97,903
Construction & field expenses	10%	of purchased equip cost (B)	195,806
Contractor fees	0%	of purchased equip cost (B)	0
Start-up	1%	of purchased equip cost (B)	19,581
Performance test	1%	of purchased equip cost (B)	19,581
Model Studies	NA	of purchased equip cost (B)	NA
Contingencies	3%	of purchased equip cost (B)	58,742
Total Indirect Capital Costs, IC	20%	of purchased equip cost (B)	**391,611**
Ozone Generator, Installed Cost			**0**
Total Capital Investment (TCI) = DC + IC (2)			**6,079,300**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**6,079,300**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	NA		-
Supervisor	NA		-
Maintenance			
Maintenance Labor	37.00	$/Hr, 0.1 hr/8 hr shift, 8409.6 hr/yr	3,889
Maintenance Materials	100%	of maintenance labor costs	3,889
Utilities, Supplies, Replacements & Waste Management			
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
Total Annual Direct Operating Costs			**7,779**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	4,667
Administration (2% total capital costs)	2%	of total capital costs (TCI)	121,586
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	60,793
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	60,793
Capital Recovery	0.0837	for a 20- year equipment life and a 5.5% interest rate	508,712
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**756,551**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**764,330**

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Table A-4: Unit 1 NOx Control - Foster Wheeler LNC3+

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Parts & Equipment:		
Equipment Life	5	years
CRF	0.0000	
Rep part cost per unit	0	$/ft^3
Amount Required	0	ft^3
Packing Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:			
Equipment Life	3		
CRF	0.3707		
Rep part cost per unit	0	$ each	
Amount Required	0	Number	
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax	
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr	OAQPS list replacement times from 5 - 20 min per bag.
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	
Annualized Cost	**0**		

Electrical Use							
	Flow acfm		**Δ P ft H2O**	**Efficiency**	**Hp**	**kW**	
Blower, Scrubber	2,234,300		0	0.7	-	0.0	EPA Cost Cont Manual 6th ed Section 5.2 Chapter 1 Eq 1.48
	Flow	**Liquid SPGR**	**Δ P ft H2O**	**Efficiency**	**Hp**	**kW**	
Circ Pump	000 gpm	1	0	0.7	-	0.0	EPA Cost Cont Manual 6th ed Section 5.2 Chapter 1 Eq 1.49
H2O WW Disch	0 gpm	1	0	0.7	-	0.0	EPA Cost Cont Manual 6th ed Section 5.2 Chapter 1 Eq 1.49
			lb/hr O_3				
LTO Electric Use	4.5	kW/lb O_3				0	
Other							
Total						0.0	

Reagent Use & Other Operating Costs								
Ozone Needed	1.8	lb O3/lb NOx	-	lb/hr O3				
Oxygen Needed	10%	wt O2 to O3 conversion			0	lb/hr O2	0	scfh O2
LTO Cooling Water	150	gal/lb O3	0	gpm				
Liquid/Gas ratio	0.0	* L/G = Gal/1,000 acf						
Circulating Water Rate	0	gpm						
Water Makeup Rate/WW Disch =	20%	of circulating water rate =			0	gpm		
Scrubber Cost	10	$/scfm Gas	$0		Incremental cost per BOC. Need to increase vessel size over standard absorber.			
Ozone Generator	$350	lb O3/day	$0	Installed	Installed cost factor per BOC.			

Direct Operating Cost Calculations | **Annual hours of operation:** **8,409.6** | **Utilization Rate:** **100%**

Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
Operating Labor							
Op Labor	0	$/Hr	0.1	hr/8 hr shift	105	0	$/Hr, 0.1 hr/8 hr shift, 8409.6 hr/yr
Supervisor	15%	of Op.			NA	-	15% of Operator Costs
Maintenance							
Maint Labor	37.00	$/Hr	0.1	hr/8 hr shift	105	3,889	$/Hr, 0.1 hr/8 hr shift, 8409.6 hr/yr
Maint Mtls	100	% of Maintenance Labor			NA	3,889	100% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.0604	$/kwh	0.0	kW-hr	0	0	$/kwh, 0 kW-hr, 8409.6 hr/yr, 100% utilization
Water	0.3100	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 8409.6 hr/yr, 100% utilization
Cooling Water	0.3208	$kgal	0.0	gpm	0	0	$kgal, 0 gpm, 8409.6 hr/yr, 100% utilization
Comp Air	0.3671	$/kscf	0	kscfm	0	0	$/kscf, 0 kscfm, 8409.6 hr/yr, 100% utilization
WW Treat Neutralization	1.9572	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 8409.6 hr/yr, 100% utilization
WW Treat Biotreatement	4.9581	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 8409.6 hr/yr, 100% utilization
SW Disposal	0.0000	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8409.6 hr/yr, 100% utilization
Haz W Disp	326.1933	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8409.6 hr/yr, 100% utilization
Ammonia Mitigation	5.6100	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8409.6 hr/yr, 100% utilization
Lost Ash Sales	12.3000	$/ton	0.0	ton/hr	0	0	$/ton, 0 ton/hr, 8409.6 hr/yr, 100% utilization
Lime	90.0000	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 8409.6 hr/yr, 100% utilization
Caustic	364.4367	$/ton	0.0	lb/hr	0	0	$/ton, 0 lb/hr, 8409.6 hr/yr, 100% utilization
Oxygen	17.9108	kscf	0.0	kscf/hr	0	0	kscf, 0 kscf/hr, 8409.6 hr/yr, 100% utilization

*annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

Great River Energy Coal Creek Station
BART Supplement - NOx Emission Control Cost Analysis
Table A-5: Unit 1 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (Maintain Ash Sales)

Operating Unit: **Unit 1**

Emission Unit Number	EU-1		Stack/Vent Number	SV-1	
Desgin Capacity	6,015	MMBtu/hr	Standardized Flow Rate	866,294	scfm @ 32º F
Expected Utiliztion Rate	100%		Temperature	330	Deg F
Expected Annual Hours of Operation	8,409.6	Hours	Moisture Content	13.3%	
Annual Interest Rate	5.5%		Actual Flow Rate	2,234,300	acfm
Expected Equipment Life	20	yrs	Standardized Flow Rate	1,391,000	scfm @ 330º F
Baseline NOx	0.201	lb/MMBtu	Dry Std Flow Rate	1,205,997	dscfm @ 330º F

CONTROL EQUIPMENT COSTS

Capital Costs		
Direct Capital Costs		
Purchased Equipment (A)		3,700,000
Purchased Equipment Total (B)		**8,465,600**
Installation - Standard Costs		1,270,000
Installation - Site Specific Costs		1,036,000
Installation Total		1,758,000
Total Capital Investment (TCI) = DC + IC		**12,176,084**
Operating Costs		
Total Annual Direct Operating Costs	Labor, supervision, materials, replacement parts, utilities, etc.	3,588,665
Total Annual Indirect Operating Costs	Sum indirect oper costs + capital recovery cost	1,018,887
Total Annual Cost (Annualized Capital Cost + Operating Cost)		**4,607,552**

Emission Control Cost Calculation

Pollutant	Max Emis Lb/Hr	Pre-control Annual T/Yr	Cont Eff %	Exit Conc	Conc Units	Cont Emis T/yr	Reduction T/yr	Cont Cost $/Ton Rem
Nitrogen Oxides (NOx)	1,208.1	5,079.9	25.0%			3809.9	1,270.0	3,628

Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1

Notes & Assumptions

1. November 2011 SNCR Evaluation from URS
2. SNCR Maintenance Costs EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.21
3. Process, emissions and cost data listed above is for one unit.
4. For units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal
5. Retrofit factor of 60% used by URS based on site visit to Coal Creek Station.
6. SW disposal and fly ash sales data from Nov. 2011 Golder Fly Ash Evaluation, Appendix B2
7. One-time cost for Technology Licensing Fee for the SNCR process is ~0.5% of the Process Capital.

Great River Energy Coal Creek Station

Technical Update 06/07/2012

BART Supplement - NOx Emission Control Cost Analysis

Table A-5: Unit 1 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (Maintain Ash Sales)

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment			**3,700,000**
Purchased Equipment Costs			
Instrumentation	10%	of purchased equipment cost	370,000
Site Specific and Prime Contractor Markup	28%	of purchased equipment cost	1,036,000
Freight	5%	of purchased equipment cost	185,000
Purchased Equipment Total	43%		5,291,000
Purchased Equipment Total+ Retrofit Factor (A)			**8,465,600**
Indirect Installation			
General Facilities		See Notes & Assumptions 1 on pg. 1 of Table	420,000
Engineering & Home Office		See Notes & Assumptions 1 on pg. 1 of Table	850,000
Process Contingency		See Notes & Assumptions 1 on pg. 1 of Table	488,000
Total Indirect Installation Costs (B)		See Notes & Assumptions 1 on pg. 1 of Table	**1,758,000**
Project Contingeny (C)		See Notes & Assumptions 1 on pg. 1 of Table	**1,540,000**
Total Plant Cost (D)		A + B + C	**11,763,600**
Allowance for Funds During Construction (E)		0 for SNCR	**0**
Prepaid Royalties (F)		See Notes & Assumptionss 1 and 7 on pg. 1 of Table	**42,000**
Pre Production Costs (G)		See Notes & Assumptions 1 on pg. 1 of Table	**236,000**
Inventory Capital (H)		Reagent Vol * $/gal	**134,484**
Intial Catalyst and Chemicals (I)		0 for SNCR	**0**
Total Capital Investment (TCI) = DC + IC		D + E + F + G +H + I	**12,176,084**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**12,176,084**

OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	NA		-
Supervisor	NA		-
Maintenance			
Maintenance Total	1.50	% of Total Capital Investment	182,641
Maintenance Materials	NA	% of Maintenance Labor	-
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.060	See Direct Operating Cost Calculations on last pg.	31,009
Water	0.310	See Direct Operating Cost Calculations on last pg.	9,072
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
Urea	500.00	See Direct Operating Cost Calculations on last pg.	3,365,942
NA	NA		-
Total Annual Direct Operating Costs			**3,588,665**
Indirect Operating Costs			
Overhead	NA	of total labor and material costs	NA
Administration (2% total capital costs)	NA	of total capital costs (TCI)	NA
Property tax (1% total capital costs)	NA	of total capital costs (TCI)	NA
Insurance (1% total capital costs)	NA	of total capital costs (TCI)	NA
Capital Recovery	0.08368	for a 20- year equipment life and a 5.5% interest rate	1,018,887
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**1,018,887**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**4,607,552**

See Summary page for notes and assumptions

Great River Energy Coal Creek Station — Technical Update 06/07/2012

BART Supplement - NOx Emission Control Cost Analysis

Table A-5: Unit 1 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (Maintain Ash Sales)

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.08368	

Replacement Catayst		<- Enter Equipment Name to Get Cost
Equipment Life	5	years
CRF	0.2342	
Rep part cost per unit	0	$\$/ft^3$
Amount Required	12	ft^3
Packing Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:		<- Enter Equipment Name to Get Cost	
Equipment Life	2	years	
CRF	0.0000		
Rep part cost per unit	0	$\$/ft^3$	
Amount Required	0 Cages		
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax	See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs
Installation Labor	0	10 min per bag, Labor + Overhead (68% = $29.65/hr)	
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	EPA CCM list replacement times from 5 - 20 min per bag.
Annualized Cost	**0**		

Electrical Use			
NOx in	0.20	lb/MMBtu	kW
NSR	0.60		
Power			61.0
Total			61.0

Reagent Use & Other Operating Costs					
NOx in	0.20	lb/MMBtu	Urea Use	1601	lb/hr
Efficiency	25%		Volume 14 day inventory	269	ton
Duty	6,015	MMBtu/hr	Inventory Cost	$134,484	
Water Use	3480	gal/hr			

Direct Operating Cost Calculations — **Annual hours of operation: 8,409.6** — **Utilization Rate: 100%**

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Operating Labor							
Op Labor	37	$/Hr	0.0	hr/8 hr shift	0	0	$/Hr, 0.0 hr/8 hr shift, 8409.6 hr/yr
Supervisor	15%	of Op.			NA	-	15% of Operator Costs
Maintenance							
Maintenance Total	1.5	% of Total Capital Investment				182,641.26	% of Total Capital Investment
Maint Mtls	0	% of Maintenance Labor			NA	0	0% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.06045	$/kwh	61.00000	kW-hr	512,985.60	31,009.11	$/kwh, 61.0 kW-hr, 8409.6 hr/yr, 100% utilization
Water	0.31000	$/kgal	3480.00000	gph	29,265.41	9,072.28	0.31 $/kgal X 3,480.0 gph/1000 X 8409.6 hr/yr X 100% utilization
Cooling Water	0.32080	$kgal	0.00000	gpm	0	0	$kgal, 0 gpm, 8409.6 hr/yr, 100% utilization
Comp Air	0.36713	$/kscf	0.00000	scfm/kacfm**	0	0	$/kscf, 0.0 scfm/kacfm**, 8409.6 hr/yr, 100% utilization
WW Treat Neutralization	1.95716	$/kgal	0.00000	gpm	0	0	$/kgal, 0.0 gpm, 8409.6 hr/yr, 100% utilization
WW Treat Biotreatement	4.95814	$/kgal	0.00000	gpm	0	0	$/kgal, 0.0 gpm, 8409.6 hr/yr, 100% utilization
SW Disposal	0.00000	$/ton	6.54014	ton/hr	55,000	0	$/ton, 6.5 ton/hr, 8409.6 hr/yr, 100% utilization
Haz W Disp	326.19330	$/ton	0.00000	ton/hr	0	0	$/ton, 0.0 ton/hr, 8409.6 hr/yr, 100% utilization
Ammonia Mitigation	5.61	$/ton	0.00000	ton/hr	0	0	$/ton, 0.0 ton/hr, 8409.6 hr/yr, 100% utilization
Lost Ash Sales	12.3	$/ton	0.00000	ton/hr	0	0	$/ton, 0.0 ton/hr, 8409.6 hr/yr, 100% utilization
Lime	90.0	$/ton	0.00000	lb/hr	0	0	$/ton, 0.0 lb/hr, 8409.6 hr/yr, 100% utilization
Urea	500.0	$/ton	0.80050	ton/hr	6,731.88	3,365,942.40	500 $/ton X 0.8005 ton/hr X 8409.6 hr/yr X 100% utilization
Oxygen	17.91078	kscf	0.00000	kscf/hr	0	0	kscf, 0.0 kscf/hr, 8409.6 hr/yr, 100% utilization

** Std Air use is 2 scfm/kacfm

*annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

Great River Energy Coal Creek Station **Technical Update 06/07/2012**

BART Supplement - NOx Emission Control Cost Analysis

Table A-6: Unit 1 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (30% Lost Ash Sales)

Operating Unit: **Unit 1**

Emission Unit Number	EU-1		Stack/Vent Number	SV-1	
Desgin Capacity	6,015	MMBtu/hr	Standardized Flow Rate	866,294	scfm @ 32º F
Expected Utiliztion Rate	100%		Temperature	330	Deg F
Expected Annual Hours of Operation	8,409.6	Hours	Moisture Content	13.3%	
Annual Interest Rate	5.5%		Actual Flow Rate	2,234,300	acfm
Expected Equipment Life	20	yrs	Standardized Flow Rate	1,391,000	scfm @ 330º F
Baseline NOx	0.201	lb/MMBtu	Dry Std Flow Rate	1,205,997	dscfm @ 330º F

CONTROL EQUIPMENT COSTS

Capital Costs								
Direct Capital Costs								
Purchased Equipment (A)								3,700,000
Purchased Equipment Total (B)								**8,465,600**
Installation - Standard Costs								1,270,000
Installation - Site Specific Costs								1,036,000
Installation Total								1,758,000
Total Capital Investment (TCI) = DC + IC								**12,176,084**
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.						5,806,840
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost						1,018,887
Total Annual Cost (Annualized Capital Cost + Operating Cost)								**6,825,727**

Emission Control Cost Calculation

Pollutant	**Max Emis Lb/Hr**	**Pre-control Annual T/Yr**	**Cont Eff %**	**Exit Conc**	**Conc Units**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
Nitrogen Oxides (NOx)	1,208.1	5,079.9	25.0%			3809.9	1,270.0	5,375

Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1

Notes & Assumptions

1. November 2011 SNCR Evaluation from URS
2. SNCR Maintenance Costs EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.21
3. Process, emissions and cost data listed above is for one unit.
4. For units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal
5. Retrofit factor of 60% used by URS based on site visit to Coal Creek Station.
6. SW disposal and fly ash sales data from Nov. 2011 Golder Fly Ash Evaluation, Appendix B2
7. One-time cost for Technology Licensing Fee for the SNCR process is ~0.5% of the Process Capital.

Great River Energy Coal Creek Station **Technical Update 06/07/2012**

BART Supplement - NOx Emission Control Cost Analysis

Table A-6: Unit 1 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (30% Lost Ash Sales)

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment			**3,700,000**
Purchased Equipment Costs			
Instrumentation	10.00%	of purchased equipment cost	370,000
Site Specific and Prime Contractor Markup	28.00%	of purchased equipment cost	1,036,000
Freight	5.00%	of purchased equipment cost	185,000
Purchased Equipment Total	43.00%		5,291,000
Purchased Equipment Total+ Retrofit Factor (A)			**8,465,600**
Indirect Installation			
General Facilities		See Notes & Assumptions 1 on pg. 1 of Table	420,000
Engineering & Home Office		See Notes & Assumptions 1 on pg. 1 of Table	850,000
Process Contingency		See Notes & Assumptions 1 on pg. 1 of Table	488,000
Total Indirect Installation Costs (B)		See Notes & Assumptions 1 on pg. 1 of Table	**1,758,000**
Project Contingeny (C)		See Notes & Assumptions 1 on pg. 1 of Table	**1,540,000**
Total Plant Cost (D)		A + B + C	**11,763,600**
Allowance for Funds During Construction (E)		0 for SNCR	**0**
Prepaid Royalties (F)		See Notes & Assumptionss 1 and 7 on pg. 1 of Table	**42,000**
Pre Production Costs (G)		See Notes & Assumptions 1 on pg. 1 of Table	**236,000**
Inventory Capital (H)		Reagent Vol * $/gal	**134,484**
Intial Catalyst and Chemicals (I)		0 for SNCR	**0**
Total Capital Investment (TCI) = DC + IC		D + E + F + G +H + I	**12,176,084**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**12,176,084**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	NA		-
Supervisor	NA		-
Maintenance			
Maintenance Total	1.50	% of Total Capital Investment	182,641
Maintenance Materials	NA	% of Maintenance Labor	-
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.060	See Direct Operating Cost Calculations on last pg.	31,009
Water	0.310	See Direct Operating Cost Calculations on last pg.	9,072
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
SW Disposal	5.44	See Direct Operating Cost Calculations on last pg.	637,648
NA	NA		-
Ammonia Mitigation	5.61	See Direct Operating Cost Calculations on last pg.	814,853
Lost Ash Sales	12.30	See Direct Operating Cost Calculations on last pg.	765,675
NA	NA		-
Urea	500.00	See Direct Operating Cost Calculations on last pg.	3,365,942
NA	NA		-
Total Annual Direct Operating Costs			**5,806,840**
Indirect Operating Costs			
Overhead	NA	of total labor and material costs	NA
Administration (2% total capital costs)	NA	of total capital costs (TCI)	NA
Property tax (1% total capital costs)	NA	of total capital costs (TCI)	NA
Insurance (1% total capital costs)	NA	of total capital costs (TCI)	NA
Capital Recovery	0.08368	for a 20- year equipment life and a 5.5% interest rate	1,018,887
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**1,018,887**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**6,825,727**

See Summary page for notes and assumptions

Great River Energy Coal Creek Station **Technical Update 06/07/2012**

BART Supplement - NOx Emission Control Cost Analysis

Table A-6: Unit 1 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (30% Lost Ash Sales)

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.08368	

Replacement Catayst		<- Enter Equipment Name to Get Cost
Equipment Life	5	years
CRF	0.2342	
Rep part cost per unit	0	$/ft^3
Amount Required	12	ft^3
Packing Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:		<- Enter Equipment Name to Get Cost	
Equipment Life	2	years	
CRF	0.0000		
Rep part cost per unit	0	$/ft^3	
Amount Required	0	Cages	
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax	See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs
Installation Labor	0	10 min per bag, Labor + Overhead (68% = $29.65/hr)	
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	EPA CCM list replacement times from 5 - 20 min per bag.
Annualized Cost	**0**		

Electrical Use			
NOx in	0.20	lb/MMBtu	kW
NSR	0.60		
Power			61.0
Total			61.0

Reagent Use & Other Operating Costs					
NOx in	0.20	lb/MMBtu	Urea Use	1601	lb/hr
Efficiency	25%		Volume 14 day inventory	269	ton
Duty	6,015	MMBtu/hr	Inventory Cost	$134,484	
Water Use	3480	gal/hr			

Direct Operating Cost Calculations — **Annual hours of operation:** **8,409.6**; **Utilization Rate:** **100%**

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Operating Labor							
Op Labor	37	$/Hr	0.0	hr/8 hr shift	0	0	$/Hr, 0.0 hr/8 hr shift, 8409.6 hr/yr
Supervisor	15%	of Op.			NA	-	15% of Operator Costs
Maintenance							
Maintenance Total	1.5	% of Total Capital Investment				182,641.26	% of Total Capital Investment
Maint Mtls	0	% of Maintenance Labor			NA	0	0% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.06045	$/kwh	61.00000	kW-hr	512,985.60	31,009.11	0.0604 $/kwh X 61.0 kW-hr X 8409.6 hr/yr X 100% utilization
Water	0.31000	$/kgal	3480.00000	gph	29,265.41	9,072.28	0.3100 $/kgal X 3,480.0 gph/1000 X 8409.6 hr/yr X 100% utilization
Cooling Water	0.32080	$kgal	0.00000	gpm	0	0	$kgal, 0 gpm, 8409.6 hr/yr, 100% utilization
Comp Air	0.36713	$/kscf	0.00000	scfm/kacfm**	0	0	$/kscf, 0.0 scfm/kacfm**, 8409.6 hr/yr, 100% utilization
WW Treat Neutralization	1.95716	$/kgal	0.00000	gpm	0	0	$/kgal, 0.0 gpm, 8409.6 hr/yr, 100% utilization
WW Treat Biotreatement	4.95814	$/kgal	0.00000	gpm	0	0	$/kgal, 0.0 gpm, 8409.6 hr/yr, 100% utilization
SW Disposal	5.43836	$/ton	13.94240	ton/hr	117,250	637,648	5.4384 $/ton X 13.9424 ton/hr X 8409.6 hr/yr X 100% utilization
Haz W Disp	326.19330	$/ton	0.00000	ton/hr	0	0	$/ton, 0.0 ton/hr, 8409.6 hr/yr, 100% utilization
Ammonia Mitigation	5.61	$/ton	17.27193	ton/hr	145,250	814,853	5.61 $/ton X 17.2719 ton/hr X 8409.6 hr/yr X 100% utilization
Lost Ash Sales	12.3	$/ton	7.40225	ton/hr	62,250.0	765,675	12.3 $/ton X 7.4023 ton/hr X 8409.6 hr/yr X 100% utilization
Lime	90.0	$/ton	0.00000	lb/hr	0	0	$/ton, 0.0 lb/hr, 8409.6 hr/yr, 100% utilization
Urea	500.0	$/ton	0.80050	ton/hr	6,731.88	3,365,942.40	500 $/ton X 0.8005 ton/hr X 8409.6 hr/yr X 100% utilization
Oxygen	17.91078	kscf	0.00000	kscf/hr	0	0	kscf, 0.0 kscf/hr, 8409.6 hr/yr, 100% utilization

** Std Air use is 2 scfm/kacfm

*annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

Great River Energy Coal Creek Station

BART Supplement - NOx Emission Control Cost Analysis

Table A-7: Unit 1 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (100% Lost Ash Sales)

Operating Unit: **Unit 1**

Emission Unit Number	EU-1		Stack/Vent Number	SV-1	
Desgin Capacity	6,015	MMBtu/hr	Standardized Flow Rate	866,294	scfm @ 32º F
Expected Utiliztion Rate	100%		Temperature	330	Deg F
Expected Annual Hours of Operation	8,409.6	Hours	Moisture Content	13.3%	
Annual Interest Rate	5.5%		Actual Flow Rate	2,234,300	acfm
Expected Equipment Life	20	yrs	Standardized Flow Rate	1,391,000	scfm @ 330º F
Baseline NOx	0.201	lb/MMBtu	Dry Std Flow Rate	1,205,997	dscfm @ 330º F

CONTROL EQUIPMENT COSTS

Capital Costs								
Direct Capital Costs								
Purchased Equipment (A)								3,700,000
Purchased Equipment Total (B)								**8,465,600**
Installation - Standard Costs								1,270,000
Installation - Site Specific Costs								1,036,000
Installation Total								1,758,000
Total Capital Investment (TCI) = DC + IC								**12,176,084**
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.						8,082,365
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost						1,018,887
Total Annual Cost (Annualized Capital Cost + Operating Cost)								**9,101,252**

Emission Control Cost Calculation

Pollutant	**Max Emis Lb/Hr**	**Pre-control Annual T/Yr**	**Cont Eff %**	**Exit Conc**	**Conc Units**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
Nitrogen Oxides (NOx)	1,208.1	5,079.9	25.0%			3809.9	1,270.0	7,167

Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1

Notes & Assumptions

1. November 2011 SNCR Evaluation from URS
2. SNCR Maintenance Costs EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.21
3. Process, emissions and cost data listed above is for one unit.
4. For units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal
5. Retrofit factor of 60% used by URS based on site visit to Coal Creek Station.
6. SW disposal and fly ash sales data from Nov. 2011 Golder Fly Ash Evaluation, Appendix B2
7. One-time cost for Technology Licensing Fee for the SNCR process is ~0.5% of the Process Capital.

Great River Energy Coal Creek Station

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BART Supplement - NOx Emission Control Cost Analysis

Table A-7: Unit 1 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (100% Lost Ash Sales)

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment			**3,700,000**
Purchased Equipment Costs			
Instrumentation	10.00%	of purchased equipment cost	370,000
Site Specific and Prime Contractor Markup	28.00%	of purchased equipment cost	1,036,000
Freight	5.00%	of purchased equipment cost	185,000
Purchased Equipment Total	43.00%		5,291,000
Purchased Equipment Total+ Retrofit Factor (A)			**8,465,600**
Indirect Installation			
General Facilities		See Notes & Assumptions 1 on pg. 1 of Table	420,000
Engineering & Home Office		See Notes & Assumptions 1 on pg. 1 of Table	850,000
Process Contingency		See Notes & Assumptions 1 on pg. 1 of Table	488,000
Total Indirect Installation Costs (B)		See Notes & Assumptions 1 on pg. 1 of Table	**1,758,000**
Project Contingeny (C)		See Notes & Assumptions 1 on pg. 1 of Table	**1,540,000**
Total Plant Cost (D)		A + B + C	**11,763,600**
Allowance for Funds During Construction (E)		0 for SNCR	**0**
Prepaid Royalties (F)		See Notes & Assumptionss 1 and 7 on pg. 1 of Table	**42,000**
Pre Production Costs (G)		See Notes & Assumptions 1 on pg. 1 of Table	**236,000**
Inventory Capital (H)		Reagent Vol * $/gal	**134,484**
Intial Catalyst and Chemicals (I)		0 for SNCR	**0**
Total Capital Investment (TCI) = DC + IC		D + E + F + G +H + I	**12,176,084**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**12,176,084**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	NA		-
Supervisor	NA		-
Maintenance			
Maintenance Total	1.50	% of Total Capital Investment	182,641
Maintenance Materials	NA	% of Maintenance Labor	-
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.060	See Direct Operating Cost Calculations on last pg.	31,009
Water	0.310	See Direct Operating Cost Calculations on last pg.	9,072
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
SW Disposal	7.40	See Direct Operating Cost Calculations on last pg.	1,941,450
NA	NA		-
NA	NA		-
Lost Ash Sales	12.30	See Direct Operating Cost Calculations on last pg.	2,552,250
NA	NA		-
Urea	500.00	See Direct Operating Cost Calculations on last pg.	3,365,942
NA	NA		-
Total Annual Direct Operating Costs			**8,082,365**
Indirect Operating Costs			
Overhead	NA	of total labor and material costs	NA
Administration (2% total capital costs)	NA	of total capital costs (TCI)	NA
Property tax (1% total capital costs)	NA	of total capital costs (TCI)	NA
Insurance (1% total capital costs)	NA	of total capital costs (TCI)	NA
Capital Recovery	0.08368	for a 20- year equipment life and a 5.5% interest rate	1,018,887
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**1,018,887**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**9,101,252**

See Summary page for notes and assumptions

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Great River Energy Coal Creek Station
BART Supplement - NOx Emission Control Cost Analysis
Table A-7: Unit 1 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (100% Lost Ash Sales)

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.08368	

Replacement Catayst		<- Enter Equipment Name to Get Cost
Equipment Life	5	years
CRF	0.2342	
Rep part cost per unit	0	$\$/ft^3$
Amount Required	12	ft^3
Packing Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:		<- Enter Equipment Name to Get Cost	
Equipment Life	2	years	
CRF	0.0000		
Rep part cost per unit	0	$\$/ft^3$	
Amount Required	0	Cages	
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax	See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs
Installation Labor	0	10 min per bag, Labor + Overhead (68% = $29.65/hr)	
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	EPA CCM list replacement times from 5 - 20 min per bag.
Annualized Cost	**0**		

Electrical Use			
NOx in	0.20	lb/MMBtu	kW
NSR	0.60		
Power			61.0
Total			61.0

Reagent Use & Other Operating Costs					
NOx in	0.20	lb/MMBtu	Urea Use	1601	lb/hr
Efficiency	25%		Volume 14 day inventory	269	ton
Duty	6,015	MMBtu/hr	Inventory Cost	$134,484	
Water Use	3480	gal/hr			

Direct Operating Cost Calculations — **Annual hours of operation: 8,409.6** — **Utilization Rate: 100%**

Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
Operating Labor							
Op Labor	37	$/Hr	0.0	hr/8 hr shift	0	0	$/Hr, 0.0 hr/8 hr shift, 8409.6 hr/yr
Supervisor	15%	of Op.			NA	-	15% of Operator Costs
Maintenance							
Maintenance Total	1.5	% of Total Capital Investment				182,641.26	% of Total Capital Investment
Maint Mtls	0	% of Maintenance Labor			NA	0	0% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.06045	$/kwh	61.00000	kW-hr	512,985.60	31,009.11	0.0604 $/kwh X 61.0 kW-hr X 8409.6 hr/yr X 100% utilization
Water	0.31000	$/kgal	3480.00000	gph	29,265.41	9,072.28	0.3100 $/kgal X 3,480.0 gph/1000 X 8409.6 hr/yr X 100% utilization
Cooling Water	0.32080	$kgal	0.00000	gpm	0	0	$kgal, 0 gpm, 8409.6 hr/yr, 100% utilization
Comp Air	0.36713	$/kscf	0.00000	scfm/kacfm**	0	0	$/kscf, 0.0 scfm/kacfm**, 8409.6 hr/yr, 100% utilization
WW Treat Neutralization	1.95716	$/kgal	0.00000	gpm	0	0	$/kgal, 0.0 gpm, 8409.6 hr/yr, 100% utilization
WW Treat Biotreatement	4.95814	$/kgal	0.00000	gpm	0	0	$/kgal, 0.0 gpm, 8409.6 hr/yr, 100% utilization
SW Disposal	7.39600	$/ton	31.21433	ton/hr	262,500	1,941,450	7.3960 $/ton X 31.2143 ton/hr X 8409.6 hr/yr X 100% utilization
Haz W Disp	326.19330	$/ton	0.00000	ton/hr	0	0	$/ton, 0.0 ton/hr, 8409.6 hr/yr, 100% utilization
Ammonia Mitigation	5.61	$/ton	0.00000	ton/hr	0	0	$/ton, 0.0 ton/hr, 8409.6 hr/yr, 100% utilization
Lost Ash Sales	12.3	$/ton	24.67418	ton/hr	207,500	2,552,250	12.3 $/ton X 24.6742 ton/hr X 8409.6 hr/yr X 100% utilization
Lime	90.0	$/ton	0.00000	lb/hr	0	0	$/ton, 0.0 lb/hr, 8409.6 hr/yr, 100% utilization
Urea	500.0	$/ton	0.80050	ton/hr	6,731.88	3,365,942.40	500.0 $/ton X 0.8005 ton/hr X 8409.6 hr/yr X 100% utilization
Oxygen	17.91078	kscf	0.00000	kscf/hr	0	0	kscf, 0.0 kscf/hr, 8409.6 hr/yr, 100% utilization

** Std Air use is 2 scfm/kacfm   *annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

Great River Energy Coal Creek Station **Technical Update 06/07/2012**

BART Supplement - NOx Emission Control Cost Analysis

Table A-8: Unit 2 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (Maintain Ash Sales)

Operating Unit: **Unit 2**

Emission Unit Number	EU-2		Stack/Vent Number	SV-2	
Desgin Capacity	6,022	MMBtu/hr	Standardized Flow Rate	866,294	scfm @ 32º F
Expected Utiliztion Rate	100%		Temperature	330	Deg F
Expected Annual Hours of Operation	8,409.6	Hours	Moisture Content	13.3%	
Annual Interest Rate	5.5%		Actual Flow Rate	2,234,300	acfm
Expected Equipment Life	20	yrs	Standardized Flow Rate	1,391,000	scfm @ 330º F
Inlet NOx	0.153	lb/MMBtu	Dry Std Flow Rate	1,205,997	dscfm @ 330º F

CONTROL EQUIPMENT COSTS

Capital Costs								
Direct Capital Costs								
Purchased Equipment (A)								3,600,000
Purchased Equipment Total (B)								**8,236,800**
Installation - Standard Costs								1,230,000
Installation - Site Specific Costs								1,008,000
Installation Total								1,702,000
Total Capital Investment (TCI) = DC + IC								**11,793,820**
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.						2,634,116
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost						986,899
Total Annual Cost (Annualized Capital Cost + Operating Cost)								**3,621,015**

Emission Control Cost Calculation

Pollutant	Max Emis Lb/Hr	Pre-control Annual T/Yr	Cont Eff %	Exit Conc	Conc Units	Cont Emis T/yr	Reduction T/yr	Cont Cost $/Ton Rem
Nitrogen Oxides (NOx)	1,209.5	5,085.8	20.0%			4068.6	1,017.2	3,560

Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1

Notes & Assumptions

1. November 2011 SNCR Evaluation from URS
2. SNCR Maintenance Costs EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.21
3. Process, emissions and cost data listed above is for one unit.
4. For units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal
5. Retrofit factor of 60% used by URS based on site visit to Coal Creek Station.
6. SW disposal and fly ash sales data from Nov. 2011 Golder Fly Ash Evaluation, Appendix B2
7. One-time cost for Technology Licensing Fee for the SNCR process is ~0.5% of the Process Capital.

Great River Energy Coal Creek Station

Technical Update 06/07/2012

BART Supplement - NOx Emission Control Cost Analysis

Table A-8: Unit 2 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (Maintain Ash Sales)

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment			**3,600,000**
Purchased Equipment Costs			
Instrumentation	10.00%	of purchased equipment cost	360,000
Site Specific and Prime Contractor Markup	28.00%	of purchased equipment cost	1,008,000
Freight	5.00%	of purchased equipment cost	180,000
Purchased Equipment Total	43.00%		5,148,000
Purchased Equipment Total+ Retrofit Factor (A)			**8,236,800**
Indirect Installation			
General Facilities		See Notes & Assumptions 1 on pg. 1 of Table	410,000
Engineering & Home Office		See Notes & Assumptions 1 on pg. 1 of Table	820,000
Process Contingency		See Notes & Assumptions 1 on pg. 1 of Table	472,000
Total Indirect Installation Costs (B)		See Notes & Assumptions 1 on pg. 1 of Table	**1,702,000**
Project Contingeny (C)		See Notes & Assumptions 1 on pg. 1 of Table	**1,490,000**
Total Plant Cost (D)		A + B + C	**11,428,800**
Allowance for Funds During Construction (E)		0 for SNCR	**0**
Prepaid Royalties (F)		See Notes & Assumptionss 1 and 7 on pg. 1 of Table	**41,000**
Pre Production Costs (G)		See Notes & Assumptions 1 on pg. 1 of Table	**227,000**
Inventory Capital (H)		Reagent Vol * $/gal	**97,020**
Intial Catalyst and Chemicals (I)		0 for SNCR	**0**
Total Capital Investment (TCI) = DC + IC		D + E + F + G +H + I	**11,793,820**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**11,793,820**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	NA		-
Supervisor	NA		-
Maintenance			
Maintenance Total	1.50	% of Total Capital Investment	176,907
Maintenance Materials	NA	% of Maintenance Labor	-
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.060	See Direct Operating Cost Calculations on last pg.	22,367
Water	0.310	See Direct Operating Cost Calculations on last pg.	6,570
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
Urea	500.00	See Direct Operating Cost Calculations on last pg.	2,428,272
NA	NA		-
Total Annual Direct Operating Costs			**2,634,116**
Indirect Operating Costs			
Overhead	NA	of total labor and material costs	NA
Administration (2% total capital costs)	NA	of total capital costs (TCI)	NA
Property tax (1% total capital costs)	NA	of total capital costs (TCI)	NA
Insurance (1% total capital costs)	NA	of total capital costs (TCI)	NA
Capital Recovery	0.08368	for a 20- year equipment life and a 5.5% interest rate	986,899
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**986,899**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**3,621,015**

See Summary page for notes and assumptions

Great River Energy Coal Creek Station **Technical Update 06/07/2012**

BART Supplement - NOx Emission Control Cost Analysis

Table A-8: Unit 2 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (Maintain Ash Sales)

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.08368	

Replacement Catayst		<- Enter Equipment Name to Get Cost
Equipment Life	5	years
CRF	0.2342	
Rep part cost per unit	0	$/ft^3
Amount Required	12	ft^3
Packing Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:		<- Enter Equipment Name to Get Cost	
Equipment Life	2	years	
CRF	0.0000		
Rep part cost per unit	0	$/ft^3	
Amount Required	0	Cages	
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax	See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs
Installation Labor	0	10 min per bag, Labor + Overhead (68% = $29.65/hr)	
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	EPA CCM list replacement times from 5 - 20 min per bag.
Annualized Cost	**0**		

Electrical Use			
NOx in	0.15	lb/MMBtu	kW
NSR	0.44		
Power			44.0
Total			44.0

Reagent Use & Other Operating Costs					
NOx in	0.15	lb/MMBtu	Urea Use	1155	lb/hr
Efficiency	20%		Volume 14 day inventory	194	ton
Duty	6,022	MMBtu/hr	Inventory Cost	$97,020	
Water Use	2520	gal/hr			

Direct Operating Cost Calculations — **Annual hours of operation: 8,409.6** — **Utilization Rate: 100%**

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Operating Labor							
Op Labor	37	$/Hr	0.0	hr/8 hr shift	0	0	$/Hr, 0.0 hr/8 hr shift, 8409.6 hr/yr
Supervisor	15%	of Op.			NA	-	15% of Operator Costs
Maintenance							
Maintenance Total	1.5	% of Total Capital Investment				176,907.30	% of Total Capital Investment
Maint Mtls	0	% of Maintenance Labor			NA	0	0% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.06045	$/kwh	44.00000	kW-hr	370,022.40	22,367.23	0.0604 $/kwh X 44.0 kW-hr X 8409.6 hr/yr X 100% utilization
Water	0.31000	$/kgal	2520.00000	gph	21,192.19	6,569.58	0.3100 $/kgal X 2,520.0 gph/1000 X 8409.6 hr/yr X 100% utilization
Cooling Water	0.32080	$kgal	0.00000	gpm	0	0	$kgal, 0 gpm, 8409.6 hr/yr, 100% utilization
Comp Air	0.36713	$/kscf	0.00000	scfm/kacfm**	0	0	$/kscf, 0.0 scfm/kacfm**, 8409.6 hr/yr, 100% utilization
WW Treat Neutralization	1.95716	$/kgal	0.00000	gpm	0	0	$/kgal, 0.0 gpm, 8409.6 hr/yr, 100% utilization
WW Treat Biotreatement	4.95814	$/kgal	0.00000	gpm	0	0	$/kgal, 0.0 gpm, 8409.6 hr/yr, 100% utilization
SW Disposal	0.00000	$/ton	6.54014	ton/hr	55,000	0	$/ton, 6.5 ton/hr, 8409.6 hr/yr, 100% utilization
Haz W Disp	326.19330	$/ton	0.00000	ton/hr	0	0	$/ton, 0.0 ton/hr, 8409.6 hr/yr, 100% utilization
Ammonia Mitigation	5.61	$/ton	0.00000	ton/hr	0	0	$/ton, 0.0 ton/hr, 8409.6 hr/yr, 100% utilization
Lost Ash Sales	12.3	$/ton	0.00000	ton/hr	0	0	$/ton, 0.0 ton/hr, 8409.6 hr/yr, 100% utilization
Lime	90.0	$/ton	0.00000	lb/hr	0	0	$/ton, 0.0 lb/hr, 8409.6 hr/yr, 100% utilization
Urea	500.0	$/ton	0.57750	ton/hr	4,856.54	2,428,272.00	500.0 $/ton X 0.5775 ton/hr X 8409.6 hr/yr X 100% utilization
Oxygen	17.91078	kscf	0.00000	kscf/hr	0	0	kscf, 0.0 kscf/hr, 8409.6 hr/yr, 100% utilization

** Std Air use is 2 scfm/kacfm   *annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

Great River Energy Coal Creek Station **Technical Update 06/07/2012**

BART Supplement - NOx Emission Control Cost Analysis

Table A-9: Unit 2 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (30% Lost Ash Sales)

Operating Unit: **Unit 2**

Emission Unit Number	EU-2		Stack/Vent Number	SV-2	
Desgin Capacity	6,022	MMBtu/hr	Standardized Flow Rate	866,294	scfm @ 32º F
Expected Utiliztion Rate	100%		Temperature	330	Deg F
Expected Annual Hours of Operation	8,409.6	Hours	Moisture Content	13.3%	
Annual Interest Rate	5.5%		Actual Flow Rate	2,234,300	acfm
Expected Equipment Life	20	yrs	Standardized Flow Rate	1,391,000	scfm @ 330º F
Inlet NOx	0.153	lb/MMBtu	Dry Std Flow Rate	1,205,997	dscfm @ 330º F

CONTROL EQUIPMENT COSTS

Capital Costs			
Direct Capital Costs			
Purchased Equipment (A)			3,600,000
Purchased Equipment Total (B)			**8,236,800**
Installation - Standard Costs			1,230,000
Installation - Site Specific Costs			1,008,000
Installation Total			1,702,000
Total Capital Investment (TCI) = DC + IC			**11,793,820**
Operating Costs			
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.	4,852,291
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	986,899
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**5,839,190**

Emission Control Cost Calculation

Pollutant	Max Emis Lb/Hr	Pre-control Annual T/Yr	Cont Eff %	Exit Conc	Conc Units	Cont Emis T/yr	Reduction T/yr	Cont Cost $/Ton Rem
Nitrogen Oxides (NOx)	1,209.5	5,085.8	20.0%			4068.6	1,017.2	5,741

Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1

Notes & Assumptions

1. November 2011 SNCR Evaluation from URS
2. SNCR Maintenance Costs EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.21
3. Process, emissions and cost data listed above is for one unit.
4. For units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal
5. Retrofit factor of 60% used by URS based on site visit to Coal Creek Station.
6. SW disposal and fly ash sales data from Nov. 2011 Golder Fly Ash Evaluation, Appendix B2
7. One-time cost for Technology Licensing Fee for the SNCR process is ~0.5% of the Process Capital.

Great River Energy Coal Creek Station

Technical Update 06/07/2012

BART Supplement - NOx Emission Control Cost Analysis

Table A-9: Unit 2 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (30% Lost Ash Sales)

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment			**3,600,000**
Purchased Equipment Costs			
Instrumentation	10.00%	of purchased equipment cost	360,000
Site Specific and Prime Contractor Markup	28.00%	of purchased equipment cost	1,008,000
Freight	5.00%	of purchased equipment cost	180,000
Purchased Equipment Total	43.00%		5,148,000
Purchased Equipment Total+ Retrofit Factor (A)			**8,236,800**
Indirect Installation			
General Facilities		See Notes & Assumptions 1 on pg. 1 of Table	410,000
Engineering & Home Office		See Notes & Assumptions 1 on pg. 1 of Table	820,000
Process Contingency		See Notes & Assumptions 1 on pg. 1 of Table	472,000
Total Indirect Installation Costs (B)		See Notes & Assumptions 1 on pg. 1 of Table	**1,702,000**
Project Contingeny (C)		See Notes & Assumptions 1 on pg. 1 of Table	**1,490,000**
Total Plant Cost (D)		A + B + C	**11,428,800**
Allowance for Funds During Construction (E)		0 for SNCR	**0**
Prepaid Royalties (F)		See Notes & Assumptionss 1 and 7 on pg. 1 of Table	**41,000**
Pre Production Costs (G)		See Notes & Assumptions 1 on pg. 1 of Table	**227,000**
Inventory Capital (H)		Reagent Vol * $/gal	**97,020**
Intial Catalyst and Chemicals (I)		0 for SNCR	**0**
Total Capital Investment (TCI) = DC + IC		D + E + F + G +H + I	**11,793,820**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**11,793,820**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	NA		-
Supervisor	NA		-
Maintenance			
Maintenance Total	1.50	% of Total Capital Investment	176,907
Maintenance Materials	NA	% of Maintenance Labor	-
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.060	See Direct Operating Cost Calculations on last pg.	22,367
Water	0.310	See Direct Operating Cost Calculations on last pg.	6,570
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
SW Disposal	5.44	See Direct Operating Cost Calculations on last pg.	637,648
NA	NA		-
Ammonia Mitigation	5.61	See Direct Operating Cost Calculations on last pg.	814,853
Lost Ash Sales	12.30	See Direct Operating Cost Calculations on last pg.	765,675
NA	NA		-
Urea	500.00	See Direct Operating Cost Calculations on last pg.	2,428,272
NA	NA		-
Total Annual Direct Operating Costs			**4,852,291**
Indirect Operating Costs			
Overhead	NA	of total labor and material costs	NA
Administration (2% total capital costs)	NA	of total capital costs (TCI)	NA
Property tax (1% total capital costs)	NA	of total capital costs (TCI)	NA
Insurance (1% total capital costs)	NA	of total capital costs (TCI)	NA
Capital Recovery	0.08368	for a 20- year equipment life and a 5.5% interest rate	986,899
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**986,899**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**5,839,190**

See Summary page for notes and assumptions

Great River Energy Coal Creek Station **Technical Update 06/07/2012**

BART Supplement - NOx Emission Control Cost Analysis

Table A-9: Unit 2 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (30% Lost Ash Sales)

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.08368	

Replacement Catayst		<- Enter Equipment Name to Get Cost
Equipment Life	5	years
CRF	0.2342	
Rep part cost per unit	0	$\$/ft^3$
Amount Required	12	ft^3
Packing Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:		<- Enter Equipment Name to Get Cost	
Equipment Life	2	years	
CRF	0.0000		
Rep part cost per unit	0	$\$/ft^3$	
Amount Required	0	Cages	
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax	See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs
Installation Labor	0	10 min per bag, Labor + Overhead (68% = $29.65/hr)	
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	EPA CCM list replacement times from 5 - 20 min per bag.
Annualized Cost	**0**		

Electrical Use			
NOx in	0.15	lb/MMBtu	kW
NSR	0.44		
Power			44.0
Total			44.0

Reagent Use & Other Operating Costs					
NOx in	0.15	lb/MMBtu	Urea Use	1155	lb/hr
Efficiency	20%		Volume 14 day inventory	194	ton
Duty	6,022	MMBtu/hr	Inventory Cost	$97,020	
Water Use	2520	gal/hr			

Direct Operating Cost Calculations — **Annual hours of operation:** **8,409.6** — **Utilization Rate:** **100%**

Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
Operating Labor							
Op Labor	37	$/Hr	0.0	hr/8 hr shift	0	0	$/Hr, 0.0 hr/8 hr shift, 8409.6 hr/yr
Supervisor	15%	of Op.			NA	-	15% of Operator Costs
Maintenance							
Maintenance Total	1.5	% of Total Capital Investment				176,907.30	% of Total Capital Investment
Maint Mtls	0	% of Maintenance Labor			NA	0	0% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.06045	$/kwh	44.00000	kW-hr	370,022.40	22,367.23	0.0604 $/kwh X 44.0 kW-hr X 8409.6 hr/yr X 100% utilization
Water	0.31000	$/kgal	2520.00000	gph	21,192.19	6,569.58	0.3100 $/kgal X 2,520.0 gph/1000 X 8409.6 hr/yr X 100% utilization
Cooling Water	0.32080	$kgal	0.00000	gpm	0	0	$kgal, 0 gpm, 8409.6 hr/yr, 100% utilization
Comp Air	0.36713	$/kscf	0.00000	scfm/kacfm**	0	0	$/kscf, 0.0 scfm/kacfm**, 8409.6 hr/yr, 100% utilization
WW Treat Neutralization	1.95716	$/kgal	0.00000	gpm	0	0	$/kgal, 0.0 gpm, 8409.6 hr/yr, 100% utilization
WW Treat Biotreatement	4.95814	$/kgal	0.00000	gpm	0	0	$/kgal, 0.0 gpm, 8409.6 hr/yr, 100% utilization
SW Disposal	5.43836	$/ton	13.94240	ton/hr	117,250	637,648	5.4384 $/ton X 13.9 ton/hr X 8409.6 hr/yr X 100% utilization
Haz W Disp	326.19330	$/ton	0.00000	ton/hr	0	0	$/ton, 0.0 ton/hr, 8409.6 hr/yr, 100% utilization
Ammonia Mitigation	5.61	$/ton	17.27193	ton/hr	145,250	814,853	5.6 $/ton X 17.2719 ton/hr X 8409.6 hr/yr X 100% utilization
Lost Ash Sales	12.3	$/ton	7.40225	ton/hr	62,250	765,675	12.3 $/ton X 7.4023 ton/hr X 8409.6 hr/yr X 100% utilization
Lime	90.0	$/ton	0.00000	lb/hr	0	0	$/ton, 0.0 lb/hr, 8409.6 hr/yr, 100% utilization
Urea	500.0	$/ton	0.57750	ton/hr	4,856.54	2,428,272.00	500.0 $/ton X 0.5775 ton/hr X 8409.6 hr/yr X 100% utilization
Oxygen	17.91078	kscf	0.00000	kscf/hr	0	0	kscf, 0.0 kscf/hr, 8409.6 hr/yr, 100% utilization

** Std Air use is 2 scfm/kacfm *annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

Great River Energy Coal Creek Station

Technical Update 06/07/2012

BART Supplement - NOx Emission Control Cost Analysis

Table A-10: Unit 2 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (100% Lost Ash Sales)

Operating Unit: **Unit 2**

Emission Unit Number	EU-2		Stack/Vent Number	SV-2	
Desgin Capacity	6,022	MMBtu/hr	Standardized Flow Rate	866,294	scfm @ 32º F
Expected Utiliztion Rate	100%		Temperature	330	Deg F
Expected Annual Hours of Operation	8,409.6	Hours	Moisture Content	13.3%	
Annual Interest Rate	5.5%		Actual Flow Rate	2,234,300	acfm
Expected Equipment Life	20	yrs	Standardized Flow Rate	1,391,000	scfm @ 330º F
Inlet NOx	0.153	lb/MMBtu	Dry Std Flow Rate	1,205,997	dscfm @ 330º F

CONTROL EQUIPMENT COSTS

Capital Costs								
Direct Capital Costs								
Purchased Equipment (A)								3,600,000
Purchased Equipment Total (B)								**8,236,800**
Installation - Standard Costs								1,230,000
Installation - Site Specific Costs								1,008,000
Installation Total								1,702,000
Total Capital Investment (TCI) = DC + IC								**11,793,820**
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.						7,127,816
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost						986,899
Total Annual Cost (Annualized Capital Cost + Operating Cost)								**8,114,715**

Emission Control Cost Calculation

Pollutant	Max Emis Lb/Hr	Pre-control Annual T/Yr	Cont Eff %	Exit Conc	Conc Units	Cont Emis T/yr	Reduction T/yr	Cont Cost $/Ton Rem
Nitrogen Oxides (NOx)	1,209.5	5,085.8	20.0%			4068.6	1,017.2	7,978

Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1

Notes & Assumptions

1. November 2011 SNCR Evaluation from URS
2. SNCR Maintenance Costs EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 4.2 Chapter 1 Eq 1.21
3. Process, emissions and cost data listed above is for one unit.
4. For units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal
5. Retrofit factor of 60% used by URS based on site visit to Coal Creek Station.
6. SW disposal and fly ash sales data from Nov. 2011 Golder Fly Ash Evaluation, Appendix B2
7. One-time cost for Technology Licensing Fee for the SNCR process is ~0.5% of the Process Capital.

Great River Energy Coal Creek Station **Technical Update 06/07/2012**

BART Supplement - NOx Emission Control Cost Analysis

Table A-10: Unit 2 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (100% Lost Ash Sales)

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment			**3,600,000**
Purchased Equipment Costs			
Instrumentation	10.00%	of purchased equipment cost	360,000
Site Specific and Prime Contractor Markup	28.00%	of purchased equipment cost	1,008,000
Freight	5.00%	of purchased equipment cost	180,000
Purchased Equipment Total	43.00%		5,148,000
Purchased Equipment Total+ Retrofit Factor (A)			**8,236,800**
Indirect Installation			
General Facilities		See footnote 1 on pg. 1 of Table	410,000
Engineering & Home Office		See footnote 1 on pg. 1 of Table	820,000
Process Contingency		See footnote 1 on pg. 1 of Table	472,000
Total Indirect Installation Costs (B)		See footnote 1 on pg. 1 of Table	**1,702,000**
Project Contingeny (C)		See footnote 1 on pg. 1 of Table	**1,490,000**
Total Plant Cost (D)		A + B + C	**11,428,800**
Allowance for Funds During Construction (E)		0 for SNCR	**0**
Prepaid Royalties (F)		See footnotes 1 and 7 on pg. 1 of Table	**41,000**
Pre Production Costs (G)		See footnote 1 on pg. 1 of Table	**227,000**
Inventory Capital (H)		Reagent Vol * $/gal	**97,020**
Intial Catalyst and Chemicals (I)		0 for SNCR	**0**
Total Capital Investment (TCI) = DC + IC		D + E + F + G +H + I	**11,793,820**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**11,793,820**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	NA		-
Supervisor	NA		-
Maintenance			
Maintenance Total	1.50	% of Total Capital Investment	176,907
Maintenance Materials	NA	% of Maintenance Labor	-
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.060	See Direct Operating Cost Calculations on last pg.	22,367
Water	0.310	See Direct Operating Cost Calculations on last pg.	6,570
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
SW Disposal	7.40	See Direct Operating Cost Calculations on last pg.	1,941,450
NA	NA		-
NA	NA		-
Lost Ash Sales	12.30	See Direct Operating Cost Calculations on last pg.	2,552,250
NA	NA		-
Urea	500.00	See Direct Operating Cost Calculations on last pg.	2,428,272
NA	NA		-
Total Annual Direct Operating Costs			**7,127,816**
Indirect Operating Costs			
Overhead	NA	of total labor and material costs	NA
Administration (2% total capital costs)	NA	of total capital costs (TCI)	NA
Property tax (1% total capital costs)	NA	of total capital costs (TCI)	NA
Insurance (1% total capital costs)	NA	of total capital costs (TCI)	NA
Capital Recovery	0.08368	for a 20- year equipment life and a 5.5% interest rate	986,899
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**986,899**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**8,114,715**

See Summary page for notes and assumptions

Great River Energy Coal Creek Station **Technical Update 06/07/2012**

BART Supplement - NOx Emission Control Cost Analysis

Table A-10: Unit 2 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (100% Lost Ash Sales)

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.08368	

Replacement Catayst		<- Enter Equipment Name to Get Cost
Equipment Life	5	years
CRF	0.2342	
Rep part cost per unit	0	$/ft^3
Amount Required	12	ft^3
Packing Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:		<- Enter Equipment Name to Get Cost	
Equipment Life	2	years	
CRF	0.0000		
Rep part cost per unit	0	$/ft^3	
Amount Required	0	Cages	
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax	See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs
Installation Labor	0	10 min per bag, Labor + Overhead (68% = $29.65/hr)	
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	EPA CCM list replacement times from 5 - 20 min per bag.
Annualized Cost	**0**		

Electrical Use			
NOx in	0.15	lb/MMBtu	kW
NSR	0.44		
Power			44.0
Total			44.0

Reagent Use & Other Operating Costs					
NOx in	0.15	lb/MMBtu	Urea Use	1155	lb/hr
Efficiency	20%		Volume 14 day inventory	194	ton
Duty	6,022	MMBtu/hr	Inventory Cost	$97,020	
Water Use	2520	gal/hr			

Direct Operating Cost Calculations — **Annual hours of operation:** **8,409.6**; **Utilization Rate:** **100%**

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Operating Labor							
Op Labor	37	$/Hr	0.0	hr/8 hr shift	0	0	$/Hr, 0.0 hr/8 hr shift, 8409.6 hr/yr
Supervisor	15%	of Op.			NA	-	15% of Operator Costs
Maintenance							
Maintenance Total	1.5	% of Total Capital Investment				176,907.30	% of Total Capital Investment
Maint Mtls	0	% of Maintenance Labor			NA	0	0% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.06045	$/kwh	44.00000	kW-hr	370,022.40	22,367.23	0.0604 $/kwh X 44.0 kW-hr X 8409.6 hr/yr X 100% utilization
Water	0.31000	$/kgal	2520.00000	gph	21,192.19	6,569.58	0.31 $/kgal X 2,520.0 gph/1000 X 8409.6 hr/yr X 100% utilization
Cooling Water	0.32080	$kgal	0.00000	gpm	0	0	$kgal, 0 gpm, 8409.6 hr/yr, 100% utilization
Comp Air	0.36713	$/kscf	0.00000	scfm/kacfm**	0	0	$/kscf, 0.0 scfm/kacfm**, 8409.6 hr/yr, 100% utilization
WW Treat Neutralization	1.95716	$/kgal	0.00000	gpm	0	0	$/kgal, 0.0 gpm, 8409.6 hr/yr, 100% utilization
WW Treat Biotreatement	4.95814	$/kgal	0.00000	gpm	0	0	$/kgal, 0.0 gpm, 8409.6 hr/yr, 100% utilization
SW Disposal	7.39600	$/ton	31.21433	ton/hr	262,500	1,941,450	7.3960 $/ton X 31.2 ton/hr X 8409.6 hr/yr X 100% utilization
Haz W Disp	326.19330	$/ton	0.00000	ton/hr	0	0	$/ton, 0.0 ton/hr, 8409.6 hr/yr, 100% utilization
Ammonia Mitigation	5.61	$/ton	0.00000	ton/hr	0	0	$/ton, 0.0 ton/hr, 8409.6 hr/yr, 100% utilization
Lost Ash Sales	12.3	$/ton	24.67418	ton/hr	207,500	2,552,250	12.3 $/ton X 24.6742 ton/hr X 8409.6 hr/yr X 100% utilization
Lime	90.0	$/ton	0.00000	lb/hr	0	0	$/ton, 0.0 lb/hr, 8409.6 hr/yr, 100% utilization
Urea	500.0	$/ton	0.57750	ton/hr	4,856.54	2,428,272.00	500.0 $/ton X 0.5775 ton/hr X 8409.6 hr/yr X 100% utilization
Oxygen	17.91078	kscf	0.00000	kscf/hr	0	0	kscf, 0.0 kscf/hr, 8409.6 hr/yr, 100% utilization

** Std Air use is 2 scfm/kacfm *annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

GREAT RIVER
ENERGY®
A Touchstone Energy® Cooperative

12300 Elm Creek Blvd • Maple Grove, Minnesota 55369-4718 • 763-445-5000 • Fax 763-445-5050 • www.GreatRiverEnergy.com

June 7, 2012

VIA ELECTRONIC
AND U.S. MAIL

Mr. Terry O'Clair
Director, Division of Air Quality
North Dakota Department of Health
918 E. Divide Ave.
Bismarck, ND 58501-1947

RE: Coal Creek NOx BART Analysis: Technical Update

Dear Mr. O'Clair:

Please find enclosed a brief technical update to accompany Great River Energy's ("GRE's") April 5, 2012 Coal Creek Station Units 1 and 2 Supplemental Best Available Retrofit Technology Refined Analysis for NOx Emissions ("Supplemental BART Analysis"). GRE has updated the tables in its Supplemental BART Analysis to assist the North Dakota Department of Health ("NDDH") to evaluate the cost of several scenarios not expressly addressed in GRE's April 5, 2012 submission. GRE's update contains new control cost numbers based on the following assumptions:

- Coal Creek Station Unit 2's NOx emissions baseline has been adjusted to 0.201 lb/MMBtu instead of 0.153 lb/MMBtu;
- Baseline operating hours for Units 1 and 2 and the resulting emissions have been scaled up to reflect emissions in non-outage years; the result of this scale-up is a control efficiency of 39% (instead of 33%) for SNCR and LNC3+ together.

This update confirms GRE's long-standing position that LNC3+ is cost effective, but that SCNR and LNC3+ is not the Best Available Retrofit Technology ("BART") for Coal Creek Station Units 1 and 2 because the combined technologies are not cost effective on an actual or incremental basis. Even under a lowest-cost scenario that assumes no impact to ash sales, which we know is infeasible, the two controls remove NOx at a cost of roughly $2,200/ton, which is well above the presumptive standards set by EPA's BART guidelines. More importantly, the incremental cost of SNCR is roughly $4,700/ton, which demonstrates SNCR is not a cost-effective addition to the already-efficient LNC3+ controls. The cost of SNCR cannot be justified given that it results in no visibility improvements beyond that achieved with LNC3+ alone.

Please do not hesitate to call me if you have any questions about this update.

Sincerely,

Mary Jo Roth

Mary Jo Roth
Manager, Environmental Services

Enclosures

c: Tom Bachman, NDDH
William M. Bumpers (via e-mail)
Eric Olsen, GRE
Deb Nelson, GRE

Coal Creek Station Units 1 and 2
June 7, 2012 Technical Update

to

"Supplemental Best Available Retrofit Technology Refined Analysis for NOx Emissions," April 5, 2012

Coal Creek Station Technical Update to Supplemental BART Analysis for NOx Emissions

June 7, 2012

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1.0 Introduction

In December 2007, GRE submitted its final Best Available Retrofit Technology (BART) evaluation for Regional Haze controls to the North Dakota Department of Health (NDDH). The NDDH incorporated the proposed emission limits for Coal Creek Station (CCS) Units 1 and 2 into their proposed State Implementation Plan (SIP) and issued a draft Permit to Construct (PTC) for these BART emission limits. As part of their review of North Dakota's draft SIP, EPA requested supplemental data and documentation concerning Coal Creek's BART analysis. GRE provided the requested information.

On September 21, 2011, EPA proposed a Federal Implementation Plan (FIP), which would override certain NDDH determinations, particularly with respect to required NOx emission limits for certain coal-fired utility units. On November 3, 2011, NDDH requested that GRE provide a supplemental BART analysis that is focused on NOx control options at Coal Creek Station. In particular, GRE performed more refined analyses on selective non-catalytic reduction (SNCR) cost assumptions, achievable control levels and the overall impacts to beneficial use of ash for Coal Creek Station Units 1 and 2. An updated refined analysis was provided to address questions from NDDH on January 19, 2012. In response to questions from NDDH, a complete supplemental submittal was provided to NDDH on April 5, 2012.

Based on these refined analyses, Great River Energy still asserts that use of its state-of-the-art coal drying technology, DryFining™, in conjunction with second generation combustion control low-NOx burners with separated overfire air (LNC3+), meets EPA's presumptive BART NOx limit of 0.17 lb/MMBtu, and is consistent with cost effective thresholds. When all factors are adequately considered, including ammoniated ash impacts and incremental improvements in visibility, SNCR is not considered cost effective for Coal Creek Station given the lack of resulting incremental visibility improvements in the affected Class I areas.

This technical update is issued in response to additional inquiries from NDDH. This technical update, in conjunction with the April 5 supplemental submittal, provides the complete refined analysis of BART controls for Coal Creek Station.

Update to Section 2.2 Revision of Baseline NOx Emissions

Although GRE does not concede that NDDH's BART analysis may disregard any existing controls in use at a unit, GRE has nonetheless calculated a revised baseline for Unit 2 of 0.201 lb. NOx/MMBtu at NDDH's request. This value represents the baseline emissions for Unit 2 taking into consideration the installation of DryFining™ technology while not including the emission reductions gained through the installation of the LNC3+ tuning. The LNC3+ technology was installed in Unit 2 prior to the installation of the DryFining technology and is currently in use. Since Unit 2 has not operated with a DryFining-only configuration, we must utilize the information from Unit 1's emissions baseline as a surrogate for the projected baseline for the operation of LNC3+ as a stand-alone technology.

Update to Section 3.1 SNCR Control Cost Analysis

This technical update has modified the precision of some of the numbers in Table 3.1. The operating scenario utilized to calculate cost effectiveness was based on averaging data from outage and non-outage years, which GRE believes most accurately reflects real-world conditions. To portray the most-conservative, worst-case conditions the operating hours have been adjusted to portray a non-outage year. Due to the change in the baseline and operating hours, the control efficiency value has increased to 39 percent for the LNC3+ with SNCR technology combination in all lost ash sale scenarios. Although the recalculations have lowered the values for cost-effectiveness they remain above EPA's presumptive cost-effectiveness thresholds, and when all factors are considered GRE's conclusion that the installation of SNCR is not cost effective remains valid. Revised Table 3.1 is below.

Table 3.1 Control Cost Summary (2011$)

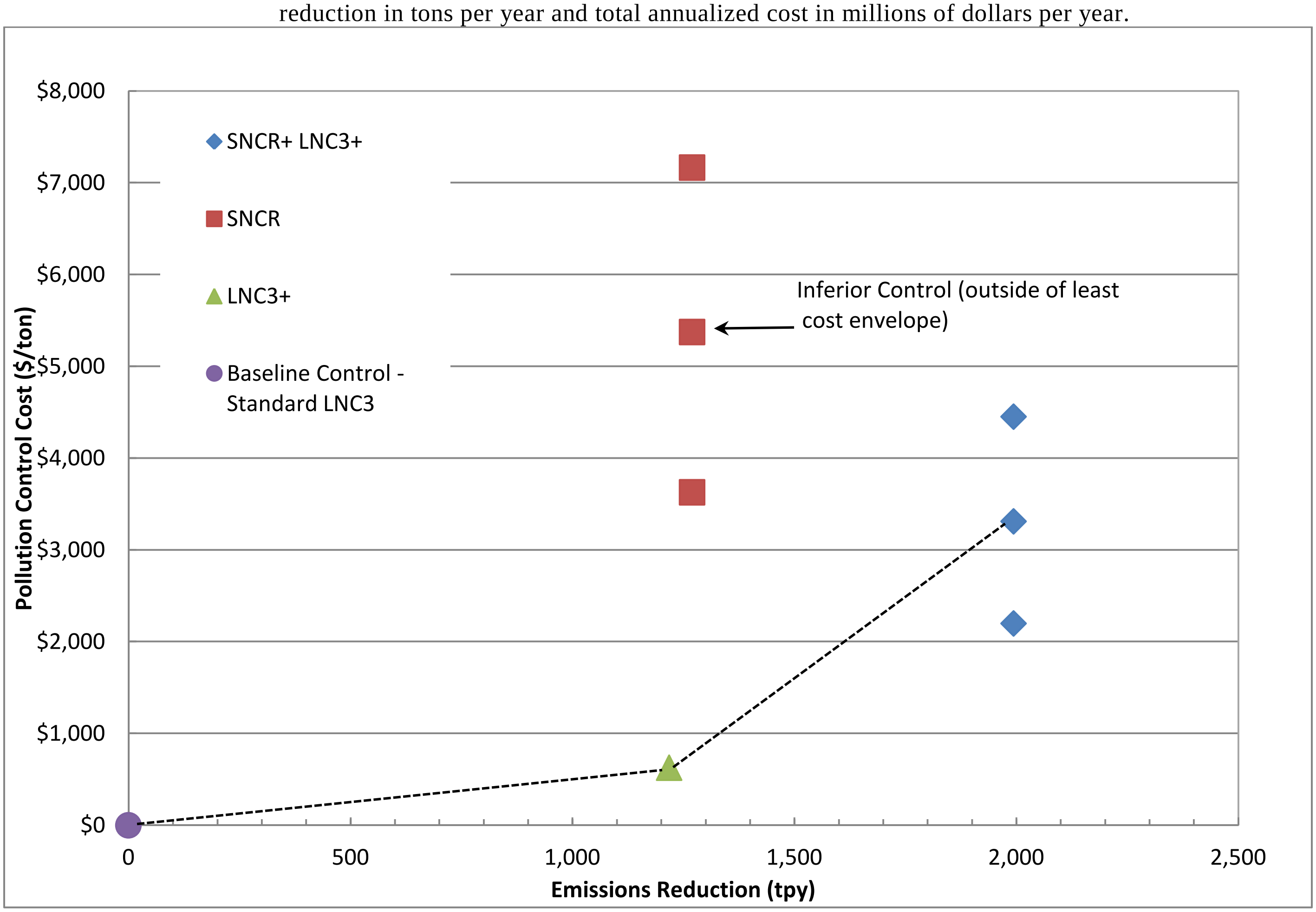
Unit ID	Control Description	NOx Emissions (lb/MMBtu)	Control Eff. From Baseline (%)	Emission Reduction from Baseline (T/yr)	Installed Capital Cost ($MM)	Annualized Operating Cost ($MM)	Pollution Control Cost ($/ton)	Incremental Cost $/ton
Unit 1	SNCR,LNC3+,100% Lost Ash Sales (Scenario B)	0.122	39%	1,994.3	$17.87	$8.879	$4,452	$10,457
	SNCR,LNC3+,30% Lost Ash Sales (Scenario C)					$6.604	$3,311	$7,524
	SNCR,LNC3+,No Ash Impacts (Scenario A)					*$4.385*	*$2,199*	*$4,666*
	SNCR, 100% Lost Ash Sales (Scenario B)	0.151	25%	1,270.0	$12.18	$9.101	$7,167	NA – Inferior Control
	SNCR, 30% Lost Ash Sales (Scenario C)					$6.826	$5,375	
	SNCR, No Ash Impacts (Scenario A)					*$4.608*	*$3,628*	
	LNC3+	0.153	24%	1,218.2	$6.08	$0.764	$627	$627
	Baseline (LNC3)	0.201	NA-Base	NA-Base	NA-Base	NA-Base	NA-Base	NA-Base
Unit 2	SNCR,LNC3+,100% Lost Ash Sales (Scenario B)	0.122	39%	1,996.6	$17.87	$8.879	$4,447	$10,444
	SNCR,LNC3+,30% Lost Ash Sales (Scenario C)					$6.604	$3,307	$7,516
	SNCR,LNC3+,No Ash Impacts (Scenario A)					*$4.385*	*$2,196*	*$4,661*
	LNC3+	0.153	24%	1,219.6	$6.08	$0.764	$627	$627
	Baseline – LNC3	0.201	NA-Base	NA-Base	NA-Base	NA-Base	NA-Base	NA-Base

A "No Ash Impacts" scenario is provided for reference only as it does not represent a feasible control option.

GRE takes this opportunity to reiterate that the controlled NOx emission concentrations and mass rates have been evaluated on an annual average basis and are not representative of anticipated operation on a shorter scale averaging period (30-day rolling or 24-hour rolling), consistent with BART guidance that costs be normalized to the expected annual emissions reduction. The 30-day rolling limits are intended to be inclusive of unit startup and shutdown as well as variability in load. Consequently, associated BART limits must be higher than stated annual averages used for estimating cost effectiveness (e.g., LNC3+ is evaluated at 0.153 lb. NOx/MMBtu on an annual average basis with an anticipated 30-day rolling limit of 0.17 lb. NOx/MMBtu). Section 2.2.2 Load Variability in the April 5, 2012 submittal summarizes these effects.

The modified baseline has also shifted the values for the least cost envelope graph which we have supplied for the sake of completeness. The assumptions concerning this table remain the same. Following the graph for least cost LNC3+ would be installed prior to installing any additional technology. The installation of SNCR alone would be an inferior technology and is deemed not cost effective.

Figure 3.1 Incremental NOx Analysis
The remaining feasible technologies are illustrated on the basis of annualized emissions reduction in tons per year and total annualized cost in millions of dollars per year.



3.3 SNCR Visibility Impacts

Table 3.2 Difference in Impairment and Incremental Cost for LNC3+ with Tuning and SNCR with LNC3+

Unit ID	2000 (dV)	2001 (dV)	2002 (dV)	Average (dV)	Incremental Cost per dV (MM$/dV)[1]
Unit 1	0.031	0.044	0.093	0.056	$103.81
Unit 1 & 2	0.062	0.083	0.172	0.106	$110.26

[1] Incremental cost comparison (2011$) of LNC3+ with SNCR with LNC3+ at 30% lost ash sales

The visibility analysis demonstrates that SNCR will not result in actual improvement to visibility in North Dakota's affected Class I areas, and potential modeled improvements will come at a prohibitive incremental cost exceeding $100 million (2011$) per deciview. Utilities in North Dakota only contribute ~6 percent to total NOx emissions in the State. Consequently, any additional utility NOx reductions will not have an appreciable effect on visibility improvement. Additional details regarding modeling inputs and visibility impairment is presented in Appendix D to the April 5, 2012 submittal.

4.0 Conclusions of Technical Update

In evaluating the impacts of Unit 1's technologies it was concluded that installation of SNCR alone (without LNC3+) is an economically inferior technology and therefore is not further evaluated incrementally. When the SNCR and LNC3+ technologies were evaluated together for Unit 1 and Unit 2 they were deemed not cost effective on an incremental basis and therefore not an appropriate BART technology. GRE included the visibility tables for the associated LNC3+, and SNCR cases presented in Table 3.1. The final conclusion for the visibility impacts is that, based on our refined analysis, the state Class I areas would not see any economically justifiable improvements in visibility by requiring a level of NOx control above LNC3+ for Coal Creek Station, and additional reductions would be cost prohibitive on a dollar per deciview basis (Table 3.2).

The refined analysis and subsequent updates clearly demonstrate that the presumptive NOx limit of 0.17 lb/MMBtu is both cost effective and results in significant visibility improvements in North Dakota's Class I areas.

Appendix A

Updated Pollution Control Cost Evaluations

Public Notice of Opportunity
to Comment on Supplemental Evaluation
of NO_x BART Determination for Coal Creek Station Units 1 and 2

The North Dakota Department of Health has conducted a supplemental evaluation of the nitrogen oxides (NO_x) Best Available Retrofit Technology (BART) determination for the Coal Creek Station. The BART determination is part of the Regional Haze State Implementation Plan that the Department has submitted to the U.S. Environmental Protection Agency. The supplemental evaluation considers new information regarding the cost of selective non-catalytic reduction (SNCR), the amount of visibility improvement expected to occur from the use of SNCR and other information provided by Great River Energy. The preliminary supplemental evaluation confirms the Department's original NO_x BART determination for the Coal Creek Station. That determination indicated that BART was combustion controls with an emission limit of 0.17 lb/MMBtu on a 30-day rolling average.

A copy of the proposed supplemental evaluation may be reviewed at the Department's website at www.ndhealth.gov/AQ/RegionalHaze/. A copy of the proposed supplement may be obtained by writing to the North Dakota Department of Health, Division of Air Quality, 918 E. Divide Ave., 2nd Floor, Bismarck, ND 58501-1947 or calling (701)328-5188. Written comments may be submitted to the above address from October 1 through October 30, 2012. A public hearing will be held only if there is a request from the public for a hearing. Any request for a hearing must be submitted in writing and received by Department before the end of the public comment period. If a hearing is requested, it will be held November 9, 2012 at 9:00 a.m. CST at the Gold Seal Center's 4th Floor conference room at 918 E. Divide Ave., Bismarck, North Dakota. If a public hearing is requested, the public comment period will remain open through November 16, 2012. If no requests for a public hearing are received, the announcement that the hearing has been cancelled will be posted on the Department's website at www.ndhealth.gov/AQ/notices.htm. The public may also call (701)328-5188 to find out if the hearing has been cancelled.

If you plan to attend a requested hearing and will need special facilities or assistance relating to a disability, please contact the Department of Health at the above-address at least three days prior to the hearing.

Dated this 12th day of September, 2012

Terry L. O'Clair, P.E.
Director
Division of Air Quality

NORTH DAKOTA
DEPARTMENT *of* HEALTH

ENVIRONMENTAL HEALTH SECTION
Gold Seal Center, 918 E. Divide Ave.
Bismarck, ND 58501-1947
701.328.5200 (fax)
www.ndhealth.gov

September 14, 2012

FILE

Mr. Carl Daly (8P-AR)
Director, Air Programs
U.S. EPA, Region 8
1595 Wynkoop Street
Denver, CO 80202-1129

Re: Supplemental Evaluation
Coal Creek NO_x BART Determination

Dear Mr. Daly:

The Department has completed its Supplemental Evaluation of the Coal Creek Station NO_x BART determination. Prior to making a final determination, the Department will be conducting a public comment period on the Supplemental Evaluation. Enclosed with this letter is a copy of the public notice. A public comment period will be held from October 1 through October 30, 2012. Also enclosed is a CD which contains the Supplemental Evaluation and additional information.

If you or your staff have any questions, please contact Tom Bachman of my staff at (701)328-5188.

Sincerely,

Terry L. O'Clair, P.E.
Director
Division of Air Quality

TLO/TB:csc
Enc:
xc/enc: Paul Seby, Special Assistant Attorney General
Margaret Olson, Assistant Attorney General
Mary Jo Roth, Great River Energy
Susan Johnson, National Park Service
Tim Allen, U.S. Fish and Wildlife Service
Mark Hummel, U.S Department if Agriculture

NORTH DAKOTA NEWSPAPER ASSOCIATION

Affidavit of Publication

Colleen Park, being duly sworn, states as follows:

1. I am the designated agent, under the provisions and for the purposes of, Section 31-04-06, NDCC, for the newspapers listed on the attached exhibits.

2. The newspapers listed on the exhibits published the advertisement of: **ND Health Department – Nitrogen Oxide Best Available Retrofit Technology; 1** time(s) as required by law or ordinance.

3. All of the listed newspapers are legal newspapers in the State of North Dakota and, under the provisions of Section 46-05-01, NDCC, are qualified to publish any public notice or any matter required by law or ordinance to be printed or published in a newspaper in North Dakota.

Signed: Colleen Park

State of North Dakota

County of Burleigh

Subscribed and sworn to before me this 25 day of October, 20 12

Sharon L. Peterson

SHARON L. PETERSON
Notary Public
State of North Dakota
My Commission Expires Nov. 8, 2017

mobile radio service (CMRS) carrier in North Dakota wire centers currently served by Qwest Corporation and SRT Communications, Inc.

The issues to be considered in this matter are:

1. Is the applicant qualified under the Telecommunications Act of 1996, Section 214(e) for designation as an ETC eligible to receive federal universal service funding?

2. What ETC universal service support area should be designated?

3. Is designation of the applicant as an ETC in the public interest?

Those interested are invited to comment on the application in writing. Persons desiring a hearing must file a written request identifying their interest in the proceeding and the reasons for requesting a hearing. Comments and requests for hearing must be received by October 26, 2012. If deemed appropriate, the Commission can determine the matter without a formal hearing.

For more information contact the Public Service Commission, State Capitol, Bismarck, North Dakota 58505, 701-328-2400; or Relay North Dakota 1-800-366-6888 TTY. If you require any auxiliary aids or services, such as readers, signers, or Braille materials please notify Darrell Nitschke, Executive Secretary.

PUBLIC SERVICE COMMISSION
Kevin Cramer, Commissioner
Brian P. Kalk, Chairman
Bonny M. Fetch, Commissioner
(September 24, 2012) 1558993

STATE OF NORTH DAKOTA
PUBLIC SERVICE COMMISSION
Midcontinent Communications/North Dakota Telephone Company Interconnection Agreement Amendment Application

Case No. PU-12-723

NOTICE OF OPPORTUNITY FOR COMMENT

September 12, 2012

On September 4, 2012, Midcontinent Communications (Midcontinent) entered into an interconnection agreement amendment with North Dakota Telephone Company (NDTC) pursuant to Section 251 of the Telecommunications Act of 1996 (Act). The agreement amendment sets forth terms and conditions under which NDTC will provide interconnection services, exchange of traffic, number portability, ancillary services and wholesale services for resale to Midcontinent in the Drake, Anamoose, and Fessenden, North Dakota exchanges. The agreement was filed with the Commission on September 5, 2012.

On September 5, 2012, Midcontinent filed a request for approval of the interconnection agreement in less than 90 days pursuant to 47 U.S.C. § 252(e)(1).

This agreement was filed under Section 252(e) of the Telecommunications Act of 1996. The Act requires that any agreement adopted by negotiation or arbitration be submitted for approval to the Commission. Under 47 U.S.C. § 252(e)(2)(A), the Commission may only reject an agreement adopted by negotiation (or a portion of the agreement) if it finds that:

1. the agreement discriminates against a telecommunications carrier that was not a party to the agreement; or

2. implementation of the agreement is not consistent with the public interest, convenience, and necessity.

In addition, under 47 U.S.C. Section 253 the Commission may include, in its review, state requirements that do not constitute barriers to entry.

The Commission will receive written comments on this agreement until October 24, 2012.

For more information contact the Public Service Commission, State Capitol, Bismarck, North Dakota 58505, 701-328-2400; or Relay North Dakota 1-800-366-6888 TTY. If you require any auxiliary aids or services, such as readers, signers, or Braille materials, please notify the Commission.

PUBLIC SERVICE COMMISSION
Kevin Cramer, Commissioner
Brian P. Kalk, Chairman
Bonny M. Fetch, Commissioner
(September 24, 2012) 1558999

their interest in the proceeding and the reasons for requesting a hearing. Comments and requests for hearings must be received by close of business on October 26, 2012.

For more information or copies of documents in these proceedings, contact the Public Service Commission, State Capitol, Bismarck, North Dakota 58505, 701-328-2400 or 877-245-6685 (toll free in North Dakota), or Relay North Dakota 1-800-366-6888 TTY. You may also view these cases, and documents, on our website.

If you require any auxiliary aids or services, such as readers, signers, or Braille materials, please notify the Commission at least 24 hours in advance.

PUBLIC SERVICE COMMISSION
Kevin Cramer, Commissioner
Brian P. Kalk, Chairman
Bonny M. Fetch, Commissioner
(September 24, 2012) 1559011

Public Notice of Opportunity to Comment on Supplemental Evaluation of Nox BART Determination for Coal Creek Station Units 1 and 2

The North Dakota Department of Health has conducted a supplemental evaluation of the nitrogen oxides (NOx) Best Available Retrofit Technology (BART) determination for the Coal Creek Station. The BART determination is part of the Regional Haze State Implementation Plan that the Department has submitted to the U.S. Environmental Protection Agency. The supplemental evaluation considers new information regarding the cost of selective non-catalytic reduction (SNCR), the amount of visibility improvement expected to occur from the use of SNCR and other information provided by Great River Energy. The preliminary supplemental evaluation confirms the Department's original NOx BART determination for the Coal Creek Station. That determination indicated that BART was combustion controls with an emission limit of 0.17 lb/MMBtu on a 30-day rolling average.

A copy of the proposed supplemental evaluation may be reviewed at the Department's website at www.ndhealth.gov/AQ/RegionalHaze/. A copy of the proposed supplement may be obtained by writing to the North Dakota Department of Health, Division of Air Quality, 918 E. Divide Ave., 2nd Floor, Bismarck, ND 58501-1947 or calling (701)328-5188. Written comments may be submitted to the above address from October 1 through October 30, 2012. A public hearing will be held only if there is a request from the public for a hearing. Any request for a hearing must be submitted in writing and received by Department before the end of the public comment period. If a hearing is requested, it will be held November 9, 2012 at 9:00 a.m. CST at the Gold Seal Center's 4th Floor conference room at 918 E. Divide Ave., Bismarck, North Dakota. If a public hearing is requested, the public comment period will remain open through November 16, 2012. If no requests for a public hearing are received, the announcement that the hearing has been cancelled will be posted on the Department's website at www.ndhealth.gov/AQ/notices.htm. The public may also call (701)328-5188 to find out if the hearing has been cancelled.

If you plan to attend a requested hearing and will need special facilities or assistance relating to a disability, please contact the Department of Health at the above-address at least three days prior to the hearing.

Dated this 12th day of September, 2012.
Terry L. O'Clair, P.E.
Director
Division of Air Quality
(September 24, 2012) 1560850

mons.
Dated September 17, 2012.
/s/ Scott C. Griffeth
Judicial Referee
East Central Judicial District
(September 24, October 1, 8, 2012) 1560863

STATE OF NORTH DAKOTA
COUNTY OF CASS
IN DISTRICT COURT
EAST CENTRAL JUDICIAL DISTRICT
The State of North Dakota, doing Business as The Bank of North Dakota, Plaintiff,
vs.
Estate of Scott W. Bubendorf, Defendant.

NOTICE OF SALE
Civil No. 09-2012-CV-01730

Notice is hereby given that by virtue of a Judgment and Decree of a foreclosure rendered and given by the Cass County District Court, North Dakota, and entered and docketed in the Office of the Clerk of Court on August 21, 2012, in an action wherein The State of North Dakota, doing business as The Bank of North Dakota was Plaintiff and the Estate of Scott W. Bubendorf, was the Defendant, adjudging that there is due and payable on the real estate mortgage described in Plaintiff's Complaint the sum of $82,477.61, which Judgment and Decree, among other things directed the sale by me of the real property hereinafter described to satisfy the amount of the Judgment with interest thereon and the cost and expenses of such sale are so much thereof as the proceeds of the sale applicable thereto will satisfy, and by virtue of a Writ to me issued out of the Office of the Clerk and under the Seal of the Court, directing me to sell the real property pursuant to said Judgment and Decree. I, Paul Laney, Sheriff of Cass County, North Dakota and the person appointed by the Court to make the sale, will sell the hereinafter described real estate to the highest bidder for cash at public auction at the front door of the courthouse in Fargo, Cass County, North Dakota, on October 31, 2012, at 10:00 a.m. of that date to satisfy the amount declared due and payable in said Judgment, with interest and costs thereon and the costs and expenses of such sale or so much thereof as the proceeds of such sale applicable thereto will satisfy. The premises to be sold pursuant to said Judgment and Decree and said Writ and to this notice are located in Cass County, North Dakota and are described in the Judgment and Decree and Writ as follows to wit:

Lot Ten, in Block Six, of Chateau Cheyenne Addition to the City of West Fargo, situate in the County of Cass and the State of North Dakota.

Parcel ID Number: 02005000710000

Which has the address of 705 Riverwood Drive, West Fargo, North Dakota 58078

The failure to include the street address in the notice, does not affect the validity of the notice. Please note the sale is subject to cancellation or postponement.

Dated this 12th day of September, 2012.
Paul Laney, Sheriff
Cass County Sheriff's Department
By: /s/ Tom Hall
Deputy Sheriff
The person to hold such sale.

Dated this 13th day of September, 2012.
State of North Dakota
Wayne Stenehjem
Attorney General
By: /s/ Douglas B. Anderson
Assistant Attorney General
State Bar ID No. 05072
Office of Attorney General
500 North 9th Street
Bismarck, ND 58501-4509
Telephone (701) 328-3640
Facsimile (701) 328-4300
Attorneys for plaintiff.
(September 24, October 1, 8, 2012) 1560948

9/24 Fargo

North Dakota Newspaper Association

1435 Interstate Loop
Bismarck, North Dakota 58503
Phone: 1-701-223-6397 Fax: 1-701-223-8185

INVOICE

October 26, 2012

Order: **12096NA0** Invoice# **1213**

Attn: Tom Bachman
ND Health Department
600 East Boulevard Avenue
Bismarck, North Dakota 58505

Voice: Fax:

Advertiser: **Administrative Services: Accounting**

Brand:

Campaign

Amount Due: $208.69

Please detach and return this portion with your payment

Administrative Services: Accounting Invoice# 1213 P.O.#:

Run Date	Ad Size	Rate Type	Rate	Color Rate	Total	Discount	(%)	Amount after Discount	Page
Bismarck Tribune (Bismarck, North Dakota)									
09/29/2012	67.00	Notice A Line	$0.78		$52.26	$0.00	(0.00%)	$52.26	
	Caption: Nitrogen Oxide Best Available Retrofit Technology								
Subtotal:	**67.00**		**$0.78**	**$0.00**	**$52.26**	**$0.00**		**$52.26**	
Fargo, The Forum (Fargo, North Dakota)									
09/24/2012	70.00	Notice A Line	$0.79		$55.30	$0.00	(0.00%)	$55.30	
	Caption: Nitrogen Oxide Best Available Retrofit Technology								
Subtotal:	**70.00**		**$0.79**	**$0.00**	**$55.30**	**$0.00**		**$55.30**	
Grand Forks Herald (Grand Forks, North Dakota)									
09/29/2012	67.00	Notice A Line	$0.75		$50.25	$0.00	(0.00%)	$50.25	
	Caption: Nitrogen Oxide Best Available Retrofit Technology								
Subtotal:	**67.00**		**$0.75**	**$0.00**	**$50.25**	**$0.00**		**$50.25**	
Minot Daily News (Minot, North Dakota)									
09/30/2012	96.00	Notice A Line	$0.53		$50.88	$0.00	(0.00%)	$50.88	
	Caption: Nitrogen Oxide Best Available Retrofit Technology								
Subtotal:	**96.00**		**$0.53**	**$0.00**	**$50.88**	**$0.00**		**$50.88**	

Gross Advertising	$208.69	Total Misc	$0.00	Amount Paid	$0.00
Agency Discount	$0.00	Tax	$0.00	Adjustments	$0.00
Other Discount	$0.00	Total Billed	$208.69	Payment Date	
Service Charge	$0.00	Unbilled	$0.00	Balance Due	$208.69

ND DEPT OF HEALTH
RECEIVED
OCT 29 2012
ACCOUNTING
TIME

OK for Payment
1250
10/30/12

United States Department of the Interior

FISH AND WILDLIFE SERVICE
National Wildlife Refuge System
Branch of Air Quality
7333 W. Jefferson Ave., Suite 375
Lakewood, CO 80235-2017

IN REPLY REFER TO:
FWS/ANWS-AR-AQ

October 29, 2012

Mr. Terry L. O'Clare, P.E., Director
Division of Air Quality
North Dakota Department of Health
918 E. Divide Avenue, 2nd Floor
Bismarck, North Dakota 58501-1947

Dear Mr. O'Clare:

On September 14, 2012, the State of North Dakota, Division of Air Quality provided its Supplemental Evaluation of the Coal Creek Station NO_x BART determination. The Division and Great River Energy are to be commended on providing additional extensive and credible analyses for the above evaluation. The additional information is comprehensive and has added value to the overall BART determination. The U.S. Fish and Wildlife Service, Branch of Air Quality, in cooperation with the National Park Service, Air Resources Division, is providing the enclosed questions and comments for your consideration.

This letter acknowledges that the U.S. Department of Interior, U.S. Fish and Wildlife Service, has conducted a substantive review of the draft Regional Haze SIP supplement in fulfillment of the requirements identified in 40 CFR 51.308(i). Please note, that only the U.S. Environmental Protection Agency can make a final determination regarding the document's completeness and, therefore, ability to receive federal approval from EPA.

We compliment you on your hard work and dedication to the significant improvement in our nation's air quality related values and visibility. If you have any questions or comments regarding these comments, please contact Tim Allen at (303) 914-3802.

Sincerely,

Meredith A Bond, DEPUTY CHIEF
for Sandra V. Silva
Chief, Branch of Air Quality

Enclosure

U. S. Fish and Wildlife Service Comments on the North Dakota Division of Air Quality Supplemental Evaluation of NO_x BART Determination for Coal Creek Station Units 1 & 2 October 29, 2012

The U. S. Fish and Wildlife Service (FWS) appreciates the opportunity to comment on the North Dakota Division of Air Quality's (DAQ) Supplemental Evaluation of NO_x BART Determination for Coal Creek Station Units 1 and 2, dated July 2012. The DAQ and Great River Energy (GRE) are to be commended on providing additional extensive and credible analyses in the above document. The additional information is comprehensive and has added value to the BART determination. In this document, we provide our evaluation as to the validity of the various conclusions without adding new data to that which has already been presented by DAQ and the U. S. Environmental Protection Agency (EPA).

As justification not to install Selective Non-Catalytic Reduction (SNCR) for Units 1 and 2, pages 1 and 33 of the Barr Engineering Company document entitled, "Coal Creek Station Units 1 and 2 – Supplemental Best Available Retrofit Technology Refined Analysis for NO_x Emissions" stated that installation of SNCR would have an imperceptible improvement in visibility that is far less than one-half of what EPA has determined to be perceptible to the human eye. Accepting that logic in its Supplemental Evaluation document on page 15, DAQ sustained the concept that the amount of visibility improvement is insignificant. It is incorrect to dismiss a control strategy on the basis that the resulting improvement is not perceptible or significant. EPA states in the preamble to its BART Guidelines, "Even though the visibility improvement from an individual source may not be perceptible, it should still be considered in setting BART because the contribution to haze may be significant relative to other source contributions in the Class I areas. Thus, we disagree that the degree of impairment should be contingent upon perceptibility. Failing to consider less-than-perceptible contributions to visibility impairment would ignore the CAA's intent to have BART requirements apply to sources that contribute to, as well as cause, such impairment."[1]

Nevertheless, Appendix Y of the Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations provides that the fifth factor in making BART determinations relates to the degree of improvement in visibility which may reasonably be anticipated to result from the use of a given technology.[2] Appendix Y further prescribes a quantitative analysis in terms of cost per deciview of visibility improvement to arrive at a conclusion.[3] Data to develop such a quantitative cost per deciview of visibility improvement are available in the various GRE BART determination reports, but they were not presented as a

[1] See Federal Register at 70 FR 30129, July 6, 2005; middle column
[2] See 40 CFR Part 51, Appendix Y, section I.C.2.(e).
[3] Ibid., See section IV.E.1.(4).

justification to not install SNCR on Units 1 and 2 by DAQ. This justification should be provided.

Our position is that such a calculation should include the cumulative impact on all affected Class I areas, rather than just the nearest Class I area (Lostwood National Wildlife Refuge). We continue to believe that it is appropriate to consider both the degree of visibility improvement in a given Class I area, as well as the cumulative effects of improving visibility across all of the affected Class I areas. It simply does not make sense to use the same metric to evaluate the effects of reducing emissions from a BART source that impacts only one Class I area as for a BART source that impacts multiple Class I areas. Additionally, it does not make sense to evaluate impacts at one Class I area, while ignoring other impacts at Class I areas that are similarly significantly impaired. When this analysis is completed DAQ may make a determination as to whether the cost per deciview of visibility improvement is reasonable using as a yardstick the cost of visibility improvement relative to other BART actions taken nationwide. The above reasoning is codified in 40 CFR Part 51, Appendix Y as follows: "A reasonable range would be a range that is consistent with the range of cost effectiveness values used in other similar permit decisions over a period of time."[4] If the cost of control options (e.g., SNCR) that achieve adequate and responsible visibility improvement remains reasonable after presumptive BART is achieved, adequate and responsible visibility improvement should remain an active consideration before the BART analysis is concluded.

The DAQ reconsideration of various estimates in the BART determination improved the overall analysis. The Golder Associates analysis of the ability to sell post-SNCR ash would seem to justify the use of some estimated percentage of ash that cannot be sold. Use of the 30% estimate for lost ash sales may be as reasonable as any for the cost analysis. It is appropriate to give deference to DAQ's environmental concerns about disposing of unsalable ash. The 1,155 lb/hr of urea reagent seemed to be reasonably justified by URS Corporation. The capital cost estimate for SNCR installation of \$20/kilowatt used by DAQ seems reasonable when compared to National Park Service NO_x BART data for several BART determinations that have been proposed nationally. DAQ acceptance of an SNCR control efficiency of 20% would seem justified, given URS Corporation's site-specific work, along with the Electric Power Research Institute's report entitled, "Low-Baseline NO_x Selective Non-Catalytic Reduction Demonstration". Adding a cost analysis using the original baseline emission rate of 0.22 lb of NO_x per million BTU, but also adding the costs related to the Dry Fining process and other interim improvements would provide an additional data point for consideration.

If the installation of SNCR is not ultimately selected for NO_x control in lieu of the Dry Fining process and low NO_x coal-and-air nozzles with close-coupled and separated overfire air (LNC3+), the proposed NO_x permit limit of 0.17 lb/MMBtu may not be sufficiently stringent,

[4] Ibid., See section IV.D.6.f.

given that Unit 2 was shown to attain a 0.153 lb/MMBtu emission rate. The 0.17 lb/MMBtu emission limit may have been chosen because it is the presumptive level of NO_x control for this type of unit. An analysis should be presented to determine an emission limit that is statistically attainable for enforcement purposes and if that limit is less than 0.17 lb/MMBtu, the proposed limit should be reduced.

The $3,305 cost per ton estimate for installation of SNCR and LNC3+ on Unit 1 should be adjusted downward as a result of reflecting a lower retrofit factor and using the original baseline emission rate of 0.22 lb of NO_x/MMBtu pursuant to EPA's comments. This would put the cost per ton estimate in a range that compares favorably with combustion controls combined with SNCR proposed to be installed on other facilities as found in the National Park Service compilation of BART proposals nationwide. This information helps to confirm that DAQ's cost estimate is in a proper range, but at the same time indicates that the cost might also be considered reasonable for BART on a cost per ton basis.[5] The FWS rejects the concept of adopting a specific cost ceiling above which a BART alternative is dismissed. All of the references to cost are relevant considerations, but the particular circumstance of the source (financially and with respect to the magnitude of necessary visibility improvements to be achieved now and in the future) bears heavily on acceptable cost ranges. In addition, the FWS believes that cost effective control options that result in emission control greater than presumptive BART (e.g., 0.17 lb of NOx/MMBtu) should be given equal consideration to lower-cost options that achieve presumptive BART.

There is validity to the consideration of adding SNCR to Coal Creek Station Units 1 and 2 based on the fact that other competing plants in North Dakota (Basin Electric Power - Leland Olds Plant, Great River Energy – Stanton Plant and Minnkota Power – MR Young Plant) have proposed SNCR for NO_x control. Appendix Y takes economic effects into consideration by stating, "Any analysis may also consider whether other competing plants in the same industry have been required to install BART controls if this information is available."[6]

Finally, we commend DAQ for its proposal to conduct pilot scale testing to answer questions for tail-end Selective Catalytic Reduction (SCR) on both soluble alkalis and ash characteristics (e.g., size, stickiness). Considering the recent drop in natural gas prices and the February 27, 2012 letter from Johnson Matthey Catalysts (LLC) to EPA Region 8 in which it stated that "JMC believes that low-dust and tail-end SCR configurations applied to North Dakota lignite fired boilers would also be technically feasible," we recommend that DAQ also re-evaluate the economic feasibility of these options (including regenerative SCR).

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[5] Ibid.

[6] Ibid., See section IV.E.3.2.

LAFARGE
NORTH AMERICA

Cement

October 16, 2012

OCT 2012
Received
Air Quality

Terry L. O'Clair, P.E., Director
North Dakota Department of Health
Division of Air Quality
918 E. Divide Ave., 2nd Floor
Bismarck, ND 58501-1947

Re: Comment on NDDH's September 12, 2012 Supplemental Evaluation of NOx BART Determination for Coal Creek Station Units 1 and 2

Dear Mr. O'Clair:

I am writing on behalf of Lafarge Dakota Inc. and Lafarge North America (collectively, "Lafarge") to provide comments on NDDH's September 12, 2012 Supplemental Evaluation of NOx BART Determination for Coal Creek Station Units 1 and 2.[1] Lafarge strongly supports NDDH's findings that transforming fly ash from an energy industry waste product into a resource for concrete has important environmental, economic, and health benefits. These considerations are especially important in North Dakota, where fly ash would have to be landfilled if not chemically acceptable as an ingredient in concrete. Should fly ash be unavailable within the state the carbon footprint for transportation cross-border would negate the current positive of reusing this waste product. It is important that fly ash in North Dakota remain locally available and is not put at risk by pollution-control technologies which, in Lafarge's experience, will result in at least some fly ash contamination.

BACKGROUND

Lafarge is the largest diversified supplier of construction materials in the United States and Canada. Our products are used in residential, commercial, and public works construction projects across North America. Lafarge products such as cement, ready-mix concrete, gypsum wallboard, aggregates, asphalt, and related products, are essential in creating the structures that shape our landscape.

Lafarge has extensive experience throughout North America and North Dakota in purchasing fly ash from industrial power plants and reusing that fly ash as a supplemental cementitious replacement for cement in manufacturing concrete. Lafarge has purchased fly ash from power plants that was later found to be contaminated by ammonia and has experience with

[1] NDDH's Supplemental Evaluation is available at https://www.ndhealth.gov/AQ/RegionalHaze/ (last visited October 10, 2012).

LAFARGE DAKOTA
684 15th Ave. SW. PO Box 757, Valley City, ND 58072
Telephone: (701) 845-2421 Fax: (701) 845-1849 Toll Free: 1-800-533-8662

the consequences including measuring ammonia levels in fly ash, fly ash disposal, and customer complaints regarding ammonia in concrete. Lafarge Dakota directly or indirectly purchases over one-hundred thousand tons of fly ash from Great River Energy's Coal Creek Station every year.

COMMENTS

1. Beneficial Uses of Fly Ash in Concrete

Lafarge has extensive experience with using fly ash as an ingredient in the concrete that it manufactures at facilities throughout the United States. Recycling fly ash in concrete has several environmental and technical benefits. First and foremost, using fly ash means we do not have to use cement which has a manufacturing process that generates CO2 due to high heat.. Furthermore, it is Lafarge's experience that concrete made of fly ash has excellent physical properties that render it more durable than usual. Fly ash also extends the life of concrete, which means less concrete must be manufactured over time. These benefits, and others, therefore make it very important that NDDH proceeds cautiously before taking any action that could put North Dakota's fly ash supply in jeopardy.

2. North Dakota's High Cement Demand

NDDH should take seriously the risk of even a small amount of fly ash being lost due to the state's high requirements.. North Dakota uses approximately 1 million tons of cement a year which arrives via limited railway transport capacity. Capacity is limited because it is not economic for railways to transport cement to North Dakota since it takes up a lot of space and does not command a high rate (as compared to other freight such as drilling supplies). This logistics issue limits the amount of concrete that can be manufactured for building projects in North Dakota to the available supply of cement and fly ash.

Any fly ash that is lost translates directly into concrete that cannot be made and that North Dakota must do without. That is because there are no other local or regional suppliers of fly ash.It is therefore, more important than ever, that fly ash remain available for use by Lafarge and other cement manufacturers, and that NDDH take no action that would put any of that fly ash at risk.

3. Fly Ash Contaminated by Ammonia

Lafarge strongly supports the NDDH's conclusion that pollution-control technologies utilizing ammonia-based reagents such as SNCR are sure to render at least some of Coal Creek Station's fly ash unmarketable. Lafarge has multiple facilities throughout the United States that have and continue to purchase fly ash from power plants using SNCR. Although these facilities all attempt to avoid any ammonia-contamination from occurring, Lafarge tests often find problematic levels of ammonia . It has been Lafarge's experience that even well-run facilities simply cannot prevent ammonia-contamination from occurring at levels that renders at least some of the fly ash unmarketable.

Lafarge's customers will not accept fly ash contaminated by ammonia. Different customers have different tolerances for ammonia-contamination depending on their intended use for the concrete.

Customers who use the concrete indoors have rejected concrete containing fly ash contaminated by ammonia at levels as low as 100 ppm. They have had workers express concerns over the resulting odor, their own safety, and compliance with OSHA requirements.

Customers who use the concrete outdoors for such things as paving have rejected concrete containing fly ash contaminated by ammonia at levels as low as 150 ppm. They expressed the same concerns as indoor users.

Lafarge thus believes its long-time experience in this industry vindicates the NDDH's concern over "the possibility of the loss of ash recycling." Supplemental Evaluation at 16. There will be lost fly ash due to the operation of SNCR, it is only a question of how much is lost.

4. Disposal Problems Arising from Ammonia-Contaminated Fly Ash

Lafarge has purchased fly ash from power plants around the country that had fly ash unintentionally contaminated by ammonia due to the operation of pollution-control technology at the power plants (e.g., SNCR). Consequently, Lafarge has experience with arranging for the transport and disposal of ammonia-contaminated fly ash. NDDH is wise to try to minimize, or eliminate entirely, the amount of fly ash having to be disposed of in North Dakota because disposing of fly ash presents a range of challenges. Fly ash is usually transported and disposed of as a liquid "slurry" that must be safely contained in order to ensure that it is properly contained. In 2008, a massive fly ash spill occurred when a retaining wall collapsed at the Kingston Fossil Plant outside of Knoxville, Tennessee. Although such risks can be managed, NDDH is correct in seeking to avoid the issue entirely by encouraging the continued recycling of fly ash in North Dakota.

I would be pleased to provide additional technical information regarding any of these issues. I can be reached at 701-845-2421.

Regards,

Roy V. Sander, Jr.

General Manager, Lafarge Dakota

Professional Engineer, ND

cc: file

NATIONAL PARKS CONSERVATION ASSOCIATION * SIERRA CLUB

October 30, 2012

Via Electronic Mail

Mr. Tom Bachman
North Dakota Department of Health
Division of Air Quality
918 E. Divide Ave.
Bismarck, ND 58501-1947
tbachman@nd.gov

Re: Supplemental Evaluation of NOx BART Determination for Coal Creek Station Units 1 and 2

Dear Mr. Bachman,

On behalf of National Parks Conservation Association and Sierra Club we respectfully submit the following comments on the North Dakota Department of Health's ("NDDH") Supplemental Evaluation of the Best Available Retrofit Technology ("BART") Determination for emissions of nitrogen oxides ("NO_x") from Coal Creek Station Units 1 and 2 ("Coal Creek"). Our organizations represent North Dakotans and people throughout the nation that care deeply about protecting the air quality in our national parks and wilderness areas in the Midwest. We support further reductions in emissions and other measures that will improve intra-state, inter-state, and regional visibility as required by the Clean Air Act's ("CAA") regional haze program. At a minimum, we support a NOx emissions limit for Coal Creek no higher than EPA's existing, lawfully issued final determination requiring a 30-day rolling average limit of 0.13 lbs/mmbtu.

I. NORTH DAKOTA'S SUPPLEMENTAL EVALUATION DOES NOT OBVIATE EPA'S LAWFUL FEDERAL IMPLEMENTATION PLAN

North Dakota's latest attempt to support its determination of BART to control NO_x emissions at Great River Energy's Coal Creek Station does not obviate EPA's Federal Implementation Plan ("FIP"). The submission is an untimely attempt to support the State's unlawful SIP—not a SIP submission that complies with the Act—and thus it cannot supplant EPA's lawfully issued FIP.

A. EPA Properly Exercised its Authority to Issue a Federal Implementation Plan

EPA properly exercised its authority under the Clean Air Act to implement a FIP both after it found North Dakota failed to submit a SIP within the time required by law, and after it found that North Dakota's untimely SIP submission did not comply with the Clean Air Act. *See* 42 U.S.C. § 7410(c)(1). North Dakota's obligation to develop a SIP addressing regional haze—including NO_x BART at Coal Creek—dates back to the 1977 Clean Air Act Amendments. With those amendments, Congress declared that ridding the nation's parks and wilderness areas of human-caused visible air pollution would henceforth be a "national goal." 42 U.S.C. § 7491(a)(2). Despite Congress's clear intent that EPA and the states immediately begin the process of clearing the haze in the national parks, *see id*. § 7491(a)(3)-(4), the program was long delayed by both EPA and state inaction. *See* 45 Fed. Reg. 80,084 (Dec. 2, 1980) (finalizing the first phase of regional haze regulations—regulations addressing visibility impairment that is "reasonably attributable" to a source or group of sources—over a year later than Congress required under 42 U.S.C. § 7491(a)(4)); 64 Fed. Reg. 35,714 (July 1, 1999) (finalizing the second phase of regional haze regulations over 20 years after the Congressional deadline). After the delays in implementing this important program, States were required to submit regional haze SIPs by December 17, 2007. 70 Fed. Reg. 39,104, 39,156 (July 6, 2005); see also 40 C.F.R. §§ 51.308(b), 51.309(c).

North Dakota failed to meet the December 17, 2007 deadline, and over one year later, EPA made a formal finding of North Dakota's failure to submit the required regional haze plan. See 74 Fed. Reg. 2,392 (Jan. 15, 2009). This formal finding triggered EPA's duty to issue a FIP within two years, unless North Dakota corrected the deficiency and EPA approved the plan before issuing a FIP. 42 U.S.C. § 7410(c)(1).

While the time for EPA to issue a FIP was running, North Dakota approved a final regional haze SIP and submitted it for EPA review on March 3, 2010. 76 Fed. Reg. 58,570, 58,579 (Sept. 21, 2011). After reviewing the SIP for compliance with the Clean Air Act, EPA proposed to find that portions of North Dakota's plan—including North Dakota's NO_x BART determination for Coal Creek—were legally inadequate. *Id.* at 58,603-04 (proposing to disapprove North Dakota's NO_x BART determination for Coal Creek "[b]ecause of the significant error underlying the State's cost analysis"). As a result, EPA proposed to exercise its authority to issue a FIP that would properly control NO_x emissions at Coal Creek. *Id.* at 58,619-23 (proposing a FIP finding that NO_x BART at Coal Creek was an emission limit of 0.12 lb/MMBtu based on installation and operation of selective non-catalytic reduction, separated overfire air, and low NO_x burners). On April 6, 2012, EPA finalized its finding that North Dakota's NO_x BART determination for Coal Creek was legally inadequate, which provided separate grounds for EPA to issue a FIP. *See* 42 U.S.C. § 7410(c)(1). EPA's FIP will improve visibility more than the State's BART determination for Coal Creek. 77 Fed. Reg. 20,894, 20,896-98(Apr. 6, 2012) (finalizing a slightly revised FIP under which NO_x BART for Coal Creek is 0.13 lb/MMBtu).

North Dakota was given ample time to submit a SIP that complied with the Clean Air Act, yet at each turn failed to do so. Consistent with the Clean Air Act, both North Dakota's failure to submit a SIP and North Dakota's later submission of a non-compliant SIP authorizes EPA to finalize a FIP bringing the state into compliance. 42 U.S.C. § 7410(c)(1)(A)-(B) (compelling EPA to promulgate a FIP within two years of determining that the "plan revision submitted by the State does not satisfy the minimum criteria established under subsection (k)(1)(A) of this section," or after it "disapproves a State implementation plan submission in whole or in part"). EPA need not have acted on North Dakota's SIP submission before promulgating a FIP, as the State's failure to submit a regional haze plan by the December 17, 2007 deadline authorized EPA to issue a FIP. *See* 42 U.S.C. § 7410(c)(1); *see also* 77 Fed. Reg.

at 20,906 (explaining that EPA would have been authorized to promulgate a regional haze FIP even without taking final action on North Dakota's SIP, given that EPA had already found that the state failed to timely submit a SIP (citing *WildEarth Guardians v. Jackson*, No. 11-cv-00001-CMA-MEH, 2011 WL 4485974, at *7 n.8 (D. Colo. Sept. 27. 2011)); Brief of Respondent at 24, *Oklahoma v. EPA*, Nos. 12-9526, 9527 (10th Cir. Aug. 14, 2012); *Coal. for Clean Air v. S. Cal. Edison Co.*, 971 F.2d 219, 223 (9th Cir. 1992).

Thus, EPA properly exercised its authority to promulgate a FIP including NO_x BART determinations of Coal Creek. The FIP corrects deficiencies in North Dakota's untimely SIP submission, and ensures that NO_x emissions from Coal Creek are controlled, protecting nearby Class I areas.

B. North Dakota's Untimely Supplemental Evaluation Does Not Supplant the FIP

Because North Dakota's supplemental evaluation of the NO_x BART determination for Coal Creek is an untimely attempt to bolster its unlawful SIP, it does not negate EPA's FIP. At the time it issued the FIP, EPA gave North Dakota the opportunity to issue a SIP revision that complied with the Clean Air Act. 77 Fed. Reg. at 20,897 (explaining that "North Dakota always has the discretion to revise its SIP and submit the revision to [EPA]. Should such a revision meet CAA requirements, [EPA] would replace [its] FIP with North Dakota's SIP revision."). Instead of re-submitting a SIP that complies with the Clean Air Act, North Dakota chose to provide a supplemental evaluation defending its prior BART determination. *See* North Dakota Department of Health, Division of Air Quality, Supplemental Evaluation of NO_x BART Determination for Coal Creek Station Units 1 and 2, 17 (Sept. 2012) ("reaffirm[ing] its decision that NO_x BART for GRE CCS [Coal Creek] is represented by combustion controls with a BART limit of 0.17 lb/106 Btu on a 30-day rolling average basis"). The time for the State to defend its prior NO_x BART determination for Coal Creek has passed.

Public comments on EPA's proposed disapproval of the State's NO_x BART determination for Coal Creek and the resultant FIP were due by November 21, 2011. 76 Fed. Reg. 58,570. North Dakota's Supplemental Evaluation of the NO_x BART determination for Coal Creek, dated September 2012, clearly comes too late. If the State's SIP depended on this analysis, Great River Energy and the State should have completed the required analysis while the State was putting together its SIP. *See* 77 Fed. Reg. at 20,918 (explaining that if Great River Energy believed that more site-specific information relevant to cost was needed to determine BART for Coal Creek, it should have provided that information within the time for the State to incorporate it into its SIP). At the latest, any necessary evaluation should have been completed within the time for public comments. Because North Dakota completed and submitted its supplemental evaluation well after the required time for public comments, the supplemental analysis has no bearing on the legality of EPA's decision to disapprove the SIP and issue a FIP. Instead, to the extent that North Dakota wants to defend its SIP, North Dakota is limited to bringing a challenge in federal court based on the evidence that was before the agency at the time of its final action, a remedy the State is actively pursuing. *See, e.g.*, Brief of Petitioner in No. 12-1844, State of North Dakota, No. 12-1844 (8th Cir. Oct. 5, 2012) (challenging, *inter alia*, EPA's disapproval of North Dakota's NO_x BART determination for Coal Creek and promulgation of a FIP); *see also* Brief of Petitioner Great River Energy, No. 12-1961 (8th Cir. Oct. 4, 2012) (same).

Given its limited scope, North Dakota's supplemental evaluation is not properly interpreted as a SIP submission that meets the requirements of the Clean Air Act and warrants EPA review. *See* 77 Fed. Reg. at 20,897 (inviting North Dakota to re-submit a SIP that complies with the Act). As its name suggests, the supplemental evaluation provides further support for why the State believes its original submission was lawful. *See, e.g.*, Supplemental Evaluation at 17. Yet as discussed above, this further support is untimely and has no bearing on EPA's prior rejection of North Dakota's NO_x BART determinations for Coal Creek. Moreover, as discussed in more detail below, because the supplemental evaluation does not demonstrate that North Dakota's NO_x BART determination for Coal Creek meets the Clean Air Act's standards, it does not and cannot displace EPA's FIP. EPA need not overturn its FIP in light of unpersuasive arguments that reaffirm a decision EPA has already found does not comply with the Clean Air Act.

II. NORTH DAKOTA'S SUPPLEMENTAL ANALYSIS IS INTERNALLY INCONSISTENT, TECHNICALLY FLAWED, AND LEGALLY DEFICIENT

Even if North Dakota's supplemental evaluation warranted EPA review, it contains significant flaws and internal inconsistencies such that its conclusion should not be considered. North Dakota fails to consider a superior technology, selective catalytic reduction ("SCR"). Its arguments against EPA's required control, selective non-catalytic reduction ("SNCR"), are flawed and often baseless. Its rejection of SNCR is inconsistent with other BART determinations proposed by the State. Furthermore, North Dakota failed to consider the cumulative impacts to all affected Class I areas, including those outside of North Dakota. Finally, all of these elements must be considered in light of the overall goal of eliminating visibility impairment in Class I areas; North Dakota does not provide such consideration. For these reasons, discussed in depth below, North Dakota's supplemental information, even if considered by EPA, does not warrant revising EPA's existing NO_x BART determination for Coal Creek.

A. North Dakota's Failure to Consider SCR Is Inappropriate

As noted above, North Dakota's submission is too limited in its scope to be properly interpreted as a SIP submission warranting EPA review. One missing element is an appropriate reconsideration of SCR. As discussed in our November 21, 2011 comments to EPA, we believe that SCR is both technically and economically feasible in the context of BART, particularly in light of Johnson Matthey's more recent offer of performance guarantees for low-dust and tail-end SCR used on plants firing North Dakota lignite. *See* Letter from Johnson Matthey to EPA, Docket ID No. EPA-R08-OAR-2010-0406-0322, dated February 27, 2012 (offering "SCR catalyst designs with reasonable operating lifetime guarantees for service in a low-dust or tail-end SCR configuration"). Regardless of the BART determination, we encourage North Dakota to move forward with the pilot testing described in its December 20, 2011 letter to EPA.

B. North Dakota's Evaluation of Non-Visibility Issues Regarding SNCR Is Flawed

North Dakota's supplemental evaluation includes additional information about SNCR, focused on "five major issues which significantly affect the BART determination" at Coal Creek.

Supplemental Evaluation at 3. As described in the Expert Report of Dr. Ranajit (Ron) Sahu, attached as Exhibit 1, this additional information is seriously flawed and lends itself to overestimating the costs associated with the use of SNCR while underestimating the benefits.

First, the baseline rate used appears to be underestimated. Underestimating the baseline can lead to lower estimated benefits and higher cost effectiveness values.

Second, North Dakota uses a lower control efficiency for SNCR than did EPA, and justifies this by claiming that the estimate is site specific. However, there is little or no support for the use of this rate, which appears to be neither site specific nor informed about state-of-the-art SNCR technology which increases control efficiency while minimizing ammonia slip.

Third, the capital cost estimates for SNCR are inflated and are not supported by underlying calculations or site specific information.

Finally, the potential for lost ash sales is exaggerated given SNCR technology designed to minimize ammonia slip and/or mitigate ammonia on fly ash. Nonetheless, North Dakota's sensitivity analysis shows that even with inflated costs, underestimated reductions, and the state's relatively low cost-effectiveness thresholds (average and incremental), SNCR + LNC3 is basically cost effective at or above 30% lost ash sales.[1]

Thus, North Dakota's supplemental evaluation provides no basis for EPA to change its existing BART determination for Coal Creek.

C. North Dakota's Rejection of SNCR Is Premised on an Internally Inconsistent and Arbitrary Analysis of Incremental Visibility Improvement

After discussion of the technical issues mentioned above, North Dakota based its BART determination and rejection of SNCR primarily on concerns that SNCR does not provide sufficient incremental visibility improvement relative to the cost. This basis for rejecting SNCR at Coal Creek is internally inconsistent and, as such, EPA need not reverse its. North Dakota's own BART determination for Stanton Station will achieve similar incremental visibility improvement for a similar cost as would be achieved under EPA's BART determination for Coal Creek. Given this internal inconsistency, North Dakota's supplemental evaluation is arbitrary and does not support reversing EPA's FIP.

In its proposed rule, EPA noted that installing SNCR at Coal Creek would cost approximately $2,500 per ton of NO_x emissions reduced (which is a conservative estimate, since the cost could be lower if fly ash contamination could be mitigated). 76 Fed. Reg. 58,570 58,623 (Sept. 21, 2011). The State of North Dakota itself selected SNCR as BART for Stanton Station, based on average cost effectiveness values ranging from $3,052 to $3,778 per ton of NO_x emissions reduced. *Id.* Even if one uses the higher average cost effectiveness for SNCR at coal Creek that the State proposes in its Supplemental Evaluation – $3,305 per ton, based on a 30% loss in fly ash sales – the average cost effectiveness is still within the range that the State

[1] Moreover, it is possible that future ash sales will be curtailed for separate reasons, e.g., federal regulation of coal ash.

approved for Stanton Station. It is also within the range that the State has established as reasonable. Supplemental Evaluation at 15 (stating that any cost effectiveness value below $3,650 per ton, in 2006 dollars, or $4,100 per ton, in 2011 dollars, would be deemed reasonable).

The same is true for visibility improvement; the incremental visibility improvement from SNCR at Coal Creek is similar to the incremental visibility improvement from SNCR at Stanton Station. The State estimated that installing SNCR at Stanton Station would create an incremental improvement in visibility of 0.135 deciviews or less. 76 Fed. Reg. at 58,623. Assuming for the sake of argument that the State's analysis is correct, the State calculates that SNCR at Coal Creek will yield a maximum visibility improvement of 0.106 deciviews. Supplemental Evaluation at 15. This is roughly the same incremental visibility improvement that the State deemed large enough to justify selecting SNCR as BART for Stanton Station.

In short, using either EPA's or the State of North Dakota's figures, the average cost effectiveness and the incremental visibility improvement from SNCR at Coal Creek is virtually the same as the average cost effectiveness and incremental visibility improvement from SNCR at Stanton Station. Given the similarity in these values, and given that the State's analysis placed great emphasis on cost and visibility improvement, it was arbitrary for North Dakota to approve SNCR as BART for Stanton Station but reject it for Coal Creek. EPA thus need not disturb its FIP in light of the State merely reiterating its internally inconsistent and arbitrary BART determination for Coal Creek.

D. The State Underestimated Visibility Improvement

1. The State underestimated visibility improvement by failing to consider cumulative visibility improvement

In the Supplemental Evaluation, the State understates the visibility improvement that would result from installing SNCR at Coal Creek. North Dakota's BART analysis depends in large part on the expected incremental visibility improvement from installing controls at Coal Creek at a single Class I area: Theodore Roosevelt National Park, North Unit. This expected visibility improvement (0.106 deciviews) would increase if the State considered the cumulative impact on all affected Class I areas, as it is authorized to do under the BART Guidelines.

Emissions from Coal Creek impact both Class I areas located in North Dakota, Theodore Roosevelt National Park and Lostwood Wilderness Area. While the State acknowledges this, and includes data in the Supplemental Evaluation for visibility improvement at both TRNP and Lostwood, the State does not add the visibility improvement that would occur at these two areas. Instead, the State focuses on visibility improvement at only the most affected Class I area, TRNP. Furthermore, as discussed below, no impacts to Class I areas outside of North Dakota were modeled, even at Medicine Lake Wilderness Area in Montana, which is within the typically modeled 300 km distance from the plant. It is likely that emissions from Coal Creek impact additional Class I areas outside of North Dakota. These impacts have not been considered.

Using a visibility improvement value from only a single Class I area skews the analysis in favor of weaker controls, since visibility improvement will always be lower at a single Class I area than it will be when summed across all affected Class I areas. EPA has demonstrated this principle in the regional haze plan for New York, stating:

> In making BART determinations, EPA also recommends the consideration of cumulative impacts and improvements that could occur at all the Class I areas a particular facility might impact. EPA's analysis of the cumulative visibility improvements at all 7 Class I areas justifies a more stringent BART emission limit.
>
> 77 Fed. Reg. 24,794, 24,814 (Apr. 25, 2012).

Likewise, EPA's BART Guidelines authorize the use of a cumulative visibility analysis. 40 C.F.R. Part 51, Appendix Y § (III)(A)(1) (authorizing states to consider the cumulative visibility impact of sources when setting a contribution threshold), § (III)(A)(2) (authorizing states to model the cumulative visibility impact of sources to show that no source is subject to BART). Based on these guidelines, and the fact that a more limited analysis could favor weaker controls, several EPA regions have considered the cumulative visibility improvement from pollution controls to be required as BART. *See* 77 Fed. Reg. 42,834, 42,857-58, 42,860-61, 42,863-64 (July 20, 2012) (Navajo Generating Station in Arizona); 77 Fed. Reg. 30,454, 30,462 (May 23, 2012) (Boardman Power Plant in Oregon); 77 Fed. Reg. at 24,814 (New York); 76 Fed. Reg. 491, 502, 503 (Jan. 5, 2011) (San Juan Generating Station in New Mexico); 75 Fed. Reg. 64,221, 64,230 (October 19, 2010) (Four Corners Power Plant in Arizona).

The State's failure to consider the full visibility improvement from SNCR is a significant flaw given that the State considered all alleged costs of the control. The State looked at the full costs of SNCR, including purported costs in addition to the direct costs of installing and operating controls – such as the indirect costs of any lost fly ash sales. Yet the State did not consider all of the benefits, namely, the visibility improvement, since the State focused on visibility improvement at a single Class I area, rather than the visibility improvement that would result at all affected Class I areas. In short, the State considered all of the costs, both direct and indirect, without considering all of the visibility benefits. By failing to consider the cumulative visibility improvement from controls at Coal Creek, the State biased its BART analysis in favor of weaker controls. For this reason alone, the State's BART analysis is deficient, and EPA properly disapproved it.

2. The State underestimated visibility improvement by considering a narrow geographic range of impacted areas and by not considering more than the 98% of impacts

As noted above, North Dakota has arbitrarily failed to model visibility benefits and impacts at all affected Class I areas, namely any that are outside of North Dakota. Historically, modeling has been limited to 300 km from the source not because the impacts end at that point, but because of the perceived reliability of the model past that point. Even within this historical assumption, North Dakota failed to document and consider impacts to Medicine Lake Wilderness Area in Montana, which is roughly 270 km from Coal Creek.

Beyond 300 km, the historical assumption that CALPUFF modeling could not reliably document impacts no longer holds; and even if it did, the impacts should at a minimum be considered qualitatively rather than ignored. EPA recently responded to a similar comment calling for review of impacts beyond 300 km; for the first time, EPA supported its truncated modeling by referencing a now-discredited 1998 report regarding CALPUFF performance. *See* Montana Regional Haze Federal Implementation Plan, 77 Fed. Reg. 57,864 (Sep. 18, 2012).

In its response to public comments on the Montana FIP, EPA stated, "[t]he Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 report (EPA, 1998) reviewed model performance evaluations of CALPUFF as a function of distance from the source and concluded that: …[u]se of CALPUFF for characterizing transport beyond 200 to 300 km should be done cautiously with an awareness of the likely problems involved." 77 Fed. Reg. at 57,867-68. EPA then concludes, "[t]herefore, given that the IWAQM guidance provides for the use of the CALPUFF model at receptor distances of up to 200 to 300 km, and given that EPA has already addressed uncertainty in the CALPUFF model, we believe it is reasonable to use CALPUFF to evaluate visibility impacts up to 300 km." *Id.* at 57,868.

We agree that CALPUFF is reliable at distances of 300 km. However, EPA's use of the IWAQM Phase 2 report to support its decision to exclude modeling at distances beyond 300 km, *id.* at 57,868-69, is arbitrary. First, changes to CALPUFF since 1998 may correct problems identified in the IWAQM Phase 2 report with modeling accuracy in the 200-1,000 km range. Second, a more recent study prepared for EPA called into question the conclusions of the IWAQM Phase 2 report upon which EPA relies. *See* Long Range Transport Models Using Tracer Field Experiment Data (May 2012) (EPA Contract No: EP-D-07-102, Work Assignment No: 4-06), attached hereto as Exhibit 2.[2] The May 2012 study concluded that "The inability of most (~90%) of the current study's CALPUFF sensitivity tests to reproduce the 1998 EPA study tracer test residence time on the 600 km receptor arc is a cause for concern." *Id.* at 11. Not only were the authors of the May 2012 study unable to reproduce the 1998 study's findings that CALPUFF overestimated pollutant concentrations at distances of 600 km, the 2012 study concluded that CALPUFF actually *underestimates* average pollutant concentrations at 600 km. *Id.* at 10.

Accordingly, reliance on CALPUFF at long distances would result in conservative estimates of visibility impacts. It is not appropriate to assume that such impacts are non-existent. North Dakota's failure to model and consider visibility impacts at all affected Class I areas – including those beyond 300 km, such as South Dakota's Badlands and Wind Cave national parks, or Montana's UL Bend Wilderness Area, all of which are between 300 and 600 km from Coal Creek – is not supported. Furthermore, North Dakota repeatedly asserts, without support, that CALPUFF overpredicts visibility impacts. North Dakota's assertions are contradicted by the May 2012 study results. To the extent that North Dakota relies on this bias in arriving at its BART determination, it should be revisited if not reversed by considering the maximum predicted impact rather than the 98th percentile.

[2] Also available on EPA's website at http://www.epa.gov/scram001/dispersion_prefrec.htm.

E. North Dakota's Analysis Unlawfully Fails To Consider Visibility Improvement in Relation to the Statutory Goal of Eliminating Visibility Impairment

North Dakota unlawfully considered visibility improvement in a vacuum, untethered from the statutory goal of eliminating visibility impairment at the Class I areas. Instead of evaluating whether the visibility improvement would help it reach the national goal, the State simply dismissed additional controls as not providing enough improvement. The State provided no criteria for judging whether a given amount of visibility improvement is enough, or in the State's terms, too "small." Indeed, the State simply asserted:

> the Department has chosen to weight the visibility impact heavily in this determination. . . Therefore, the Department gave greater consideration to the fact that the use of the more expensive SNCR at CCS provides only a small amount of improvement in visibility results. Accordingly, the use of SNCR at CCS is not warranted based on the small amount of improvement in visibility that could result from its use.

Supplemental Evaluation at 17.

Since BART is one element of a regional haze plan that must be designed to return Class I areas to natural visibility conditions, the visibility improvement from potential BART controls should be weighed in light of the amount of visibility improvement needed to reach the statutory goal of natural visibility. The presumptive goal established by EPA is to reach natural visibility by 2064. 40 C.F.R. § 51.308(d)(1)(i),(ii). To attain natural visibility in 2064 would require improving visibility 0.17 deciviews every year, for Theodore Roosevelt National Park, and 0.19 deciviews per year for Lostwood. 76 Fed. Reg. at 58,581.

North Dakota gives great weight to its claim that the maximum incremental visibility improvement from SNCR is 0.106 deciviews. But this amount represents nearly the entire improvement needed in a single year to be on a path toward attaining natural visibility in 2064. So even if it is appropriate to consider only the visibility improvement at a single Class I area (which it is not) the visibility improvement from SNCR is substantial when it is considered in light of the improvement needed to meet the uniform rate of progress at North Dakota's Class I areas.

This conclusion is bolstered by the fact that North Dakota does not purport to meet the uniform rate of progress and attain natural visibility in 2064, but rather proposes to reach natural visibility in 156 years at Theodore Roosevelt National Park and 232 years at Lostwood. 76 Fed. Reg. At 58,628. Under these scenarios, North Dakota would achieve far less visibility improvement than the 0.17 and 0.19 deciviews per year that would be necessary to meet the uniform rate of progress. 76 Fed. Reg. At 58,581. Thus, an incremental visibility improvement of 0.106 dv is even larger and more significant extent when considered in light of the yearly visibility improvement North Dakota would make under its reasonable progress goals. This incremental visibility improvement is significant even when the average is considered in addition to the maximum.

In sum, North Dakota failed to supply a reasoned explanation for its conclusion that the visibility improvement from SNCR is "small." Since North Dakota's BART determination was based primarily on a consideration of visibility improvement, this failure to explain the principal rationale renders North Dakota's determination arbitrary and capricious. Moreover, when the visibility improvement from SNCR is considered in light of the statutory goal of making reasonable progress toward natural visibility, the visibility improvement from SNCR is significant. Thus, EPA properly disapproved the State's proposed BART determination for Coal Creek.

CONCLUSION

EPA need not review the Supplemental Evaluation of the NO_x BART determination for Coal Creek because the Evaluation is untimely and is not a SIP submission. Even if EPA were to consider the Supplemental Evaluation, it provides no support for revising the NO_x BART determination that EPA adopted in its FIP. The Clean Air Act provides EPA with both the authority and the obligation to issue a FIP containing a NO_x BART determination for Coal Creek. Moreover, EPA properly determined that NO_x BART for Coal Creek Units 1 and 2 should, at a minimum, be an emissions limit reflecting the operation of SNCR.

Thank you for the opportunity to comment on NDDH's proposed Supplemental Evaluation of NO_x BART Determination for Coal Creek Station Units 1 and 2.

Sincerely,

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Documentation of the Evaluation of CALPUFF and Other Long Range Transport Models Using Tracer Field Experiment Data

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Documentation of the Evaluation of CALPUFF and Other Long Range Transport Models Using Tracer Field Experiment Data

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FOREWARD

This report documents the evaluation of the CALPUFF and other Long Range Transport (LRT) dispersion models using several inert tracer study field experiment data. The LRT dispersion modeling was performed primarily by the U.S. Environmental Protection Agency (EPA) during the 2008-2010 time period and builds off several previous LRT dispersion modeling studies that evaluated models using tracer study field experiments (EPA, 1986; 1998a; Irwin, 1997). The work was performed primarily by Mr. Bret Anderson while he was with EPA Region VII, EPA/OAQPS and the United States Forest Service (USFS). Mr. Roger Brode and Mr. John Irwin (retired) of the EPA Office of Air Quality Planning and Standards (OAQPS) also assisted in the LRT model evaluation. The LRT modeling results were provided to ENVIRON International Corporation who quality assured and documented the results in this report under Task 4 of Work Assignment No. 4-06 of EPA Contract EP-D-07-102. The report was prepared for the Air Quality Modeling Group (AQMG) at EPA/OAQPS that is led by Mr. Tyler Fox. Dr. Sarav Arunachalam from the University Of North Carolina (UNC) Institute for Environment was the Work Assignment Manager (WAM) for the prime contractor to EPA. The report was prepared by Ralph Morris, Kyle Heitkamp and Lynsey Parker of ENVIRON.

Numerous people provided assistance and guidance to EPA in the data collection, operation and evaluation of the LRT dispersion models. We would like to acknowledge assistance from the following people:

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- Joseph Scire and Dave Strimaitis (Exponent) – CAPTEX meteorological observations and puff-splitting sensitivity tests guidance
- Mesoscale Model Interface (MMIF) Development Team:
  - EPA OAQPS; EPA Region 7, EPA Region 10; US Department of Interior (USDOI) Fish & Wildlife Service Branch of Air Quality, USDOI National Park Service Air Division and US Department of Agriculture (USDA) Forest Service Air Resources Management Program

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Appendices

EXECUTIVE SUMMARY

ABSTRACT

The CALPUFF Long Range Transport (LRT) air quality dispersion modeling system is evaluated against several atmospheric tracer field experiments. Meteorological inputs for CALPUFF were generated using MM5 prognostic meteorological model processed using the CALMET diagnostic wind model with and without meteorological observations. CALPUFF meteorological inputs were also generated using the Mesoscale Model Interface (MMIF) tool that performs a direct "pass through" of the MM5 meteorological variables to CALPUFF without any adjustments or re-diagnosing of meteorological variables, as is done by CALMET. The effects of alternative options in CALMET on the CALMET meteorological model performance and the performance of the CALPUFF LRT dispersion model for simulating observed atmospheric tracer concentrations was analyzed. The performance of CALPUFF was also compared against past CALPUFF evaluation studies using an earlier version of CALPUFF and some of the same tracer test field experiments as used in this study. In addition, up to five other LRT dispersion models were also evaluated against some of the tracer field experiments. CALPUFF and the other LRT models represent three distinct types of LRT dispersion models: Gaussian puff, particle and Eulerian photochemical grid models. Numerous sensitivity tests were conducted using CALPUFF and the other LRT models to elucidate the effects of alternative meteorological inputs on dispersion model performance for the tracer field studies, as well as to intercompare the performance of the different dispersion models.

INTRODUCTION

Near-Source and Far-Field Dispersion Models

Dispersion models, such as the Industrial Source Complex Short Term (ISCST) or American Meteorological Society/Environmental Protection Agency Regulatory Model (AERMOD) typically assume steady-state, horizontally homogeneous wind fields instantaneously over the entire modeling domain and are usually limited to distances of less than 50 kilometers from a source. However, dispersion model applications of distances of hundreds of kilometers from a source require other models or modeling systems. At these distances, the transport times are sufficiently long that the mean wind fields can no longer be considered steady-state or homogeneous. As part of the Prevention of Significant Deterioration (PSD) program, new sources or proposed modifications to existing sources may be required to assess the air quality and Air Quality Related Value (AQRV) impacts at Class I and sensitive Class II areas that may be far away from the source (e.g., > 50 km). AQRVs include visibility and acid (sulfur and nitrogen) deposition. At these far downwind distances, the steady-state Gaussian plume assumptions of models like ISCST and AERMOD are likely not valid and Long Range Transport (LRT) dispersion models are required.

The Interagency Workgroup on Air Quality Modeling (IWAQM) consists of the U.S. EPA and Federal Land Managers (FLMs; i.e., NPS, USFS and FWS) and was formed to provide a focus for the development of technically sound recommendations regarding assessment of air pollutant source impacts on Federal Class I areas. One objective of the IWAQM is the recommendation of LRT dispersion models for assessing air quality and AQRVs at Class I areas. One such LRT dispersion model is the CALPUFF Gaussian puff modeling system, which includes the CALMET diagnostic wind model and the CALPOST post-processor. In 1998, EPA published a report that evaluated CALPUFF against two short-term tracer test field experiments (EPA, 1998a). Later in 1998 IWAQM released their Phase II recommendations (EPA, 1998b) that included recommendations for using the CALPUFF LRT dispersion model for addressing far-field air quality and AQRV issues at Class I areas. The IWAQM Phase II report did not recommend any specific settings for running CALMET and noted that the required expert judgment to develop a set of recommended CALMET settings would be developed over time.

In 2003, EPA issued revisions to the Guidelines on Air Quality Models (Appendix W) that recommended using the CALPUFF LRT dispersion model to address far-field (> 50 km) air quality issues associated with chemically inert compounds. The EPA Air Quality Modeling Guidelines were revised again in 2005 to include AERMOD as the EPA-recommended dispersion model for near-source (< 50 km) air quality issues.

CALPUFF Modeling Guidance

EPA convened a CALPUFF workgroup starting in 2005 to help identify issues with the 1998 IWAQM Phase II recommendations. The CALPUFF workgroup began to revisit the evaluation of CALPUFF against tracer test field experiments. In May 2009, EPA released a reassessment of the IWAQM Phase II recommendations (EPA, 2009a) that raised issues with settings used in recent CALMET model applications. CALMET is typically applied using prognostic meteorological model (i.e., MM5 or WRF) three-dimensional wind fields as an input first guess and then applying diagnostic wind effects (e.g., blocking, deflection, channeling and slope flows) to produce a STEP1 wind field. CALMET then blends in surface and upper-air meteorological observations into the STEP1 wind field using an objective analysis (OA) procedure to produce the resultant STEP2 to wind field that is provided as input into CALPUFF. CALMET also diagnoses several other meteorological variables (e.g., mixing heights). CALMET contains numerous options that can significantly affect the resultant meteorological fields. The EPA IWAQM reassessment report found that the CALMET STEP1 diagnostic effects and STEP2 OA procedures can degrade the MM5/WRF wind fields. Furthermore, the IWAQM reassessment report noted that options used in some past CALMET applications were selected based on obtaining a desired outcome rather than based on good science. Consequently, the 2009 IWAQM reassessment recommended CALMET settings that would “pass through” MM5/WRF meteorological fields as much as possible for input into CALPUFF. However, further testing of CALMET by the EPA CALPUFF workgroup found that the recommended CALMET settings in the May 2009 IWAQM reassessment report did not achieve the intended desired result to “pass through” as much as possible the MM5/WRF meteorological variables as CALMET still re-diagnosed some and modified other meteorological variables. Based in part on testing by the CALPUFF workgroup using the tracer test field experiments, on August 31, 2009 EPA released a Clarification Memorandum (EPA, 2009b) that contained specific EPA-FLM recommended settings for operating CALMET for regulatory applications.

Mesoscale Model Interface (MMIF) Tool

In the meantime, EPA has developed the Mesoscale Model Interface (MMIF) tool that will “pass through” as much as possible the MM5/WRF meteorological output to CALPUFF without modifying the meteorological fields (Emery and Brashers, 2009; Brashers and Emery 2011; 2012). The CALPUFF Workgroup has been evaluating the CALPUFF model using the CALMET and MMIF meteorological drivers for four tracer test field experiments. For some of the field experiments, additional LRT dispersion models have also been evaluated. This report documents the work performed by the CALPUFF workgroup over the 2009-2011 time frame to evaluate CALPUFF and other LRT dispersion models using four tracer test field experiment databases.

OVERVIEW OF APPROACH

Up to six LRT dispersion models were evaluated using four atmospheric tracer test field experiments.

Tracer Test Field Experiments

LRT dispersion models are evaluated using four atmospheric tracer test field studies as follows:

1980 Great Plains: The 1980 Great Plains (GP80) field study released several tracers from a site near Norman, Oklahoma in July 1980 and measured the tracers at two arcs to the northeast at distances of 100 and 600 km (Ferber et al., 1981).

1975 Savannah River Laboratory: The 1975 Savannah River Laboratory (SRL75) study released tracers from the SRL in South Carolina and measured them at receptors approximately 100 km from the release point (DOE, 1978).

1983 Cross Appalachian Tracer Experiment: The 1983 Cross Appalachian Tracer Experiment (CAPTEX) was a series of five three-hour tracer released from Dayton, OH or Sudbury, Canada during September and October, 1983. Sampling was made in a series of arcs approximately 100 km apart that spanned from 300 to 1,100 km from the Dayton, OH release site.

1994 European Tracer Experiment: The 1994 European Tracer Experiment (ETEX) consisted of two tracer releases from northwest France in October and November 1994 that was measured at 168 monitoring sites in 17 countries.

LRT Dispersion Models Evaluated

The six LRT dispersion models that were evaluated using the tracer test field study data in this study were:

CALPUFF[1]: The California Puff (CALPUFF Version 5.8; Scire et al, 2000b) model is a Lagrangian Gaussian puff model that simulates a continuous plume using overlapping circular puffs. CALPUFF was applied using both the CALMET meteorological processor (Scire et al., 2000a) that includes a diagnostic wind model (DWM) and the Mesoscale Model Interface (MMIF; Emery and Brashers, 2009; Brashers and Emery, 2011; 2012) tool that will "pass through" output from the MM5 or WRF prognostic meteorological models.

SCIPUFF[2]: The Second-order Closure Integrated PUFF (SCIPUFF Version 2.303; Sykes et al., 1998) is a Lagrangian puff dispersion model that uses Gaussian puffs to represent an arbitrary, three-dimensional time-dependent concentration field. The diffusion parameterization is based on turbulence closure theory, which gives a prediction of the dispersion rate in terms of the measurable turbulent velocity statistics of the wind field.

HYSPLIT[3]: The Hybrid Single Particle Lagrangian Integrated Trajectory (HYSPLIT Version 4.8; Draxler, 1997) is a complete system for computing simple air parcel trajectories to complex dispersion and deposition simulations. The dispersion of a pollutant is calculated by assuming either puff or particle dispersion. HYSPLIT was applied primarily in the default particle model where a fixed number of particles are advected about the model domain by the mean wind field and spread by a turbulent component.

1 http://www.src.com/calpuff/calpuff1.htm
2 http://www.sage-mgt.net/services/modeling-and-simulation/scipuff-dispersion-model
3 http://www.arl.noaa.gov/HYSPLIT_info.php

FLEXPART[4]: The FLEXPART (Version 6.2; Siebert, 2006; Stohl et al., 2005[5]) model is a Lagrangian particle dispersion model. FLEXPART was originally designed for calculating the long-range and mesoscale dispersion of air pollutants from point sources, such as after an accident in a nuclear power plant. In the meantime FLEXPART has evolved into a comprehensive tool for atmospheric transport modeling and analysis

CAMx[6]: The Comprehensive Air-quality Model with extensions (CAMx; ENVIRON, 2010) is a photochemical grid model (PGM) that simulates inert or chemical reactive pollutants from the local to continental scale. As a grid model, it simulates transport and dispersion using finite difference techniques on a three-dimensional array of grid cells.

CALGRID: The California Mesoscale Photochemical Grid Model (Yamartino, et al., 1989, Scire et al., 1989; Earth Tech, 2005) is a PGM that simulates chemically reactive pollutants from the local to regional scale. CALGRID was originally designed to utilize meteorological fields produced by the CALMET meteorological processor (Scire et al., 2000a), but was updated in 2006 to utilize meteorology and emissions in UAM format (Earth Tech, 2006).

The six LRT dispersion models represent two non-steady-state Gaussian puff models (CALPUFF and SCIPUFF), two three-dimensional particle dispersion models (HYSPLIT and FLEXPART) and two three-dimensional photochemical grid models (CAMx and CALGRID). HYSPLIT can also be run in a puff and hybrid particle/puff modes, which was investigated in sensitivity tests. All six LRT models were evaluated using the CAPTEX Release 3 and 5 field experiments and five of the six models (except CALGRID) were evaluated using the ETEX field experiment database.

Evaluation Methodology

Two different model performance evaluation methodologies were utilized in this study. The Irwin (1997) fitted Gaussian plume approach, as used in the EPA 1998 CALPUFF evaluation study (EPA, 1998a), was used for the same two tracer test field experiments used in the 1998 EPA study (i.e., GP80 and SRL75). This was done to elucidate how updates to CALPUFF model over the last decade have improved its performance. The second model evaluation approach adopts the spatial, temporal and global statistical evaluation framework of ATMES-II (Mosca et. al., 1998; Draxler et al., 1998). The ATMES-II uses statistical performance metrics of spatial, scatter, bias, correlation and cumulative distribution to describe model performance. An important finding of this study is that the fitted Gaussian plume model evaluation approach is very limited and can be a poor indicator of LRT dispersion model performance, with the ATMES-II approach providing a more comprehensive assessment of LRT model performance.

Fitted Gaussian Plume Evaluation Approach

The fitted Gaussian plume evaluation approach fits a Gaussian plume across the observed and predicted tracer concentrations along an arc of receptors at a specific downwind distance from the tracer release site. The approach focuses on a LRT dispersion model's ability to replicate centerline concentrations and plume widths, modeled/observed plume centerline azimuth, plume arrival time, and plume transit time across the arc. We used the fitted Gaussian plume evaluation approach to evaluate CALPUFF for the GP80 and SRL75 tracer experiments where the tracer concentrations were observed along arcs of receptors, as was done in the EPA 1998 CALPUFF evaluation study (EPA, 1998a).

4 http://transport.nilu.no/flexpart

5 http://www.atmos-chem-phys.net/5/2461/2005/acp-5-2461-2005.html

6 http://www.camx.com/

CALPUFF performance is evaluated by calculating the predicted and observed cross-wind integrated concentration (CWIC), azimuth of plume centerline, and the second moment of tracer concentration (lateral dispersion of the plume [σ_y]). The CWIC is calculated by trapezoidal integration across average monitor concentrations along the arc. By assuming a Gaussian distribution of concentrations along the arc, a fitted plume centerline concentration (Cmax) can be calculated by the following equation:

$$Cmax = CWIC/[(2\pi)^{1/2}\sigma_y]$$

The measure σ_y describes the extent of plume horizontal dispersion. This is important to understanding differences between the various dispersion options available in the CALPUFF modeling system. Additional measures for temporal analysis include plume arrival time and the plume transit time on arc. Table ES-1 summarizes the spatial, temporal and concentration statistical performance metrics used in the fitted Gaussian plume evaluation methodology.

Table ES-1. Model performance metrics used in the fitted Gaussian plume evaluation methodology from Irwin (1997) and 1998 EPA CALPUFF Evaluation (EPA, 1998a).

Statistics	Description
Spatial	
Azimuth of Plume Centerline	Comparison of the predicted angular displacement of the plume centerline from the observed plume centerline on the arc
Plume Sigma-y	Comparison of the predicted and observed fitted plume widths (i.e., dispersion rate)
Temporal	
Plume Arrival Time	Compare the time the predicted and observed tracer clouds arrives on the receptor arc
Transit Time on Arc	Compare the predicted and observed residence time on the receptor arc
Concentration	
Crosswind Integrated Concentration	Compares the predicted and observed average concentrations across the receptor arc
Observed/Calculated Maximum	Comparison of the predicted and observed fitted Gaussian plume centerline (maximum) concentrations (Cmax) and maximum concentration at any receptor along the arc (Omax)

Spatial, Temporal and Global Statistics Evaluation Approach

The model evaluation methodology as employed in ATMES-II (Mosca et al., 1998) and recommended by Draxler et al., (2002) was also used in this study. This approach defines three types of statistical analyses:

- Spatial Analysis: Concentrations at a fixed time are considered over the entire domain. Useful for determining differences spatial differences between predicted and observed concentrations.
- Temporal Analysis: Concentrations at a fixed location are considered for the entire analysis period. This can be useful for determining differences between the timing of predicted and observed tracer concentrations.
- Global Analysis: All concentration values at any time and location are considered in this analysis. The global analysis considers the distribution of the values (probability), overall tendency towards overestimation or underestimation of measured values (bias and error), measures of scatter in the predicted and observed concentrations and measures of correlation.

Table ES-2 defines the twelve ATMES-II spatial and global statistical metrics used in this study, some of the temporal statistics were also calculated but not reported. The RANK model performance statistic is designed to provide an overall score of model performance by combining performance metrics of correlation/scatter (R^2), bias (FB), spatial (FMS) and cumulative distribution (KS). Its use as an overall indication of the rankings of model performance for different models was evaluated and found that it usually was a good indication, but there were some cases where it could lead to misleading results and is not a substitute for examining all performance attributes.

Table ES-2. ATMES-II spatial and global statistical metrics.

Statistical Metric	Definition	Perfect Score
Spatial Statistics		
Figure of Merit in Space (FMS)	$FMS = \frac{A_M \cap A_P}{A_M \cup A_P} \times 100\%$	100%
False Alarm Rate (FAR)	$FAR = \left(\frac{a}{a+b}\right) \times 100\%$	0%
Probability of Detection (POD)	$POD = \left(\frac{b}{b+d}\right) \times 100\%$	100%
Threat Score (TS)	$TS = \left(\frac{b}{a+b+d}\right) \times 100\%$	100%
where,	• "a" represents the number of times a condition that has been forecast, but was not observed (false alarm) • "b" represents the number of times the condition was correctly forecasted (hits) • "c" represents the number of times the nonoccurrence of the condition is correctly forecasted (correct negative); and • "d" represents the number of times that the condition was observed but not forecasted (miss).	
Global Statistics		
Factor of Exceedance (FOEX)	$FOEX = \left[\frac{N_{(P_i > Ni_i)}}{N} - 0.5\right] \times 100\%$	0%
Factor of α (FA2 and FA5)	$FA\alpha = \left[\frac{N(y - y0 = [x - x0]\alpha)}{N}\right] \times 100$	100%
Normalized Mean Squared Error (NMSE)	$NMSE = \frac{1}{N\overline{PM}} \sum (P_i - M_i)^2$	0%
Pearson's Correlation Coefficient (PCC or R)	$R = \frac{\sum_i (M_i - \overline{M}) \bullet (P_i - \overline{P})}{\left[\sqrt{\sum (M_i - \overline{M})^2}\right]\left[\sqrt{\sum (P_i - \overline{P})^2}\right]}$	1.0
Fraction Bias (FB)	$FB = 2\overline{B} / (\overline{P} + \overline{M})$	0%
Kolmogorov-Smirnov (KS) Parameter	$KS = Max\lvert C(M_k) - C(P_k) \rvert$	0%
RANK	$RANK = \lvert R^2 \rvert + (1 - \lvert FB/2 \rvert) + FMS/100 + (1 - KS/100)$	4.0

MODEL PERFORMANCE EVALUATION OF LRT DISPERSION MODELS

The CALPUFF LRT dispersion model was evaluated using four tracer test field study experiments. Up to five additional LRT models were also evaluated using some of the field experiments.

1980 Great Plains (GP80) Field Experiment

The CALPUFF LRT dispersion model was evaluated against the GP80 July 8, 1980 GP80 tracer release from Norman, Oklahoma. The tracer was measured at two receptor arcs located 100 km and 600 km downwind from the tracer release point. The fitted Gaussian plume approach was used to evaluate the CALPUFF model performance, which was the same approach used in the EPA 1998 CALPUFF evaluation study (EPA, 1998a). CALPUFF was evaluated separately for the 100 km and 600 km arc of receptors.

<u>GP80 CALPUFF Sensitivity Tests</u>

Several different configurations of CALMET and CALPUFF models were used in the evaluation that varied CALMET grid resolution, grid resolution of the MM5 meteorological model used as input to CALMET, and CALMET and CALPUFF model options, including:

- CALMET grid resolution of 4 and 10 km for 100 km and 4 and 20 km for 600 km receptor arc.
- MM5 output grid resolution of 12, 36 and 80 km, plus no MM5 data.
- Use of surface and upper-air meteorological data used as input to CALMET:
  - A = Use surface and upper-air observations;
  - B = Use surface but not upper-air observations; and
  - C = Use no meteorological observations.
- Three CALPUFF dispersion algorithms:
  - CAL = CALPUFF turbulence dispersion;
  - AER = AERMOD turbulence dispersion; and
  - PG = Pasquill-Gifford dispersion.
- MMIF meteorological inputs for CALPUFF using 12 and 36 km MM5 data.

The “BASEA” CALPUFF/CALMET configuration was designed to emulate the configuration used in the 1998 EPA CALPUFF evaluation study, which used only meteorological observations and no MM5 data in the CALMET modeling and ran the CALPUFF CAL and PG dispersion options. However, an investigation of the 1998 EPA evaluation study revealed that the slug near-field option was used in CALPUFF (MSLUG = 1). The slug option is designed to better simulate a continuous plume near the source and is a very non-standard option for CALPUFF LRT dispersion modeling. For the initial CALPUFF simulations, the slug option was used for the 100 km receptor arc, but not for the 600 km receptor arc. However, additional CALPUFF sensitivity tests were performed for the 600 km receptor arc that investigated the use of the slug option, as well as alternative puff splitting options.

<u>Conclusions of GP80 CALPUFF Model Performance Results</u>

For the 100 km receptor arc, there was a wide variation in CALPUFF model performance across the sensitivity tests. The results were consistent with the 1998 EPA study with the following key findings for the GP80 100 km receptor arc evaluation:

- CALPUFF tended to overstate the maximum observed concentrations and understate the plume widths at the 100 km receptor arc.
- The best performing CALPUFF configuration in terms of predicting the maximum observed concentrations and plume width was when CALMET was run with MM5 data and surface meteorological observations but no upper-air meteorological observations.
- The CALPUFF CAL and AER turbulence dispersion options produced nearly identical results and the performance of the CAL/AER turbulence versus PG dispersion options varied by model configuration and statistical performance metric.
- The performance of CALPUFF/MMIF in predicting plume maximum concentrations and plume widths was comparable or better than all of the CALPUFF/CALMET configurations, except when CALMET used MM5 data and surface but no upper-air meteorological observations.
- The modeled plume centerline tended to be offset from the observed centerline location by 0 to 14 degrees.
- Use of CALMET with just surface and upper-air meteorological observations produced the best CALPUFF plume centerline location performance, whereas use of just MM5 data with no meteorological observations, either through CALMET or MMIF, produced the worst plume centerline angular offset performance.
- Different CALMET configurations give the best CALPUFF performance for maximum observed concentration (with MM5 and just surface and no upper-air observations) versus location of the plume centerline (no MM5 and both surface and upper-air observations) along the 100 km receptor arc. For Class I area LRT dispersion modeling it is important for the model to estimate both the location and the magnitudes of concentrations.

The evaluation of the CALPUFF sensitivity tests for the 600 km arc of receptors included both plume arrival, departure and residence time analysis as well as fitted Gaussian plume statistics. The observed residence time of the tracer on the 600 km receptor arc was at least 12 hours. Note that due to the presence of an unexpected low-level jet, the tracer was observed at the 600 km receptor arc for the first sampling period. Thus, the observed 12 hour residence time is a lower bound (i.e., the observed tracer could have arrived before the first sampling period). The 1998 EPA CALPUFF evaluation study estimated tracer plume residence times of 14 and 13 hours, which compares favorably with the observed residence time (12 hours). However, the 1998 EPA study CALPUFF modeling had the tracer arriving at least 1 hour later and leaving 2-3 hours later than observed, probably due to the inability of CALMET to simulate the low-level jet.

Most (~90%) of the current study CALPUFF sensitivity tests underestimated the observed tracer residence time on the 600 km receptor arc by approximately a factor of two. The exception to this was: (1) the BASEA_PG CALPUFF/CALMET sensitivity test (12 hours) that used just meteorological observations in CALMET and the PG dispersion option in CALPUFF; and (2) the CALPUFF/CALMET EXP2C series of experiments (residence time of 11-13 hours) that used 36 km MM5 data and CALMET run at 4 km resolution with no meteorological observations (NOOBS = 2). The remainder of the 28 CALPUFF sensitivity tests had tracer residence time on the 600 km receptor arc of 4-8 hours; that is, almost 90% of the CALPUFF sensitivity tests failed to reproduce the good tracer residence time performance statistics from the 1998 EPA study.

For the 600 km receptor arc, the CALPUFF sensitivity test fitted Gaussian plume statistics were very different than the 100 km receptor arc as follows:

- The maximum observed concentration along the arc or observed fitted centerline plume concentration was underestimated by -42% to -72% and the plume widths overestimated by 47% to 293%.
- The CALPUFF underestimation bias of the observed maximum concentration tends to be improved using CALMET runs with no meteorological observations.
- The use of the PG dispersion option tends to exacerbate the plume width overestimation bias relative to using the CAL or AER turbulence dispersion option.
- The CALPUFF predicted plume centerline tends to be offset from the observed value by 9 to 20 degrees, with the largest centerline offset (> 15 degrees) occurring when no meteorological observations are used with either CALMET or MMIF .
- The 1998 CALPUFF runs overestimated the observed CWIC by 15% and 30% but the current study's BASEA configuration, which was designed to emulate the 1998 EPA study, underestimates the observed CWIC by -14% and -38%.

The inability of most (~90%) of the current study's CALPUFF sensitivity tests to reproduce the 1998 EPA study tracer test residence time on the 600 km receptor arc is a cause for concern. For example, the 1998 EPA study CALPUFF simulation using the CAL dispersion option estimates a tracer residence time on the 600 km receptor arc of 13 hours that compares favorably to what was observed (12 hours). However, the current study CALPUFF BASEA_CAL configuration, which was designed to emulate the 1998 EPA CALPUFF configuration, estimates a residence time of almost half of the 1998 EPA study (7 hours). One notable difference between the 1998 EPA and the current study CALPUFF modeling for the GP80 600 km receptor arc was the use of the slug option in the 1998 EPA study. Another notable difference was the ability of the current version of CALPUFF to perform puff splitting, which EPA has reported likely extends the downwind distance applicability of the CALPUFF model (EPA, 2003). Thus, a series of CALPUFF sensitivity tests were conducted using the BASEA_CAL CALPUFF/CALMET and MMIF_12KM CAL and PG CALPUFF/MMIF configurations that invoked the slug option and performed puff splitting. Two types of puff splitting were analyzed, default puff splitting (DPS) that turns on the vertical puff splitting flag once per day and all hours puff splitting (APS) that turns on the puff splitting flag for every hour of the day. The following are the key findings from the CALPUFF slug and puff splitting sensitivity tests for the GP80 600 km receptor arc:

- Use of puff splitting had no effect on the tracer test residence time (7 hours) in the CALPUFF/CALMET (BASEA_CAL) configuration.
- Use of the slug option with CALPUFF/CALMET increased the tracer residence time on the 600 km receptor arc from 7 to 15 hours, suggesting that the better performance of the 1998 EPA CALPUFF simulations on the 600 km receptor arc was due to invoking the slug option.
- On the other hand, the CALPUFF/MMIF sensitivity tests were more sensitivity to puff splitting than CALPUFF/CALMET with the tracer residence time increasing from 6 to 8 hours using DPS and to 17 hours using APS when the CAL dispersion option was specified.
- The use of the slug option on top of APS has very different effect on the CALPUFF/MMIF residence time along the 600 km receptor depending on which dispersion option is utilized, with slug reducing the residence time from 17 to 15 hours using the CAL and increasing the residence time from 11 to 20 hours using PG dispersion options.

- The best performing CALPUFF configuration from all of the sensitivity tests when looking at the performance across all of the fitted plume performance statistics was use of the slug option with puff splitting in CALPUFF/MMIF.

A key result of the GP80 600 km receptor arc evaluation was the need to invoke the near-source slug option to adequately reproduce the CALPUFF performance from the 1998 EPA CALPUFF evaluation study. Given that the slug option is a very nonstandard option for LRT dispersion modeling, this finding raises concern regarding the previous CALPUFF evaluation. Another important finding of the GP80 CALPUFF sensitivity tests is the wide variation in modeling results that can be obtained using the various options in CALMET and CALPUFF. This is not a desirable attribute for regulatory modeling and emphasizes the need for a standardized set of options for regulatory CALPUFF modeling.

1975 Savannah River Laboratory (SRL75) Field Experiment

The 1975 Savannah River Laboratory (SRL75) field experiment released a tracer on December 10, 1975 and measured it at receptors located approximately 100 km downwind from the tracer release site. The fitted Gaussian plume model evaluation approach was used to evaluate numerous CALPUFF sensitivity tests. Several CALMET sensitivity tests were run to provide meteorological inputs to CALPUFF that varied whether MM5 data was used or not and how meteorological observations were used (surface and upper-air, surface only or no observations). As in the GP80 sensitivity tests, three dispersion options were used in CALPUFF (CAL, AER and PG). In addition, CALPUFF/MMIF sensitivity tests were performed using MM5 output at 36, 12 and 4 km resolution.

Because of the long time integrated sampling period used in the SRL75 experiment, the plume arrival, departure and residence statistics were not available and only the fitted Gaussian plume statistics along the 100 km receptor arc were used in the evaluation. The key findings of the SRL75 CALPUFF evaluation are as follows:

- The maximum plume centerline concentrations from the fitted Gaussian plume to the observed tracer concentrations is approximately half the maximum observed tracer concentration at any monitor along the 100 km receptor arc. As a plume centerline concentration in a Gaussian plume represents the maximum concentration, this indicates that the fitted Gaussian plume is a very poor fit to the observations. Thus, the plume centerline and plume width statistics that depend on the fitted Gaussian plume are a poor indication of model performance for the SRL75 experiment. The observed fitted Gaussian plume statistics were taken from the 1998 EPA study (EPA, 1998a).
- Given that there are many more (~5 times) CALPUFF receptors along the 100 km receptor arc than monitoring sites where the tracer was observed, the predicted maximum concentration along the arc is expected to be greater than the observed maximum concentration. Such is the case with the CALPUFF/MMIF runs, but is not always the case for the CALMET/CALPUFF sensitivity tests using no MM5 data.
- The CALPUFF plume centerline is offset from the observed plume centerline by 8 to 20 degrees. The largest angular offset occurs (17-20 degrees) when CALMET is run with no MM5 data. When MM5 data is used with the surface and upper-air observations the CALPUFF angular offset is essentially unchanged (18-19 degrees) and the removal of the upper-air observations also has little effect on the plume centerline angular offset. However, when only MM5 data are used, in either in CALMET (11-12 degrees) or MMIF (9-10 degrees), the CALPUFF plume centerline offset is improved.

The main conclusion of the SRL75 CALPUFF evaluation is that the fitted Gaussian plume evaluation approach can be a poor and misleading indicator of LRT dispersion model performance. In fact, the whole concept of a well-defined Gaussian plume at far downwind distances (e.g., > 50 km) is questionable since wind variations and shear can destroy the Gaussian distribution. Thus, we recommend that future studies no longer use the fitted Gaussian plume evaluation methodology for evaluating LRT dispersion models and adopt alternate evaluation approaches that are free from a priori assumption regarding the distribution of the observed tracer concentrations.

Cross Appalachian Tracer Experiment (CAPTEX)

The Cross Appalachian Tracer Experiment (CAPTEX) performed five tracer releases from either Dayton, Ohio or Sudbury, Ontario with tracer concentrations measured at hundreds of monitoring sites deployed in the northeastern U.S. and southeastern Canada out to distances of 1000 km downwind of the release sites. Numerous CALPUFF sensitivity tests were performed for the third (CTEX3) and fifth (CTEX5) CAPTEX tracer releases from, respectively, Dayton and Sudbury. The performance of the six LRT models was also intercompared using the CTEX3 and CTEX5 field experiments.

<u>CAPTEX Meteorological Modeling</u>

MM5 meteorological modeling was conducted for the CTEX3 and CTEX5 periods using modeling approaches prevalent in the 1980's (e.g., one 80 km grid with 16 vertical layers) that was sequentially updated to use a more current MM5 modeling approach (e.g., 108/36/12/4 km nested grids with 43 vertical layers). The MM5 experiments also employed various levels of four dimensional data assimilation (FDDA) from none (i.e., forecast mode) to increasing aggressive use of FDDA.

CALMET sensitivity tests were conducted using 80, 36 and 12 km MM5 data as input and using CALMET grid resolutions of 18, 12 and 4 km. For each MM5 and CALMET grid resolution combination, additional CALMET sensitivity tests were performed to investigate the effects of different options for blending the meteorological observations into the CALMET STEP1 wind fields using the STEP2 objective analysis (OA) procedures to produce the wind field that is provided as input to CALPUFF:

- A – RMAX1/RMAX2 = 500/1000
- B – RMAX1/RMAX2 = 100/200
- C – RMAX1/RMAX2 = 10/100
- D – no meteorological observations (NOOBS = 2)

Wind fields estimated by the MM5 and CALMET CTEX3 and CTEX5 sensitivity tests were paired with surface wind observations in space and time, then aggregated by day and then aggregated over the modeling period. The surface wind comparison is not an independent evaluation since many of the surface wind observations in the evaluation database are also provided as input to CALMET. Since the CALMET STEP2 OA procedure is designed to make the CALMET winds at the monitoring sites better match the observed values, one would expect CALMET simulations using observations to perform better than those that do not. However, as EPA points out in their 2009 IWAQM reassessment report, CALMET's OA procedure can also produce discontinuities and artifacts in the wind fields resulting in a degradation of the wind fields even though they may match the observed winds better at the locations of the observations (EPA, 2009a). The key findings from the CTEX5 MM5 and CALMET meteorological evaluation are as follows:

- The MM5 wind speed, and especially wind direction, model performance is better when FDDA is used then when FDDA is not used.
- The “A” and “B” series of CALMET simulations produce wind fields least similar to the MM5 simulation used as input, which is not surprising since CALMET by design is modifying the winds at the location of the monitoring sites to better match the observations.
- CALMET tends to slow down the MM5 wind speeds even when there are no wind observations used as input (i.e., the “D” series).
- For this period and MM5 model configuration, the MM5 and CALMET wind model performance is better when 12 km grid resolution is used compared to coarser resolution.

CAPTEX CALPUFF Model Evaluation and Sensitivity Tests

The CALPUFF model was evaluated against tracer observations from the CTEX3 and CTEX5 field experiments using meteorological inputs from the various CALMET sensitivity tests described above as well as the MMIF tool applied using the 80, 36 and 12 km MM5 databases. The CALPUFF configuration was held fixed in all of these sensitivity tests so that the effects of the meteorological inputs on the CALPUFF tracer model performance could be clearly assessed. The CALPUFF default model options were assumed for most CALPUFF inputs. One exception was for puff splitting where more aggressive vertical puff splitting was allowed to occur throughout the day, rather than the default where vertical puff splitting is only allowed to occur once per day.

The ATMES-II statistical model evaluation approach was used to evaluate CALPUFF for the CAPTEX field experiments. Twelve separate statistical performance metrics were used to evaluate various aspects of the CALPUFF’s ability to reproduce the observed tracer concentrations in the two CAPTEX experiments. Below we present the results of the RANK performance statistic that is a composite statistic that represents four aspects of model performance: correlation, bias, spatial and cumulative distribution. Our analysis of all twelve ATMES-II statistics has found that the RANK statistic usually provides a reasonable assessment of the overall performance of dispersion models tracer test evaluations. However, we have also found situations where the RANK statistic can provide misleading indications of the performance of dispersion models and recommend that all model performance attributes be examined to confirm that the RANK metric is providing a valid ranking of the dispersion model performance.

CTEX3 CALPUFF Model Evaluation

Figure ES-1 summarizes the RANK model performance statistics for the CALPUFF sensitivity simulations that used the 12 km MM5 data as input. Using a 4 km CALMET grid resolution, the EXP6B (RMAX1/RMAX2 = 100/200) has the lowest rank of the CALPUFF/CALMET sensitivity tests. Of the CALPUFF sensitivity tests using the 12 km MM5 data as input, the CALPUFF/MMIF (12KM_MMIF) sensitivity test has the highest RANK statistic (1.43) followed closely by EXP4A (1.40; 12 km CALMET and 500/1000), EXP6C (1.38; 4 km CALMET and 10/500) with the lowest

RANK statistic (1.22) exhibited by EXP4B (12 km CALMET and 100/200) and EXP6B (4 km CALMET and 100/200).

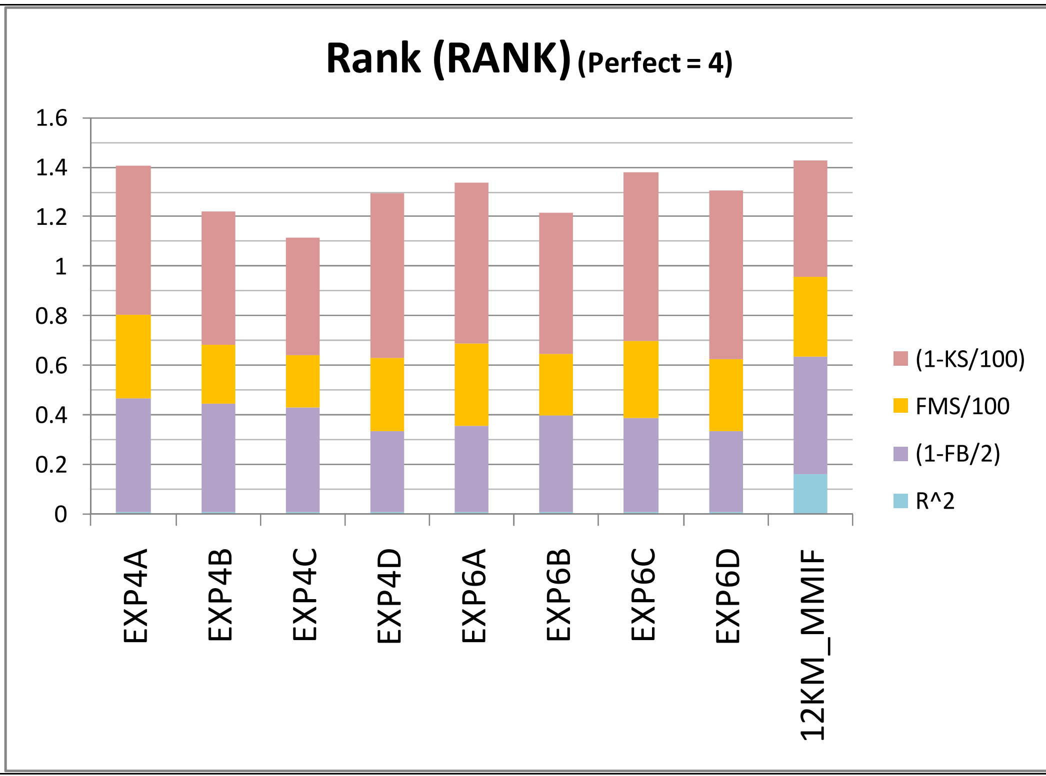

Figure ES-1. RANK performance statistics for CTEX3 CALPUFF sensitivity tests that used 12 km MM5 as input to CALMET or MMIF.

Figure ES-2 compares the RANK model performance statistics for “B” (RMAX1/RMAX2 = 100/200) and “D” (no observations) series of CALPUFF/CALMET sensitivity tests using different CALMET/MM5 grid resolutions of 18/80 (BASEB), 12/80 (EXP1), 12/36 (EXP3), 12/12 (EXP4) 4/36 (EXP5) and 4/12 (EXP6) along with the CALPUFF/MMIF runs using 36 and 12 km MM5 data. The CALPUFF/CALMET sensitivity tests using no observations (“D” series) generally have a higher rank metric than when meteorological observations are used with CALPUFF (“B” series). The CALMET/MMIF sensitivity test using 36 and 12 km MM5 data are the configurations with the highest RANK metric.The CALPUFF/MMIF show a strong relationship between observed and predicted winds than the CALPUFF/CALMET sensitivity tests, which had no to slightly negative correlations with the tracer observations.

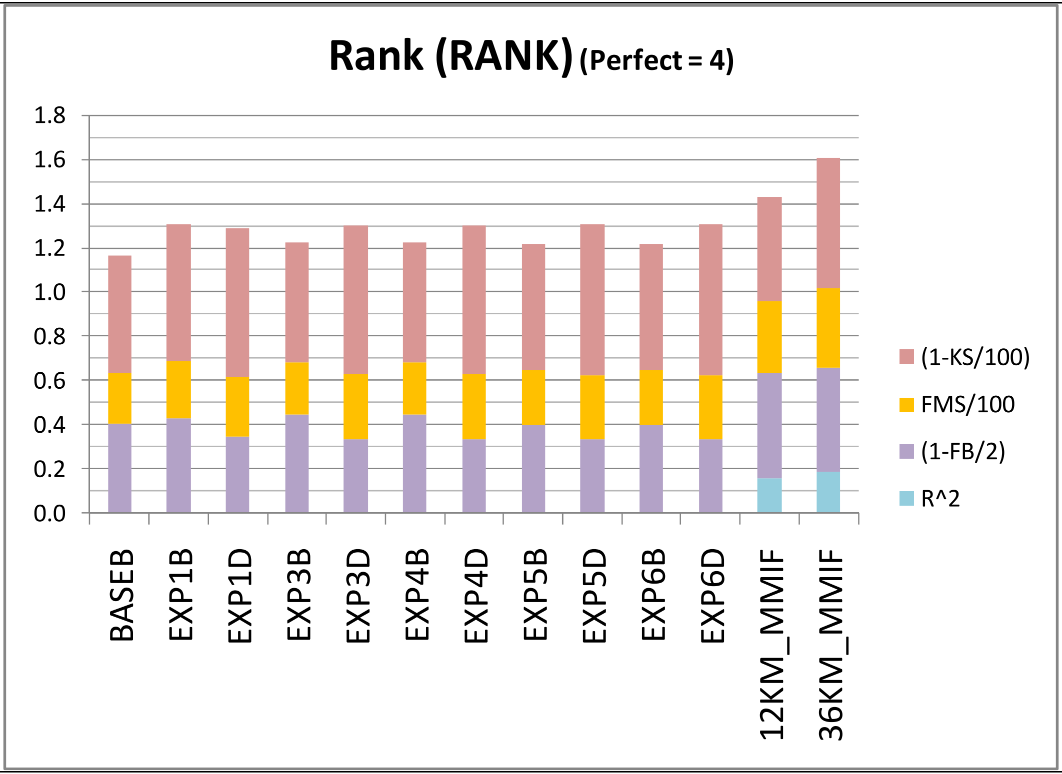

Figure ES-2. RANK performance statistics for CTEX3 CALPUFF sensitivity tests that used RMAX1/RMAX2 = 100/200 ("B" series) or no observations in CALMET ("D" series) and various CALMET/MM5 grid resolutions plus CALMET/MMIF using 36 and 12 km MM5 data.

Table ES-3 ranks all of the CALPUFF CTEX3 sensitivity tests using the RANK statistics. It is interesting to note that the EXP3A and EXP4A CALPUFF/CALMET sensitivity test that uses the, respectively, 36 km and 12 km MM5 data with 12 km CALMET grid resolution and RMAX1/RMAX2 values of 500/1000 have a rank metric that is third highest, but the same model configuration with alternative RMAX1/RMAX2 values of 10/100 (EXP3C and EXP4C) degrades the model performance of the CALPUFF configuration according to the RANK statistic, with a RANK value of 1.12. This is largely due to decreases in the FMS and KS metrics.

Note that the finding that CALPUFF/CALMET model performance using CALMET wind fields based on setting RMAX1/RMAX2 = 100/200 (i.e., the "B" series) produces worse CALPUFF model performance for simulating the observed atmospheric tracer concentrations is in contrast to the CALMET surface wind field comparison that found the "B" series most closely matched observations at surface meteorological stations. Since the CALPUFF tracer evaluation is an independent evaluation of the CALMET/CALPUFF modeling system, whereas the CALMET surface wind evaluation is not, the CALPUFF tracer evaluation may be a better indication of the best performing CALMET configuration. The CALMET "B" series approach for blending the wind observations in the wind fields may just be the best approach for getting the CALMET winds to match the observations at the monitoring sites, but possibly at the expense of degrading the wind fields away from the monitoring sites resulting in worse overall depiction of transport conditions.

Table ES-3. Final Rankings of CALPUFF CTEX3 Sensitivity Tests using the RANK model performance statistics.

Ranking	Sensitivity Test	RANK Statistics	MM5 (km)	CALGRID (km)	RMAX1/RMAX2	Met Obs
1	36KM_MMIF	1.610	36	--	--	--
2	12KM_MMIF	1.430	12	--	--	--
3	EXP3A	1.400	36	12	500/1000	Yes
4	EXP4A	1.400	12	12	500/1000	Yes
5	EXP5C	1.380	36	4	10/100	Yes
6	EXP6C	1.380	12	4	10/100	Yes
7	EXP1C	1.340	36	18	10/100	Yes
8	EXP5A	1.340	36	4	500/1000	Yes
9	EXP6A	1.340	12	4	500/1000	Yes
10	EXP5D	1.310	36	4	--	No
11	EXP6D	1.310	12	4	--	No
12	EXP1B	1.300	36	18	100/200	Yes
13	EXP3D	1.300	36	12	--	No
14	EXP4D	1.300	12	12	--	No
15	BASEA	1.290	80	18	500/1000	Yes
16	EXP1D	1.290	36	18	--	No
17	EXP1A	1.280	36	18	500/1000	Yes
18	EXP3B	1.220	36	12	100/200	Yes
19	EXP5B	1.220	36	4	100/200	Yes
20	EXP4B	1.220	12	12	100/200	Yes
21	EXP6B	1.220	12	4	100/200	Yes
22	BASEC	1.170	80	18	10/100	Yes
23	BASEB	1.160	80	18	100/200	Yes
24	EXP3C	1.120	36	12	10/100	Yes
25	EXP4C	1.120	12	12	10/200	Yes

CTEX5 CALPUFF Model Evaluation

Figure ES-3 summarizes the RANK model performance statistics for the CTEX5 CALPUFF sensitivity simulations that used the 12 km MM5 data as input to CALMET and the 12 and 4 km MM5 data as input to MMIF.

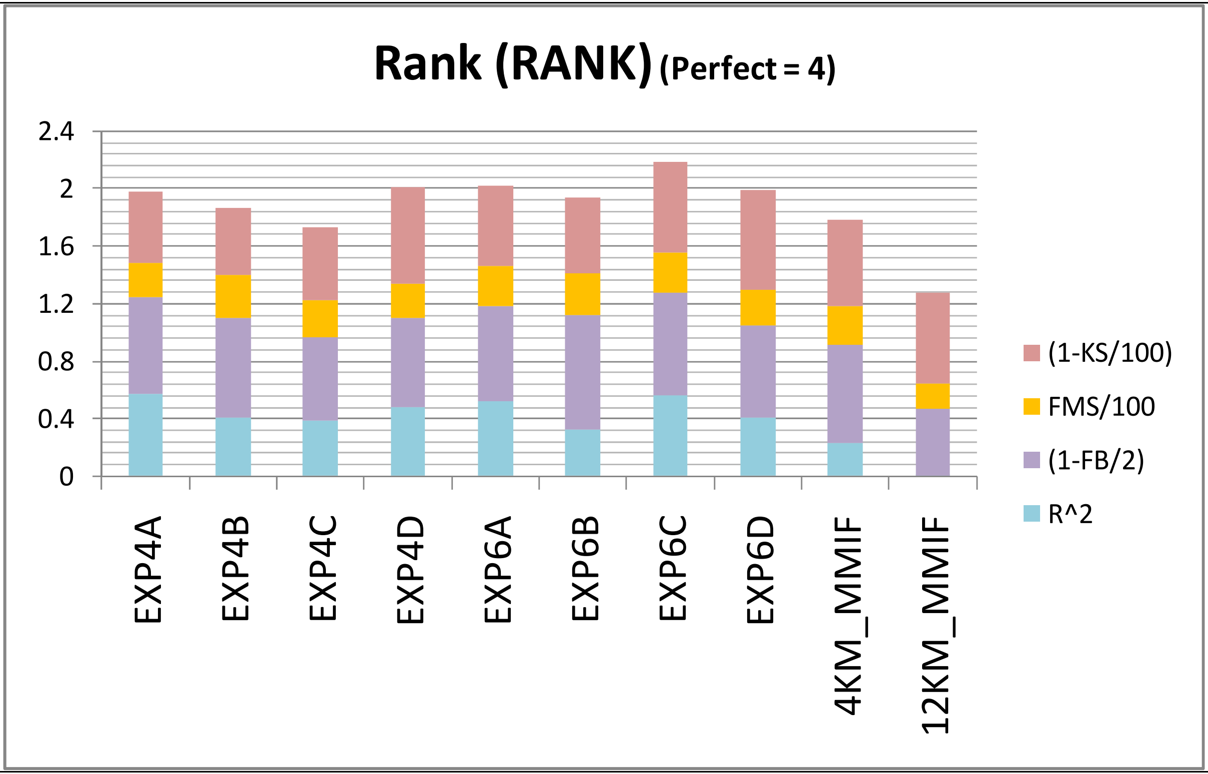

Figure ES-3. RANK performance statistics for CTEX5 CALPUFF sensitivity tests that used 12 km MM5 as input to CALMET or MMIF.

Table ES-4 ranks the model performance of the CTEX5 CALPUFF sensitivity tests using the RANK composite statistic. The 12, 36 and 80 km CALPUFF/MMIF sensitivity tests have the lowest RANK values in the 1.28 to 1.42 range.

Table ES-4. Final Rankings of CALPUFF CTEX5 Sensitivity Tests using the RANK model performance statistic.

Ranking	Sensitivity Test	RANK Statistics	MM5 (km)	CALGRID (km)	RMAX1/RMAX2	Met Obs
1	EXP6C	2.19	12	4	10/100	Yes
2	EXP5D	2.10	36	4	--	No
3	BASEA	2.06	80	18	500/1000	Yes
4	BASEC	2.05	80	18	10/100	Yes
5	EXP5A	2.03	36	4	500/1000	Yes
6	EXP6A	2.02	12	4	500/1000	Yes
7	EXP4D	2.00	12	12	--	No
8	EXP6D	1.99	12	4	--	No
9	EXP4A	1.98	12	12	500/1000	Yes
10	EXP6B	1.94	12	4	100/200	Yes
11	EXP5B	1.89	36	4	100/200	Yes
12	EXP4B	1.86	12	12	100/200	Yes
13	BASEB	1.82	80	18	100/200	Yes
14	EXP5C	1.80	36	4	10/100	Yes

15	BASED	1.79	80	18	--	No
16	EXP3A	1.79	36	12	10/100	Yes
17	EXP3B	1.79	36	12	100/200	Yes
18	EXP3C	1.79	36	12	500/1000	Yes
19	EXP3D	1.79	36	12	--	No
20	4KM_MMIF	1.78	4	--	--	No
21	EXP4C	1.72	12	12	10/100	Yes
22	36KM_MMIF	1.42	36	--	--	No
23	80KM_MMIF	1.42	80	--	--	No
24	12KM_MMIF	1.28	12	--	--	No

Conclusions of the CAPTEX CALPUFF Tracer Sensitivity Tests

There are some differences and similarities in CALPUFF's ability to simulate the observed tracer concentrations in the CTEX3 and CTEX5 field experiments. The overall conclusions of the evaluation of the CALPUFF model using the CAPTEX tracer test field experiment data can be summarized as follows:

- There is a noticeable variability in the CALPUFF model performance depending on the selected input options to CALMET.
  - By varying CALMET inputs and options through their range of plausibility, CALPUFF can produce a wide range of concentrations estimates.
- Regarding the effects of the RMAX1/RMAX2 parameters on CALPUFF/CALMET model performance, the "A" series (500/1000) performed best for CTEX3 but the "C" series (10/100) performed best for CTEX5 with both CTEX3 and CTEX5 agreeing that the "B" series (100/200) is the worst performing setting for RMAX1/RMAX2.
  - This is in contrast to the CALMET wind evaluation that found the "B" series was the CALMET configuration that most closely matched observed surface winds.
  - The CALMET wind evaluation was not an independent evaluation since some of the wind observations used in the model evaluation database were also used as input to CALMET.

Evaluation of Six LRT Dispersion Models using the CTEX3 Database

Six LRT dispersions models were applied for the CTEX3 experiment using common meteorological inputs based solely on MM5. Figure ES-4 displays the RANK model performance statistic for the six LRT dispersion models. The RANK statistical performance metric was proposed by Draxler (2001) as a single model performance metric that equally ranks the combination of performance metrics for correlation (PCC or R^2), bias (FB), spatial analysis (FMS) and unpaired distribution comparisons (KS). The RANK metrics ranges from 0.0 to 4.0 with a perfect model receiving a score of 4.0.

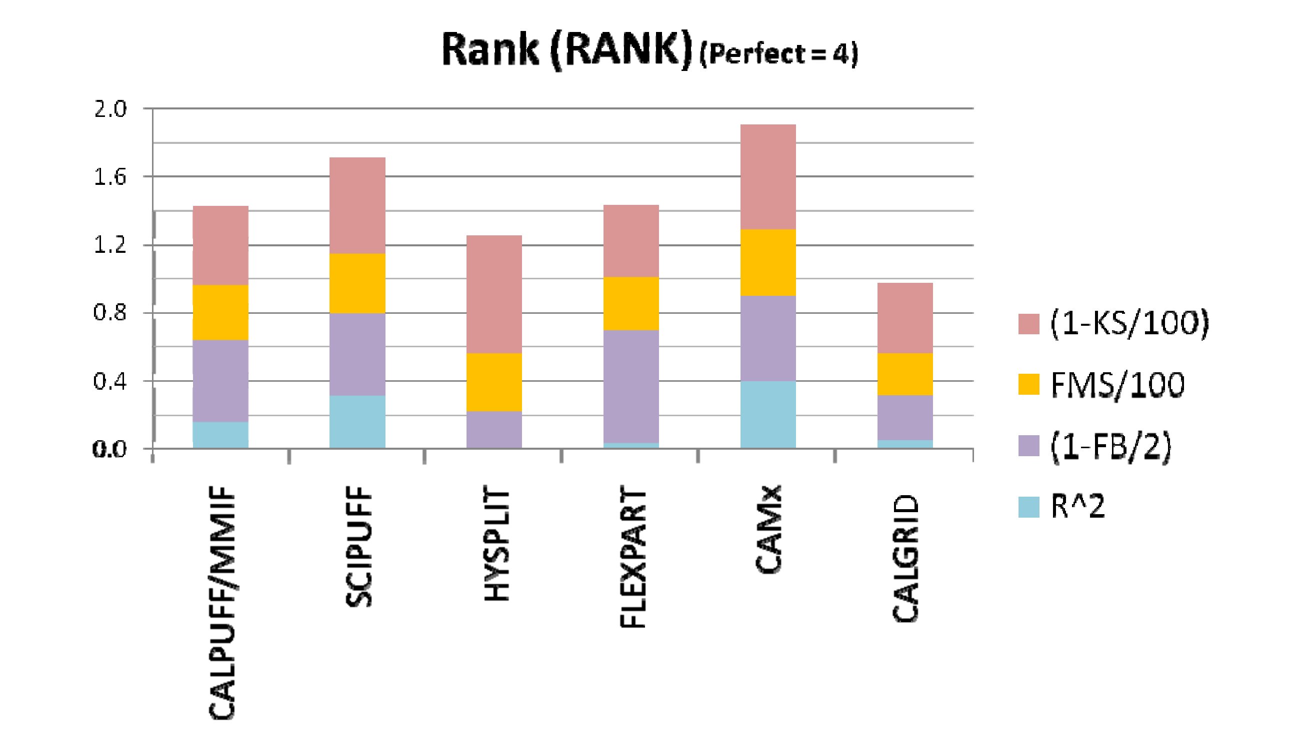

Figure ES-4. RANK statistical performance metric for the six LRT models and CAPTEX Release 3.

Table ES-5 summarizes the rankings between the six LRT models for the 11 performance statistics analyzed and compares them to the rankings obtained using the RANK performance statistic. In testing the efficacy of the RANK statistic for providing an overall ranking of model performance the ranking of the six LRT models using the average rank of the 11 performance statistics (Table ES-5) versus the ranking from the RANK statistical metric (Figure ES-4) are compared as follows:

Ranking	Average of 11 Statistics	RANK
1.	CAMx	CAMx
2.	SCIPUFF	SCIPUFF
3.	FLEXPART	FLEXPART
4.	HYSPLIT	CALPUFF
5.	CALPUFF	HYSPLIT
6.	CALGRID	CALGRID

For the CTEX3 experiment, the average rankings across the 11 statistics is nearly identical to the rankings produced by the RANK integrated statistic that combines the four of the statistics for correlation (PCC), bias (FB), spatial (FMS) and cumulative distribution (KS) with only HYSPLIT and CALPUFF exchanging places. This switch was due to CALPUFF having lower scores in the FA2 and FA5 metrics compared to HYSPLIT. If not for this, the average rank across all 11 metrics would have been the same as Draxler's RANK score. However, the analyst should use discretion in relying too heavily upon RANK score without consideration to which performance metrics are important measures for the particular evaluation goals. For example, if performance goals are not concerned with a model's ability to perform well in space and time, then reliance upon spatial statistics, such as the FMS, in the composite RANK value may not be appropriate.

Table ES-5. Summary of model ranking for the CTEX3 using the ATMES-II statistical performance metrics and comparing their average rankings to the RANK metric.

Statistic	1st	2nd	3rd	4th	5th	6th
FMS	CAMx	SCIPUFF	HYSPLIT	CALPUFF	FLEXPART	CALGRID
FAR	FLEXPART	CAMx	SCIPUFF	CALPUFF	HYSPLIT	CALGRID
POD	CAMx	FLEXPART	SCIPUFF	HYSPLIT	CALPUFF	CALGRID
TS	FLEXPART	CAMx	SCIPUFF	HYSPLIT	CALPUFF	CALGRID
FOEX	HYSPLIT	CAMx	SCIPUFF	CALPUFF	CALGRID	FLEXPART
FA2	CAMx	SCIPUFF	FLEXPART	HYSPLIT	CALGRID	CALPUFF
FA5	CAMx	SCIPUFF	FLEXPART	HYSPLIT	CALPUFF	CALGRID
NMSE	FLEXPART	CAMx	CALPUFF	SCIPUFF	CALGRID	HYSPLIT
PCC or R	CAMx	SCIPUFF	CALPUFF	CALGRID	FLEXPART	HYSPLIT
FB	FLEXPART	CAMx	SCIPUFF	CALPUFF	CALGRID	HYSPLIT
KS	HYSPLIT	CAMx	SCIPUFF	CALPUFF	FLEXPART	CALGRID
Avg. Ranking	CAMx	SCIPUFF	FLEXPART	HYSPLIT	CALPUFF	CALGRID
Avg. Score	1.55	2.72	3.0	4.0	4.27	5.55
RANK Ranking	CAMx	SCIPUFF	FLEXPART	CALPUFF	HYSPLIT	CALGRID
RANK	1.91	1.71	1.44	1.43	1.25	0.98

Evaluation of Six LRT Dispersion Models using the CTEX5 Database

Figure ES-5 displays the RANK model performance statistics for the six LRT models and the CTEX5 field experiment.

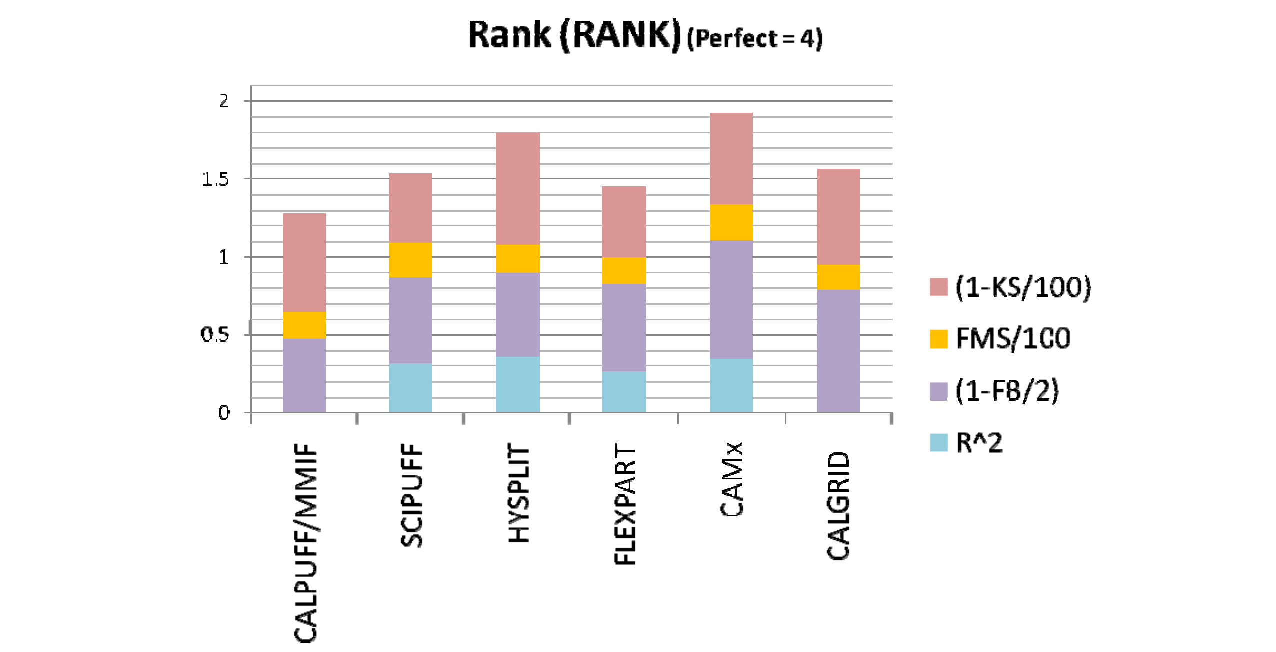

Figure ES-5. RANK statistical performance metric for the six LRT models and CAPTEX Release 5.

Table ES-6 summarizes the rankings of the six LRT models for the 11 performance statistics analyzed for CAPTEX Release 5 and compares the averaging ranking across the 11 statistics against the RANK metric rankings. Unlike the CTEX3 experiment, where CAMx (46%) and FLEXPART (36%) accounted for 82% of the first placed ranked models, there is a wide variation of which model was ranked best performing across the 11 statistical metrics in the CTEX5 experiment. In testing the efficacy of the RANK statistic, overall rankings across all eleven statics were obtained using an average modeled ranking. The average rank across all 11 performance statistics and the RANK model rankings are as follows:

Ranking	Average of 11 Statistics	RANK
1.	CAMx	CAMx
2.	HYSPLIT	HYSPLIT
3.	SCIPUFF	CALGRID
4.	FLEXPART	SCIPUFF
5.	CALPUFF	FLEXPART
6.	CALGRID	CALPUFF

The results from CAPTEX Release 5 present an interesting case study on the use of the RANK metric to characterize overall model performance. As noted in Table ES-6 and given above, the relative ranking of models using the average rankings across the 11 statistical metrics is considerably different than the RANK scores after the two highest ranked models (CAMx and

HYSPLIT). Both approaches show CAMx and HYSPLIT as the highest ranking models for CTEX5 with rankings that are fairly close to each other, however after that the two ranking techniques come to very different conclusions regarding the ability of the models to simulate the observed tracer concentrations for the CTEX5 field experiment.

The most noticeable feature of the RANK metric for ranking models in CTEX5 is the third highest ranking model using RANK, CALGRID (1.57). CALGRID ranks as the worst or second worst performing model in 9 of the 11 performance statistics, so is one of the worst performing model 82% of the time and has an average ranking of 5th best model out of the 6 LRT dispersion models. In examining the contribution to the RANK metric for CALGRID, there is not a consistent contribution from all four broad categories to the composite scores (Figure ES-5). As noted in Table ES-2, the RANK score is defined by the contribution of the four of the 11 statistics that represent measures of correlation/scatter (R^2), bias (FB), spatial (FMS) and cumulative distribution (KS):

$$RANK = \left|R^2\right| + \left(1 - \left|FB/2\right|\right) + FMS/100 + \left(1 - KS/100\right)$$

The majority of CALGRID's 1.57 RANK score comes from the fractional bias (FB) and Kolmogorov-Smirnov (KS) performance statistics with little or no contributions from the correlation (R^2) or spatial (FMS) statistics. As shown in Table ES-6, CALGRID performs very poorly for the FOEX and FA2/FA5 statistics due to a large underestimation bias. The FB component to the RANK composite score for CALGRID is one of the highest among the six models in this study, yet the underlying statistics indicate both marginal spatial skill and a large degree of under-prediction (likely due to the spatial skill of the model).

The current form of the RANK score uses the absolute value of the fractional bias. This approach weights underestimation equally to overestimation. However, in a regulatory context, EPA is most concerned with models not being biased towards under-prediction. Models can produce seemingly good (low) bias metrics through compensating errors by averaging over- and under-predictions. The use of an error statistic (e.g., NMSE) instead of a bias statistic (i.e., FB) in the RANK composite metrics would alleviate this problem.

Adaptation of RANK score for regulatory use will require refinement of the individual components to insure that this situation does not develop and to insure that the regulatory requirement of bias be accounted for when weighting the individual statistical measures to produce a composite score.

Table ES-6. Summary of model rankings using the statistical performance metrics and comparison with the RANK metric.

Statistic	1st	2nd	3rd	4th	5th	6th
FMS	SCIPUFF	CAMx	HYSPLIT	CALPUFF	FLEXPART	CALGRID
FAR	FLEXPART	HYSPLIT	CAMx	SCIPUFF	CALGRID	CALPUFF
POD	SCIPUFF	CAMx	HYSPLIT	FLEXPART	CALPUFF	CALGRID
TS	FLEXPART	HYSPLIT	CAMx	SCIPUFF	CALPUFF	CALGRID
FOEX	CALPUFF	CAMx	HYSPLIT	CALGRID	SCIPUFF	FLEXPART
FA2	HYSPLIT	CAMx	CALPUFF	SCIPUFF	FLEXPART	CALGRID
FA5	HYSPLIT	CAMx	SCIPUFF	CALPUFF	FLEXPART	CALGRID
NMSE	CAMx	SCIPUFF	FLEXPART	HYSPLIT	CALPUFF	CALGRID
PCC or R	HYSPLIT	CAMx	SCIPUFF	FLEXPART	CALGRID	CALPUFF
FB	CAMx	CALGRID	FLEXPART	SCIPUFF	HYSPLIT	CALPUFF
KS	HYSPLIT	CALPUFF	CALGRID	CAMx	FLEXPART	SCIPUFF
Avg. Ranking	CAMx	HYSPLIT	SCIPUFF	FLEXPART	CALPUFF	CALGRID
Avg. Score	2.20	2.4	3.4	3.8	4.3	5.0
RANK Ranking	CAMx	HYSPLIT	CALGRID	SCIPUFF	FLEXPART	CALPUFF
RANK	1.91	1.80	1.57	1.53	1.45	1.28

European Tracer Experiment (ETEX)

The European Tracer Experiment (ETEX) was conducted in 1994 with two tracer releases from northwest France that was measured at 168 samplers located in 17 European countries. Five LRT dispersion models were evaluated for the first (October 23, 1994) ETEX tracer release period (CALPUFF, SCICHEM, HYSPLIT, FLEXPART and CAMx). All five LRT dispersion models were exercised using a common 36 km MM5 database for their meteorological inputs. For CALPUFF, the MMIF tool was used to process the MM5 data. Default model options were mostly selected for the LRT dispersion models. An exception to this is that for CALPUFF puff splitting was allowed to occur throughout the day, instead of once per day which is the default setting. The MM5 simulation was evaluated using surface meteorological variables. The MM5 performance did not always meet the model performance benchmarks and exhibited a wind speed and temperature underestimation bias. However, since all five LRT dispersion models used the same MM5 fields, this did not detract from the LRT model performance intercomparison. The ATMES-II model evaluation approach was used in the evaluation that calculated 12 model performance statistics of spatial, scatter, bias, correlation and cumulative distribution.

<u>ETEX LRT Dispersion Model Performance Evaluation</u>

Figure ES-6 displays the ranking of the five LRT dispersion models using the RANK model performance statistic with Table ES-7 summarizing the rankings for the other 11 ATMES-II performance statistics. Depending on the statistical metric, three different models were ranked as the best performing model for a particular statistic with CAMx being ranked first most of the time (64%) and HYSPLIT ranked first second most (27%). In order to come up with an overall rank across all eleven statistics we average the modeled ranking order to come up with an average ranking that listed CAMx first, HYSPLIT second, SCIPUFF third, FLEXPART fourth and CALPUFF the fifth. This is the same ranking as produced by the RANK integrated statistics that combines the four statistics for correlation (PCC), bias (FB), spatial (FMS) and cumulative distribution (KS), giving credence that the RANK statistic is a potentially useful performance statistic for indicating overall model performance of a LRT dispersion model for the ETEX evaluation.

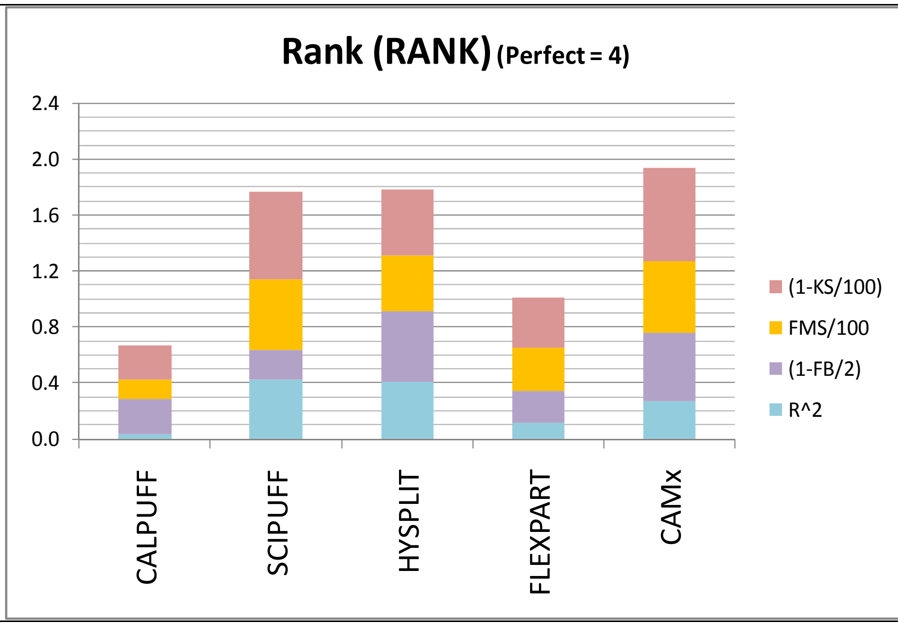

Figure ES-6. RANK statistical performance metric for the five LRT models and the ETEX tracer field experiment.

Table ES-7. Summary of ETEX model ranking using the eleven ATMES-II statistical performance metrics and their average rankings that are compared against the rankings by the RANK composite model performance metric.

Statistic	1st	2nd	3rd	4th	5th
FMS	CAMx	SCIPUFF	HYSPLIT	FLEXPART	CALPUFF
FAR	HYSPLIT	FLEXPART	CAMx	SCIPUFF	CALPUFF
POD	CAMx	SCIPUFF	HYSPLIT	FLEXPART	CALPUFF
TS	CAMx	HYSPLIT	SCIPUFF	FLEXPART	CALPUFF
FOEX	CAMx	SCIPUFF	HYSPLIT	FLEXPART	CALPUFF
FA2	CAMx	SCIPUFF	HYSPLIT	FLEXPART	CALPUFF
FA5	CAMx	SCIPUFF	HYSPLIT	FLEXPART	CALPUFF
NMSE	HYSPLIT	CAMx	CALPUFF	FLEXPART	SCIPUFF
PCC or R	SCIPUFF	HYSPLIT	CAMx	FLEXPART	CALPUFF
FB	HYSPLIT	CAMx	CALPUFF	FLEXPART	SCIPUFF
KS	CAMx	SCIPUFF	HYSPLIT	FLEXPART	CALPUFF
Avg. Ranking	CAMx	HYSPLIT	SCIPUFF	FLEXPART	CALPUFF
Avg. Score	1.55	2.27	2.73	3.82	4.64
RANK Ranking	CAMx	HYSPLIT	SCIPUFF	FLEXPART	CALPUFF
RANK Score	1.9	1.8	1.8	1.0	0.7

Spatial Displays of Model Performance

Figures ES-7 and ES-8 display the spatial distributions of the predicted and observed tracer concentrations 36 and 60 hours after the beginning of the ETEX tracer release. CALPUFF advects the tracer too far north keeping a circular Gaussian plume distribution and fails to reproduce the northwest to southeast diagonal orientation of the observed tracer cloud. The other four LRT dispersion models do a much better job in reproducing the observed tracer cloud spatial distribution. SCIPUFF tends to overestimate the tracer cloud extent and surface concentrations. FLEXPART, on the other hand, underestimates the observed tracer cloud spatial extent and CAMx and HYSPLIT do the best job overall in reproducing the spatial extent of the observed tracer cloud.

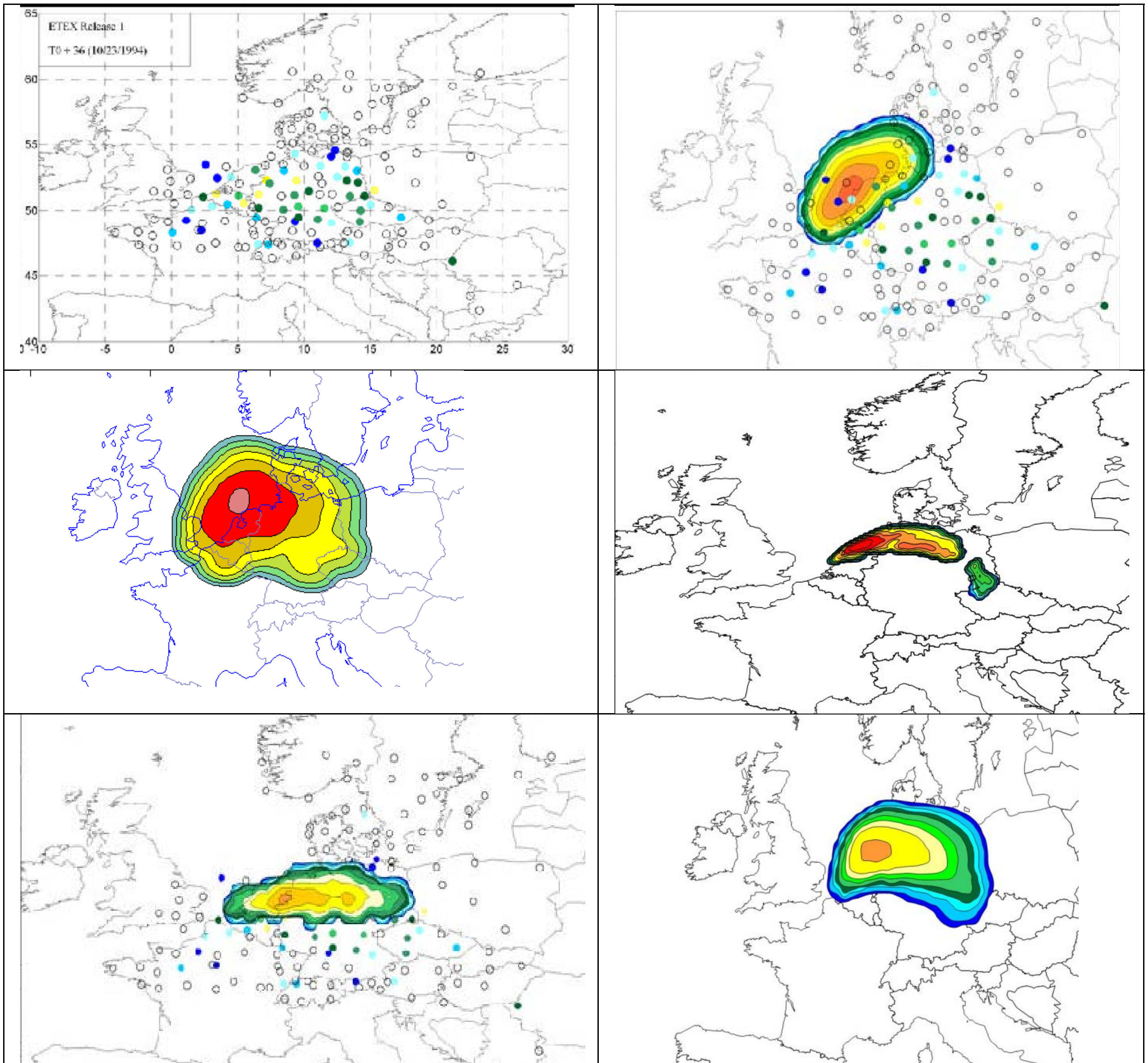

Figure ES-7. Comparison of spatial distribution of the ETEX tracer concentrations 36 hours after release for the observed (top left), CALPUFF (top right), SCIPUFF (middle left), FLEXPART (middle right), HYSPLIT (bottom left) and CAMx (bottom right).

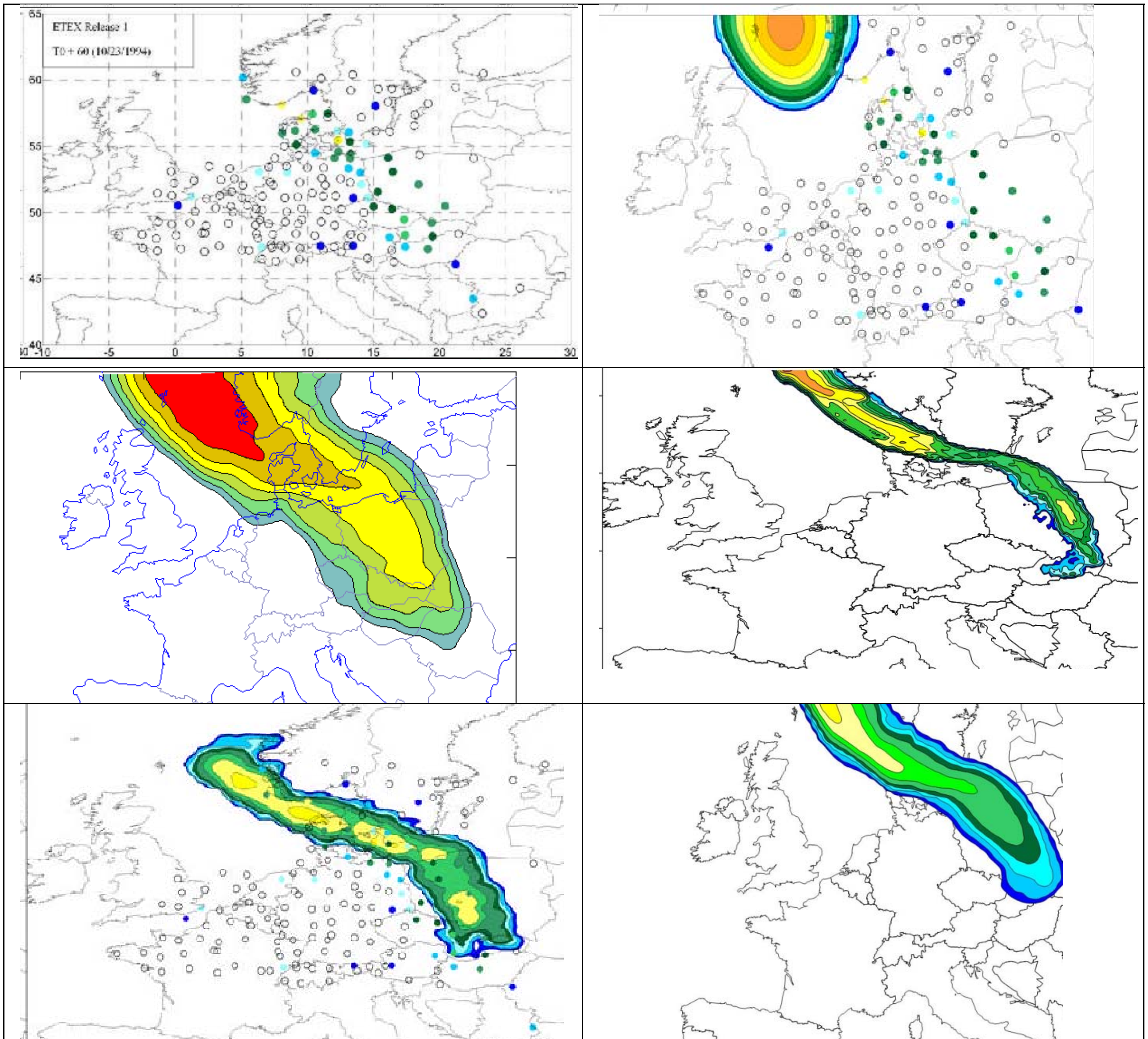

Figure ES-8. Comparison of spatial distribution of the ETEX tracer concentrations 60 hours after release for the observed (top left), CALPUFF (top right), SCIPUFF (middle left), FLEXPART (middle right), HYSPLIT (bottom left) and CAMx (bottom right).

ETEX LRT Dispersion Model Sensitivity Tests

Sensitivity tests were conducted using the CAMx, CALPUFF and HYSPLIT models and the ETEX field study data.

For CAMx, the effects of alternative vertical mixing coefficients (OB70, TKE, ACM2 and CMAQ), horizontal advection solvers (PPM and Bott) and use of the subgrid-scale Plume-in-Grid (PiG) module were evaluated. The key findings from the CAMx ETEX sensitivity tests were as follows:

- The vertical mixing parameter had the biggest effect on model performance, with the CMAQ vertical diffusion coefficients producing the best performing CAMx simulations.
- The horizontal advection solver had a much smaller effect on CAMx model performance with the PPM algorithm performing slightly better than Bott.
- The use of no PiG module produced slightly better performance than use of the PiG module.
- The default CAMx configuration used in the ETEX evaluation (CMAQ/PPM/No PiG) was the best performing CAMx sensitivity test.

CALPUFF sensitivity tests were performed to examine the effects of puff splitting on the CALPUFF model performance for the ETEX field experiment. When EPA listed CALPUFF as the EPA-recommended LRT dispersion model in 2003, they noted that the implementation of puff splitting likely will extend the models applicability beyond 300 km downwind (EPA, 2003). Since many of the ETEX monitoring sites are sited further than 300 km downwind from the release, one potential explanation for the poor CALPUFF model performance is that it is being applied farther downwind than the model is applicable for. Figure ES-9 displays a time series of the Figure of Merit in Space (FMS) performance statistic for the five LRT dispersion models. Although CALPUFF performs reasonably well within the first 12 hours of the tracer release, its performance quickly degrades even within 300 km of the source. Thus, CALPUFF’s poor model performance is not due to applying the model to downwind distances beyond its applicability.

Eight CALPUFF puff splitting sensitivity tests were conducted ranging from no puff splitting to aggressive puff splitting for all hours of the day and relaxing some of the puff splitting initiation criteria so that even more puff splitting can occur. The CALPUFF ETEX model performance using no puff splitting and all hour puff splitting was very similar, thus we saw no evidence to support EPA’s 2003 statements that puff splitting may extend the downwind applicability of the model. In fact, when some of the puff splitting initiation criteria were relaxed to allow more puff splitting, the CALUFF performance degraded.

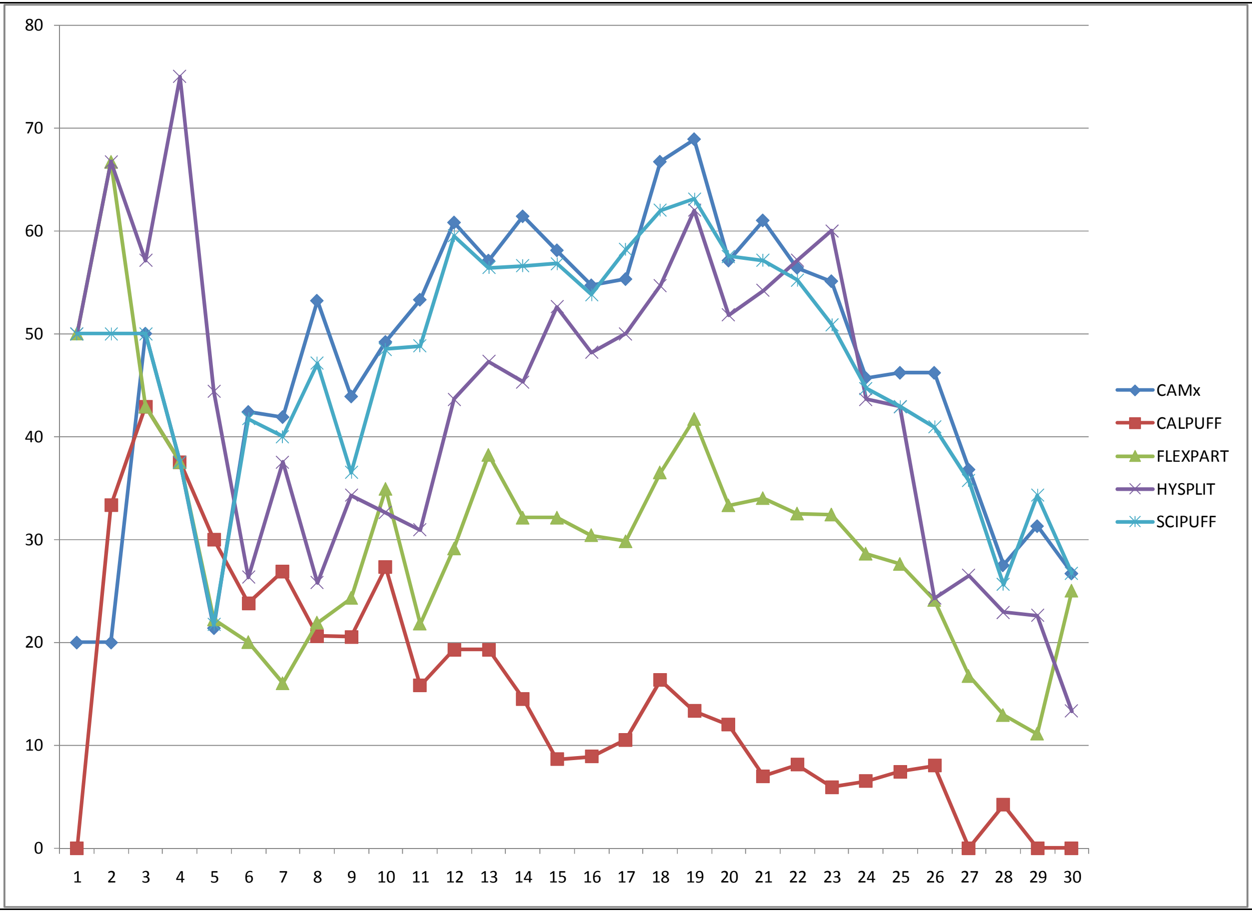

Figure ES-9. Figure of Merit (FMS) spatial model performance statistics as a function of time at three hour increments since the beginning of the tracer release.

The HYSPLIT LRT model was unique among the five LRT dispersion models examined in that it can be run in a particle mode, a Gaussian puff mode or hybrid particle/puff and puff/particle modes. The default configuration used in the HYSPLIT simulations presented previously was the three-dimensional particle mode. Nine HYSPLIT sensitivity tests were performed using different particle and puff formulation combinations. The RANK scores for the HYSPLIT ETEX sensitivity simulations ranged from 1.01 to 2.09, with the fully puff formulation ranked the lowest and hybrid puff/particle combinations ranked highest.

<u>Conclusions of the ETEX LRT Dispersion Model Evaluation</u>

Five LRT dispersion models were evaluated using the 1994 ETEX tracer test field experiment data. The CAMx, HYSPLIT and SCIPUFF models were the highest ranked LRT dispersions models, with CAMx performing slightly better than the other two models. The reasons for the poor performance of CALPUFF appear to be due to its inability to adequately treat horizontal and vertical wind shear. The CALPUFF Gaussian puff formulation retains a well-mixed circular puff despite the presence of wind variations across the puff that would advect tracer concentrations in different directions. Because the puff can only be transported by one wind, CALPUFF is unable to adequately treat such wind variations across the puff. The use of puff splitting, which EPA postulated in 2003 may extend the downwind applicability of the model, failed to have any significant effect on CALPUFF model performance.

CONCLUSIONS OF LRT DISPERSION MODEL TRACER TEST EVALUATION

The following are some of the key conclusions of the LRT dispersion model tracer test field experiment evaluation.

CALPUFF/CALMET Concentration Predictions are Highly Variable: Use of alternative CALMET input options within their range of reasonableness can produce wide variations in the CALPUFF concentration predictions. Given the regulatory use of CALPUFF, this result points toward the need to have a standard set of recommended CALMET settings for regulatory application of CALPUFF to assure consistency and eliminate the potential of selecting CALMET options to obtain a desired outcome in CALPUFF. No one CALMET configuration consistently produced the best CALPUFF model performance, although use of MM5 data with CALMET did tend to improve CALPUFF model performance with 36 and 12 km MM5 data being better than 80 km MM5 data.

Comparison of Current CALPUFF Model Performance with Previous Studies: The comparison of the model performance for current version of CALPUFF with past CALPUFF evaluations from the 1998 EPA study (EPA, 1998a) using the GP80 and SRL75 tracer study field experiments was mixed. For the GP80 100 km receptor arc, the current and past CALPUFF model performance evaluations were consistent with CALPUFF tending to overestimate the plume maximum concentrations and underestimate plume horizontal dispersion. The current version of CALPUFF had difficulty in reproducing the good performance of the past CALPUFF application in estimating the tracer residence time on the GP80 600 km receptor arc. Only by invoking the CALPUFF slug option, as used in the 1998 EPA study, was CALPUFF/CALMET able to reproduce the tracer residence time on the 600 km receptor arc. As the slug option is for near-source modeling and is a very non-standard option for LRT dispersion modeling, this result questions the validity of the 1998 CALPUFF evaluation study as applied for CALPUFF LRT modeling. The CALPUFF/MMIF was less sensitive to the slug option and more sensitive to puff splitting than CALPUFF/CALMET. For consistency, the current and EPA 1998 study CALPUFF evaluation approach both used the fitted Gaussian plume model evaluation methodology, along with angular plume centerline offset and tracer receptor arc timing statistics. The fitted Gaussian plume evaluation approach assumes that the observed and predicted concentration along a receptor arc has a Gaussian distribution. At longer downwind distances such an assumption may not be valid. For the CALPUFF evaluation using the SRL75 tracer field experiment, there was a very poor fit of the Gaussian plume to the observations resulting in some model performance statics that could be misleading. We do not recommend using the fitted Gaussian plume evaluation approach in future studies and instead recommend using approaches like the ATMES-II statistical evaluation approach that is free from any a priori assumption regarding the observed tracer distributions.

EPA-FLM Recommended CALMET Settings from the 2009 Clarification Memorandum: The EPA-FLM recommended CALMET settings in the 2009 Clarification Memorandum (EPA, 2009b) produces wind field estimates closest to surface wind observations based on the CAPTEX CALMET modeling. However, when used as input into CALPUFF, the EPA-FLM recommended CALMET settings produced one of the poorer performing CALPUFF/CALMET configurations when comparing CALPUFF predictions against the observed atmospheric tracer concentrations. Given that the CALMET wind evaluation is not an independent evaluation because some of the wind observations used in the evaluation database are also input into CALMET, the CALPUFF tracer evaluation bears more weight. Other aspects of the EPA-FLM recommended settings generally produced better CALPUFF tracer model performance including use of prognostic meteorological data as input to CALPUFF. The CALPUFF evaluation also found better CALPUFF performance when 12 km grid resolution is used in MM5 or CALMET as opposed to 80 or 36 km.

CALPUFF Model Performance using CALMET versus MMIF: The CALPUFF tracer model performance using meteorological inputs based on the MMIF tool versus CALMET was mixed. The variations of the CALPUFF model predictions using MMIF were much less than when CALMET was used and the CALPUFF/MMIF model performance was usually within the range of the performance exhibited by CALPUFF/CALMET. Specific examples from the tracer tests are as follows:

- For the GP80 100 km receptor arc, the CALPUFF/MMIF exhibited better fitted plume observed tracer model performance statistics than all of the CALPUFF/CALMET configurations except when CALMET was run using MM5 and surface meteorological observations but no upper-air meteorological observations.
- CALPUFF/CALMET using no MM5 data and just meteorological observations exhibited the best plume centerline location on the GP80 100 km receptor arc with CALPUFF/CALMET using just MM5 data and no observations and CALMET/MMIF exhibiting the worst plume centerline location.
- For the GP80 600 km receptor arc, the CALPUFF/MMIF fitted plume model performance statistics are in the middle of the performance statistics for the CALPUFF/CALMET configurations.
- The slug option was needed for CALPUFF/CALMET to produce good 600 km receptor arc tracer residence time statistics but had little effect on CALPUFF/MMIF. However, use of puff splitting greatly improved the CALPUFF/MMIF tracer residence time statistics.
- Of all the CALPUFF sensitivity tests examined, CALPUFF/MMIF using the slug option and puff splitting produced the best CALPUFF fitted plume tracer model performance statistics for the GP80 600 km receptor arc.
- In an opposite fashion to the GP80 100 km receptor arc, for the SRL75 100 km receptor arc the best plume centerline offset was achieved when CALPUFF was run with just MM5 data and no meteorological observations (either with CALMET or MMIF) with performance degraded when meteorological observations are used with CALMET.
- The CALPUFF model performance using the MMIF tool and 36 and 12 km MM5 data performed better than all of the CALPUFF/CALMET sensitivity tests for the CAPTEX CTEX3 experiment. However, the CALPUFF/MMIF using 36 and 12 km MM5 data performed worse than all of the CALPUFF/CALMET sensitivity tests for the CAPTEX CTEX5 experiment.

Comparison of Model Performance of LRT Dispersion Models: Six LRT dispersion modeled were evaluated using the CAPTEX Release 3 and 5 tracer database and five LRT dispersion models were evaluated using the ETEX tracer test field experiment. In each case the same MM5 meteorological data were used as input into all of the dispersion models, although different MM5 configuration options were selected for each tracer experiement.

The CAMx and CALGRID Eulerian photochemical grid models, FLEXPART Lagrangian particle model, HYSPLIT Lagrangian particle, puff and particle/puff hybrid model and CALPUFF and SCIPUFF Gaussian puff models were evaluated. For all three tracer experiments (CTEX3, CTEX5 and ETEX), the CAMx model consistently ranked highest when looking across all of the model performance statistics or when using the RANK composite performance statistic. For the CTEX3 field experiment, the RANK composite performance statistic gave consistent rankings of model performance with the suite of statistical metrics with CAMx being the higheset RANK score (1.91) followed by SCICHEM (1.71).

The rankings of the models using all of the statistics versus the RANK composite statistic were inconsistent for the CTEX5 experiment. Both approaches showed CAMx and HYSPLIT were the highest ranking LRT dispersion model for the CTEX5 field experiment. However, the RANK statistic ranked CALGRID as the 3rd best performing model, whereas when looking at all the performance statistics it was the worst performing model because it exhibited a large spread underestimation bias, had no correlation with the observations and little skill in reproducing the spatial distribution of the observed tracer. The CTEX5 LRT model evaluation points out the need to examine all performance statistics and not rely solely on the RANK composite statistic. It also points out the need to define a RANK-type composite statistic that focuses on the regulatory application of LRT dispersion models where an underestimation bias is undesirable.

Of the three top performing LRT dispersion models, CAMx had the highest RANK composite statistic and scored the highest for most (64%) of the other ATMES-II statistical model performance metrics, with HYSPLIT scoring the highest for 27% of the metrics. Additional findings of the ETEX tracer test evaluation are as follows:

- The model performance rankings were preserved closer to the source (e.g., within 300 km) as well as further downwind.
- CALPUFF puff splitting sensitivity tests had little effect on CALPUFF model performance.
- CAMx vertical mixing and horizontal advection solver sensitivity tests found that use of the MM5CAMx CMAQ-like vertical mixing diffusion coefficients and the PPM advection solver produced the best tracer test model performance. Similar results were seen in the CTEX3 and CTEX5 sensitivity modeling.
- HYSPLIT sensitivity tests using solely particle, solely puff and hybrid particle/puff and puff/particle combinations found that the hybrid configurations performed best and the puff configuration performed worst, with the CTEX3 and CTEX5 sensitivity test producing similar results.

1.0 INTRODUCTION

Dispersion models, such as the Industrial Source Complex Short Term (ISCST; EPA, 1995) or American Meteorological Society/Environmental Protection Agency Regulatory Model (AERMOD; EPA, 2004; 2009c) typically assume steady-state, horizontally homogeneous wind fields instantaneously over the entire modeling domain and are usually limited to distances of less than 50 kilometers from a source. However, dispersion model applications of distances of hundreds of kilometers from a source require other models or modeling systems. At these distances, the transport times are sufficiently long that the mean wind fields cannot be considered steady-state or homogeneous. As part of the Prevention of Significant Deterioration (PSD) program, new sources or proposed modifications to existing sources may be required to assess the air quality and Air Quality Related Values (AQRVs) impacts at Class I and sensitive Class II areas that may be far away from the source. AQRVs include visibility and acid (sulfur and nitrogen) deposition. There are 156 federally mandated Class I areas in the U.S. that consist of National Parks, Wilderness Areas and Wildlife Refuges that are administered by Federal Land Managers (FLMs) from the National Park Service (NPS), United States Forest Service (USFS) and Fish and Wildlife Service (FWS), respectively. Thus, non-steady-state Long Range Transport (LRT) dispersion models are needed to address air quality and AQRVs issues at distances beyond 50 km from a source.

1.1 BACKGROUND

The Interagency Workgroup on Air Quality Modeling (IWAQM) was formed to provide a focus for the development of technically sound recommendations regarding assessment of air pollutant source impacts on Federal Class I areas. Meetings were held with personnel from interested Federal agencies, including the Environmental Protection Agency (EPA), the USFS, NPS and FWS. The purpose of these meetings was to review respective modeling programs, to develop an organizational framework, and to formulate reasonable objectives and plans that could be presented to management for support and commitment. One objective of the IWAQM is the recommendation of LRT dispersion models for assessing air quality and AQRVs at Class I areas.

One such LRT dispersion model is the CALPUFF modeling system (Scire et al., 2000b). The CALPUFF modeling system consists of several components: (1) CALMET (Scire et al., 2000a), a meteorological preprocessor that can use as input surface, upper air, and/or on-site meteorological observations and/or prognostic meteorological model output data to create a three-dimensional wind field and derive boundary layer parameters based on gridded land use data; (2) CALPUFF, a Lagrangian puff dispersion model that can simulate the effects of temporally and spatially varying meteorological conditions on pollutant transport, remove pollutants through dry and wet deposition processes, and includes limited ability to transform pollutant species through chemical reactions; and (3) CALPOST, a postprocessor that takes the hourly estimates from CALPUFF and generates *n*-hr estimates as well as tables of maximum values.

In 1998, EPA published the report entitled "A Comparison of CALPUFF Modeling Results to Two Tracer Field Experiments" (EPA-454/R-98-009) (EPA, 1998a). The 1998 EPA study examined concentration estimates from the CALPUFF dispersion model that were compared to observed tracer concentrations from two short term field experiments. The first experiment was at the Savannah River Laboratory (SRL75) in South Carolina in December 1975 (DOE, 1978) and the second was the Great Plains experiment (GP80) near Norman, Oklahoma (Ferber et al., 1981) in

July 1980. Both experiments examined long-range transport of inert tracer materials to demonstrate the feasibility of using other tracers as alternatives to the more commonly used sulfur hexafluoride (SF_6). Several tracers were released for a short duration (3-4 hours) and the resulting plume concentrations were recorded at an array of monitors downwind from the source. For the SRL75 field experiment, monitors were located approximately 100 kilometers from the source. For the Great Plains experiment, arcs of monitors were located 100 and 600 kilometers from the source.

In 1998, IWAQM released their Phase 2 recommendations in a report "Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts" (EPA, 1998b[7]). These recommendations included a screening and refined LRT modeling approach based on the CALPUFF modeling system. The IWAQM recommendations were based in part on the 1998 EPA tracer test CALPUFF evaluation. It was IWAQM's conclusion at the time that it was not possible to prescribe all of the decisions needed in a CALPUFF/CALMET application: *"The control of the CALMET options requires expert understanding of mesoscale and microscale meteorological effects on meteorological conditions, and finesse to adjust the available processing controls within CALMET to develop the desired effects. The IWAQM does not anticipate the lessening in this required expertise in the future"* (EPA, 1998b).

On April 15, 2003, EPA issued a "Revision to the Guideline on Air Quality Models: Adoption of a Preferred Long Range Transport Model and Other Revisions" in the Federal Register (EPA, 2003[8]) that adopted the CALPUFF model as the EPA-recommended (Appendix W) model for assessing the far-field (> 50 km) air quality impacts due to chemically inert pollutants. In 2005, EPA issued another revision to the air quality modeling guidelines that recommended the AERMOD steady-state Gaussian plume model be used for near-source air quality issues. Thus, from 2005 on to present, there are two EPA-recommended models to address air quality issues due to primary pollutants: AERMOD for near-source (< 50 km) assessments; and CALPUFF for far-field (> 50 km) assessments.

In 2005, EPA formed a CALPUFF workgroup to help identify issues with the existing 1998 IWAQM guidance. In response to this, EPA initiated reevaluation of the CALPUFF system to update the 1998 IWAQM Phase 2 Recommendations.

In May 2009, EPA released a draft document entitled the "Reassessment of the Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 Summary Report: Revisions to the Phase 2 Recommendations" (EPA, 2009a). In this document, EPA described the developmental status of the CALPUFF modeling system. CALPUFF has evolved continuously since the publication of the original 1998 IWAQM Phase 2 recommendations; however, the status of CALPUFF related guidance has not kept pace with the developmental process. The May 2009 IWAQM Phase 2 Reassessment Report noted that *"The required expertise and collective body of knowledge in mesoscale meteorological models has never fully emerged from within the dispersion modeling community to support the necessary expert judgment on selection of CALMET control options"* (EPA, 2009a). In regards to the 1998 IWAQM Phase 2 lack of prescribing recommended CALMET settings, the May 2009 IWAQM Phase 2 Reassessment Report states: *"In a regulatory context, this situation has often resulted in an 'anything goes' process, whereby model control option selection can be leveraged as an instrument to achieve a desired modeled outcome,*

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7 http://www.epa.gov/scram001/7thconf/calpuff/phase2.pdf

8 http://www.federalregister.gov/articles/2003/04/15/03-8542/revision-to-the-guideline-on-air-quality-models-adoption-of-a-preferred-long-range-transport-model

without regard to the scientific legitimacy of the options selected" (EPA, 2009a). The CALPUFF working group noted that when running CALMET with prognostic meteorological model (e.g., WRF and MM5) output as input, the CALMET diagnostic effects and blending of meteorological observations with the WRF/MM5 output degraded the WRF/MM5 meteorological fields. Thus, the 2009 IWAQM Phase 2 Reassessment Report recommended CALMET settings with an objective to try and "pass through" the WRF/MM5 meteorological model output as much as possible for input into CALPUFF.

However, further testing of CALMET and CALPUFF by EPA's CALPUFF workgroup found that the recommended CALMET settings in the May 2009 IWAQM Phase 2 Reassessment Report did not achieve the intended result to "pass through" the WRF/MM5 meteorological variables as CALMET still re-diagnosed some and modified other meteorological variables thereby degrading the WRF/MM5 meteorological fields. Based in part of CALMET evaluations using tracer test field study databases (presented in Appendix B of this report), EPA determined interim CALMET settings that produced the best CALMET performance when compared to observed surface winds and on August 31, 2009 released a Clarification Memorandum "Clarification on EPA-FLM Recommended Settings for CALMET" (EPA, 2009b) with new recommended settings for CALMET. In the August 2009 Clarification Memorandum, EPA reiterated the desire to "pass through" meteorology from the WRF/MM5 prognostic meteorological models to CALPUFF, but the CALMET model at this time was incapable of achieving that objective.

In the meantime, EPA has developed the Mesoscale Model Interface (MMIF) software that where possible directly converts prognostic meteorological output data from the MM5 or WRF models to the parameters and formats required for direct input into the CALPUFF dispersion model thereby bypassing CALMET. Version 1.0 of MMIF was developed in June 2009 (Emery and Brashers, 2009) with versions 2.0 (Brashers and Emery, 2011) and 2.1 (Brashers and Emery, 2012) developed in, respectively, September 2011 and February 2012; we expect that MMIF Version 2.1 will be publicly released in February 2012. MMIF specifically processes geophysical and meteorological output files generated by the fifth generation mesoscale model (MM5) or the Weather Research and Forecasting (WRF) model (Advanced Research WRF [ARW] core, versions 2 and 3) and reformats the MM5/WRF output for input into CALPUFF..

The EPA CALPUFF workgroup has been evaluating CALPUFF using CALMET and MMIF meteorological drivers using data from several historical tracer field studies. In addition to a reevaluation of CALPUFF using CALMET and MMIF for the GP80 and SRL75 tracer studies that were used in the 1998 EPA CALPUF tracer evaluation report (EPA, 1998a), the CALPUFF workgroup has also evaluated CALPUFF using CALMET and MMIF meteorological drivers along with 5 other LRT dispersion models for the 1983 Cross Appalachian Tracer Experiment (CAPTEX). CALPUFF, along with four other LRT dispersion models, were also evaluated using data from the 1994 European Tracer Experiment (ETEX).

1.2 PURPOSE

The purpose of this report is to document the evaluation of the CALPUFF LRT dispersion model using data from four atmospheric tracer experiment field study databases. This includes the comparison of the CALPUFF model performance using meteorological inputs based on the CALMET and MMIF software and comparison of the CALPUFF model performance with other LRT dispersion models.

1.3 ORGANIZATION OF REPORT

Chapter one provides a background and purpose for the study. In Chapter 2, the four tracer field study experiments and LRT dispersion models used in the model performance evaluation are summarized. Chapter 2 also summarizes related previous studies and the approach and methods for the model performance evaluation of the LRT dispersion models.

Chapters 3, 4, 5 and 6 contain the evaluation of the LRT dispersions models using the GP80, SRL75, CAPTEX and ETEX tracer study field experiment data. References are provided in Chapter 7. Appendix A contains an evaluation of the MM5 and CALMET meteorological models using the CAPTEX Release #5 (CTEX5) database. Appendix B presents the evaluation of the CALMET meteorological model using the CAPTEX Release #3 (CTEX3) database that was used in part to formulate the EPA-FLM recommended settings in the 2009 Clarification Memorandum (EPA, 2009b). Results of the evaluation of six LRT dispersion models using the CAPTEX tracer field experiments are presented in Appendix C.

2.0 OVERVIEW OF APPROACH

2.1 SUMMARY OF TRACER TEST FIELD EXPERIMENTS

LRT dispersion models are evaluated using four atmospheric tracer test field studies as follows:

1980 Great Plains: The 1980 Great Plains (GP80) field study released several tracers from a release site near Norman, Oklahoma in July 1980 and measured the tracers at two arcs to the northeast at distances of 100 and 600 km (Ferber et al., 1981).

1975 Savannah River Laboratory: The 1975 Savannah River Laboratory (SRL75) study released tracers from the SRL in South Carolina and measured them at several receptors approximately 100 km from the release point (DOE, 1978).

1983 Cross Appalachian Tracer Experiment: The 1983 Cross Appalachian Tracer Experiment (CAPTEX) was a series of three-hour tracer released from Dayton, OH and Sudbury, Canada during September and October, 1983. Sampling was made in a series of arcs approximately 100 km apart that spanned from 300 to 1,100 km from the Dayton, OH release site (Ferber et al., 1986).

1994 European Tracer Experiment: The 1994 European Tracer Experiment (ETEX) consisted of two tracer releases from northwest France in October and November 1994 that was measured at 168 monitoring sites in 17 countries (Von Dop et al., 1998).

2.2 SUMMARY OF LRT DISPERSION MODELS

Up to six LRT dispersion models were evaluated using the tracer test field study data:

CALPUFF[9]: The California Puff (CALPUFF Version 5.8; Scire et al, 2000b) model is a Lagrangian Gaussian puff model that simulates a continuous plume using overlapping circular puffs. Included with CALPUFF is the CALMET meteorological processor (Scire et al., 2000a) that includes a diagnostic wind model (DWM). The EPA has developed a new Mesoscale Model Interface (MMIF; Emery and Brashers, 2009; Brashers and Emery, 2011; 2012) tool that will "pass through" output from the MM5 or WRF prognostic meteorological models without modifying or rediagnosing the meteorological variables, as is done in CALMET. A major objective of this study was to compare the CALPUFF model performance using CALMET and MMIF meteorological drivers.

SCIPUFF[10]: The Second-order Closure Integrated PUFF (SCIPUFF Version 2.303; Sykes et al., 1998) is a Lagrangian puff dispersion model using Gaussian puffs to represent an arbitrary, three-dimensional time-dependent concentration field. The diffusion parameterization is based on turbulence closure theory, which gives a prediction of the dispersion rate in terms of the measurable turbulent velocity statistics of the wind field. The SCIPUFF contains puff splitting when wind shear is encountered across a puff and puff merging when two puffs occupy the same space.

HYSPLIT[11]: The Hybrid Single Particle Lagrangian Integrated Trajectory (HYSPLIT Version 4.8; Draxler, 1997) is a complete system for computing simple air parcel trajectories to complex dispersion and deposition simulations. The dispersion of a pollutant is calculated by assuming either puff or particle or hybrid puff/particle dispersion. In the puff model,

9 http://www.src.com/calpuff/calpuff1.htm
10 http://www.sage-mgt.net/services/modeling-and-simulation/scipuff-dispersion-model
11 http://www.arl.noaa.gov/HYSPLIT_info.php

puffs expand until they exceed the size of the meteorological grid cell (either horizontally or vertically) and then split into several new puffs, each with its share of the pollutant mass. In the particle model, a fixed number of particles are advected about the model domain by the mean wind field and spread by a turbulent component. The model's default configuration assumes a 3-dimensional particle distribution (horizontal and vertical).

FLEXPART[12]: The FLEXPART (Version 6.2; Siebert, 2006; Stohl et al., 2005[13]) model is a Lagrangian particle dispersion model developed at the Norwegian Institute for Air Research in the Department of Atmospheric and Climate Research. FLEXPART was originally designed for calculating the long-range and mesoscale dispersion of air pollutants from point sources, such as after an accident in a nuclear power plant. In the meantime FLEXPART has evolved into a comprehensive tool for atmospheric transport modeling and analysis

CAMx[14]: The Comprehensive Air-quality Model with extensions (CAMx; ENVIRON, 2010) is a photochemical grid model (PGM) that simulates inert or chemical reactive pollutants from the local to continental scale. As a grid model, it simulates transport and dispersion using finite difference techniques on a three-dimensional array of grid cells. To treat the near-source dispersion of plumes, CAMx includes a subgrid-scale Lagrangian puff Plume-in-Grid (PiG) module whose mass is transferred to the grid model when the plume size is comparable to the grid size.

CALGRID: The California Mesoscale Photochemical Grid Model (Yamartino, et al., 1989, Scire et al., 1989; Earth Tech, 2005) is a PGM that simulates chemically reactive pollutants from the local to regional scale. As with CAMx, it is a grid model that simulates transport and dispersion using finite differencing techniques on a three-dimensional array of grid cells. CALGRID was originally designed to utilize meteorological fields produced by the CALMET meteorological processor (Scire et al., 2000a), but was updated in 2006 to utilize meteorology and emissions in UAM format (Earth Tech, 2006).

Although up to six LRT dispersion models were run for two of the tracer field experiments, a key component of this study was the evaluation of the CALPUFF model and running CALPUFF with various configurations of its meteorological drivers, CALMET and MMIF to help inform regulatory guidance on the operation of the CALPUFF system. Key to developing insight into the performance of any single model is to evaluate other models when configured similarly and using similar meteorological databases. Table 2-1 summarizes which LRT models were run with the four field study tracer experiments presented in this report.

For the GP80 CALPUFF/CALMET application, numerous CALPUFF sensitivity tests were performed using different configurations of CALMET including with and without MM5 data and use of no observations. A limited set of CALPUFF sensitivity tests were also conducted using different dispersion options. The other LRT models (save CALGRID) results were also evaluated for the 600 km distant arc of receptors, but are not presented in the CALPUFF comparison because this evaluation is based upon the NOAA DATEM statistical framework and is not consistent with how CALPUFF was evaluated by EPA for this experiment in 1998.

12 http://transport.nilu.no/flexpart

13 http://www.atmos-chem-phys.net/5/2461/2005/acp-5-2461-2005.html

14 http://www.camx.com/

The evaluation of the LRT models using the SRL75 tracer data only has results for CALPUFF. Several CALPUFF/CALMET sensitivity tests were run using only meteorological observations, only MM5 data and hybrid MM5 plus meteorological observations. CALPUFF/MMIF was run using 36, 12 and 4 km MM5 data.

Two tracer releases were evaluated using the CAPTEX database, Releases No. 3 and 5. While all of the models listed in Table 2-1 were run for the CAPTEX database, numerous CALMET sensitivity tests were also conducted, including the evaluation of CALMET using various configurations for CAPTEX Release No. 3 and 5 that helped define the EPA-FLM recommended CALMET settings in the August 2009 Clarification Memorandum (EPA, 2009b).

The LRT model intercomparison using the CAPTEX and ETEX databases was done differently than the other two tracer test evaluations. The objective of the ETEX with CAPTEX LRT model evaluation intercomparison was to evaluate the LRT dispersion models using a common meteorological input database. Thus, all LRT models used the same MM5 meteorological inputs.

Table 2-1. Model availability for the four tracer test field experiments.

Model	GP80	SRL75	CAPTEX	ETEX
CALPUFF/CALMET	Yes	Yes	Yes	No
CALMET/MMIF	Yes	Yes	Yes	Yes
SCIPUFF	No	No	Yes	Yes
HYSPLIT	No	No	Yes	Yes
FLEXPART	No	No	Yes	Yes
CAMx	No	No	Yes	Yes
CALGRID	No	No	Yes	No

2.3 RELEATED PREVIOUS STUDIES

Over the years there have been numerous studies that have evaluated dispersion models using tracer test and other field study databases. In fact, much of the early development of Gaussian plume dispersion formulation was assisted by radioactive ambient field data (Slade, 1968). The development and evaluation of the AERMOD steady-state Gaussian plume model used almost 20 near-source field study datasets[15]. The discussion below is limited to long range transport (LRT) dispersion model evaluations that have been related to the development of the CALPUFF modeling system, which in 2003 was identified as the EPA recommended regulatory LRT model for far-field (> 50 km) air quality modeling of chemically inert compounds (EPA, 2003).

2.3.1 1986 Evaluation of Eight Short-Term Long Range Transport Models

EPA sponsored a study to evaluate 8 LRT models using the GP80 tracer field experiment and Krypton-85 releases from the Savannah River Laboratory (SRL; Telegadas et al., 1980) databases (Policastro et al., 1986). The eight models were MESOPUFF, MESOPLUME, MSPUFF, MESOPUFF-II, MTDDIS, ARRPA, RADM and RTM-II. MESOPUFF, MSPUFF and MESOPUFF-II are Lagrangian puff models that all have their original basis on the MESOPUFF model. MESOPLUME is a Lagrangian plume segment model. MTDDIS is a variable trajectory model that also uses the Gaussian puff formulation. ARRPA is a single-source segmented plume model. RADM and RTM-II are Eulerian grid models. Model performance was evaluated by graphical and statistical methods. The primary means for the evaluation of model performance was the use of the American Meteorological Society (AMS) statistics (Fox, 1981). The AMS statistics recommends

15 http://www.epa.gov/ttn/scram/dispersion_prefrec.htm#aermod

that performance evaluation be based on comparisons of the full set of predicted/observed data pairs as well as the highest predicted and observed values per event and the highest N values (e.g., N=10) unpaired in space or time that represents the highest end of the concentration distribution.

Six of the eight LRT models were applied to both the GP80 and SRL75 experiments. The ARRPA model could only be applied to the GP80 database and the MTDDIS model could only be applied to the SRL75 database. Model performance was generally consistent between the two tracer databases and was characterized by three features:

- A spatial offset of the predicted and observed patterns.
- A time difference between the predicted and observed arrival of the plumes to the receptors.
- A definite angular offset of the predicted and observed plumes that could be as much as 20-45 degrees.

The LRT models tended to underestimate the horizontal spreading of the plume at ground level resulting in too high peak (centerline) concentrations when compared to the observations. For the Lagrangian models this is believed to be due to using sigma-y dispersion (Turner) curves that are representative of near-source and are applied for longer (> 50 km) downwind distances. The spatial and angular offsets resulted in poor correlations and large bias and error between the predicted and observed tracer concentrations when paired by time and location. However, when comparing the maximum predicted and observed concentrations unmatched by time and location, the models performed much better. For example, the average of the highest 25 predicted and observed concentrations (unpaired in location and time) were within a factor of two for six of the eight models evaluated (MESOPUFF, MESOPLUME, MESOPLUME, MTDDIS, ARRPA and RTM-II). The study concluded that the LRT models' observed tendency to over-predict the observed peak concentrations errs on the conservative side for regulatory applications. However, this over-prediction must be weighed against the general tendency of those models to underestimate horizontal spreading and to predict a plume pattern that is spatially offset from the observed data.

2.3.2 Rocky Mountain Acid Deposition Model Assessment Project – Western Atmospheric Deposition Task Force

A second round of LRT model evaluations was conducted as part of the Rocky Mountain Acid Deposition Model Assessment (EPA, 1990). In this study, the eight models from the 1986 evaluation were compared against a newer model, the Acid Rain Mountain Mesoscale Model (ARM3) (EPA, 1988). The statistical evaluation considered data paired in time/space and also unpaired in time/space equally. In this study, it was found that the MESOPUFF-II (Scire et al., 1984a, and 1984b) model performed best when using unpaired data, and that the ARM3 model performed best when using paired data. A final model score was assigned on the basis of a model's performance relative to the others in each of the areas (paired in time/space, unpaired in time/space, and paired in time, not space) for each of two tracer releases considered.

The primary objective was to assemble a mesoscale air quality model based primarily on models or model components available at the time for use by state and federal agencies to assess acid deposition in the complex terrain of the Rocky Mountains.

2.3.3 Comparison of CALPUFF Modeling Results to Two Tracer Field Experiments

The CALPUFF dispersion model (CALPUFF Version 4) was compared against tracer measurements from the GP80 and SRL75 field study experiments in a study conducted by James O. Paumier and Roger W. Brode (EPA, 1998a). The evaluation approach adopted the method used by Irwin (1997) that examined fitted predicted and observed plume concentrations across an arc of receptors. Meteorological inputs for the CALPUFF model were based on CALMET using observed surface and upper-air meteorological data. The study found that for these three tracer releases, there was overall agreement between the observed times and modeled times for both the time required for the plume to reach the receptor arc, as well as the time to pass completely by the arc. However, the transport direction had an angular offset. For the GP80 100 km arc, CALPUFF underestimated the lateral dispersion of the plume and overestimated the plume peak as well as the cross wind integrated concentration (CWIC) average concentrations across the plume; the lateral dispersion and CWIC were within a factor of two of the observed value and the CALPUFF fitted plume centerline concentrations was 2 to 2½ times greater than observed. Very different model performance was seen at the 600 km arc of receptors with simulated maximum and CWIC that were 2 to 2 ½ times lower than observed and lateral dispersion that was 2½ to 3½ times greater than observed.

2.3.4 ETEX and ATMES-II

After the Chernobyl accident in April 1986, the Atmospheric Transport Model Evaluation Study (ATMES) was initiated to compare the evolution of the radioactive cloud from Chernobyl with predictions by mathematical models for atmospheric dispersion, using as input the estimated source term and the meteorological data for the days following the accident. Considerable work was undertaken by ATMES in order to identify and make available the databases of radionuclide concentration in air measured after the Chernobyl accident and of meteorological conditions that occurred. The ATMES LRT dispersion modeling and model evaluation was conducted in the 1989-1990 time period. The performance of the LRT models to predict the observed radionuclides was hampered by the poor characterization of the emissions release from Chernobyl.

In May 1989, it was proposed to carry out a massive tracer experiment in Europe designed to address the weaknesses of ATMES modeling. In the following year the proposal was analyzed and modified to adapt it to the European context, and to take account of the ATMES results, as they became available. The experiment was named ETEX[16], European Tracer Experiment. It was designed to test the readiness of interested services to respond in the case of an emergency, to organize the tracer release and compile a data set of measured air concentrations and to investigate the performance of long range atmospheric transport and dispersion models using that data set.

The period 15 October-15 December 1994 was selected as the possible window for the two tracer experiments as part of ETEX. The first release started at 1600 UTC on October 23, 1994, and lasted 11 hours and 50 minutes. 340 kg of PMCH (perfluoromethylcyclohexane) tracer were released in Monterfil, France (48° 03' 30'' N, 2° 00' 30'' W) at an average flow rate of 8.0 g/s. The second ETEX tracer experiment started at 1500 UTC on November 14, 1994 and lasted for 9 hours and 45 minutes and released 490 kg of PMCP (perfluromethlcyclopentane) from Monterfil for an average release rate of 11.58 g/s.

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16 http://rem.jrc.ec.europa.eu/etex/

The ETEX real-time LRT modeling phase was performed in parallel with the tracer field experiment. When the release started, 28 modeling groups were notified of the starting time, source location, and emission rate. They ran their LRT models in real-time to predict the evolution of the tracer cloud, and their predictions were sent as soon as they were available to the statistical evaluation team at JRC-Ispra. The capability of providing these predictions in real-time was considered to be an important factor, as well as the model performance itself. Therefore, only those institutions that had access to a meteorological model or that received real-time forecasts from a meteorological centre could participate.

The analysis of these calculations could not distinguish the differences between predictions and measurements arising from dispersion model inadequacies as opposed to those arising from the meteorological forecasts used. Almost two years after the ETEX releases, the ATMES-II modeling exercise was launched to evaluate the LRT models in hindcast mode. ATMES-II participants were required to calculate the concentration fields of the first ETEX tracer experiment using ECMWF analyzed meteorological data as input to their own dispersion models. Any institution operating a long-range dispersion model could now participate whether or not it had real-time access to the meteorological data, and the number of participants (49) was increased compared to the ETEX real-time modeling exercise, even though not all of the original ETEX modelers took part in ATMES-II.

Contrary to ETEX, the differences between the measured and modeled concentration fields in ATMES-II could be more directly related to the dispersion simulation, thanks to the use of the same meteorological fields. However, even in this case, discrepancies between models were due not only to the calculation of dispersion, but also to the different ways in which the meteorological information was used. Moreover, ATMES-II modelers could also submit results obtained with a meteorological analysis different from that of ECMWF.

As for the statistical analysis in ETEX real-time modeling exercise, the analysis of ATMES-II model results was divided into time, space and global analyses. The same statistical indices of the first ETEX release were computed in the time analysis, while for the other two analyses some different indices were computed following the requirements of modelers, and the experience gained during the two real-time exercises.

In a general, a substantial improvement in the models' performance in the ATMES-II modeling was seen compared to the ETEX real-time modeling phase for the common statistical indices.

When comparing the results of the ATMES-II statistical analysis with those for the real-time simulation of the first ETEX release, a general improvement of the model performances for those who took part in both exercises is evident. This can be explained by the better resolution of the meteorological fields used, the availability of the measured values of tracer concentration that allowed participants to tune some parameters in their long-range dispersion model and the time elapsed between the two exercises (2 years) during which improvements in model formulation and application procedures took place.

Spatial Analysis: In ATMES-II the spatial analysis consisted of the calculation of the Figure of Merit in Space (FMS) at 12, 24, 36, 48, 60 hours after the release start. The FMS is the ratio of the spatial distribution of the overlap of the predicted and observed tracer pattern to the union of the predicted and observed tracer pattern and is expressed as a percent (note that all statistical metrics are defined in detail in Section 2.4). A big improvement could be observed in the models' FMS compared to the ETEX real-time exercise for the first release. For instance, at 36 hours in ATMES-II all the models had a non-zero FMS, half of the models had FMS>45% and a quarter of the models had FMS>55%, with a maximum FMS value of 71%. In ETEX, at 36 hours one tenth of the models had a zero FMS (i.e., no overlap of the predicted and observed tracer cloud) and a quarter had an FMS>45%, with a maximum FMS of 67%. At 60 hours in ATMES-II half of the models (against only a quarter of the models of ETEX) had a FMS>30% and the maximum FMS was 58%, while the maximum FMS for ETEX models was 52%.

Temporal Analysis: The temporal analysis was carried out at two arcs of receptors at distances of approximately 600 and 1,200-1,400 km from the release point. In general, the LRT models were better at predicting the time of arrival, duration and peak concentration of the tracer cloud for the central stations of the two arcs, and less satisfactory for the external stations. The Figure of Merit in Time (FMT, see Section 2.4 for definition) the best performances were observed for the central stations of the two arcs. For all the stations selected for the time analysis, FMT of models in ATMES-II improved when compared to the first ETEX release exercise.

Global Statistics: The global statistical indexes also indicate a general improvement of models' performance in ATMES-II compared to the ETEX real time modeling exercise. For instance, only eight models out of 49 (16%) had a bias higher than 0.4 ngm^{-3} (400 pg/m^3) in absolute value; the number of models above the same threshold in ETEX real time was 24 out of the 28 (86%) participants. Almost all models showed a satisfactory agreement with the measured values. However, few models were distinguished by a particularly good (or bad) performance in all respects. More than half of the models showed a relatively small error (NMSE), indicating a limited spread of the predictions around the corresponding measurements. Again, while in the ETEX real-time exercise only four models had an NMSE less than 100, 42 models were below this threshold in ATMES-II. Improvements compared to ETEX could also be seen in the number of predicted and observed pairs within a factor of 2 (FA2) and 5 (FA5) of each other; whereas in ATMES-II half of the models had FA5>45%, in ETEX no model reached that value. There was no negative Pearson correlation coefficient, with the best models showing values slightly less than 0.7.

Conclusions: The three main original objectives of ETEX as follows:

- to test the capability of institutes involved in emergency response to produce predictions of the cloud evolution in real-time;
- to evaluate the validity of their predictions; and
- to assemble a database that allows the evaluation of long-range atmospheric dispersion models.

The ETEX study has formulated the following conclusions:

- The objectives stated in the project design were met.
- ETEX demonstrated the feasibility of conducting a continental scale tracer experiment across Europe using the perfluorocarbon tracer technique.
- There is a large number of institutes that can (and will in the event of a real accident) predict the long-range atmospheric dispersion of a pollutant cloud.
- The rapidity of LRT dispersion modeling groups in predicting the tracer cloud evolution and transmitting the results to a central point was excellent.
- Regarding the quality of the predictions, differences between observations and calculations of 3 to 6 hours in arrival time and a factor of 3 in maximum airborne concentrations at ground level should be viewed as the best achievable with current LRT models.
- The simulation of cloud dispersion at short and mesoscale distances seems to have considerable influence on the long-range cloud development.
- The transition of the dispersion scales from local to long-range modeling should be investigated in more detail.
- ETEX assembled a unique experimental database of tracer concentrations and meteorological data accessible via the Internet.
- ETEX created widespread interest and resulted in considerable dispersion model development as well as the reinforcement of communication and collaboration between national institutes and international organizations.
- The ETEX network of national institutes and international organizations should be maintained and improved to continue model development and demonstrate the technical capability necessary to support emergency management in real cases.
- Further investigations are needed to determine the quality of predictions under complex meteorological conditions, and to quantify the uncertainty of models for emergency management.

2.3.5 Data Archive of Tracer Experiments and Meteorology (DATEM)

The Data Archive of Tracer Experiments and Meteorology (DATEM[17]) is not a single particular study but an archive of tracer experiment and meteorological data and suggested procedures for evaluating LRT dispersion models using atmospheric tracer data (Draxler, Heffter and Rolph, 2002). The DATEM archive currently incorporates data from five long-range dispersion experiments, which represent a collection of more than 19,000 air concentration samples, re-analysis fields from the National Center for Atmospheric Research (NCAR) / National Centers for Environmental Prediction (NCEP) re-analysis project, and statistical analysis programs based upon the ATMES-II evaluation of ETEX. All the emissions and sampling data are in space delimited text files, easily used by FORTRAN programs or imported into any spreadsheet. Meteorological data fields have been reformatted for use by HYSPLIT and are available for download. The statistical programs are all written in FORTRAN and include PC executables with the source code so that they can be compiled on other platforms.

The five long range transport tracer field experiments whose atmospheric and meteorological data reside on the DATEM website are as follows:

17 http://www.arl.noaa.gov/DATEM.php

ACURATE: The Atlantic Coast Unique Regional Atmospheric Tracer Experiment (ACURATE) operating during 1982-1983 and consisted of measuring Krypton^{85} air concentrations from emissions out of the Savannah River Plant in South Carolina (Heffter et al., 1984). 12- and 24-hour average samples were collected for 19 months at five monitoring sites that were 300 to 1,000 km from the release point.

ANATEX: The Across North America Tracer Experiment (ANATEX) consisted of 65 releases of three types of Perflurocarbon Tracers (PFTs) that were released from Glasgow, Montana and St. Cloud, Minnesota over three months (January-March, 1987). The PFTs were measured at 75 monitoring sites covering the eastern U.S. and southeastern Canada (Draxler and Heffter, Eds, 1989).

CAPTEX: The Cross Appalachian Tracer Experiment (CAPTEX) occurred during September and October, 1983 and consisted of 4 PFT releases from Dayton, Ohio and 2 PFT releases from Sudbury, Ontario, Canada (Ferber et al., 1986). Sampling occurred at 84 sites from 300 to 800 km from the PFT release sites.

INEL74: The Idaho National Engineering Laboratory (INEL74) experiment consisted of releases of Krypton^{85} during February-March, 1974 with sampling taken at 11 sites approximately 1,500 km downwind stretching from Oklahoma City to Minneapolis (Ferber et al., 1977; Draxler, 1982).

GP80: The 1980 Oklahoma City Great Plains (GP80) consisted of two releases of PFTs on July 8 and July 11, 1980. The first PFT release was sampled at two arcs at a distance 100 km and 600 km with 10 and 35 monitoring sites on each arc, respectively (Ferber et al., 1981). The second PFT release was only monitored at a distance of 100 km at the corresponding 10 sites from the July 8 release.

The DATEM website also includes a model evaluation protocol for evaluating LRT dispersion models using tracer field experiment that was designed following the procedures by Mosca et al. (1998) for the ATMES-II study and Stohl et al., (1998). The DATEM model evaluation protocol has four broad categories of model evaluation:

1. Scatter among paired measured and calculated values;
2. Bias of the calculations in terms of over- and under-predictions;
3. Spatial distribution of the calculation relative to the measurements; and
4. Differences in the distribution of unpaired measured and calculated values.

A recommended set of statistical performance measures are provided along with a FORTRAN program (statmain) to calculate them. The DATEM recommendations have been adopted in this study and more details on the DATEM recommended ATMES-II model evaluation approach is provided in section 2.4.3.

2.4 MODEL PERFORMANCE EVALUATION APROACHES AND METHODS

2.4.1 Model Evaluation Philosophy

To date, no specific guidance has been developed by the USEPA for evaluating LRT models. According to EPA's *Interim Procedures for Evaluating Air Quality Models (Revised)*, the rationale for selecting a particular data group combination depends upon the objective of the performance evaluation. For this it is necessary to translate the regulatory purposes of the intended use of the model into performance evaluation objectives (EPA, 1984; Britter, et al., 1995). Under the approach for both the 1986 and 1998 EPA LRT model evaluation projects, no particular emphasis was placed on any data group combination or set of statistical measures.

In this study we expand the LRT model performance philosophy to include spatial, correlation/scatter, bias, error and frequency distribution performance metrics.

In their regulatory use within the United States, LRT models are used to predict impacts of criteria pollutants for national ambient air quality standards (NAAQS) and Prevention of Significant Deterioration of Air Quality (PSD) Class I increments. Additionally, Federal Land Management Agencies rely upon the same LRT models in the PSD program for estimates of chemical transformation and removal to assess impacts on air quality related values (AQRV's) such as visibility and acid deposition. The chemistry of aerosol formation is highly dependent upon the spatial and temporal variability of meteorology (e.g., relative humidity and temperature) and precursors (e.g., ammonia).

Recognizing the need for developing an evaluation approach that reflects the intended regulatory uses of LRT models, the model performance evaluation approach of Mosca et al., (1998) and Stohl et al., (1998) used in the ATMES-II study and recommended by DATEM (Draxler, Heffter and Rolph, 2002) was adopted for this study.

We have also included elements of the plume fitting evaluation approach of Irwin (1997) for comparison with the results from the original 1998 tracer evaluation study (EPA, 1998a). The Irwin model evaluation approach is only applicable when you have an arc of receptors at a given distance downwind of the source so that a cross plume distribution and dispersion statistics can be generated. Whereas, the ATMES-II is more applicable when you have receptors spread over a large region and can calculate statistical parameters related to the predicted and observed distribution of the tracer concentrations. Accordingly, we use the Irwin plume fitting statistical evaluation approach for the GP80 and SRL75 tracer experiments whose receptors were defined along arcs at a given distance from the source and we used the ATMES-II statistical evaluation approach for the CAPTEX and ETEX tracer experiments that had receptors that were defined across a broad area.

2.4.2 Irwin Plume Fitting Model Evaluation Approach

Irwin (1997) focused his evaluation of the CALPUFF modeling system on its ability to replicate centerline concentrations and plume widths, with more emphasis placed upon these factors than data such as modeled/observed plume azimuth, plume arrival time, and plume transit time. The Great Plains and Savannah River tracer CALPUFF evaluations (EPA, 1998a) followed the tracer evaluation methodology of the Idaho National Engineering Laboratory (INEL) tracer study conducted on April 19, 1977 near Idaho Falls, Idaho (Irwin, 1997).

Irwin examined CALPUFF performance by calculating the cross-wind integrated concentration (CWIC), azimuth of plume centerline, and the second moment of tracer concentration (lateral dispersion of the plume [σ_y]). The CWIC is calculated by trapezoidal integration across average monitor concentrations along the arc. By assuming a Gaussian distribution of concentrations along the arc, a fitted plume centerline concentration (Cmax) can be calculated by the following equation:

$$\text{Cmax} = \text{CWIC}/[(2\pi)^{1/2}\sigma_y] \qquad (2\text{-}1)$$

The measure σ_y describes the extent of plume horizontal dispersion. This is important to understanding differences between the various dispersion options available in the CALPUFF modeling system. Additional measures for temporal analysis include plume arrival time and the plume transit time on arc. Table 2-2 summarizes the statistical metrics used in the Irwin fitted Gaussian plume evaluation methodology.

Table 2-2. Model performance metrics from Irwin (1997) and 1998 EPA CALPUFF Evaluation (EPA, 1998a).

Statistics	Description
Spatial	
Azimuth of Plume Centerline	Comparison of the predicted angular displacement of the plume centerline from the observed centerline on the arc
Plume Sigma-y	Comparison of the predicted and observed fitted plume widths (i.e., dispersion rate)
Temporal	
Plume Arrival Time	Compare the time the predicted and observed tracer clouds arrives on the receptor arc
Transit Time on Arc	Compare the predicted and observed residence time on the receptor arc
Performance	
Crosswind Integrated Concentration	Compares the predicted and observed average concentrations across the receptor arc (CWIC)
Observed/Calculated Maximum	Comparison of the predicted and observed fitted Gaussian plume centerline (maximum) concentrations (Cmax) and maximum concentration at any receptor along the arc Omax)

The measures employed by Irwin (1997) and EPA (1998a) provide useful diagnostic information about the performance of LRT modeling systems, such as CALPUFF, but they do not always lend themselves easily to spatiotemporal analysis or direct model intercomparison.

For tracer studies such as the Great Plains Tracer Experiment and Savannah River where distinct arcs of monitors were present, the Irwin plume fitting evaluation approach was used in this study.

2.4.3 ATMES-II Model Evaluation Approach

The model evaluation methodology employed for this study was designed following the procedures of Mosca et al. (1998) and Draxler et al. (2002). Mosca et al. (1998) defined three types of statistical analyses:

- Spatial Analysis: Concentrations at a fixed time are considered over the entire domain. Useful for determining differences spatial differences between predicted and observed concentrations.
- Temporal Analysis: Concentrations at a fixed location are considered for the entire analysis period. This can be useful for determining differences between the timing of predicted and observed tracer concentrations.
- Global Analysis: All concentration values at any time and location are considered in this analysis. The global analysis considers the distribution of the values (probability), overall tendency towards overestimation or underestimation of measured values (bias and error), measures of scatter in the predicted and observed concentrations and measures of correlation.

2.4.3.1 Spatial Analysis

To examine similarities between the predicted and observed ground level concentrations, the Figure of Merit in Space (FMS) is calculated at a fixed time and for a fixed concentration level. The FMS is defined as the ratio between the overlap of the measured (A_M) and predicted (A_P) areas above a significant concentration level and their union:

$$FMS = \frac{A_M \cap A_P}{A_M \cup A_P} \times 100\% \qquad (2\text{-}2)$$

The more the predicted and measured tracer clouds overlap one another, the greater the FMS values are. A high FMS value corresponds to better model performance, with a perfect model achieving a 100% FMS score.

Additional spatial performance measures of Probability Of Detection (POD), False Alarm Rate (FAR), and Threat Score (TS) are also used. Typically used as a method for meteorological forecast verification, these three interrelated statistics are useful descriptions of an air quality model's ability to spatially forecast a certain condition. The forecast condition for the model is the predicted concentration above a user-specified threshold (at the 0.1 ngm^{-3} (100 pgm^{-3}) level for ATMES-II study). In these equations:

- "a" represents the number of times a condition that has been forecast, but was not observed (false alarm)
- "b" represents the number of times the condition was correctly forecasted (hits)
- "c" represents the number of times the nonoccurrence of the condition is correctly forecasted (correct negative); and
- "d" represents the number of times that the condition was observed but not forecasted (miss).

The FAR (Equation 2-3) is described as a measure of the percentage of times that a condition was forecast, but was not observed. The range of the score is 0 to 1 or 0% to 100%, with the ideal FAR score of 0 or 0% (i.e., there are observed tracer concentrations at a monitor/time every time the model predicts there is a tracer concentration at that monitor/time).

$$FAR = \left(\frac{a}{a+b}\right) \times 100\% \qquad (2\text{-}3)$$

The POD is a statistical measure which describes the fraction of observed events of the condition forecasted was correctly forecasted. Equation 2-4 shows that POD is defined as the ratio of "hits" to the sum of "hits" and "misses." The range of the POD score is 0 to 1 (or 0%to 100%), with the ideal score of 1 (or 100%).

$$POD = \left(\frac{b}{b+d}\right) \times 100\% \qquad (2\text{-}4)$$

The TS (Equation 2-5) is described as the measure describing how well correct forecasts corresponded to observed conditions. The TS does not consider correctly forecasted negative conditions, but penalizes the score for both false alarms and misses. The range of the TS is the same as the POD, ranging from 0 to 1 (0% to 100%), with the ideal score of 1 (100%).

$$TS = \left(\frac{b}{a+b+d} \right) \times 100\% \qquad (2\text{-}5)$$

2.4.3.2 Temporal Analysis

In Section 2.4.1 temporal statistics related to the timing of when the predicted and observed tracer arrives at a monitor or arc of monitors, its residence time over a monitor (or arc) and when the tracer leaves the monitor (or arc) were discussed. Another temporal analysis statistics is the Figure of Merit in Time (FMT), which is analogous to the FMS only it is calculated at a fixed location (*x*) rather than a fixed time as the FMS. The FMT evaluates the overlap between the measures (M) and predicted (P) concentration at location *x* and time t_j. The FMT is normalized to the maximum predicted or measured value at each time interval and is expressed as a percentage value in the same manner as the FMS (Mosca et al., 1998).

$$FMT(\bar{x}) = \frac{\sum_j \min\{M(\bar{x}, t_j), P(\bar{x}, t_j)\}}{\sum_j \max\{M(\bar{x}, t_j), P(\bar{x}, t_j)\}} \times 100\% \qquad (2\text{-}6)$$

The FMT is sensitive to both differences between measured and predicted and any temporal shifts that may occur.

2.4.3.3 Global Analysis

Following Draxler et al. (2002), four broad categories were used for global analysis of model evaluation. These broad categories are: (1) scatter; (2) bias; (3) spatial distribution of predictions relative to measurements; and (4) differences in the distribution of unpaired measured and predicted values. One or more statistical measures are used from each of the four categories in the global analysis. These include the percent over-prediction, number of calculations within a factor of 2 and 5 of the measurements, normalized mean square error, correlation coefficient, bias, fractional bias, figure of merit in space, and the Kolmogorov-Smirnov parameter representing the differences in cumulative distributions (Draxler et al., 2002).

Factor of Exceedance: In the scatter category, better model performance is observed when the Factor of Exceedance (FOEX) measure is close to zero and FA2 (described next) has a high percentage. A high positive FOEX and high percentage of FA5 would indicate a model's tendency towards over-prediction when compared to observed values.

$$FOEX = \left[\frac{N_{(P_i > Ni_i)}}{N} - 0.5 \right] \times 100\% \qquad (2\text{-}7)$$

Where, *N* in the numerator is the number of pairs when the prediction (*P*) exceeds the measurement (*M*) and the *N* in the denominator is the total number of pairs in the evaluation. In FOEX, all 0-0 pairs are excluded from the analysis. FOEX can range from -50% to +50% with a perfect model receiving a 0% value.

Factor of α (FAα): FAα represents the percentage of predicted values that are within a factor of α, where we have used α = 2 or 5. As with FOEX, in FAα all 0-0 pairs are excluded.

$$FA\alpha = \left[\frac{N(y - y0 = [x - x0]\alpha)}{N} \right] \times 100 \tag{2-8}$$

Normalized Mean Squared Error (NMSE): Normalized mean squared error is the average of the square of the differences divided by the product of the means. NMSE gives information about the deviations, but does not yield estimations of model over-prediction or under-prediction.

$$NMSE = \frac{1}{N\overline{P}\overline{M}} \sum (P_i - M_i)^2 \tag{2-9}$$

Pearson's Correlation Coefficient (PCC): Also referred to as the linear correlation coefficient, its value ranges between -1.0 and +1.0. A value of +1.0 indicates "perfect positive correlation" or having all pairings of (M_i, P_i) lay on straight line on a scatter diagram with a positive slope. Conversely, a value of -1.0 indicates "perfect negative correlation" or having all pairings of (M_i, P_i) lie on a straight line with a negative slope. A value of near 0.0 indicates the clear absence of relationship between the model predictions and observed values.

$$R = \frac{\sum_i \left(M_i - \overline{M}\right) \bullet \left(P_i - \overline{P}\right)}{\left[\sqrt{\sum \left(M_i - \overline{M}\right)^2}\right]\left[\sqrt{\sum \left(P_i - \overline{P}\right)^2}\right]} \tag{2-10}$$

Fractional Bias (FB): Calculated as the mean difference in prediction minus observation pairings divided by the average of the predicted and observed values.

$$FB = 2\overline{B} / \left(\overline{P} + \overline{M}\right) \tag{2-11}$$

Kolmogorov-Smirnov Parameter (KS): The KS parameter is defined as the maximum difference between two cumulative distributions. The KS parameter provides a quantitative estimate where C is the cumulative distribution of the measured and predicted concentrations over the range of k. The KS is a measure of how well the model reproduces the measured concentration distribution regardless of when or where it occurred. The maximum difference between any two distributions cannot be more than 100%.

$$KS = Max\left|C(M_k) - C(P_k)\right| \tag{2-12}$$

RANK: Given the large number of metrics, a single measure describing the overall performance of a model could be useful. Stohl et al. (1998) evaluated many of the above measures and discovered ratio based statistics such as FA2 and FA5 were highly susceptible to measurement errors. Draxler proposed a single metric, which he calls RANK, which is the composite of one statistical measure from each of the four broad categories.

$$RANK = \left|R^2\right| + \left(1 - \left|FB/2\right|\right) + FMS/100 + \left(1 - KS/100\right) \qquad \text{(2-13)}$$

The final score, model rank (*RANK*), provides a combined measure to facilitate model intercomparison. RANK is the sum of four of the statistical measures for scatter, bias, spatial coverage, and the unpaired distribution. RANK scores range between 0.0 and 4.0 with 4.0 representing the best model ranking. Using this measure allows for direct intercomparison of models across each of the four broader statistical categories.

2.4.3.4 Treatment of Zero Concentration Data

One issue in the performance evaluation was how to treat zero concentration data. Mosca et al. (1998) filtered the ETEX observational dataset by only retaining non-zero data and zero data within two sample time intervals (6 hours) of the arrival and departure times of the tracer cloud along with any zero observations in between these two time points. Stohl (1998) employed a Monte Carlo approach by adding normally distributed "random errors" to the original values to test the sensitivity of certain statistical measures to zero or near zero values. Stohl (1998) identified that certain statistical parameters may be sensitive to small variations in measurements when using "zero" or near "zero" background concentration data. While the inclusion of "zero" data creates concern about the robustness of certain statistical measures, especially ratio based statistics, there was also concern that only examining model statistics at locations where the tracer cloud was observed provides a limited snapshot of a model's performance at those locations, and did not offer any insight into a model that may show poorer performance by transporting emissions to incorrect locations or advection to correct locations at incorrect times.

While the arguments for "filtering" of data are valid, it is also important to consider additional statistical measures such as the FAR, POD, and TS where all zero data must be considered. All zero data was retained for inclusion in the spatial analysis, but was filtered for the global statistical analysis. The approach used in this project differs from the approach used by Draxler et al. (2001) in that all zero-zero pairs are considered in their analysis of HYSPLIT performance.

3.0 1980 GREAT PLAINS FIELD STUDY

3.1 DESCRIPTION OF 1980 GREAT PLAINS FIELD STUDY

LRT tracer test experiments were conducted in 1980 with the release of a perfluorocarbon and sulfur hexafluoride tracers from the National Oceanic and Atmospheric Administration (NOAA) National Severe Storms Laboratory (NSSL) in Norman, Oklahoma (Ferber et al., 1981). Two arcs of monitoring sites were used to sample the tracer plumes; an arc of 30 samplers with a 4-5 km spacing located approximately 100 km from the release point that sampled at 45 minute intervals and an arc of 38 samplers through Nebraska and Missouri located approximately 600 km from the release site that sampled at an hourly interval. Figure 3-1 displays the locations of the tracer release site and the monitoring sites on the arcs that are 100 km and 600 km downwind of the source. Two experiments were conducted, one on July 8, 1980 that included both the 100 km and 600 km sampling arcs and one on July 11, 1980 that only included the 100 km sampling arc. The July 8, 1980 tracer field experiment and subsequent Perfluoro-Dimethyl-cyclohexane (PDCH) observed concentrations were used in this model evaluation study. The PDCH tracer was released over a three-hour period from 1900-2200 GMT (1400-1700 CDT) on July 8, 1980 from an open field near the NOAA/NSSL.

3.2 MODEL CONFIGURATION AND APPLICATION

The CALPUFF modeling system uses a grid system consisting of an array of horizontal grid cells and multiple vertical layers. Two grids must be defined in the CALPUFF model, a meteorological grid and a computational grid. The meteorological grid defines the extent over which landuse, winds, and other meteorological variables are defined in the CALMET simulation. The computational grid defines the extent of the concentration calculations in the CALPUFF simulation, and is required to be identical to or a subset of the meteorological grid. For the GP80 simulations, the computational grid is defined to be identical to the meteorological grid. A third grid, the sampling grid, is optional, and is used by CALPUFF to define a rectangular array of receptor locations. The sampling grid must be identical to or a subset of the computational grid. It may also be nested inside the computational grid (i.e., several sampling grid cells per computational grid cell). For the GP80 applications, a sampling grid identical to the computational grid was used with a nesting factor of one (sampling grid cell size equal to the cell size of the computational grid).

To properly characterize the meteorology for the CALPUFF modeling system, a grid that spans, at a minimum, the distance between source and receptor is required. However, to allow for possible recirculation of puffs that may be transported beyond the receptors and to allow for upstream influences on the wind field, the meteorological and computational domains should be larger than this minimum.

The GP80 site is shown in Figure 3-1. Two arcs of monitors were deployed during the field experiment at 100 and 600 kilometers from the source. For this analysis, two separate modeling domains were defined for simulating tracer concentrations on the 100 km and 600 km receptor arcs. For the 100-kilometer arc, a grid extending approximately from 35º N to 36.5º N latitude and from 96º W to 98.5º W longitude was defined.

CALPUFF was operated for the July 8, 1980 GP80 tracer experiment using meteorological inputs based on CALMET and MMIF. For the CALPUFF simulations using CALMET, a UTM coordinate system was used to be consistent with past CALPUFF evaluations (Policastro et al., 1986; EPA, 1998a).

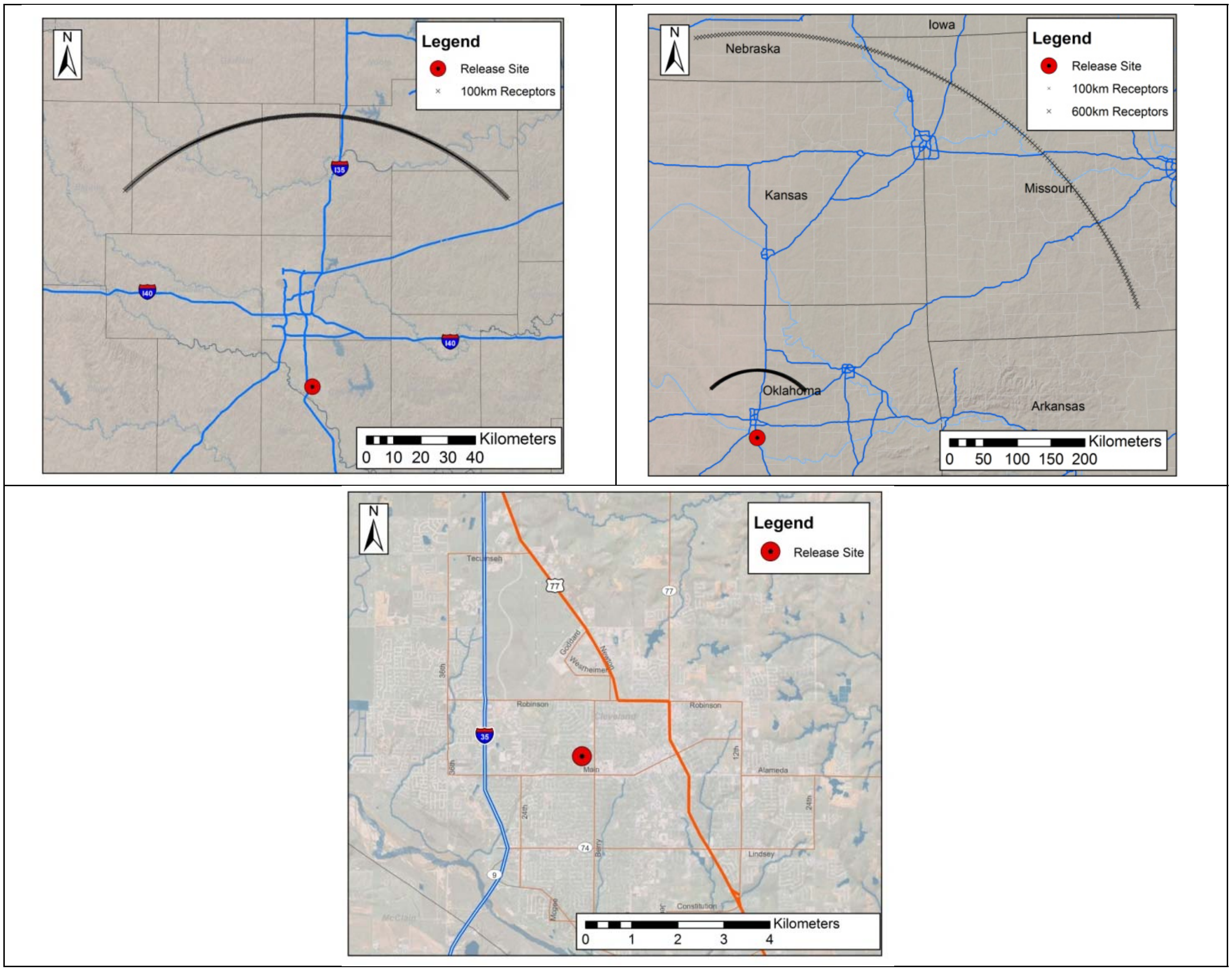


Figure 3-1. Locations of the release site and the 100 km arc (top left) and 600 km arc (top right) of monitoring sites along with a close in view of the release site (bottom) for the GP80 tracer experiment.

3.2.1 CALPUFF/CALMET BASE Case Model Configuration

For the CALPUFF/CALMET 100 km arc BASE case scenario, a 42 by 40 horizontal grid with a 10 km grid resolution was used for the meteorological and computational grids. For the 600 km arc BASE case, the grid extended from approximately 35° N to 42° N latitude and from 89° W to 100° W longitude using a 44 by 40 horizontal grid with a 20 km grid resolution. In addition, a 220 by 200 horizontal grid with a 4 km grid resolution was also used that encompassed both the 100 km and 600 km arcs.

To adequately characterize the vertical structure of the atmosphere, ten vertical layers were defined corresponding to layer heights at 0, 20, 40, 80, 160, 320, 640, 1,200, 2,000, 3,000 and 4,000 meters above ground level (AGL). The vertical layer structure conforms to the recommendations in EPA's August 2009 Clarification Memorandum on recommended settings for CALMET modeling (EPA, 2009b)

The CALMET preprocessor utilizes National Weather Service (NWS) meteorological data and on-site data to produce temporally and spatially varying three dimensional wind fields for CALPUFF. Only NWS data were used for this effort and came from two compact disc (CD) data sets. The first was the *Solar and Meteorological Surface Observation Network* (SAMSON) compact discs, which were used to obtain the hourly surface observations. The following surface stations were used for each of the field experiments:

Table 3-1. Surface meteorological monitoring sites used in the GP80 CALMET modeling.

State	City
Arkansas	Fort Smith
Illinois	Springfield
Kansas	Dodge City, Topeka, Wichita
Missouri	Columbia, Kansas City, Springfield, St. Louis
Nebraska	Grand Island, Omaha, North Platte
Oklahoma	Oklahoma City, Tulsa
Texas	Amarillo, Dallas-Fort Worth, Lubbock, Wichita Falls

Twice daily upper-air meteorological soundings came from the second set of compact discs, the *Radiosonde Data for North America*. The following stations were used for each of the field experiments:

Table 3-2. Radiosonde monitoring sites used in the GP80 CALMET modeling.

State	City
Arkansas	Little Rock
Illinois	Peoria
Kansas	Dodge City, Topeka
Missouri	Monett
Nebraska	Omaha, North Platte
Oklahoma	Oklahoma City
Texas	Amarillo

Consistent with the August 2009 Clarification Memorandum, some of the CALPUFF/CALMET sensitivity tests utilized CALMET simulations using prognostic meteorological model output as the first-guess wind field for CALMET and then perform the CALMET STEP1 procedures to apply diagnostic effects to the wind fields. CALMET then uses the surface and upper air observations in the objective analysis (OA) phase that blends the meteorological observations with the STEP1 wind field to produce the STEP2 wind field. This method is often referred to as the "hybrid" method.

The terrain and GIS land use data on the original CALPUFF CD were used to define gridded land use data for each field experiment. These data are defined with a resolution of 1/6° latitude and 1/4° longitude. The program PRELND1.EXE, also provided on the CD, was run to extract the data from the GIS data base and map the data to the meteorological domain for each field experiment. The program ELEVAT.EXE (also provided on the CD) was used to process the raw terrain data into average gridded terrain data. The file of terrain and geophysical parameters required by CALMET was constructed from the output files generated by ELEVAT and PRELND1 with additional required records inserted manually to create the final forms of the file for GP80 tracer experiment.

One of the primary purposes of the GP80 experiment was to demonstrate the efficacy of perfluorocarbons as tracers in atmospheric dispersion field studies. Perfluoromonomethylcyclohexane (PMCH) and perfluorodimethylcyclohexane (PDCH) were released during this experiment. For the 1998 EPA CALPUFF evaluation report and the current analyses, the PDCH emission rate was used in the CALPUFF evaluation since the monitoring data appeared to have a more complete record of PDCH concentrations than the other tracers. Table 3-3 displays the source characteristics for the PDCH tracer used in the CALPUFF modeling of the July 8, 1980 GP80 experiment.

Table 3-3. Source characteristics for the CALPUFF modeling of the July 8, 1980 GP80 experiment.

Source	Release height (m)	Stack diameter (m)	Exit velocity (m/s)	Exit temp. (°K)	Total tracer released (kg)	Length of release (hr)	PDCH emission rate (g s^{-1})
Oklahoma	10.0	1.0 [a]	0.001	Ambient [b] (250)	186	3.0	17.22

Notes:
a – The stack diameter was set to 1 meter in diameter to conform to previous tracer evaluation studies.
b – The exit temperature was assumed to be the same as ambient atmospheric temperature. CALPUFF checks the difference between the stack exit temperature and the surface station temperature. If this difference is less than zero, the difference is set to zero. To insure this condition, an exit temperature of 250 K was input to the model.

In the CALPUFF modeling system, each of the three programs (CALMET, CALPUFF, and CALPOST) uses a control file of user-selectable options to control the data processing. There are numerous options in each and several that can result in significant differences. The following model controls for CALMET and CALPUFF were employed for the analyses with the tracer data.

<u>3.2.1.1 CALMET Options</u>

The following CALMET control parameters and options were chosen for the BASE CALPUFF model simulations. The BASE control parameters and options were chosen to be consistent with two previous CALMET/CALPUFF evaluations (Irwin 1997, and EPA 1998a). The most important CALMET options relate to the development of the wind field and were set as follows for the BASE model configuration:

NOOBS	= 0	Use surface, overwater, and upper air station data
IWFCOD	= 1	Use diagnostic wind model to develop the 3-D wind fields
IFRADJ	= 1	Compute Froude number adjustment effects (thermodynamic blocking effects of terrain)
IKINE	= 1	Compute kinematic effects
IOBR	= 0	Do NOT use O'Brien procedure for adjusting vertical velocity
IEXTRP	= 4	Use similarity theory to extrapolate surface winds to upper layers
IPROG	= 0	Do NOT use prognostic wind field model output as input to diagnostic wind field model (for observations only sensitivity test)
ITPROG	= 0	Do NOT use prognostic temperature data output

Mixing heights are important in the estimating ground level concentrations. The CALMET options that affect mixing heights were set as follows:

IAVEZI	= 1	Conduct spatial averaging
MNDAV	= 3	**100km BASE case** – Maximum search radius (in grid cells) in averaging process
	= 1	**600km BASE Case**
HAFANG	= 30.	Half-angle of upwind looking cone for averaging

ILEVZI	= 1	Layer of winds to use in upwind averaging
DPTMIN	= .001	Minimum potential temperature lapse rate (K/m) in stable layer above convective mixing height
DZZI	= 200	Depth of layer (meters) over which the lapse rate is computed
ZIMIN	= 100	**100km BASE case** – Minimum mixing height (meters) over land
	= 50	**600km BASE Case**
ZIMAX	= 3200	**100km BASE case** – Maximum mixing height (meters) over land, defined to be the top of the modeling domain
	= 3000	**600km BASE Case**

A number of CALMET model control options have no default CALMET values, particularly radii of influence values for terrain and surface and upper air observations. The CALMET options that affect radius of influence were set as follows:

RMAX1	= 20	Minimum radius of influence in surface layer (km)
RMAX2	= 50	Minimum radius of influence over land aloft (km)
RMIN	= 2	**100km BASE case** – Minimum radius of influence in wind field interpolation (km)
	= 0.1	**600km BASE Case**
TERRAD	= 10	Radius of influence of terrain features (km)
RPROG	= 0	Weighting factors of prognostic wind field data (km)

A review of the respective CALMET parameters between the 1998 EPA CALMET/CALPUFF evaluation study using CALMET Version 4.0 and the 600 km BASE case scenario in the current CALMET/CALPUFF evaluation using CALMET Version 5.8 indicates differences in some CALMET options. The differences between the two scenarios are presented below in Table 3-4. All other major CALMET options for 600 km BASE case scenario matched the original 1998 EPA analysis. There were no significant differences between the CALMET parameters 100 km BASE case scenarios for the 1998 (CALMET Version 4.0) and the current evaluation (CALMET Version 5.8).

Table 3-4. CALMET Parameters July 8, 1980 GP80 experiment, 1998 and current 600 km analysis.

CALMET Option	Description	1998 EPA Setup	BASE Setup
MNDAV	Maximum search radius for averaging mixing heights (# grid cells)	3	1
ZIMIN	Minimum overland mixing height (in meters)	100	50
ZIMAX	Maximum overland mixing height (in meters)	3200	3000
RMIN	Minimum radius of influence in wind field interpolation (in km)	2.0	0.1

3.2.1.2 CALPUFF Control Options

The following CALPUFF control parameters, which are a subset of the control parameters, were used. These parameters and options were mostly chosen to be consistent with the 1977 INEL study (Irwin 1997) and 1998 EPA CALPUFF evaluation (EPA, 1998a) studies. This includes the use of the slug option (MSLUG = 1) for the 100 km arc CALPUFF simulations. The use of the slug option is very non-standard for LRT modeling and inconsistent with the EPA-FLM recommendations for far-field CALPUFF modeling. As stated on the CALPUFF website[18]:

> "A slug is simply an elongated puff. For most CALPUFF applications, the modeling of emissions as puffs is adequate. The selection of puffs produces very similar results as compared to the slug option, while resulting in significantly faster computer runtimes. However, there are some cases where the slug option may be preferred. One such case is the episodic time-varying emissions, e.g., an accidental release scenario. Another case would be where transport from the source to receptors of interest is very short (possibly involving sub-hourly transport times). These cases generally involve demonstration of causality effects due to specific events in the near- to intermediate-field."

For the farther out 600 km arc, the slug option was not selected (MSLUG = 0) for the initial CALPUFF sensitivity tests even through the slug option was used in the 1997 INEL and 1998 EPA studies. However, we did investigate the use of the slug option, as well as puff splitting, in a set of additional CALPUFF sensitivity tests for the 600 km arc.

CALPUFF options for technical options (group 2):

MCTADJ	= 0	No terrain adjustment
MCTSG	= 0	No subgrid scale complex terrain is modeled
MSLUG	= 1	**For 100 km BASE case** near-field puffs modeled as slugs
MSLUG	= 0	**For 600 km BASE case** modeled as puffs (i.e., no slugs)
MTRANS	= 1	Transitional plume rise is modeled
MTIP	= 1	Stack tip downwash is modeled
MSHEAR	= 0	**100 km BASE case** – Vertical wind shear is NOT modeled above stack top
	= 1	**600km BASE case**
MSPLIT	= 0	No puff splitting

18 **http://www.src.com/calpuff/FAQ-answers.htm**

MCHEM	= 0	No chemical transformations
MWET	= 0	No wet removal processes
MDRY	= 0	No dry removal processes
MPARTL	= 0	**100 km BASE case –** No partial plume penetration
	= 1	**600 km BASE case**
MPDF	= 0	**100 km BASE case –** PDF not used for dispersion under convective conditions
	= 1	**600 km BASE case**
MREG	= 0	No check made to see if options conform to regulatory Options

Two different values were used for the dispersion parameterization option MDISP:

= 2	Dispersion coefficients from internally calculated sigmas
= 3	PG dispersion coefficients for RURAL areas (PG)

In addition, under MDISP = 2 dispersion option, two different options were used for the MCTURB option that defines the method used to compute turbulence sigma-v and sigma-w using micrometeorological variables:

= 1	Standard CALPUFF routines (CAL)
= 2	AERMOD subroutines (AER)

Several miscellaneous dispersion and computational parameters (group 12) were set as follows:

SYTDEP	= 550.	Horizontal puff size beyond which Heffter equations are used for sigma-y and sigma-z
MHFTSZ	= 0	Do not use Heffter equation for sigma-z
XMXLEN	= 0.1	**100 km BASE case –** Maximum length of slug (in grid cells)
	= 1	**600 km BASE case**
XSAMLEN	= 0.1	**100 km BASE case –** Maximum travel distance of puff/slug (in grid cells) during one sampling step
	= 1	**600 km BASE case**
MXNEW	= 199	**100 km BASE case –** Maximum number of slugs/puffs released during one time step
	= 99	**600 km BASE case**
WSCALM	= 1.0	**100 km BASE case –** Minimum wind speed (m/s) for non-calm conditions
	= 0.5	**600 km BASE case**
XMAXZI	= 3300	**100 km BASE case –** Maximum mixing height (meters)
	= 6000	**600 km BASE case**
XMINZI	= 20	**100 km BASE case –** Minimum mixing height (meters)
	= 0	**600 km BASE case**
SL2PF	= 5	**100 km BASE case –** Slug-to-puff transition criterion factor (= sigma-y/slug length)
	= 10	**600 km BASE case**

A review of the respective CALPUFF parameters between the 1998 EPA CALMET/CALPUFF evaluation study using CALMET Version 4.0 and the 600 km BASE case scenario in the current CALMET/CALPUFF evaluation using CALPUFF Version 5.8 indicates differences in some parameters. The differences between the two scenarios are presented below in Table 3-5. All other major CALPUFF options for 600 km BASE case scenario matched the original 1998 EPA analysis. There were no significant differences between the CALPUFF parameters 100 km BASE case scenarios for the 1998 (CALPUFF Version 4.0) and the current evaluation (CALPUFF Version 5.8).

Table 3-5. CALPUFF Parameters July 8, 1980 GP80 experiment, 1998 and Current 600km analysis.

CALPUFF Option	Description	1998 EPA Setup	600KM BASE Setup
MSHEAR	Vertical wind shear is modeled above stack top? (0 = No; 1 = Yes)	0	1
MPARTL	Partial plume penetration of elevated inversion? (0 = No; 1 = Yes)	0	1
WSCALM	Minimum wind speed (m/s) for non-calm conditions	1.0	0.5
XMAXZI	Maximum mixing height (meters)	3300	3000
XMINZI	Minimum mixing height (meters)	20	0
XMXLEN	Maximum length of slug (in grid cells)	0.1	1
XSAMLEN	Maximum travel distance of puff/slug (in grid cells) during one sampling step	0.1	1
MXNEW	Maximum number of slugs/puffs released during one time step	199	99
SL2PF	Slug-to-puff transition criterion factor (= sigma-y/slug length)	5.0	10.0

3.2.2 GP80 CALPUFF/CALMET Sensitivity Tests

Table 3-6 and 3-7 describe the CALMET/CALPUFF sensitivity tests performed for the modeling of the 100 km and 600 km arcs of receptors. The BASEA simulations use the same configuration as used in the 1998 EPA CALPUFF evaluation report for the 100 km arc simulations, only updated from CALPUFF Version 4.0 to CALPUFF Version 5.8. For the 600 km arc simulations, the BASEA used the same configuration as the 1998 EPA study only the near-field slug option was not used. The CALMET and CALPUFF parameters of the BASE case simulations were discussed earlier in this section.

The sensitivity simulations are designed to examine the sensitivity of the CALPUFF model performance to choice of grid resolution in the CALMET meteorological model simulation (10 and 4 km for the 100 km arc of receptors and 20 and 4 km for the 600 km arc of receptors), the use of and resolution of the MM5 output data used as input to CALMET (none, 12 and 36 km) and the use of surface and upper-air meteorological observations in CALMET through NOOBS = 0 (“A” series, use surface and upper-air observation), 1 (“B” series, use only surface observations) and 2 (“C” series, don’t use any meteorological observations).

In addition, for each experiment using different CALMET model configurations, three CALPUFF dispersion options were examined as shown in Table 3-8. Two of the CALPUFF dispersion sensitivity tests using dispersion based on sigma-v and sigma-w turbulence values using the CALPUFF (CAL) and AERMOD (AER) algorithms. Whereas the third dispersion test (PG) uses Pasquill-Gifford dispersion coefficients.

Table 3-6. CALPUFF/CALMET experiments for the 100 km arc and GP80 July 8, 1980 tracer experiment.

Experiment	CALMET Grid	MM5 Data	NOOBS	Comment
BASEA	10 km	None	0	Original met observations only configuration (no MM5)
EXP1A	10 km	12 km	0	Aug 2009 IWAQM w/10 km grid using 12 km MM5
EXP1B	10 km	12 km	1	Don't use observed upper-air meteorological data
EXP1C	10 km	12 km	2	Don't use observed surface/upper-air meteorological data
EXP2A	4 km	36 km	0	Aug 2009 IWAQM w/ 4 km grid and 36 km MM5
EXP2B	4 km	36 km	1	No upper-air meteorological data
EXP2C	4 km	36 km	2	No surface or upper-air meteorological data
EXP3A	4 km	12 km	0	Aug 2009 IWAQM w/ 4 km grid and 12 km MM5
EXP3B	4 km	12 km	1	No upper-air meteorological data
EXP3C	4 km	12 km	2	No surface or upper-air meteorological data

Table 3-7. CALPUFF/CALMET experiments for the 600 km arc and GP80 July 8, 1980 tracer experiment.

Experiment	CALMET Grid	MM5 Data	NOOBS	Comment
BASEA	20 km	None	0	Original met observations only configuration (no MM5)
EXP1A	20 km	12 km	0	Aug 2009 IWAQM recommendation using 12 km MM5
EXP1B	20 km	12 km	1	Don't use observed upper-air meteorological data
EXP1C	20 km	12 km	2	Don't use observed surface/upper-air meteorological data
EXP2A	4 km	36 km	0	Aug 2009 IWAQM w/ 4 km grid and 36 km MM5
EXP2B	4 km	36 km	1	No upper-air meteorological data
EXP2C	4 km	36 km	2	No surface or upper-air meteorological data
EXP3A	4 km	12 km	0	Aug 2009 IWAQM w/ 4 km grid and 12 km MM5
EXP3B	4 km	12 km	1	No upper-air meteorological data
EXP3C	4 km	12 km	2	No surface or upper-air meteorological data

Table 3-8. CALPUFF dispersion options examined in the CALPUFF sensitivity tests.

Experiment	MDISP	MCTURB	Comment
CAL	2	1	Dispersion coefficients from internally calculated sigma-v and sigma-w using micrometeorological variables and CALPUFF algorithms
AER	2	2	Dispersion coefficients from internally calculated sigma-v and sigma-w using micrometeorological variables and AERMOD algorithms
PG	3	--	PG dispersion coefficients for rural areas and MP coefficients for urban areas

The CALMET and CALPUFF simulations used for the sensitivity analyses were updated from the BASE case simulations and use the recommended settings for many variables from the EPA August 2009 Clarification Memorandum (EPA, 2009b). A summary of CALMET parameters that changed from the BASE case scenarios for the 100 km and 600 km CALPUFF sensitivity analyses are presented in Tables 3-9 and 3-10. The 100 km CALMET BASE case simulation (BASEA) matched up with the 1998 EPA study CALMET parameters, but did not match up with the EPA-FLM recommendations in the August 2009 Clarification Memorandum. Other than a few CALMET parameters, the 600 km CALMET BASE case simulation (BASEA) matched up well with August 2009 Clarification Memorandum, but not the 1998 EPA study CALMET parameters.

Table 3-9. CALMET wind field parameters for July 8, 1980 GP80 experiment, 100 km analysis.

CALMET Option	2009 EPA-FLM Default	BASEA	EXP1A	EXP1B	EXP1C	EXP2A	EXP2B	EXP2C	EXP3A	EXP3B	EXP3C
NOOBS	0	0	0	1	2	0	1	2	0	1	2
ICLOUD	0	0	0	0	3	0	0	3	0	0	3
IKINE	0	1	0	0	0	0	0	0	0	0	0
IEXTRP	-4	4	-4	-4	1	-4	-4	1	-4	-4	1
IPROG	14	0	14	14	14	14	14	14	14	14	14
ITPROG	0	0	0	1	2	0	1	2	0	1	2
MNDAV	1	3	1	1	1	1	1	1	1	1	1
ZIMIN	50	100	50	50	50	50	50	50	50	50	50
ZIMAX	3000	3200	3000	3000	3000	3000	3000	3000	3000	3000	3000
RMAX1	100	20	100	100	100	100	100	100	100	100	100
RMAX2	200	50	200	200	200	200	200	200	200	200	200
RMIN	0.1	2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
TERRAD	15	10	20	20	20	20	20	20	20	20	20
ZUPWND	1, 1000	1, 2000	1, 1000	1, 1000	1, 1000	1, 1000	1, 1000	1, 1000	1, 1000	1, 1000	1, 1000

Table 3-10. CALMET wind field parameters for July 8, 1980 GP80 experiment, 600 km analysis.

CALMET Option	2009 EPA-FLM Default	BASEA	EXP1A	EXP1B	EXP1C
NOOBS	0	0	0	1	2
ICLOUD	0	0	0	0	3
IKINE	0	1	0	0	0
IEXTRP	-4	4	-4	-4	1
IPROG	14	0	14	14	14
ITPROG	0	0	0	1	2
RMAX1	100	20	100	100	100
RMAX2	200	50	200	200	200
TERRAD	15	10	20	20	20

3.2.3 CALPUFF/MMIF Sensitivity Tests

With the MMIF software tool designed to pass through and reformat the MM5/WRF meteorological model output data for input into CALPUFF, there are not as many options available and hence much fewer sensitivity tests. Note that MMIF adopts the grid resolution and vertical layer structure of the MM5 model and passes through the meteorological variables to CALPUFF so only 36 km and 12 km grid resolutions were examined. The three alternative dispersion options in CALPUFF (CAL, AER and PG) were analyzed using the MMIF 12 km and 36 km CALPUFF inputs. Note that for the 600 km arc CALPUFF/MMIF modeling we found some issues in one of the CALPUFF runs using the AER dispersion option so do not present any AER dispersion results for the 600 km arc modeling; given the similarity in CALPUFF performance using the CAL and AER dispersion options this does not affect the study's results. In addition, 36 km CALPUFF/MMIF results are also not presented for the 600 km arc modeling.

Table 3-11. CALPUFF/MMIF sensitivity tests analyzed with the July 8, 1980 GP80 database.

Grid Resolution	MM5	MDISP	MCTURB	Comment
36 km	36 km	2	1	36 km MM5 with CALPUFF turbulence dispersion (CAL)
36 km	36 km	2	2	36 km MM5 with AERMOD turbulence dispersion (AER)
36 km	36 km	3		36 km MM5 with Pasqual-Gifford dispersion (PG)
12 km	12 km	2	1	12 km MM5 with CALPUFF turbulence dispersion (CAL)
12 km	12 km	2	2	12 km MM5 with AERMOD turbulence dispersion (AER)
12 km	12 km	3		12 km MM5 with Pasqual-Gifford dispersion (PG)

3.3 QUALITY ASSURANCE

The quality assurance (QA) of the CALPUFF modeling system simulations for the GP80 tracer experiment was assessed by analyzing the CALMET and CALPUFF input and output files and the dates they were generated. The input file options were compared against the August 2009 EPA-FLM recommended settings for CALMET and the definitions of the sensitivity tests to assure that the intended parameters were defined. The QA of the MMIF runs was not as complete because no input files or list files were provided to document the MMIF parameters. However, since all the MMIF tool does is pass through the MM5 output to CALPUFF there are not many options available.

The 100 km and 600 km receptor arc CALMET sensitivity simulations used a TERRAD value of 20 km (radius of influence of terrain on wind fields, in kilometers). The 2009 EPA-FLM clarification memorandum recommends that TERRAD = 15. Four CALMET parameters (BIAS, NSMTH, NINTR2, and FEXTR2) require a value for each vertical layer processed in CALMET. The 100 km and 600 km CALMET Base Cases are based on six vertical layers, but the sensitivity simulations are based on ten vertical layers. The CALMET sensitivity simulations were provided with only six values for BIAS, NSMTH, NINTR2, and FEXTR2 even though ten vertical layers were simulated. Therefore, CALMET used default values for the upper four vertical layers (1200 m, 2000 m, 3000 m, and 4000 m).

In addition to the three CALPUFF dispersion options (AERMOD, CALPUFF, and PG), there were other CALPUFF parameters that differed between the 100 km and 600 km CALPUFF/CALMET BASE case and sensitivity cases and CALPUFF/MMIF modeling scenarios. Differences in the CALPUFF parameters used in the 100 km and 600 km receptor arc simulation include:

- All of the CALPUFF 600 km sensitivity runs (CALPUFF/CALMET and CALPUFF/MMIF) and 100 km CALPUFF/MMIF runs were all conducted using only puffs (MSLUG = 0), but the 100 km CALPUFF/CALMET and 1998 CALPUFF simulations assume near-field slug formation (MSLUG = 1).
- CALPUFF 100 km CALPUFF/MMIF runs and all 600 km CALPUFF runs allowed for vertical wind shear (MSHEAR = 1), the 100 km BASE case and 100 km CALPUFF/CALMET sensitivity scenarios assume no vertical wind shear. The IWAQM Phase II (1998) guidance recommends MSHEAR = 0.
- The initial CALPUFF 100 km and 600 km sensitivity tests assumed no puff splitting (MSPLIT = 0), whereas the IWAQM Phase II (1998) recommends that default puff splitting be performed (MSPLIT = 1). This issue was investigated for the 600 km arc using additional CALPUFF sensitivity tests.

- CALPUFF 100 km (all dispersion options) and 600 km PG dispersion simulations, CALPUFF was set-up to not allow for partial plume penetration of inversion layer (MPARTL = 0). The IWAQM Phase II (1998) guidance recommends MPARTL = 1.
- CALPUFF 600 km AERMOD and CALPUFF turbulence dispersion simulations, CALPUFF was set-up to use the Probability Density Function (PDF) option for convective dispersion (MPDF = 1). The IWAQM Phase II guidance does not recommend using PDF for convective dispersion.
- CALPUFF 600 km simulations and 100 km CALPUFF/MMIF simulations use minimum and maximum mixing height values of 0 m and 6000 m, respectively. The CALPUFF 100 km BASE case and sensitivity simulations use minimum and maximum mixing height values of 20 m and 3300 m, respectively. The 1998 IWAQM Phase II guidance recommends the minimum and maximum mixing heights be set equal to 50 m and 3000 m, respectively.
- The CALPUFF 100 km BASE case and sensitivity simulations use a maximum slug length of 0.1 CALMET grid units (XMXLEN = 0.1), whereas the 100 km CALPUFF/MMIF simulations used a maximum length of 1.0 CALMET grid units. The IWAQM Phase II guidance recommends XMXLEN = 1.
- The CALPUFF 100 km BASE case and sensitivity simulations use a maximum slug/puff travel distance of 0.1 grid units per sampling period (XSAMLEN = 0.1), whereas the 100 km CALPUFF/MMIF simulations used a maximum travel distance of 1.0 grid units. The IWAQM Phase II guidance recommends XSAMLEN = 1.
- The CALPUFF 100 km BASE case and sensitivity simulations use a maximum of 199 slugs/puffs released from one source per sampling step (MXNEW = 199), whereas the 100 km CALPUFF/MMIF simulations used a maximum of 99 new slugs/puffs. The IWAQM Phase II guidance recommends MXNEW = 99.
- The CALPUFF 100 km BASE case and sensitivity simulations use a maximum of 5 sampling steps per slug/puff during one time step (MXSAM = 5), whereas the 100 km CALPUFF/MMIF simulations used a maximum of 99 sampling steps per slug/puff. The IWAQM Phase II guidance recommends MXSAM = 99.
- The CALPUFF 100 km BASE case and sensitivity simulations use a minimum sigma-y and sigma-z value of 0.01 m per new slug/puff (SYMIN = 0.01 and SZMIN = 0.01), whereas the 100 m CALPUFF/MMIF simulations used a minimum sigma-y and sigma-z value of 1 m per new slug/puff. The IWAQM Phase II guidance recommends SYMIN = 1 and SZMIN = 1.
- The CALPUFF 100 km BASE case and sensitivity simulations use a minimum wind speed of 1 m/s for non-calm conditions (WSCALM = 1), whereas the 100 km CALPUFF/MMIF simulations used a minimum wind speed of 0.5 m/s. The IWAQM Phase II guidance recommends WSCALM = 0.5.

We noted that the date on the CALMET input control file for the BASEA sensitivity test was later than the date on the CALMET output file for BASEA. We reran the BASEA CALMET and CALPUFF sensitivity tests and got slightly different results.

3.4 GP80 MODEL PERFORMANCE EVALUATION

Previous studies evaluated CALPUFF using the GP80 tracer experiment data using the Irwin plume fitting evaluation approach (EPA, 1998a). Thus, the same approach was adopted in this study so we could compare the performance of the newer version of CALPUFF with past evaluation studies and evaluate whether new options in CALPUFF (e.g., puff splitting) improve CALPUFF's model performance.

3.4.1 CALPUFF GP80 Evaluation for the 100 km Arc of Receptors

Table 3-12 evaluates the CALPUFF sensitivity tests ability to estimate the timing of the plume arrival at the 100 km arc of receptors and the duration of time the plume resides on the 100 km receptor arc. The tracer was observed on the 100 km arc for 5 hours. The 1998 EPA report CALPUFF modeling matched this well using CALPUFF turbulence (CAL) dispersion and estimated the tracer remained on the arc one hour longer than observed using the PG dispersion option. The CALPUFF/CALMET sensitivity tests estimated that the predicted tracer cloud was on the arc the same amount of time as was observed (5 hours) or within one hour of that duration (i.e., within ±20%). With one exception, when the CALPUFF/CALMET estimated that the duration of time on the arc was off by one hour, it was underestimating the amount of time on the arc (i.e., 4 instead of 5 hours). The exception to this was the EXP2A_PG scenario that estimates the tracer plume was on the 100 km arc for 6 hours.

The CALPUFF/MMIF sensitivity tests had the tracer plume arriving at the 100 km arc one hour late and either leaving on time (12 km MMIF) or leaving an hour early. This results in the CALPUF/MMIF sensitivity test underestimating the observed time on the arc by 1 (12 km MMIF) to 2 (36 km MMIF) hours.

Table 3-12. Tracer plume arrival and duration statistics for the GP80 100 km arc.

Scenario	Arrival on Arc		Leave Arc		Duration on Arc	
	Day	Hour	Day	Hour	Hours	Difference
Observed	190	16	190	20	5	
1998 EPA Report						
1998EPA_PG	190	16	190	21	6	20%
1998_CAL	190	16	190	20	5	0%
CALPUFF/CALMET						
BASEA_AER	190	16	190	20	5	0%
BASEA_CAL	190	16	190	20	5	0%
BASEA_PG	190	16	190	20	5	0%
EXP1A_AER	190	16	190	20	5	0%
EXP1A_CAL	190	16	190	20	5	0%
EXP1A_PG	190	16	190	20	5	0%
EXP1B_AER	190	16	190	19	4	-20%
EXP1B_CAL	190	16	190	19	4	-20%
EXP1B_PG	190	16	190	19	4	-20%
EXP1C_AER	190	17	190	20	4	-20%
EXP1C_CAL	190	17	190	20	4	-20%
EXP1C_PG	190	17	190	20	4	-20%
EXP2A_AER	190	16	190	20	5	0%
EXP2A_CAL	190	16	190	20	5	0%
EXP2A_PG	190	16	190	21	6	20%
EXP2B_AER	190	16	190	19	4	-20%
EXP2B_CAL	190	16	190	19	4	-20%
EXP2B_PG	190	16	190	20	5	0%
EXP2C_AER	190	17	190	20	4	-20%
EXP2C_CAL	190	17	190	20	4	-20%
EXP2C_PG	190	17	190	20	4	-20%
EXP3A_AER	190	16	190	20	5	0%
EXP3A_CAL	190	16	190	20	5	0%
EXP3A_PG	190	16	190	20	5	0%
EXP3B_AER	190	16	190	20	5	0%
EXP3B_CAL	190	16	190	20	5	0%
EXP3B_PG	190	16	190	19	4	-20%
EXP3C_AER	190	17	190	20	4	-20%
EXP3C_CAL	190	17	190	20	4	-20%
EXP3C_PG	190	17	190	20	4	-20%
CALPUFF/MMIF						
MMIF12_AER	190	17	190	20	4	-20%
MMIF12_CAL	190	17	190	20	4	-20%
MMIF12_PG	190	17	190	20	4	-20%
MMIF36KM_AER	190	17	190	19	3	-40%
MMIF36KM_CAL	190	17	190	19	3	-40%
MMIF36KM_PG	190	17	190	19	3	-40%

Tables 3-13 and Figures 3-2 through 3-6 display the plume fitting model performance statistics for the various CALPUFF sensitivity tests and the 100 km arc of receptors in the GP80 field experiment and compares them with the previous results as reported by EPA (1998a). The fitted predicted and observed plume centerline concentrations (Cmax) and the percent differences, expressed as a mean normalized bias (MNB), are shown in Table 3-13 with the MNB results reproduced in Figure 3-2. Similar results are seen for the predicted and observed maximum concentrations at any monitoring site along the arc (Omax) that are shown in Table 3-13 and Figure 3-3. The use of either the CALPUFF (CAL) or AERMOD (AER) algorithms for the turbulence dispersion doesn't appear the affect the maximum concentration model performance. Most CALPUFF sensitivity simulations overestimate the observed Cmax value by over 40%, with the 1998EPA_PG and EXP2C_PG simulations overestimating the observed Cmax value by over a factor of 2 (> 100%). The overestimation of the observed Omax value is even greater, exceeding 60% for most of the CALPUFF simulations. The PG dispersion produces much higher maximum concentrations compared to CAL/AER dispersion for experiments EXP2B and EXP2C. But the PG maximum concentrations are comparable or even a little lower than CAL/AER for the other experiments; although in the 1998 EPA study the PG dispersion option produced much higher maximum concentrations. The EXP1B, EXP2B and EXP3B CALPUFF simulations do not exhibit the large overestimation bias of Cmax and Omax as seen in the other experiments and are closest to reproducing the observed maximum concentrations on the 100 km arc, matching the observed values to within ±25%; note that the "B" series of experiments use MM5 data (12, 36 and 12 km for EXP1, EXP2 and EXP3, respectively) but only surface and no upper-air meteorological observations. The CALPUFF/MMIF simulation using the 12 km MM5 data and PG dispersion also reproduced the maximum concentrations to within ±25%.

Most of the CALPUFF sensitivity simulations underestimate the plume spread (σ_y) by 20% to 35% (Figure 3-4), which is consistent with overestimating the observed maximum concentration (i.e., insufficient dispersion leading to overestimation of the maximum concentrations). The exceptions to this are again the "B" series of CALPUFF/CALMET experiments and MMIF12KM_PG. Another exception to this is the EPA1998_PG simulation which agrees with the observed plume spread amount quite well; the explanation for this is unclear and seems inconsistent with the fact that 1998BASE_PG overestimated the observed Cmax/Omax values. The 1998EPA_PG results were taken from the EPA (1998a) report and could not be verified or quality assured so we cannot explain this discrepancy.

The deviations between the observed and predicted plume centerline along the 100 km arc of receptors in degrees is shown in Figure 3-5. The modeled plume centerline tends to be 0 to14 degrees off from the observed plume centerline. The best performing model configuration for the plume centerline location is the BASEA series that uses CALMET with observed surface and upper-air meteorological data but no MM5 data. The CALPUFF/CALMET sensitivity tests that use surface and upper-air ("A" series) and just surface ("B" series) meteorological observations tend to perform best for the plume centerline location, whereas the sensitivity tests that uses no meteorological observations ("C" series) performs the worse, with the plume centerline tending to be 10 to 14 degrees too far west on the 100 km arc for the "C" series of CALPUFF/CALMET sensitivity tests. The CALPUFF/MMIF runs, which also do not include any meteorological observations, also tend to have plume centerlines that are 6 to 12 degrees too far to the west.

Most of the CALPUFF sensitivity tests have cross wind integrated concentrations (CWIC) that are within ±20% of the observed value along the 100 km arc (Figure 3-6 and Table 5-13). The exceptions to this are the EPA1998_PG simulation, the BASEA series of simulations, EXP2A_PG, EXP2B_PG and EXP2C_PG. In general, the CAL and AER CALPUFF dispersion options are performing much better for the CWIC statistics along the 100 km arc than the PG dispersion option.

Table 3-13. CALPUFF model performance statistics using the Irwin plume fitting evaluation approach for the GP80 100 km arc of receptors, the EPA 1998 CALPUFF V4.0 modeling and the CALPUFF sensitivity tests.

CALPUFF Sensitivity Test	Cmax		Omax		Sigma-y		Plume Centerline		CWIC	
	(ppt)	MNB	(ppt)	MNB	(m)	MNB	(degrees)	Diff	(ppt-m)	MNB
Observed	**1.287**		**1.052**		**9,059**		**361.0**		**29,220**	
EPA 1998										
PG	2.700	110%	2.600	147%	9,000	-1%	357.0	-4.0	61,000	109%
Similarity	1.900	48%	1.800	71%	6,900	-24%	360.0	-1.0	33,000	13%
CALPUFF/CALMET										
BASEA_AER	2.221	73%	2.040	94%	7,136	-21%	361.4	0.4	39,720	36%
BASEA_CAL	2.214	72%	2.034	93%	7,165	-21%	361.4	0.4	39,770	36%
BASEA_PG	2.126	65%	1.934	84%	8,827	-3%	359.8	-1.2	47,050	61%
EXP1A_AER	2.086	62%	2.045	94%	5,977	-34%	357.1	-3.9	31,260	7%
EXP1A_CAL	2.088	62%	2.046	94%	5,999	-34%	357.0	-4.0	31,390	7%
EXP1A_PG	1.885	46%	1.839	75%	6,438	-29%	358.3	-2.7	30,420	4%
EXP1B_AER	1.407	9%	1.303	24%	8,492	-6%	358.8	-2.2	29,940	2%
EXP1B_CAL	1.414	10%	1.313	25%	8,478	-6%	358.8	-2.2	30,050	3%
EXP1B_PG	1.291	0%	1.217	16%	8,956	-1%	359.7	-1.3	28,980	-1%
EXP1C_AER	1.979	54%	1.937	84%	6,587	-27%	348.1	-12.9	32,670	12%
EXP1C_CAL	1.988	54%	1.945	85%	6,590	-27%	348.0	-13.0	32,840	12%
EXP1C_PG	2.016	57%	1.983	88%	6,041	-33%	349.4	-11.6	30,530	4%
EXP2A_AER	2.047	59%	1.996	90%	6,209	-31%	357.2	-3.8	31,860	9%
EXP2A_CAL	2.049	59%	1.999	90%	6,236	-31%	357.1	-3.9	32,020	10%
EXP2A_PG	2.013	56%	2.260	115%	11,330	25%	351.2	-9.8	57,180	96%
EXP2B_AER	1.265	-2%	1.145	9%	9,033	0%	359.4	-1.6	28,630	-2%
EXP2B_CAL	1.269	-1%	1.152	10%	9,030	0%	359.4	-1.6	28,710	-2%
EXP2B_PG	1.811	41%	2.034	93%	9,161	1%	357.6	-3.4	41,590	42%
EXP2C_AER	2.138	66%	2.106	100%	6,021	-34%	350.8	-10.2	32,270	10%
EXP2C_CAL	2.144	67%	2.112	101%	6,026	-33%	350.7	-10.3	32,380	11%
EXP2C_PG	2.938	128%	2.897	175%	6,044	-33%	349.4	-11.6	44,510	52%
EXP3A_AER	2.042	59%	1.992	89%	6,212	-31%	356.7	-4.3	31,800	9%
EXP3A_CAL	2.048	59%	1.998	90%	6,238	-31%	356.5	-4.5	32,030	10%
EXP3A_PG	1.827	42%	1.766	68%	6,805	-25%	358.0	-3.0	31,160	7%
EXP3B_AER	1.274	-1%	1.228	17%	8,928	-1%	357.9	-3.1	28,520	-2%
EXP3B_CAL	1.297	1%	1.247	19%	8,828	-3%	357.8	-3.2	28,700	-2%
EXP3B_PG	1.011	-21%	1.140	8%	11,010	22%	359.7	-1.3	27,900	-5%
EXP3C_AER	1.949	51%	1.911	82%	6,612	-27%	347.4	-13.6	32,300	11%
EXP3C_CAL	1.965	53%	1.927	83%	6,615	-27%	347.3	-13.7	32,590	12%
EXP3C_PG	1.999	55%	1.971	87%	6,085	-33%	349.0	-12.0	30,500	4%
CALPUFF/MMIF										
MMIF12KM_AER	1.872	45%	1.836	75%	6,811	-25%	349.5	-11.5	31,970	9%
MMIF12KM_CAL	1.897	47%	1.860	77%	6,805	-25%	349.3	-11.7	32,350	11%
MMIF12KM_PG	1.468	14%	1.318	25%	9,574	6%	350.3	-10.7	35,230	21%
MMIF36KM_AER	1.837	43%	1.811	72%	6,788	-25%	353.2	-7.8	31,250	7%
MMIF36KM_CAL	1.860	45%	1.832	74%	6,768	-25%	353.1	-7.9	31,550	8%
MMIF36KM_PG	1.608	25%	1.567	49%	7,055	-22%	355.1	-5.9	28,440	-3%

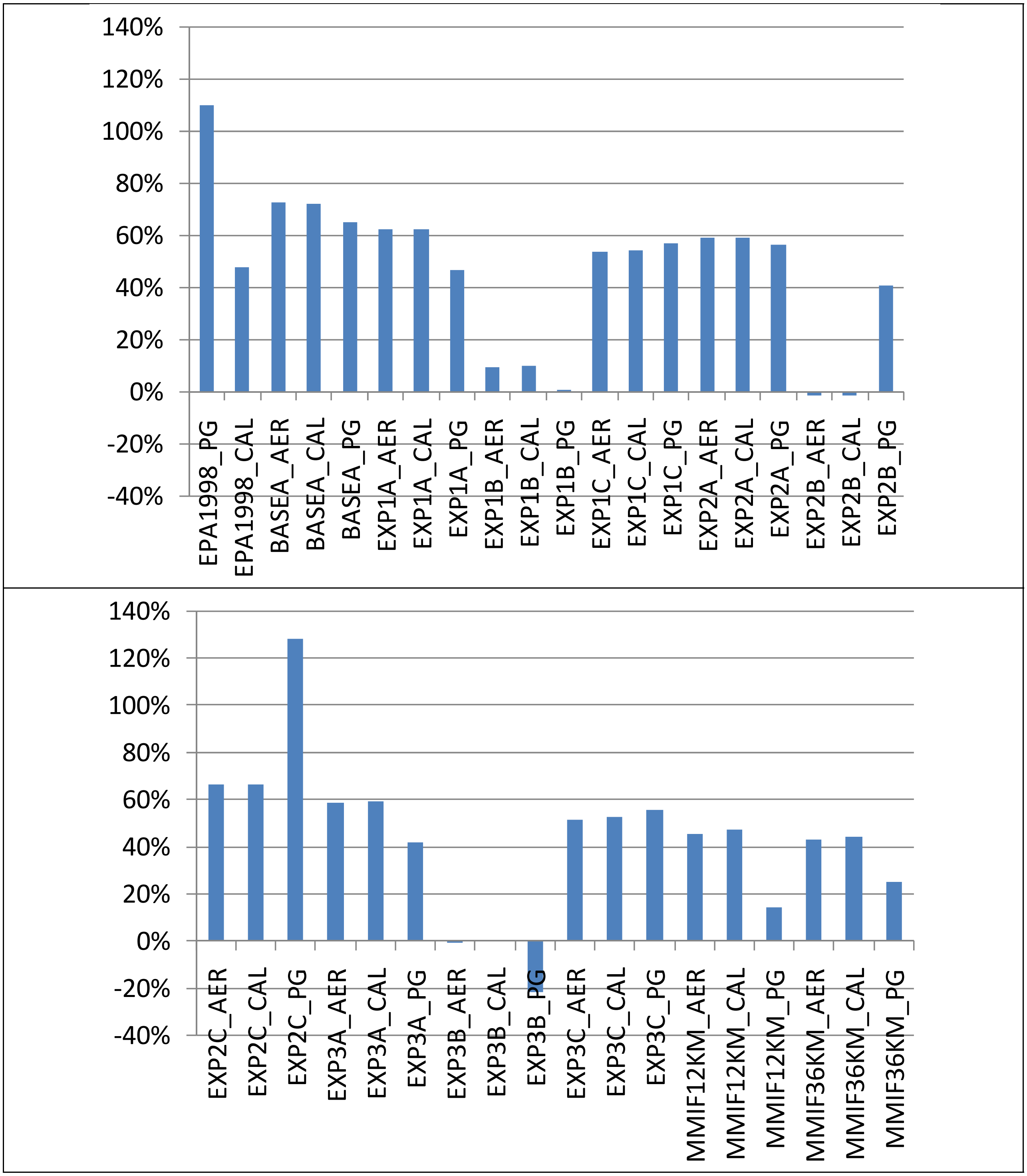


Figure 3-2. Percent difference (mean normalized bias) between the predicted and observed fitted plume centerline concentration (Cmax) for GP80 100 km receptor arc and the CALPUFF sensitivity tests.

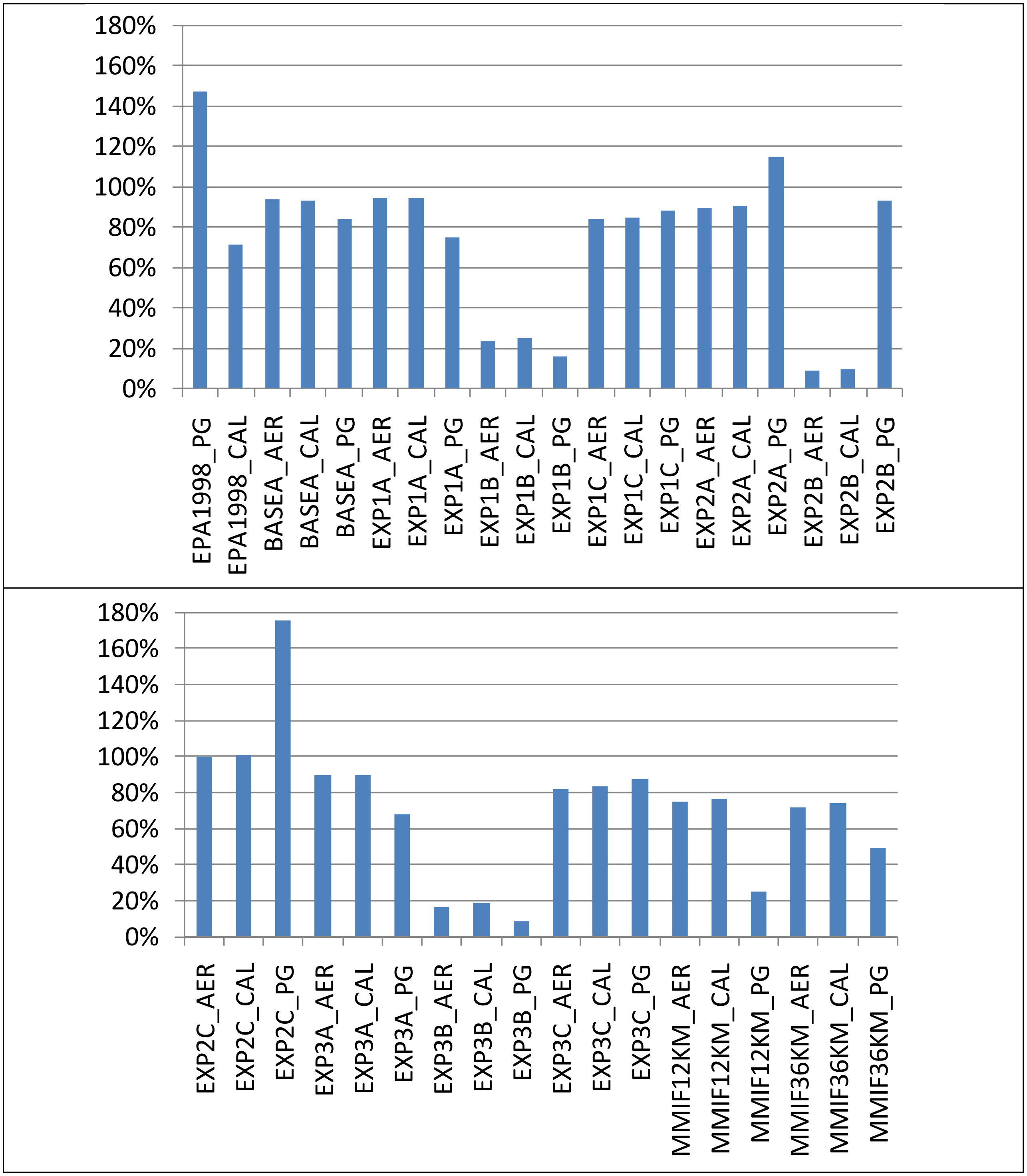


Figure 3-3. Percent difference (mean normalized bias) between the predicted and observed maximum concentration at any receptor/monitor (Omax) for GP80 100 km receptor arc and the CALPUFF sensitivity tests.

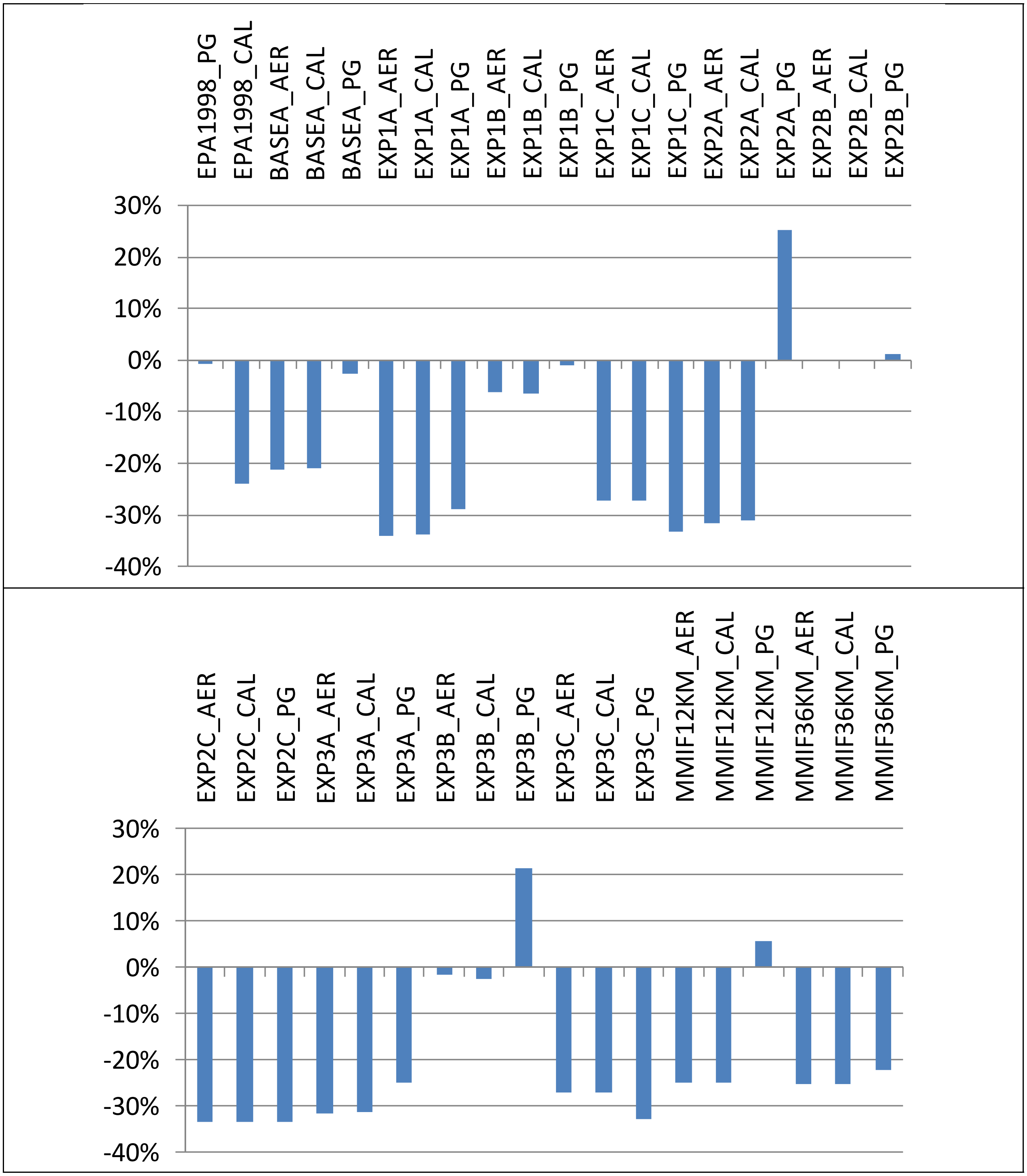


Figure 3-4. Percent difference (mean normalized bias) between the predicted and observed plume spread (σ_y) for GP80 100 km receptor arc and the CALPUFF sensitivity tests.

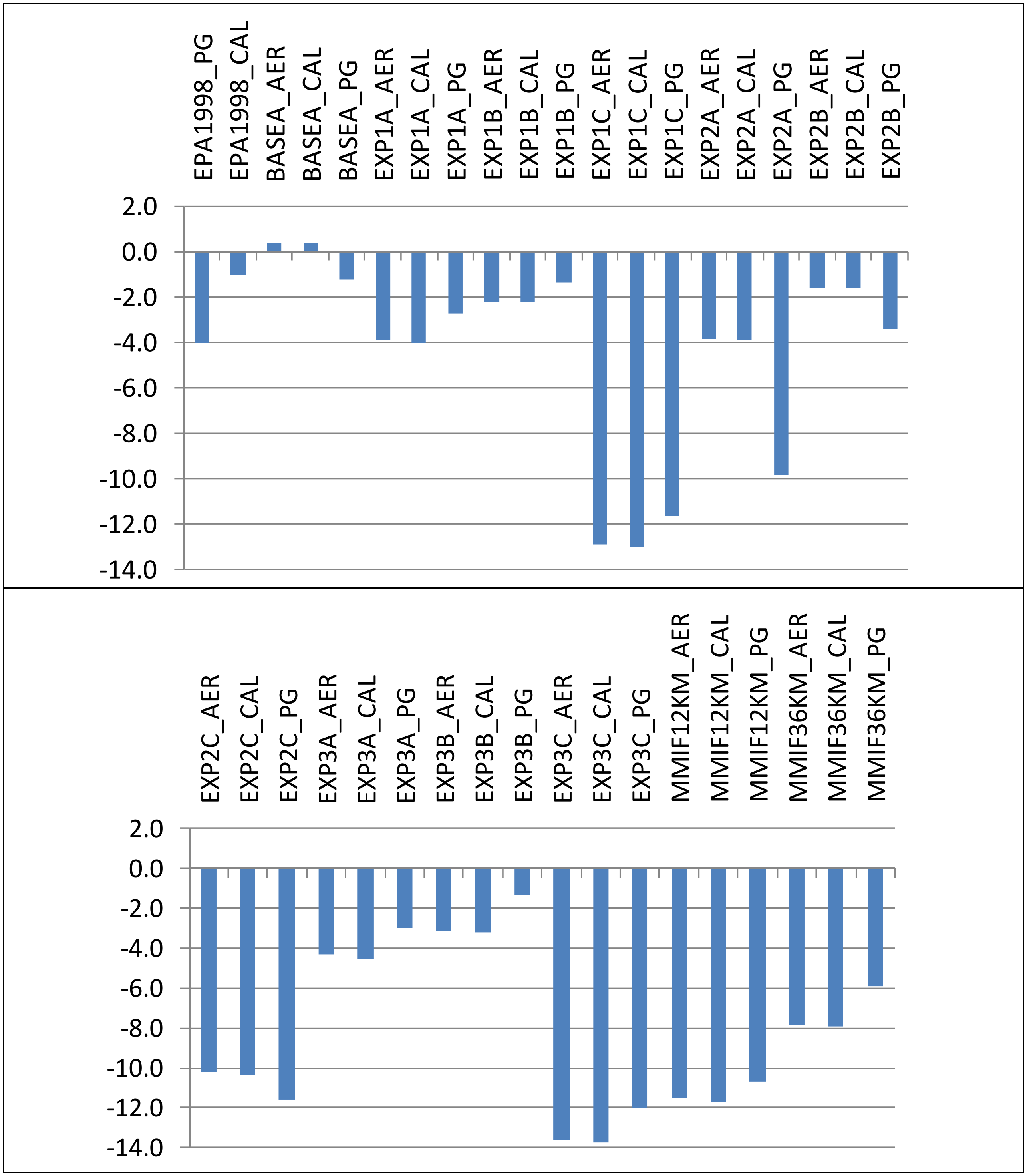


Figure 3-5. Difference in predicted and observed location of plume centerline (degrees) for the GP10 100 km receptor arc and the CALPUFF sensitivity tests.

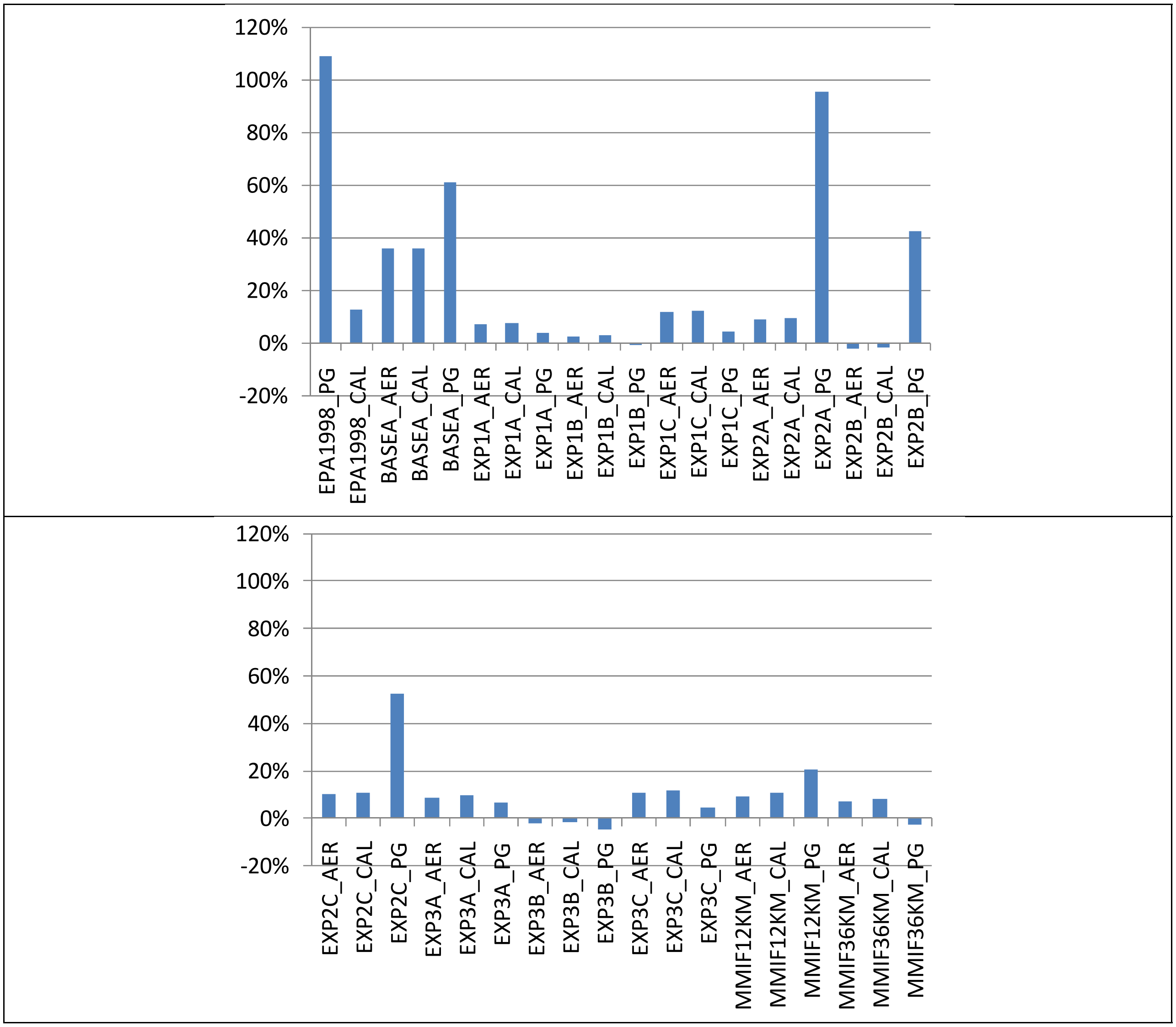


Figure 3-6. Percent difference (mean normalized bias) between the predicted and observed cross wind integrated concentration (CWIC) for the GP10 100 km receptor arc and the CALPUFF sensitivity tests.

3.4.2 CALPUFF GP80 Evaluation for the 600 km Arc of Receptors

Table 3-14 lists the predicted and observed plume arrival and exit time statistics from the 600 km arc of receptors and the duration of time the tracer resides on the 600 km arc for the initial CALPUFF sensitivity tests. Note that the observed tracer was found on the 600 km arc during the first sampling period (hour 2 on Julian Day 191) so the observed tracer may have arrived earlier than that. As explained by EPA (1998a), the observed tracer arrived earlier than expected due to the presence of a low-level jet that was not anticipated. Thus, the observed 12 hour tracer duration on the 600 km receptor arc that assumes it arrived during the first sampling interval at hour 2 could be an underestimate of the actual tracer residence time on the 600 km arc.

Figure 3-7 displays the percent differences in the tracer duration time on the 600 km arc for the initial CALPUFF 600 km sensitivity tests. For most of the initial CALPUFF sensitivity tests, the tracer duration time on the 600 km receptor arc is approximately half (5-6 hours) of what was observed (12 hours). This is in contrast to the 1998 EPA CALPUFF evaluation runs that overstate the duration the tracer resides on the 600 km arc, with values of 14 hours (1998EPA_PG) and 13 hours (1998EPA_CAL). Since the 1998 EPA CALPUFF runs estimated that the tracer arrives after the sampling started (hour 3), then this is a true overstatement of the tracer residence time and not an artifact of the tracer sampling starting after, or at the same time, the observed tracer arrived at the arc. There are a couple exceptions to the initial CALPUFF simulations performed in this study that understated the observed tracer duration on the arc by approximately a factor of 2, which are discussed below.

> The BASEA_PG scenario estimates that the tracer is on the arc for 12 hours, the same as the observed. However, it estimates the tracer leaves three hours earlier (hour 14) than observed (hour 11). Why the BASEA_PG tracer plume time statistics are so different from the two companion turbulence dispersion CALPUFF sensitivity tests (BASEA_CAL and BASEA_AER) is unclear. The same meteorological fields were used in the three BASEA CALPUFF sensitivity tests and the only difference was in the dispersion options. This large difference in the CALPUFF predicted tracer residence time due to use of the PG versus CAL or AER dispersion options (12 hours versus 6-7 hours) was not seen in any of the other CALPUFF sensitivity experiment configurations. Although use of the PG dispersion sometimes increases the estimated tracer residence time on the arc by one hour in some of the CALPUFF sensitivity tests (Table 3-14).

> The EXP2C series of experiments have estimated tracer plume duration times (11-13 hours) that is comparable to what was observed. EXP2C uses 36 km MM5 data and CALMET was run using a 4 km grid resolution with no meteorological observations (NOOBS = 2). When meteorological observations are added, either surface data alone (EXP2B) or surface and upper-air measurements (EXP2A), the tracer duration statistics degrades to only 5 to 8 hours on the arc. It is interesting to note that all of the “C” series of experiments (i.e., use of no meteorological observations in CALMET) exhibit better plume residence time statistics than the experiments that used meteorological observations (with the exception of BASEA_PG discussed previously). But only experiment EXP2C (and BASEA_PG) using 36 km MM5 data and CALMET run with 4 km grid resolution was able to replicate the observed tracer residence time.

Most of the initial CALPUFF sensitivity tests were unable to reproduce the observed tracer residence time on the 600 km arc, as was done in the EPA 1998 study using earlier versions of CALPUFF. Even the BASEA_CAL sensitivity test, which was designed to be mostly consistent with the 1998EPA_CAL simulation, estimated tracer plume residence time that was half of what was observed and estimated by the 1998EPA_CAL simulation. In addition to using difference versions of the CALPUFF model (Version 4.0 versus 5.8), the BASEA_CAL simulation also did not invoke the slug option as was used in 1998EPA_CAL (MSLUG = 1). The use of the slug option is designed for near-source applications and is not typically used in LRT dispersion modeling, so in this study the initial CALPUFF sensitivity tests did not use the slug option for modeling of the 600 km arc. The effect of the slug option is investigated in additional CALPUFF sensitivity tests discussed later in this Chapter.

Figure 3-7. Percent difference in the predicted and observed duration of time tracer is residing on the GP80 600 km arc for the CALPUFF sensitivity tests using puff model formulation and no puff splitting.

Table 3-14. Tracer plume arrival and duration statistics for the GP80 600 km arc and the initial CALPUFF sensitivity tests.

Scenario	Arrival on Arc (Julian Day)	Arrival on Arc Hour (LST)	Leave Arc (Julian Day)	Leave Arc Hour (LST)	Duration on Arc (Hours)	Duration on Arc Difference (%)
Observed	191	2	191	14	12	
1998EPA_PG	191	3	191	17	14	17%
1998EPA_CAL	191	3	191	16	13	8%
CALPUFF/CALMET						
BASEA_AER	191	2	191	7	6	-50%
BASEA_CAL	191	2	191	8	7	-42%
BASEA_PG	191	0	191	11	12	0%
EXP1A_AER	191	2	191	6	5	-58%
EXP1A_CAL	191	2	191	6	5	-58%
EXP1A_PG	191	2	191	6	5	-58%
EXP1B_AER	191	1	191	5	5	-58%
EXP1B_CAL	191	1	191	5	5	-58%
EXP1B_PG	191	1	191	4	4	-67%
EXP1C_AER	191	3	191	8	6	-50%
EXP1C_CAL	191	3	191	8	6	-50%
EXP1C_PG	191	2	191	8	7	-42%
EXP2A_AER	191	2	191	6	5	-58%
EXP2A_CAL	191	2	191	6	5	-58%
EXP2A_PG	191	2	191	9	8	-33%
EXP2B_AER	191	1	191	6	6	-50%
EXP2B_CAL	191	1	191	6	6	-50%
EXP2B_PG	191	1	191	6	6	-50%
EXP2C_AER	191	0	191	10	11	-8%
EXP2C_CAL	191	0	191	10	11	-8%
EXP2C_PG	191	0	191	12	13	8%
EXP3A_AER	191	2	191	6	5	-58%
EXP3A_CAL	191	2	191	6	5	-58%
EXP3A_PG	191	2	191	6	5	-58%
EXP3B_AER	191	1	191	5	5	-58%
EXP3B_CAL	191	1	191	5	5	-58%
EXP3B_PG	191	1	191	6	6	-50%
EXP3C_AER	191	2	191	9	8	-33%
EXP3C_CAL	191	2	191	9	8	-33%
EXP3C_PG	191	2	191	9	8	-33%
CALPUFF/MMIF						
MMIF12_CAL	191	3	191	8	6	-50%
MMIF12_PG	191	2	191	8	7	-42%

The fitted Gaussian plume statistics for the GP80 600 receptor arc and the initial CALPUFF sensitivity tests are shown in Table 3-15, with the percent differences (or angular offset for the plume centerline location) between the model predictions and observations also shown graphically in Figures 3-8 through 3-12. Unlike the CALPUFF performance for the 100 km arc that mostly overestimated the fitted plume centerline (Cmax) and observed maximum concentrations at any receptor (Omax), the CALPUFF sensitivity tests under-estimate the Cmax/Omax values for the 600 km arc by 40% to 80% (Table 3-15 and Figures 3-8 and 3-9). The Cmax/Omax underestimation bias is lower (-40% to -60%) with the "C" series (i.e., no meteorological observations in CALMET) of CALPUFF sensitivity tests. The CALPUFF sensitivity tests overstate the amount of plume spread (σ_y) along the 600 km receptor arc compared to the plume that is fitted to the observations (Figure 3-10). The "A" and "B" series of CALPUFF experiments using the turbulence dispersion (CAL and AER) tend to overestimate the plume spread along the 600 km arc by ~50% with the "C" series overestimating plume spread by ~100%. For many of the experiments, use of the PG dispersion option greatly exacerbates the plume spread overestimation bias with overestimation amounts above 250% for EPA1998_PG and its related BASEA_PG scenarios. Given the similarity of the "C" series (CALMET with no meteorological observations) and MMIF CALPUFF sensitivity simulations, it is not surprising that the MMIF runs also overestimate plume spread by ~100%.

The predicted plume centerline angular offset from the observed value has an easterly bias of 9 to 19 degrees (Figure 3-12). The "A" series of CALPUFF/CALMET sensitivity runs tend to have larger (> 15 degrees) plume centerline offsets than the "B" and "C" series of experiments, indicating that using upper-air meteorological observations in CALMET tends to worsen the plume centerline predictions in the CALPUFF sensitivity runs. Surprisingly, the CALPUFF/MMIF sensitivity runs, which also do not use the upper-air meteorological measurements, have angular offsets in excess of 15 degrees.

The observed cross wind integrated concentration (CWIC) across the plume at the 600 km arc is matched better by the CALPUFF sensitivity tests than the maximum (Cmax/Omax) concentrations (Table 3-15 and Figure 3-12). The EPA1998_PG and EPA1998_CAL overestimate the CWIC by 30% and 15%, respectively. However, the BASEA_PG and BASEA_CAL experiments, which are designed to emulate the EPA 1998 CALPUFF runs, underestimate the CWIC by -14% and -38%, respectively. The use of meteorological observations in CALMET appears to have the biggest effect on the CALPUFF CWIC performance with the "A" series (use both surface and upper-air observations) have the largest CWIC underestimation bias and the CALPUFF CWIC performance statistics as upper-air ("B" series) and then surface and upper-air ("C" series) are removed from the CALPUFF modeling. The CALPUFF/MMIF runs underestimated the CWIC by approximately -30%.

Table 3-15. CALPUFF model performance statistics using the Irwin plume fitting evaluation approach for the GP80 600 km arc of receptors for the EPA 1998 CALPUFF V4.0 modeling and the current study CALPUFF V5.8 sensitivity tests.

CALPUFF Sensitivity Test	Cmax		Omax		Sigma-y		Centerline		CWIC	
	(ppt)	MNB	(ppt)	MNB	(m)	MNB	(deg)	Diff	(ppt-m)	MNB
Observed	0.3152		0.3068		16,533		369.06		13,060	
1998EPA_PG	0.1100	-65%	0.1300	-58%	64,900	293%	25.00	15.94	17,000	30%
1998EPA_CAL	0.1400	-56%	0.1300	-58%	42,600	158%	24.00	14.94	15,000	15%
CALPUFF/CALMET										
BASEA_AER	0.1024	-68%	0.1000	-67%	27,780	68%	29.43	20.37	7,133	-45%
BASEA_CAL	0.0875	-72%	0.0817	-73%	36,870	123%	27.55	18.49	8,084	-38%
BASEA_PG	0.0763	-76%	0.0780	-75%	58,780	256%	23.74	14.68	11,240	-14%
EXP1A_AER	0.1004	-68%	0.0985	-68%	25,490	54%	27.39	18.33	6,414	-51%
EXP1A_CAL	0.1020	-68%	0.0997	-68%	25,500	54%	27.30	18.24	6,520	-50%
EXP1A_PG	0.0991	-69%	0.0969	-68%	25,280	53%	28.12	19.06	6,277	-52%
EXP1B_AER	0.1141	-64%	0.1106	-64%	34,040	106%	18.91	9.85	9,739	-25%
EXP1B_CAL	0.1168	-63%	0.1136	-63%	33,600	103%	18.77	9.71	9,840	-25%
EXP1B_PG	0.1117	-65%	0.1085	-65%	29,660	79%	21.76	12.70	8,304	-36%
EXP1C_AER	0.1388	-56%	0.1365	-56%	34,660	110%	19.01	9.95	12,060	-8%
EXP1C_CAL	0.1412	-55%	0.1387	-55%	35,070	112%	18.54	9.48	12,410	-5%
EXP1C_PG	0.1313	-58%	0.1283	-58%	32,400	96%	20.06	11.00	10,660	-18%
EXP2A_AER	0.1068	-66%	0.1046	-66%	24,520	48%	27.72	18.66	6,565	-50%
EXP2A_CAL	0.1073	-66%	0.1052	-66%	24,600	49%	27.57	18.51	6,614	-49%
EXP2A_PG	0.1204	-62%	0.1180	-62%	39,900	141%	24.41	15.35	12,040	-8%
EXP2B_AER	0.1474	-53%	0.1463	-52%	25,520	54%	19.37	10.31	9,426	-28%
EXP2B_CAL	0.1539	-51%	0.1516	-51%	24,230	47%	19.12	10.06	9,346	-28%
EXP2B_PG	0.1007	-68%	0.1149	-63%	42,590	158%	21.27	12.21	10,750	-18%
EXP2C_AER	0.1603	-49%	0.1648	-46%	35,810	117%	21.55	12.49	14,390	10%
EXP2C_CAL	0.1660	-47%	0.1712	-44%	35,330	114%	21.47	12.41	14,700	13%
EXP2C_PG	0.1842	-42%	0.1736	-43%	40,850	147%	19.35	10.29	18,860	44%
EXP3A_AER	0.1075	-66%	0.1048	-66%	24,370	47%	26.82	17.76	6,568	-50%
EXP3A_CAL	0.1079	-66%	0.1057	-66%	24,510	48%	26.70	17.64	6,630	-49%
EXP3A_PG	0.1041	-67%	0.1015	-67%	24,180	46%	27.82	18.76	6,312	-52%
EXP3B_AER	0.1332	-58%	0.1305	-57%	24,030	45%	18.54	9.48	8,025	-39%
EXP3B_CAL	0.1357	-57%	0.1327	-57%	24,050	45%	18.41	9.35	8,179	-37%
EXP3B_PG	0.0733	-77%	0.0655	-79%	38,960	136%	23.12	14.06	7,160	-45%
EXP3C_AER	0.1470	-53%	0.1436	-53%	33,260	101%	18.33	9.27	12,250	-6%
EXP3C_CAL	0.1485	-53%	0.1454	-53%	33,210	101%	18.38	9.32	12,360	-5%
EXP3C_PG	0.1380	-56%	0.1360	-56%	31,260	89%	20.80	11.74	10,820	-17%
CALPUFF/MMIF										
MMIF12KM_CAL	0.1029	-67%	0.1012	-67%	34,290	107%	26.43	17.37	8,842	-32%
MMIF12KM_PG	0.0956	-70%	0.0887	-71%	39,120	137%	24.89	15.83	9,371	-28%

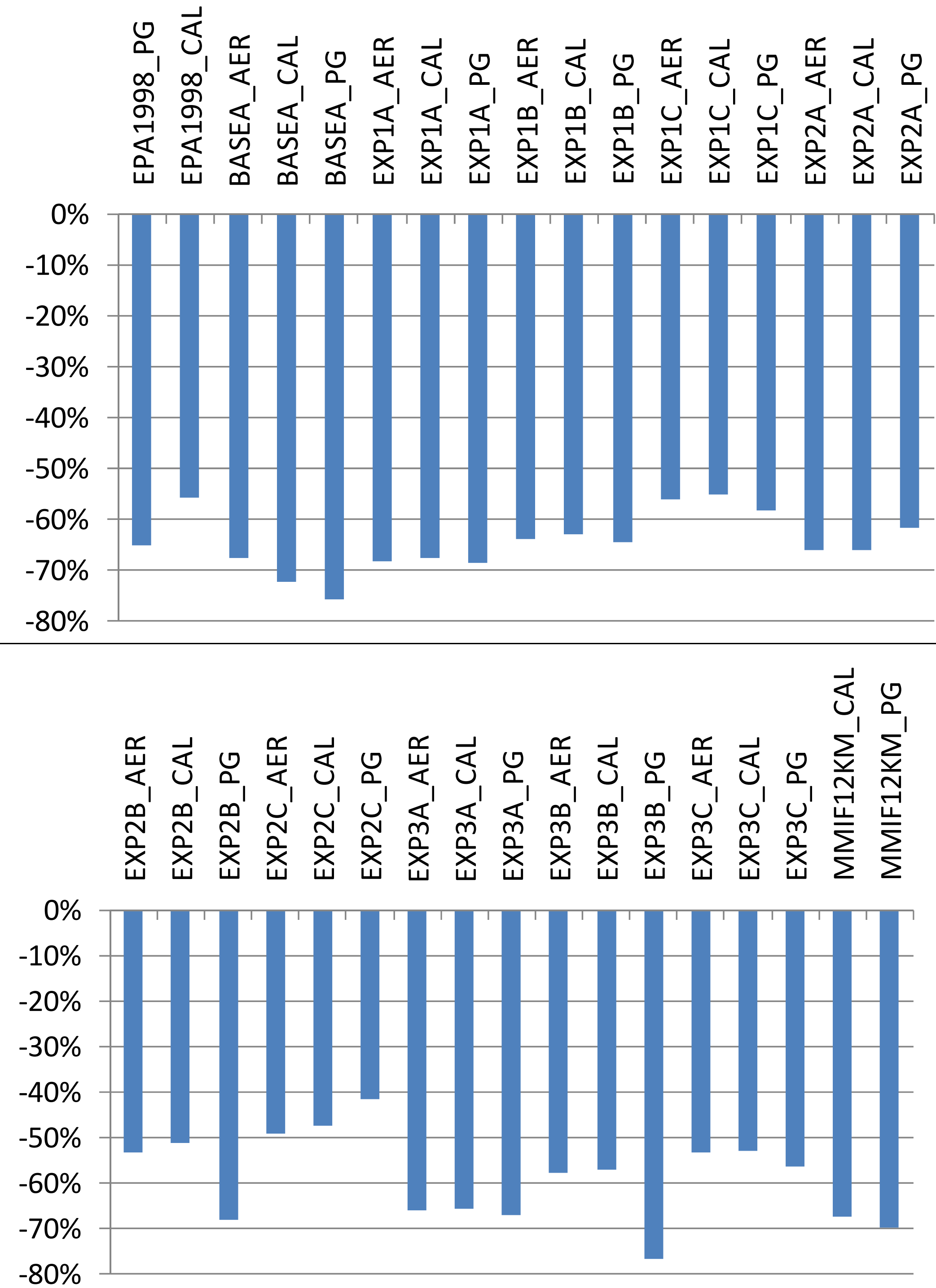


Figure 3-8. Percent difference (mean normalized bias) between the predicted and observed fitted plume centerline concentration (Cmax) for GP80 600 km receptor arc and the CALPUFF sensitivity tests.

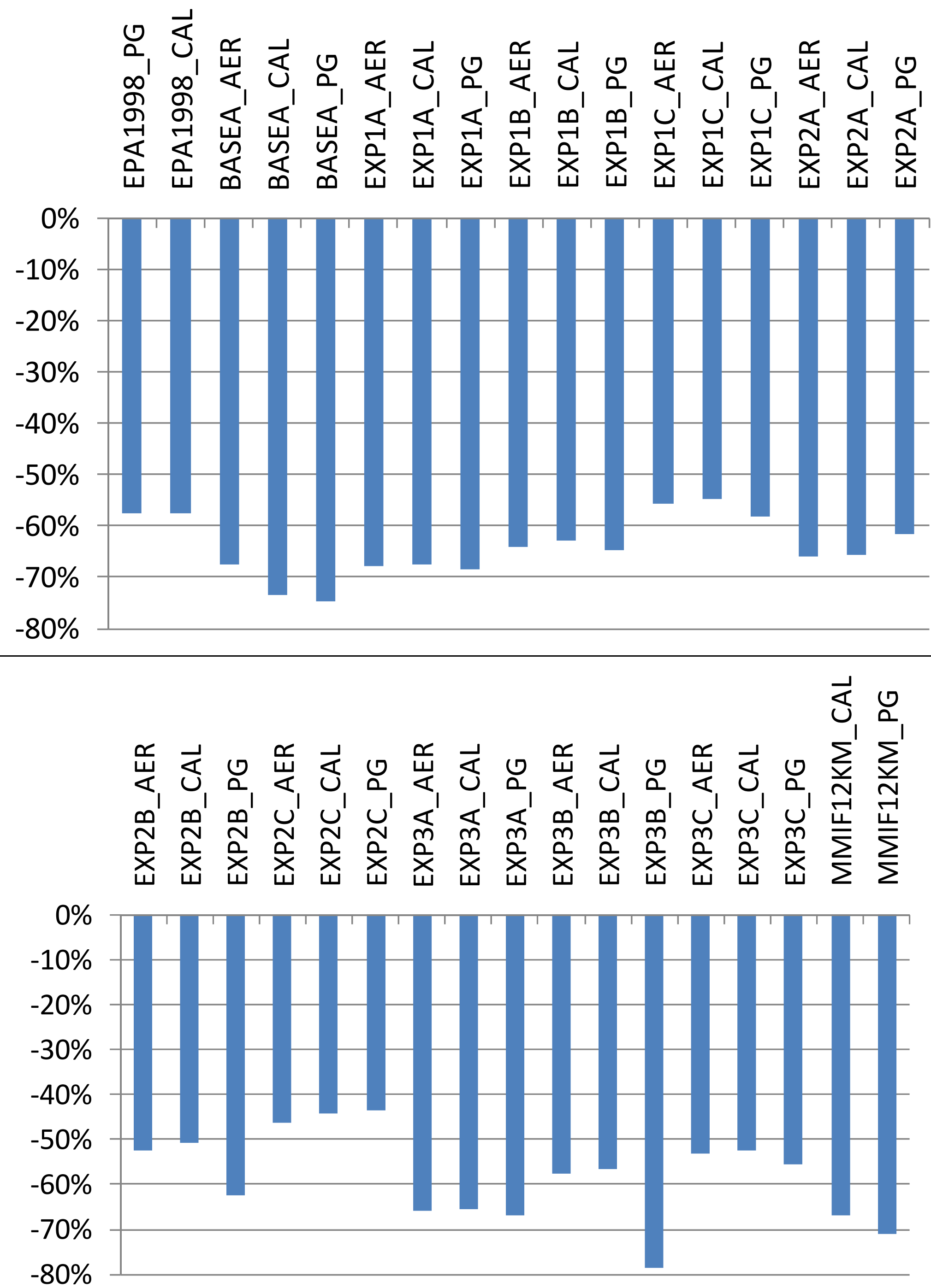


Figure 3-9. Percent difference (mean normalized bias) between the predicted and observed maximum concentration at any receptor/monitor (Omax) for GP80 600 km receptor arc and the CALPUFF sensitivity tests.

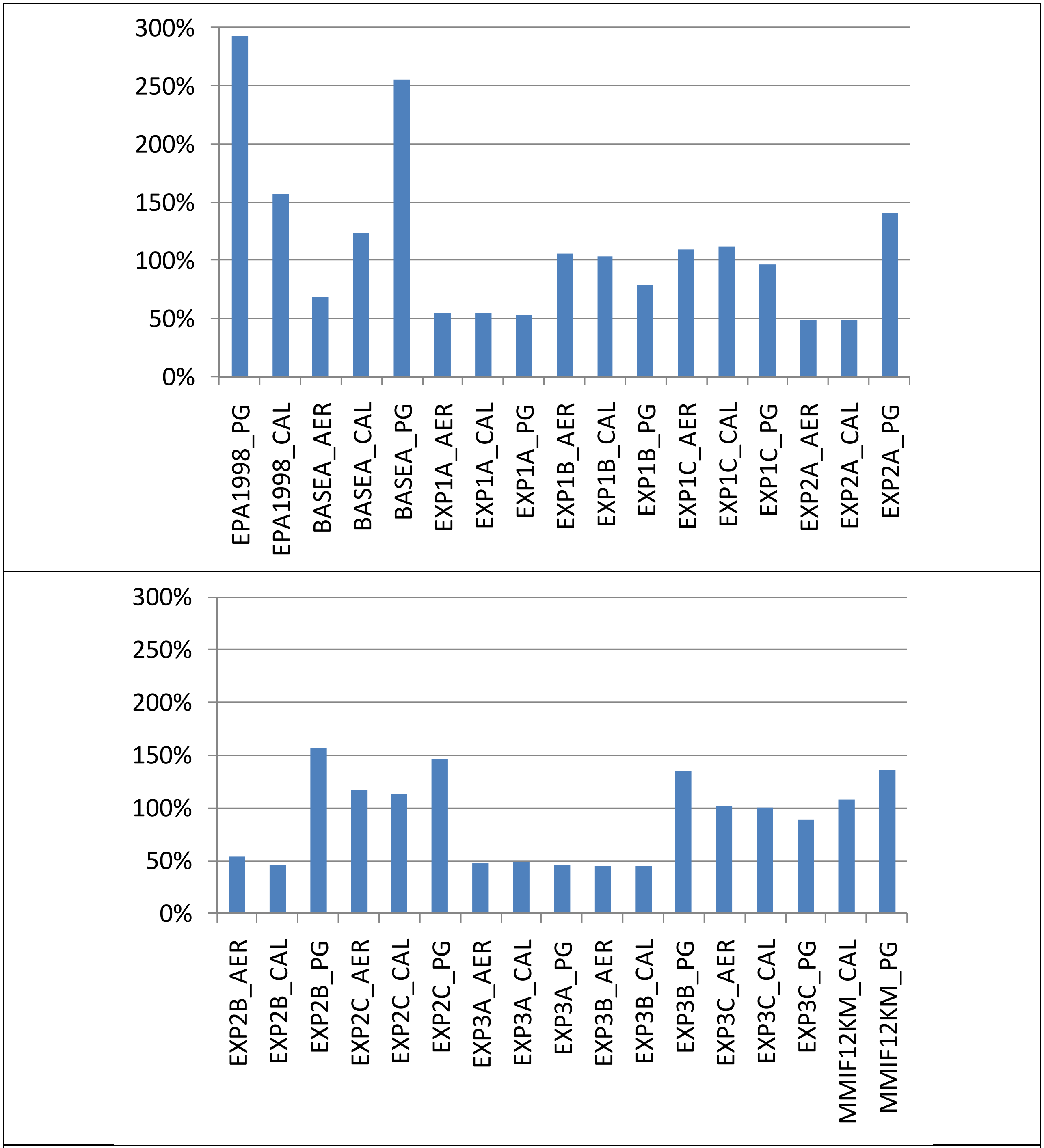


Figure 3-10. Percent difference (mean normalized bias) between the predicted and observed plume spread (σ_y) for GP80 600 km receptor arc and the CALPUFF sensitivity tests.

Figure 3-11. Difference in predicted and observed location of plume centerline (degrees) for the GP10 600 km receptor arc and the CALPUFF sensitivity tests.

Figure 3-12. Percent difference (mean normalized bias) between the predicted and observed cross wind integrated concentration (CWIC) for the GP10 600 km receptor arc and the CALPUFF sensitivity tests.

3.4.3 SLUG and Puff Splitting Sensitivity Tests for the 600 km Arc

One issue of concern with the initial CALPUFF sensitivity tests was the large differences between the estimated residence time of the tracer on the 600 km receptor arc in the EPA 1998 and current CALPUFF simulations using the CALPUFF (CAL) turbulence dispersion options when the same meteorological observations are used as input into CALPUFF. The 1998EPA_CAL CALPUFF sensitivity simulation estimated that the tracer would remain on the 600 km receptor arc for 13 hours, which compares favorably with what was observed (12 hours) but is almost double what the BASEA_CAL simulation estimated (7 hours). In addition to updates to the CALMET and CALPUFF models that have occurred over the last decade, a major difference in the 1998 EPA and current CALPUFF 600 km arc simulations was that the 1998 EPA CALPUFF modeling used the near-source slug option, whereas the current analysis did not. Another major difference between the version of CALPUFF used in the 1998 EPA and current study was that CALPUFF now has the ability to perform puff splitting. In fact, it was the presence of puff splitting in CALPUFF that caused EPA to comment that CALPUFF may be applicable to distances further downwind than 300 km in the 2003 air quality modeling guideline revision that led to CALPUFF being the recommended long-range transport model for chemically inert pollutants (EPA, 2003).

To investigate this issue, a series of slug and puff splitting sensitivity tests were carried out using the BASEA_CAL CALPUFF/CALMET configuration by incrementally adding the near-source slug option (MSLUG = 1) and puff splitting option (MSPLIT = 1) to the BASEA_CAL model configuration. CALPUFF slug and puff splitting sensitivity tests were also carried out using the MMIF12_CAL and MMIF12_PG model configurations. Two types of puff splitting sensitivity tests were carried out:

- Default Puff Splitting (DPS) whereby the vertical puff splitting flag was turned on for just hour 17 (i.e., IRESPLIT is equal to 1 for just hour 17 and is 0 the other hours); and
- All hours Puff Splitting (APS) that turned on the vertical puff splitting flag for all hours of the day (i.e., IRESPLIT has 24 values of 1).

Table 3-16 displays the tracer residence time statistic on the 600 km receptor arc for the slug and puff splitting sensitivity tests. Using the puff model formulation and no puff splitting (BASEA_CAL), CALPUFF estimates that the tracer resides on the 600 km arc for 7 hours, which is -42% less than observed (12 hours). Using all hours puff splitting in CALPUFF, but still using the puff model formation (BASEA_APS_CAL), does not affect the estimated plume residence time statistic (7 hours). However, when the slug option is used (BASEA_SLUG_CAL) the residence time of the estimate tracer on the 600 km receptor arc more than doubles increasing from 7 to 15 hours. And adding puff splitting (APS) to the slug model formulation increases the estimated tracer duration on the arc by another hour (16 hours).

The sensitivity of the CALPUFF/MMIF model configuration 600 km receptor arc tracer residence time statistic to the specification of the slug and puff splitting options is a little different than the CALPUFF/CALMET BASEA model configuration. Whereas the CALPUFF/CALMET BASEA model configuration saw little sensitivity of the estimated tracer concentration residence time on the arc due to puff splitting, the implementation of default puff splitting increases the tracer residence time from 6 to 8 hours (CAL dispersion) and from 7 to 11 hours (PG dispersion) with all hours puff splitting increasing the residence time even more. The effect of the slug option using the CALPUFF/MMIF modeling platform has a very different effect on the tracer duration time on the arc using the CAL and PG dispersion algorithms. Using the CAL dispersion option with APS, implementing the slug option decreases the tracer residence time of the 600 km arc from 17 to 15 hours. However, using the PG dispersion option with APS, the tracer residence on the 600 km receptor arc increased from 11 to 20 hours when the slug option is invoked using the PG dispersion option.

Table 3-16. Duration of time tracer resides on the GP80 600 km receptor arc (hours) for the CALPUFF slug and puff splitting sensitivity tests.

Scenario	MSLUG	MSPLIT	Duration on 600 km Arc	
			Time (Hours)	Difference (%)
Observed			12	
		CALPUFF/CALMET		
BASEA_CAL	0	0	7	-42%
BASEA_APS_CAL	0	1	7	-42%
BASEA_SLUG_CAL	1	0	15	+25%
BASEA_SLUG_APS_CAL	1	1	16	+33%
		CALPUFF/MMIF		
MMIF12_CAL	0	0	6	-50%
MMIF12_DPS_CAL	0	1	8	-33%
MMIF12_APS_CAL	0	1	17	+42%
MMIF12_SLUG_APS_CAL	1	1	15	25%
MMIF12_PG	0	0	7	-42%
MMIF12_DPS_PG	0	1	11	-8%
MMMIF12_APS_PG	0	1	11	-8%
MMIF12_SLUG_APS_PG	1	1	20	+67%

Table 3-17 summarizes the plume fitting model performance statistics for the CALPUFF slug and puff splitting sensitivity tests. For the CALPUFF/CALMET BASEA_CAL slug and puff splitting sensitivity tests, the improvements in CALPUFF's estimated tracer residence time on the 600 km receptor arc when the slug option is invoked is accompanied by a further degradation in CALPUFF's ability to estimate the maximum concentrations (Cmax/Omax) as well as increasing CALPUFF's overestimate of the observed plume spread (σ_y) (~16,500 m) from ~120% (~35,000 m) without the slug option to over 250% (~60,000 m) with the slug option. The use of the slug option also improves the angular offset of the plume centerline from off by ~18 degrees to off by ~14 degrees. Finally, without using APS, CALPUFF's CWIC performance is improved from a -38% underestimation to a -12% underestimation, whereas with using APS the improvement in CWIC performance due to using the slug option is less dramatic (-31% to -25%)

Using the CALPUFF/MMIF modeling platform, the changes in the maximum (Cmax/Omax) and plume spread model performance statistics due to the use of the slug option are much less than seen with the BASEA CALPUFF/CALMET modeling platform. Use of the slug option using the CALPUFF/MMIF platform increases the maximum concentrations slightly, whereas with the CALPUFF/CALMET platform the slug option resulting in slight deceases in concentrations. The use of puff splitting had little effect on the CALPUFF/MMIF estimated maximum concentrations and resulted in slightly wider plume widths. The biggest effect puff splitting had on the CALPUFF/MMIF model performance was for the plume centerline angular displacement that improved from 16-17 to 7-8 degrees offset from observed due to the use of puff splitting (DPS or APS). In fact, of all the CALPUFF sensitivity tests examined, CALPUFF/MMIF using puff splitting is the best performing model configuration for estimating plume centerline location. Puff splitting resulted in small improvements in CALPUFF's ability to predict CWIC across the 600 km arc. But the slug option greatly improved CALPUFF/MMIF's ability to reproduce the observed CWIC. For example, using the CAL turbulence dispersion option, CALPUFF/MMIF underestimates the observed CWIC at the 600 km receptor arc by -32% using the puff model configuration and no puff splitting. Using the DPS and APS puff splitting approach reduces the CWIC underestimation bias to -28% and -21%, respectively, And then adding the slug formulation with the APS completely eliminates the CWIC underestimation bias (-2%). In fact, use of the APS and slug options with the CALPUFF/MMIF modeling platform results in the best performing CALPUFF sensitivity test for estimating CWIC across the 600 km arc of all the CALPUFF sensitivity tests analyzed (Tables 3-15 and 3-17).

Table 3-17. Plume fitting statistics for the CALPUFF slug and puff splitting sensitivity tests.

CALPUFF slug and puff splitting sensitivity test	Cmax		Omax		Sigma-y		Centerline		CWIC	
	(ppt)	MNB	(ppt)	MNB	(m)	MNB	(deg)	Diff	(ppt-m)	MNB
Observed	0.3152		0.3068		16,533		369.06		13,060	
CALPUFF/CALMET										
BASEA_CAL	0.0875	-72%	0.0817	-73%	36,870	123%	27.55	18.49	8,084	-38%
BASEA_APS_CAL	0.1014	-68%	0.1029	-66%	35,510	115%	27.19	18.13	9,023	-31%
BASEA_SLUG_CAL	0.0728	-77%	0.0726	-76%	62,650	279%	22.49	13.43	11,430	-12%
BASEA_SLUG_APS_CAL	0.0673	-79%	0.0652	-79%	58,440	253%	23.56	14.50	9,855	-25%
CALPUF/MMIF										
MMIF12KM_CAL	0.1029	-67%	0.1012	-67%	34,290	107%	26.43	17.37	8,842	-32%
MMIF12KM_DPS_CAL	0.1049	-67%	0.1016	-67%	35,960	118%	16.74	7.68	9,454	-28%
MMIF12KM_APS_CAL	0.1108	-65%	0.1076	-65%	37,120	125%	16.30	7.24	10,310	-21%
MMIF12KM_SLUG_CAL	0.1458	-54%	0.1462	-52%	35,190	113%	16.92	7.86	12,860	-2%
MMIF12KM_PG	0.0956	-70%	0.0887	-71%	39,120	137%	24.89	15.83	9,371	-28%
MMIF12KM_DPS_PG	0.1085	-66%	0.1143	-63%	41,610	152%	17.04	7.98	11,310	-13%
MMIF12KM_APS_PG	0.1085	-66%	0.1143	-63%	41,610	152%	17.04	7.98	11,310	-13%
MMIF12KM_SLUG_PG	0.1251	-60%	0.1115	-64%	41,770	153%	17.43	8.37	13,100	0%

3.5 CONCLUSIONS ON GP80 TRACER TEST EVALUATION

For the 100 km receptor arc CALPUFF/CALMET sensitivity simulations, the ability of CALPUFF to simulate the observed tracer concentrations varied among the different CALMET configurations and were not inconsistent with the results of the 1998 EPA CALPUFF evaluation study (EPA, 1998a). The best performing CALPUFF/CALMET configuration was when CALMET was run using MM5 data and just surface meteorological observations and no upper-air meteorological observations. In general, the CAL and AER turbulence dispersion options in CALPUFF performed similarly and performed better than the PG dispersion option. The performance of CALPUFF using the MMIF tool tended to be in the middle of the range of model performance for the CALPUFF/CALMET sensitivity tests; not as good as the performance of CALPUFF/CALMET using MM5 and just surface observations data in CALMET, but better than the performance of CALPUFF using MM5 data and no meteorological observations in CALMET.

The CALPUFF sensitivity modeling results for the GP80 600 km receptor arc were quite variable. With two notable exception (the BASEA_PG and EXP2C configurations), the initial CALPUFF sensitivity tests were unable to duplicate the observed tracer residence time on the 600 km receptor arc as was seen in the 1998 EPA CALPUFF evaluation study (EPA, 1998a). However, when the near-source slug option was used, CALPUFF/CALMET was better able to reproduce the amount of time that the tracer was observed on the 600 km receptor arc. The standard application of CALPUFF for LRT applications is the puff model formulation rather than the slug model formation, which is designed to better simulate a near-source continuous plume. The fact that the slug formulation is needed to produce reasonable CALPUFF model performance for residence time on the 600 km receptor suggests that the findings of the 1998 EPA CALPUFF evaluation study should be re-evaluated.

In general, the CALPUFF/CALMET sensitivity tests that are based on CALMET using MM5 data with no meteorological observations exhibit better plume fitting model performance statistics for the 600 km receptors arc than when meteorological observations are used with CALMET. The use of the slug option with CALMET/CALPUFF, which improved the plume residence time statistics, degrades the maximum concentrations and plume width statistics, but improves the plume centerline and CWIC average plume concentration statistics. Puff splitting had little effect on the CALPUFF/CALMET model predictions on the 600 km receptor arc. However, puff splitting did improve the CALPUFF/MMIF plume centerline and CWIC average plume concentration statistics, as well as the tracer residence time statistics. Puff splitting resulted in a slight degradation of the plume width statistics in CALPUFF/MMIF. Using the slug option with puff splitting in CALPUFF/MMIF results in the best performing CALPUFF model configuration of all the sensitivity tests for the plume centerline and CWIC average plume statistics, although the use of slug and puff splitting does degrade the plume width statistic.

4.0 1975 SAVANNAH RIVER LABORATORY FIELD STUDY

4.1 DESCRIPTION OF THE 1975 SAVANNAH RIVER LABORATORY FIELD STUDY

The 1975 Savannah River Laboratory (SRL75) field experiment was located in South Carolina and occurred in December 1975 (DOE, 1978). A SF_6 tracer was released for four hours between 10:25 and 14:25 LST on December 10, 1975 from a 62 m stack with a diameter of 1.0 m, exit velocity of 0.001 m/s and at ambient temperature. A single monitoring arc was used in the SRL75 experiment that was approximately 100 kilometers from the source with monitoring sites located along I-95 from Mile Post (MP) 76 near St. George, SC in the south to Hwy 36 west of Tillman, SC to the north and along SC 336.

The 1998 EPA CALPUFF evaluation (EPA, 1998a) used the SRL75 SF_6 tracer release in the CALPUFF model evaluation. However, the 1986 8 LRT dispersion model evaluation study (Policastro et al., 1986) used the longer-term SRL Krypton-85 release database (Telegadas et al., 1980). In this study we evaluated CALPUFF using the SRL75 SF_6 database to be consistent with the 1998 EPA study.

4.2 MODEL CONFIGURATION AND APPLICATION

Both the CALMET meteorological model and MMIF tools were used to provide meteorological inputs to CALPUFF. The CALMET modeling was performed using a Universal Trans Mercator (UTM) map projection in order to be consistent with the past CALPUFF applications (EPA, 1998a). The MMIF meteorological processing used a Lambert Conformal Conic (LCC) map projection because in must be consistent with the MM5 coordinate system. Figure 4-1 displays the CALMET/CALPUFF UTM modeling domain and locations of the ~200 receptors used in the CALPUFF modeling that lie along an arc 100 km from the source. The tracer was observed using ~40 monitors that were located along I-95 between MP 24 and 76 that were approximately 100 km from the source. When using the Irwin Gaussian plume fitting model evaluation approach, the tracer observations at the monitoring sites are assumed to be on an arc of receptors 100 km from the source.

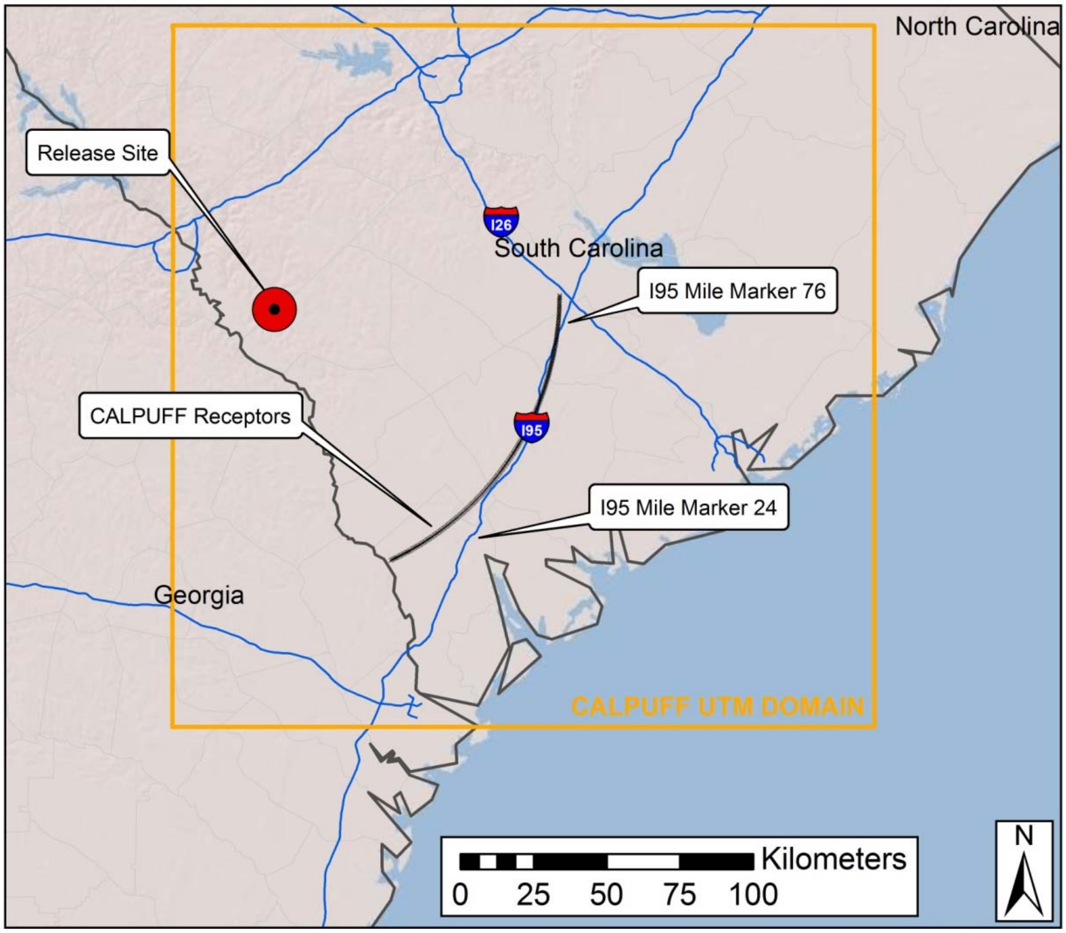


Figure 4-1. CALPUFF/CALMET UTM modeling domain and location of tracer release site and CALPUFF receptors along am arc 100 km from the source for the SRL75 CALPUFF modeling.

In the CALPUFF modeling system, each of the three programs (CALMET, CALPUFF, and CALPOST) uses a control file of user-selectable options to control the data processing. There are numerous options in each and several that can result in significant differences. The following model controls for CALMET and CALPUFF were employed for the analyses with the SRL75 tracer data.

4.2.1 CALMET Options

The following CALMET control parameters and options were chosen for the BASE case model evaluation. The BASE case control parameters and options were chosen to be consistent with two previous CALMET/CALPUFF evaluations (Irwin 1997 and EPA 1998a). The most important CALMET options relate to the development of the wind field and were set as follows:

NOOBS	= 0	Use surface, overwater, and upper air station data
IWFCOD	= 1	Use diagnostic wind model to develop the 3-D wind fields
IFRADJ	= 1	Compute Froude number adjustment effects (thermodynamic blocking effects of terrain)
IKINE	= 0	Do NOT compute kinematic effects
IOBR	= 0	Do NOT use O'Brien procedure for adjusting vertical velocity
IEXTRP	= 4	Use similarity theory to extrapolate surface winds to upper layers

IPROG	= 0	Do NOT use prognostic wind field model output as input to diagnostic wind field model (for observations only sensitivity test)
ITPROG	= 0	Do NOT use prognostic temperature data output

Mixing heights are important in the estimating ground level concentrations. The CALMET options that affect mixing heights were set as follows:

IAVEZI	= 1	Conduct spatial averaging
MNMDAV	= 1	Maximum search radius (in grid cells) in averaging process
HAFANG	= 30.	Half-angle of upwind looking cone for averaging
ILEVZI	= 1	Layer of winds to use in upwind averaging
DPTMIN	= .001	Minimum potential temperature lapse rate (K/m) in stable layer above convective mixing height
DZZI	= 200	Depth of layer (meters) over which the lapse rate is computed
ZIMIN	= 100	Minimum mixing height (meters) over land
ZIMAX	= 3200	Maximum mixing height (meters) over land, defined to be the top of the modeling domain

A number of CALMET model control options have no recommended default values, particularly radii of influence values for terrain and surface and upper air observations. The CALMET options that affect radius of influence were set as follows:

RMAX1	= 20	Minimum radius of influence in surface layer (km)
RMAX2	= 50	Minimum radius of influence over land aloft (km)
RMIN	= 0.1	Minimum radius of influence in wind field interpolation (km)
TERRAD	= 10	Radius of influence of terrain features (km)
RPROG	= 0	Weighting factors of prognostic wind field data (km)

A review of the respective CALMET parameters between the 1998 EPA CALMET/CALPUFF evaluation study using CALMET Version 4.0 and the BASE case scenario in the current CALMET/CALPUFF evaluation using CALMET Version 5.8 indicates differences in some CALMET options. The differences between the two scenarios are presented below in Table 4-1. All other major CALMET options for BASE case scenario matched the original 1998 EPA analysis.

Table 4-1. CALMET parameters for the SRL75 tracer field experiment modeling used in the, 1998 EPA and current BASE case analysis.

CALMET Option	Description	1998 EPA Setup	BASE Setup
IKINE	Adjust winds using Kinematic effects? (yes = 1 and no = 0)	1	0
MNMDAV	Maximum search radius for averaging mixing heights (# grid cells)	3	1
ZUPWND	Bottom and top layer through which domain-scale winds are calculated (in meters)	1,2000	1,1000
RMIN	Minimum radius of influence in wind field interpolation (in km)	2	0.1
RMIN2	Minimum upper air station to surface station extrapolation radius (in km)	-1	4

The CALMET preprocessor can utilize National Weather Service (NWS) meteorological data and on-site data to produce temporally and spatially varying three dimensional wind fields for CALPUFF. Only NWS data were used for this effort and came from two compact disc (CD) data sets. The first was the *Solar and Meteorological Surface Observation Network* (SAMSON) compact discs, which were used to obtain the hourly surface observations. The surface stations used for the SRL75 CALMET modeling are shown in Table 4-2.

Table 4-2. 1975 Savannah River Laboratory surface meteorological stations.

State	Cities
Georgia	Athens, Atlanta, Augusta, Macon, Savannah
North Carolina	Asheville, Charlotte, Greensboro, Raleigh-Durham, Wilmington
South Carolina	Charleston, Columbia, Greer-Spartanburg

Twice daily soundings came from the second set of compact discs, the *Radiosonde Data for North America*. The upper-air rawinsonde meteorological observations used in the SRL75 CALMET modeling are shown in Table 4-3.

Table 4-3. 1975 Savannah River Laboratory tracer experiment rawinsonde sites.

State	Cities
Georgia	Athens, Waycross
North Carolina	Greensboro, Cape Hatteras
South Carolina	Charleston

Six vertical layers were defined for the CALPUFF modeling to be consistent with the Irwin (1997) and EPA (1998a) modeling as follows: surface-20, 20-50, 50-100, 100-500, 500-2000, and 2000-3300 meters.

MM5 prognostic meteorological model simulations were conducted using grid resolutions of 36, 12 and 4 km. The CALMET modeling used the 12 km MM5 data. The MMIF tool was applied using all three MM5 grid resolutions and using the first 27 MM5 vertical layers from the surface to approximately 6,500 m AGL.

4.2.2 CALPUFF Control Options

The following CALPUFF control parameters, which are a subset of the control parameters, were used. These parameters and options were chosen to be consistent with the 1977 INEL study (Irwin 1997) and 1998 EPA CALPUFF evaluation (EPA, 1998a) studies. Note that use of the slug option (MSLUG = 1) is fairly non-standard for LRT modeling. However, that was what was used in the 1997 INEL and 1998 EPA studies so it was also used in this study's CALPUFF evaluation using the SRL75 tracer database.

Technical options (group 2):

MCTADJ	= 0	No terrain adjustment
MCTSG	= 0	No subgrid scale complex terrain is modeled
MSLUG	= 1	Near-field puffs modeled as elongated (i.e., slugs)
MTRANS	= 1	Transitional plume rise is modeled
MTIP	= 1	Stack tip downwash is modeled
MSHEAR	= 0	Vertical wind shear is NOT modeled above stack top
MSPLIT	= 0	No puff splitting
MCHEM	= 0	No chemical transformations
MWET	= 0	No wet removal processes
MDRY	= 0	No dry removal processes
MPARTL	= 0	No partial plume penetration

MPDF	= 0	PDF NOT used for dispersion under convective conditions
MREG	= 0	No check made to see if options conform to regulatory Options

Two different values were used for the dispersion parameterization option MDISP:

= 2	Dispersion coefficients from internally calculated sigmas
= 3	PG dispersion coefficients for RURAL areas (PG)

In addition, under MDISP = 2 dispersion option, two different options were used for the MCTURB option that defines the method used to compute turbulence sigma-v and sigma-w using micrometeorological variables:

= 1	Standard CALPUFF routines (CAL)
= 2	AERMOD subroutines (AER)

Several miscellaneous dispersion and computational parameters (group 12) were set as follows:

SYTDEP	= 550.	Horizontal puff size beyond which Heffter equations are used for sigma-y and sigma-z
MHFTSZ	= 0	Do NOT use Heffter equation for sigma-z
XMXLEN	= 1	Maximum length of slug (in grid cells)
XSAMLEN	= 1	Maximum travel distance of puff/slug (in grid cells) during one sampling step
MXNEW	= 99	Maximum number of slugs/puffs released during one time step
WSCALM	= 0.5	Minimum wind speed (m/s) for non-calm conditions
XMAXZI	= 3000	Maximum mixing height (meters)
XMINZI	= 50	Minimum mixing height (meters)
SL2PF	= 10	Slug-to-puff transition criterion factor (= sigma-y/slug length)

A review of the respective CALPUFF parameters between the 1998 EPA CALMET/CALPUFF evaluation study using CALMET Version 4.0 and the BASE case scenario in the current CALMET/CALPUFF evaluation using CALPUFF Version 5.8 indicates differences in some parameters. The differences between the two scenarios are presented below in Table 4-4. All other major CALPUFF options for current BASE case scenario matched the original 1998 EPA analysis.

Table 4-4. CALPUFF parameters used in the SRL75 tracer field experiment modeling for the 1998 EPA and current BASE case analysis.

CALPUFF Option	Description	1998 EPA Setup	Current Study BASE Setup
SYMIN	Minimum sigma y (meters)	0.01	1
SZMIN	Minimum sigma z (meters)	0.01	1
WSCALM	Minimum wind speed (m/s) for non-calm conditions	1.0	0.5
XMAXZI	Maximum mixing height (meters)	3300	3000
XMINZI	Minimum mixing height (meters)	20	50
XMXLEN	Maximum length of slug (in grid cells)	0.1	1
XSAMLEN	Maximum travel distance of puff/slug (in grid cells) during one sampling step	0.1	1
MXNEW	Maximum number of slugs/puffs released during one time step	199	99
MXSAM	Maximum number of sampling steps per slug/puff during one time step	5	99
SL2PF	Slug-to-puff transition criterion factor (= sigma-y/slug length)	5.0	10.0

4.2.3 SRL75 CALPUFF/CALMET Sensitivity Tests

Table 4-5 describes the CALMET/CALPUFF sensitivity tests performed for the modeling of the 100 km arc of receptors in the SRL75 field study. The BASE simulation uses the same configuration as used in the 1998 EPA CALPUFF evaluation report, only updated from CALPUFF Version 4.0 to CALPUFF Version 5.8. The CALMET and CALPUFF parameters of the BASE case simulations were discussed earlier in this section.

The sensitivity simulations are designed to examine the sensitivity of the CALPUFF model performance to 10 km grid resolution in the CALMET meteorological model simulation, the use of 12 km resolution MM5 output data used as input to CALMET, and the use of surface and upper-air meteorological observations in CALMET through NOOBS = 0 (use surface and upper-air observation), 1 (use only surface observations) and 2 (don't use any observations).

In addition, for each experiment using different CALMET model configurations, three CALPUFF dispersion options were examined as shown in Table 4-6. Two of the CALPUFF dispersion sensitivity tests using dispersion based on sigma-v and sigma-w turbulence values using the CALPUFF (CAL) and AERMOD (AER) algorithms. Whereas the third dispersion option (PG) uses Pasquill-Gifford dispersion coefficients.

Table 4-5. CALPUFF/CALMET experiments for the SRL75 tracer experiment.

Experiment	CALMET Grid	MM5 Data	NOOBS	Comment
BASE	10 km	None	0	Original met observations only configuration
EXP1A	10 km	12 km	0	Aug 2009 IWAQM w/10 km grid using 12 km MM5
EXP1B	10 km	12 km	1	Don't use observed upper-air meteorological data
EXP1C	10 km	12 km	2	Don't use observed surface/upper-air meteorological data

Table 4-6. CALPUFF dispersion options examined in the CALPUFF sensitivity tests.

Experiment	MDISP	MCTURB	Comment
CAL	2	1	Dispersion coefficients from internally calculated sigma-v and sigma-w using micrometeorological variables and CALPUFF algorithms
AER	2	2	Dispersion coefficients from internally calculated sigma-v and sigma-w using micrometeorological variables and AERMOD algorithms
PG	3	--	PG dispersion coefficients for rural areas and MP coefficients for urban areas

The CALMET and CALPUFF simulations used for the sensitivity analyses were updated from the BASE case model configuration that was designed to be consistent with the 1998 EPA study by using recommended settings for many variables from the August 2009 EPA Clarification Memorandum. A summary of CALMET parameters that changed from the BASE case scenarios for the CALPUFF sensitivity tests are presented in Table 4-7.

Table 4-7. CALMET wind field parameters for the SRL75 tracer experiment.

CALMET Option	2009 EPA-FLM Default	BASE	EXP1A	EXP1B	EXP1C
NOOBS	0	0	0	1	2
ICLOUD	0	0	0	0	3
IEXTRP	-4	4	-4	-4	1
IPROG	14	0	14	14	14
ITPROG	0	0	0	1	2
ZIMIN	50	100	50	50	50
ZIMAX	3000	3200	3000	3000	3000
RMAX1	100	20	100	100	50
RMAX2	200	50	200	200	100

4.2.4 CALPUFF/MMIF Sensitivity Tests

With the MMIF software tool designed to reformat the MM5/WRF meteorological model output data for input into CALPUFF, there are much less options available and hence much fewer sensitivity tests as shown in Table 4-8.

Table 4-8. CALPUFF/MMIF sensitivity tests analyzed with the SRL75 tracer experiment.

Grid Resolution	MM5	MDISP	MCTURB	Comment
36 km	36 km	2	1	36 km MM5 with CALPUFF turbulence dispersion
36 km	36 km	2	2	36 km MM5 with AERMOD turbulence dispersion
36 km	36 km	3	--	36 km MM5 with Pasquill-Gifford dispersion
12 km	12 km	2	1	12 km MM5 with CALPUFF turbulence dispersion
12 km	12 km	2	2	12 km MM5 with AERMOD turbulence dispersion
12 km	12 km	3	--	12 km MM5 with Pasquill-Gifford dispersion
4 km	4 km	2	1	4 km MM5 with CALPUFF turbulence dispersion
4 km	4 km	2	2	4 km MM5 with AERMOD turbulence dispersion
4 km	4 km	3	--	4 km MM5 with Pasquill-Gifford dispersion

4.3 QUALITY ASSURANCE

The quality assurance (QA) of the CALPUFF modeling system simulations for the SRL tracer experiment was assessed by analyzing the CALMET and CALPUFF input and output files and the dates they were generated. The input file options were compared against the EPA-FLM recommended settings from the August 2009 Clarification Memorandum (EPA, 2009b) and the definitions of the sensitivity tests to assure that the intended parameters were varied. The QA of the MMIF runs was not completed because no input files or list files were provided to document the MMIF parameters.

The CALMET sensitivity simulations used a radius of influence of terrain on wind fields equal to 10 m (TERRAD = 10). The 2009 EPA Clarification Memorandum recommends TERRAD = 15. The CALMET sensitivity simulations used a minimum extrapolation distance between surface and upper air stations of 4 km (RMIN2 = 4). The 2009 EPA Clarification Memorandum recommends RMIN2 = -1.

Four CALMET parameters (BIAS, NSMTH, NINTR2, and FEXTR2) require a value for each vertical layer processed in CALMET. The CALMET BASE case has six vertical layers, but the sensitivity simulations are based on ten vertical layers. The CALMET sensitivity simulations were provided with only six values for BIAS, NSMTH, NINTR2, and FEXTR2 even though ten vertical layers were simulated. Therefore, CALMET used default values for the upper four vertical layers (i.e., 1200 m, 2000 m, 3000 m, and 4000 m).

In addition to the three CALPUFF dispersion options (AERMOD, CALPUFF, and PG), there were other CALPUFF parameters that differed between the CALPUFF/CALMET (BASE and sensitivity cases) and CALPUFF/MMIF modeling scenarios. The CALPUFF parameter differences include:

- CALPUFF/CALMET sensitivity runs using AERMOD and CALPUFF dispersion were conducted using near-field slug formation (MSLUG = 1), but the CALPUFF/CALMET PG and CALPUFF/MMIF runs were conducted using puffs (MSLUG = 0).
- CALPUFF/CALMET sensitivity runs using AERMOD and CALPUFF dispersion were set-up to not allow for partial plume penetration of inversion layer (MPARTL = 0).

The quality assurance of the post-processing of the SRL75 CALPUFF runs uncovered two errors. The first was that the conversion factor to convert the SF_6 tracer concentrations from mass per volume to ppt was approximately three times too large. The second error was that when calculating the integrated concentrations along the arc, the wrong time period was specified. These two errors were fixed and the CALPUFF results re-processed to generate new plume fitting statistical performance measures.

4.4 MODEL PERFORMANCE EVALUATION FOR THE SRL75 TRACER EXPERIMENT

The Irwin (1997) plume fitting evaluation approach was used to evaluate CALPUFF for the SRL75 field experiment. There are two components to the Irwin plume fitting evaluation approach:

1. A temporal analysis that examines the time the tracer arrives, leaves and resides on the receptor arc; and
2. A plume fitting procedures that compares the predicted observed peak and average plume concentrations and the width of the plume by fitting a Gaussian plume through the predicted or observed concentrations across the arc of receptors or monitors that lie on the 100 km receptor arc.

Because only long-term integrated average observed SF_6 samples were available, the timing component of the evaluation could not be compared against observed values in the SRL75 experiments.

Most of the CALPUFF sensitivity tests estimated that the tracer arrived at the 100 km arc on hour 13 LST, 2½ hours after the beginning to the tracer release. The exceptions to this are the CALPUFF/MMIF simulations using the 4 km MM5 data and CALPUFF/MMIF using the 36 km and PG dispersion that estimated the plume arrives at hour 14 LST. With one exception, the CALPUFF simulations estimated that the tracer resided either 5 or 6 hours on the arc. And with two exceptions, it was the meteorological data rather than the dispersion option that defined the residence time of the estimated tracer on the 100 km receptor arc. The exceptions were for the PG dispersion sensitivity test that in two cases predicted the tracer would remain one less hour on the arc; the CALPUFF/CALMET BASE sensitivity test using the PG dispersion estimated that the tracer would reside only 4 hours on the 100 km receptor arc. Without any observed tracer timing statistics, these results are difficult to interpret.

Table 4-9 displays the model performance evaluation for the various CALPUFF sensitivity tests using the Irwin plume fitting evaluation approach. The observed values were taken from the 1998 EPA CALPUFF tracer test evaluation report data (EPA, 1998a). Also shown in Table 4-4 are the statistics from the 1998 EPA report for the CALPUFF V4.0 modeling using Pasquill-Gifford (PG) and similarity (CAL) dispersion. Note that the EPA 1998 CALPUFF modeling used CALMET with just observations so is analogous to the BASE sensitivity scenario that used CALPUFF V5.8. There are five statistical parameters evaluated using the Irwin plume fitting evaluation approach:

- Cmax, which is the plume fitted centerline concentration.
- Omax, which is the maximum observed value at the ~40 monitoring sites or maximum predicted value across the ~200 receptors along the 100 km arc.
- Sigma-y, which the second moment of the Gaussian distribution and a measure of the plume spread.
- Plume Centerline, which is the angle of the plume centerline from the source to the 100 km arc.
- CWIC, the cross wind integrated concentration (CWIC) across the predicted and observed fitted Gaussian plume.

The first thing we note in Table 4-9 is that the maximum centerline concentration of the fitted Gaussian plume to the observed SF_6 tracer concentrations across the 12 monitors (2.739 ppt) is almost half the observed maximum at any of the monitors (5.07 ppt). As the centerline concentrations in a Gaussian plume represents the maximum concentration, this means that the fitted Gaussian plume is not a very good fit of the observations and the Cmax parameter is not a good indicator of model performance. Comparison of the predicted and observed Omax values that represents the maximum observed concentration across the monitoring sites and the maximum predicted value at any of the 200 receptors along the arc is an apple-orange comparison. We would expect the predicted Omax value to be the same or larger than the observed Omax value given there are ~5 times more samples of the plume in the model predictions compared to the observations. This is the case for all of the CALPUFF/MMIF sensitivity tests. However, when CALPUFF is run using CALMET with no MM5 data (BASE), the predicted Omax value is less than the observed value for both CALPUFF V4.0 and CALPUFF V5.8, which is an undesirable attribute.

The fitted plume width (sigma-y) based on observations is almost doubled the fitted plume width based on the CALPUFF model predictions for all the CALPUFF simulations. However, this is likely due in part to the poor Gaussian plume fit of the observations. Figure 4-2 is reproduced from the 1998 EPA CALPUFF tracer test report and compares the CALPUFF fitted Gaussian plume concentrations with the 13 observed tracer concentrations, where the predicted and observed tracer distributions have been rotated so that their centerlines match up. Of the 13 monitors pictured along the 100 km arc, four have substantial (> 2.0 ppt) concentrations whereas the tracer concentrations at the remaining monitoring sites are mostly <0.2 ppt. Based on this figure, the predicted and observed plume widths match quite well. However, when fitting a Gaussian plume to the observations it appears that the "observed" width is overstated due to the low tracer concentration monitoring sites on the wings of the plume. These results suggest that in the real world the concept of a Gaussian plume may not hold at longer downwind distances, such as the 100 km receptor arc used in the SRL75 field experiment. Consequently, the use of a fitted Gaussian plume as a model evaluation tool may be a poor indicator of model performance for LRT dispersion models.

The plume centerline metric is a useful tool for evaluating the main flow of the center of mass of a plume from the source to receptor arc. The observed plume centerline is at 126 degrees. The CALPUFF/MMIF estimated centerline is off by 8-10 degrees too far south. However, CALPUFF using CALMET and just observations is off by 17 degrees (EPA, 1998a) and 20 degrees (BASE) and it is too far south. Adding the 12 km MM5 data with the observations in CALPUFF (EXP1) only improves the centerline angular offset from 20 to 19 degrees. Removing the upper-air meteorological observations from the CALMET modeling (EXP2) results in no improvements in the CALPUFF/CALPUFF centerline offset (still 19 degrees). However, also removing the surface meteorological observations from the CALMET modeling (EXP3, NOOBS = 2) improves the CALPUFF/CALMET centerline angular offset from 19 to 12 degrees so that it is almost as good as the CALPUFF/MMIF simulations (8 to 10 degrees offset).

Table 4-9. CALPUFF model performance statistics using the Irwin plume fitting evaluation approach using the SRL75 field experiment and the 1998 EPA study and the CALPUFF sensitivity tests.

CALPUFF	Cmax[1]		Omax		Sigma-y[1]		Plume Centerline		CWIC	
Sensitivity Test	(ppt)	MNB	(ppt)	MNB	(meters)	MNB	(degrees)	Diff (deg)	(ppt/m^2)	MNB
Observed	2.739		5.07		11643		125.59		79,940	
EPA 1998										
PG	7.20	163%	6.90	36%	7200	-38%	143	17	129,000	61%
Similarity	5.1	86%	5.00	-1%	6000	-48%	143	17	77,000	-4%
MMMIF										
4KM_AER	8.791	221%	8.625	70%	6810	-42%	135.9	10.31	150,100	88%
4KM_CAL	8.79	221%	8.625	70%	6801	-42%	135.9	10.31	149,800	87%
4KM_PG	8.798	221%	8.656	71%	6844	-41%	135.9	10.31	150,900	89%
12KM_AER	10.63	288%	10.41	105%	6587	-43%	133.8	8.21	175,500	120%
12KM_CAL	10.79	294%	10.42	106%	6492	-44%	133.8	8.21	175,500	120%
12KM_PG	10.7	291%	10.49	107%	6545	-44%	133.8	8.21	175,500	120%
36KM_AER	11.61	324%	11.4	125%	6315	-46%	134.1	8.51	183,800	130%
36KM_CAL	11.62	324%	11.41	125%	6311	-46%	134.1	8.51	183,800	130%
36KM_PG	12.46	355%	12.24	141%	6072	-48%	133.7	8.11	189,700	137%
CALMET										
BASE_AER	3.495	28%	3.241	-36%	6640	-43%	145.8	20.21	58,180	-27%
BASE_CAL	3.505	28%	3.239	-36%	6612	-43%	145.8	20.21	58,100	-27%
BASE_PG	7.322	167%	6.734	33%	6941	-40%	144.8	19.21	127,400	59%
EXP1A_AER	4.849	77%	4.691	-7%	6383	-45%	144.5	18.91	77,580	-3%
EXP1A_CAL	4.849	77%	4.691	-7%	6385	-45%	144.5	18.91	77,600	-3%
EXP1A_PG	7.138	161%	7.337	45%	6307	-46%	143.4	17.81	112,800	41%
EXP1B_AER	5.318	94%	5.289	4%	6132	-47%	145.3	19.71	81,740	2%
EXP1B_CAL	5.303	94%	5.277	4%	6148	-47%	145.3	19.71	81,720	2%
EXP1B_PG	6.468	136%	7.022	39%	6190	-47%	144.7	19.11	100,300	25%
EXP1C_AER	7.892	188%	7.754	53%	5939	-49%	137.4	11.81	117,500	47%
EXP1C_CAL	7.981	191%	7.843	55%	5926	-49%	137.4	11.81	118,600	48%
EXP1C_PG	8.318	204%	8.167	61%	5697	-51%	137.1	11.51	118,800	49%

1. Because of the poor fit of the fitted Gaussian plume with the observed tracer concentrations in the SRL75 experiment, the Cmax and Sigma-y are not meaningful metrics of model performance.

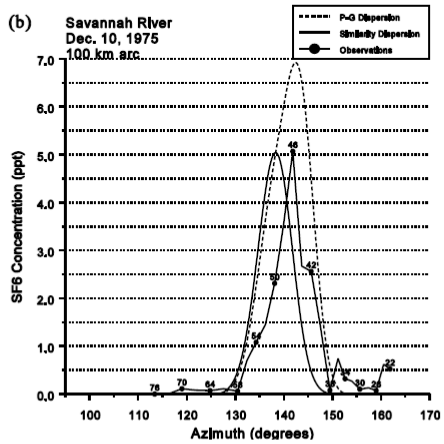


Figure 3. Simulated and observed 7-hour average plume for the Savannah River Laboratory tracer study for a) actual locations and b) observed plume offset 17° to the south.

Figure 4-2. Comparison of predicted fitted plume with observations for the SRL75 tracer experiments (Source: EPA, 1998a). Note that results from this study are not shown.

With the exception of the plume centerline statistic, the Irwin plume fitting evaluation approach was not a very useful evaluation tool for comparing the model predictions and observations using the SRL75 field experiment data. However, it is a useful tool for comparing the CALPUFF simulations using the different versions of CALPUFF/CALMET. The BASE CALPUFF/CALMET sensitivity test in this study was designed to be setup in the same fashion as the 1998 EPA tracer modeling study. Although there are some similarities, there are also some differences. For example, using the PG dispersion results in much higher CWIC in both the 1998 EPA (129,000 ppt/m^2) and BASE (127,400 ppt/m^2) sensitivity tests versus using the CAL turbulence/similarity dispersions options (77,000 ppt/m^2 for 1998 EPA and ~58,000 ppt/m^2 for BASE). The maximum estimated concentration at any of the 200 receptors along the 100 km arc using the PG dispersion are very similar for the 1998 EPA (6.9 ppt) and BASE sensitivity (6.7 ppt) scenario and lower concentrations are estimated using the CAL turbulence dispersion in the 1998 EPA (5.0 ppt) and the BASE (3.2 ppt) sensitivity test.

4.5 CONCLUSIONS OF THE SRL75 MODEL PERFORMANCE EVALUATION

Because the fit of the Gaussian plume to the observed tracer concentrations along the SRL75 100 km receptor arc did not match the observed values well, the fitted plume evaluation approach did not work well using the SRL75 database. Thus, there are few conclusions that can be drawn about the CALPUFF model performance using the SRL75 tracer field experiment data. The plume centerline evaluation is still valid and the use of CALPUFF without using meteorological observations with CALMET either through MMIF or with CALMET using no observations (NOOBS = 2) produces better plume centerline performance than when meteorological observations are used with CALMET. These results are consistent with EPA's thoughts in the 2009 IWAQM Reassessment Report (EPA, 2009a) and August 2009 Clarification Memorandum (EPA, 2009b); it is better to pass through the wind fields and other meteorological field from MM5/WRF to CALPUFF, rather than running them through CALMET, which can introduce artifacts and upset the dynamic balance of the meteorological fields.

5.0 1983 CROSS APPALACHIAN TRACER EXPERIMENT

5.1 DESCRIPTION OF THE 1983 CROSS APPALACHIAN TRACER EXPERIMENT

A series of tracer test field experiments were conducted between September 18 and October 29, 1983 over the northeastern U.S. and southeastern Canada (Ferber et al., 1986; Draxler et al., 1988). The Cross-Appalachian Tracer Experiment (CAPTEX) consisted of 5 tracer releases from Dayton, Ohio and 2 tracer releases from Sudbury, Ontario. Each release was independent of the others and was conducted when the forecast was for the tracer to pass through the center of the sampling network. Samplers were placed at a variety of locations in the northeast U.S. and southeast Canada to distances of about 1,000 km from Dayton. Although synoptic meteorological conditions were similar between releases at each location, there were large differences in the spatial concentration patterns, from narrow to wide. There was even a case of the tracer plume passing over the samplers without mixing to the surface.

The CALPUFF LRT modeling system was evaluated for various model configurations and meteorological inputs using two of the five CAPTEX tracer release experiments:

> <u>CTEX3</u>: The third CAPTEX tracer release occurred on October 2, 1983 where a tracer was released from Dayton, Ohio for two hours between the hours of 1400 and 1600 LST with a release rate of 18.611 g/s.
>
> <u>CTEX5</u>: The fifth CAPTEX tracer release occurred during the end of October with a two hour tracer release from Sudbury, Ontario between hour 23 on October 25, 1983 and hour 01 on October 26, 1983 with a release rate of 16.667 g/s.

Figure 5-1 displays the locations of the two tracer release sites and the tracer sampling network for the CAPTEX tracer field experiments. Also shown in Figure 5-1 are the CALPUFF, CALMET and MMIF modeling domains.

This section describes the evaluation of the CALPUFF LRT dispersion model using the CTEX3 and CTEX5 field experiments using numerous sensitivity tests with alternative meteorological inputs. Appendices A and B present the evaluation of the MM5 and CALMET sensitivity simulations using surface meteorological observations for the, respectively, CTEX5 and CTEX3 experiments. Appendix C presents the evaluation of six LRT dispersion models using the CTEX3 and CTEX5 field studies and common MM5 meteorological inputs.

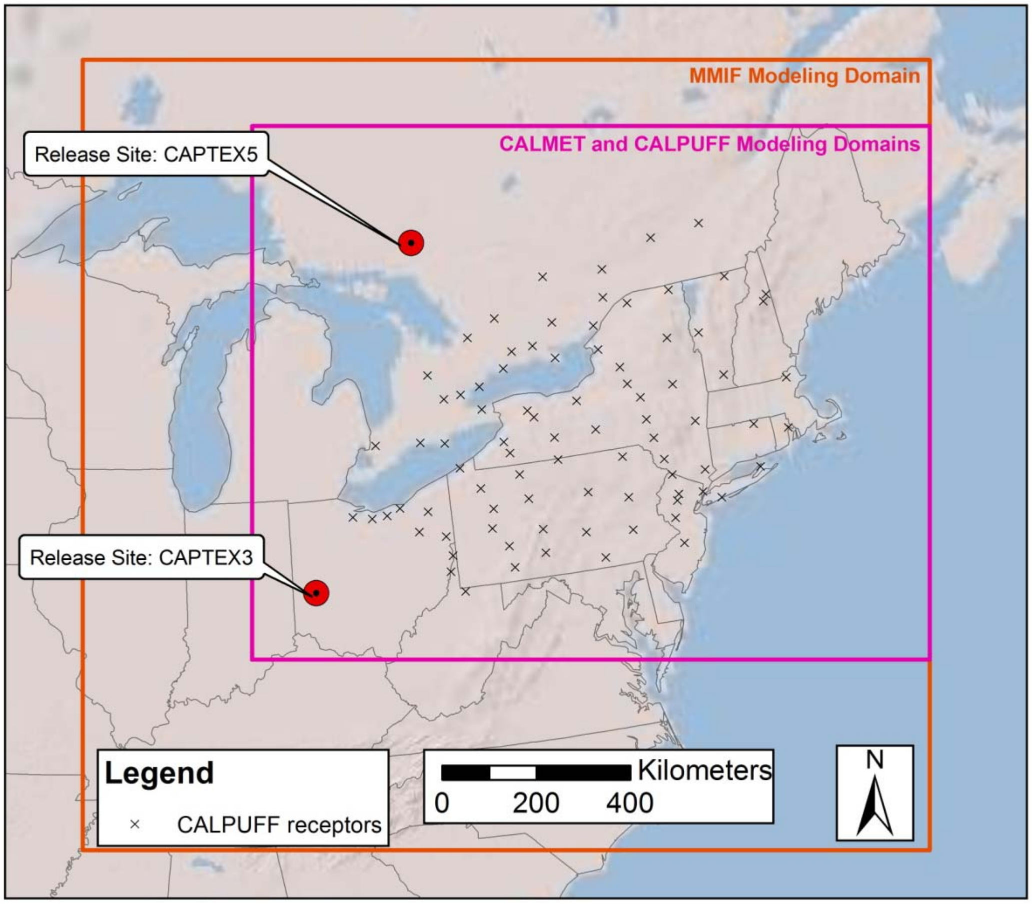


Figure 5-1. Location of Dayton and Sudbury tracer release sites and the tracer sampling network for the CAPTEX tracer field experiments.

5.2 MODEL CONFIGURATION AND APPLICATION

CALPUFF was applied using several different meteorological inputs. The first set was designed to use the same meteorological modeling technology as used in previous years to evaluate CALPUFF V4.0 only using the current regulatory versions of CALPUFF (V5.8) to document the effects of version changes. For the CTEX5 experiment period, the MM5 prognostic meteorological model was applied using grid resolutions of 80, 36 and 12 km to investigate the sensitivity of CALMET and CALPUFF model performance to MM5 grid resolution. For the CTEX3 experiment period, MM5 modeling was performed using grid resolution of 36 and 12 km, for the MM5 80 km sensitivity tests historical 80 km MM4 output data were utilized. CALMET was also run with different grid resolutions (18, 12 and 4 km) using the different MM5/MM4 grid resolution data as input. CALPUFF V5.8 was evaluated using the ATMES-II procedures using the various MM5/CALMET meteorological inputs, as well as inputs from the Mesoscale Model Interface (MMIF) tool that performs a "pass through" of the MM5 meteorological output to provide meteorological inputs to CALPUFF.

5.2.1 MM5 Prognostic Meteorological Modeling

The most recent version of the publicly available non-hydrostatic version of MM5 (version 3.7.4) was used. The MM5 preprocessors pregrid, regrid, little_r, and interpf were used to develop initial and boundary conditions. Nine separate MM5 sensitivity tests were performed for the CTEX5 field experiment period as listed in Table 5-1. As noted previously, for CTEX3 period no 80 km MM5 modeling was performed and historical 80 km MM4 data were used for the CTEX3 CALPUFF sensitivity tests.

The MM5 modeling for this study was based on three vertical structures designed to replicate common vertical structures of meteorological modeling from the 1980's to 2000's with vertical definitions of 16, 33, and 43 layers. The MM5 vertical domain definition for the 33 and 43 layer MM5 sensitivity simulations are presented in both sigma and height coordinates in Tables 5-2 and 5-3. Topographic information for the MM5 system was developed using the NCAR and the United States Geological Survey (USGS) terrain databases. Vegetation type and land use information was developed using the most recent NCAR/PSU databases provided with the MM5 distribution [available at ftp://ftp.ucar.edu/mesouser]. Standard MM5 surface characteristics corresponding to each land use category were used.

Four different grid configurations were defined for the MM5 sensitivity modeling. The first experiment (EXP1) was a baseline run using the horizontal and vertical configuration of MM4 simulations of the late 1980's and early 1990's (similar to the original MM4 dataset published by the EPA). The baseline simulation uses a single domain (no nests) with a horizontal grid resolution of 80 km and 16 vertical levels. The baseline configuration used older physics options more consistent with physics options available at the time of publication of the original EPA MM4 dataset. Physics options include the Blackadar (BLKDR) Planetary Boundary Layer (PBL) parameterization, Anthes-Kuo (AK) convective parameterization, Dudhia Radiation (DRAD), Dudhia Simple Ice Microphysics (SIM), and a 5-layer soil model (5LAYSOIL).

The second MM5 experiment (EXP2) was designed to reflect common grid and physics configurations used in numerical weather modeling for air quality simulations in the late 1990's and early 2000's. EXP2A through EXP2C used three nested domains (108, 36, and 12 km) with a 33 vertical layer vertical structure (Table 5-2). Physics options include the Medium Range Forecast model (MRF) PBL parameterization, Kain-Fritsch (KF) convective parameterization, rapid radiative transfer model (RRTM) radiation, SIM microphysics, and the 5LAYSOIL soil model. EXP2H is a variation of EXP2C, reflecting another common configuration of the period, but using the BLKDR PBL parameterization instead of the MRF PBL.

The third MM5 experiment (EXP3) was designed to reflect the more recent advances in numerical weather modeling for air quality simulations, both in terms of grid configuration and physics options. These options are largely consistent with annual MM5 simulations conducted by the EPA and the Regional Haze Regional Planning Organizations (RPOs). Consistent with EXP2, EXP3 uses three nested domains (108, 36, and 12 km). EXP3 uses the Pleim-Xu (PX) PBL parameterization, the Kain-Fritsch 2 (KF2) convective parameterization, DRAD radiation, and the Pleim-Xu (PX) land surface model (LSM).

A key facet in the MM5 sensitivity modeling was to measure the effectiveness of various four-dimensional data assimilation (FDDA) strategies on meteorological model performance and also determine the importance of assimilated fields in enhancing the performance of long range transport (LRT) model simulations. In EXP1 and EXP2 series, there are a minimum of three

MM5 runs, the first without FDDA (i.e., in forecasting mode), the second with three-dimensional analysis nudging above the PBL only, and the third using both three-dimensional analysis nudging above the PBL and surface analysis nudging below the PBL. Nudging within the PBL was turned off for temperature and mixing ratio. Default nudging strengths were used for both three-dimensional analysis and surface analysis nudging in these scenarios.

In scenarios EXP2I and EXP2J, alternative data assimilation strategies were tested while keeping the three-dimensional and surface analysis nudging. In EXP2I, the nudging strength was doubled. Observational nudging was turned on for EXP2J in addition to the nudging strengths used in EXP2I. The NCAR ds472.0 dataset was used to provide surface observations for the observational nudging.

Although new MM5 meteorological modeling was performed for the scenarios in Table 5-1 for the CTEX5 field experiment, for the CTEX3 field experiment the historical 80 km MM4 data was used for the 80 km MM5/MM4 scenarios and the FDDA sensitivity tests were not performed.

Table 5-1. Summary of CTEX5 MM5 sensitivity tests. design.

Sensitivity Test	Horizontal Grid	Vertical Layers	Physics Options	FDDA Used
EXP1A	80 km	16	BLKDR, AK, DRAD, SIM, 5LAYSOIL	No FDDA
EXP1B	80 km	16	BLKDR, AK, DRAD, SIM, 5LAYSOIL	Analysis Nudging
EXP1C	80 km	16	BLKDR, AK, DRAD, SIM, 5LAYSOIL	Analysis Nudging Surface Analysis Nudging
EXP2A	108/36/12km	33	MRF, KF, RRTM, SIM, 5LAYSOIL	No FDDA
EXP2B	108/36/12km	33	MRF, KF, RRTM, SIM, 5LAYSOIL	Analysis Nudging
EXP2C	108/36/12km	33	MRF, KF, RRTM, SIM, 5LAYSOIL	Analysis Nudging Surface Analysis Nudging
EXP2F	108/36/12km	43	BLKDR, KF, DRAD, SIM, 5LAYSOIL	No FDDA
EXP2G	108/36/12km	43	BLKDR, KF, DRAD, SIM, 5LAYSOIL	Analysis Nudging
EXP2H	108/36/12km	43	BLKDR, KF, DRAD, SIM, 5LAYSOIL	Analysis Nudging Surface Analysis Nudging
EXP2I	108/36/12km	43	BLKDR, KF, DRAD, SIM, 5LAYSOIL	Analysis Nudging Surface Analysis Nudging FDDA x 2 strength
EXP2J	108/36/12km	43	BLKDR, KF, DRAD, SIM, 5LAYSOIL	Analysis Nudging Surface Analysis Nudging FDDA x 2 strength Observational Nudging
EXP4	108/36/12km	43	PXPBL, KF2, DRAD, R2, PXLSM	Analysis Nudging Surface Analysis Nudging
4 km	4 km	43	BLKDR, KF, DRAD, SIM, 5LAYSOIL (EXP2H)	Analysis Nudging Surface Analysis Nudging

Table 5-2. MM5 sensitivity tests EXP2A through EXP2C vertical domain definition using 33 vertical layers.

k(MM5)	sigma	Press. (bar)	height(m)	depth(m)
33	0.0000	10000	14662	1841
32	0.0500	14500	12822	1466
31	0.1000	19000	11356	1228
30	0.1500	23500	10127	1062
29	0.2000	28000	9066	939
28	0.2500	32500	8127	843
27	0.3000	37000	7284	767
26	0.3500	41500	6517	704
25	0.4000	46000	5812	652
24	0.4500	50500	5160	607
23	0.5000	55000	4553	569
22	0.5500	59500	3984	536
21	0.6000	64000	3448	506
20	0.6500	68500	2942	480
19	0.7000	73000	2462	367
18	0.7400	76600	2095	266
17	0.7700	79300	1828	259
16	0.8000	82000	1569	169
15	0.8200	83800	1400	166
14	0.8400	85600	1235	163
13	0.8600	87400	1071	160
12	0.8800	89200	911	236
11	0.9100	91900	675	154
10	0.9200	92800	598	153
9	0.9300	93700	521	152
8	0.9400	94600	445	151
7	0.9500	95500	369	149
6	0.9600	96400	294	74
5	0.9700	97300	220	111
4	0.9800	98200	146	37
3	0.9850	98650	109	37
2	0.9900	99100	73	36
1	0.9950	99550	36	36
0	1.0000	100000	0	0

Table 5-3. MM5 sensitivity tests EXP2F through EXP2H vertical domain definition using 43 vertical layers.

k(MM5)	sigma	Press(mb)	height(m)	depth(m)
43	0.0000	10000	14662	409
42	0.0100	10900	14253	571
41	0.0250	12250	13682	696
40	0.0450	14050	12986	635
39	0.0650	15850	12351	724
38	0.0900	18100	11627	660
37	0.1150	20350	10966	724
36	0.1450	23050	10242	663
35	0.1750	25750	9579	710
34	0.2100	28900	8869	742
33	0.2500	32500	8127	681
32	0.2900	36100	7446	630
31	0.3300	39700	6815	587
30	0.3700	43300	6228	483
29	0.4050	46450	5745	458
28	0.4400	49600	5287	435
27	0.4750	52750	4852	415
26	0.5100	55900	4436	341
25	0.5400	58600	4095	329
24	0.5700	61300	3766	318
23	0.6000	64000	3448	307
22	0.6300	66700	3141	297
21	0.6600	69400	2844	288
20	0.6900	72100	2556	279
19	0.7200	74800	2277	271
18	0.7500	77500	2005	220
17	0.7750	79750	1785	215
16	0.8000	82000	1569	211
15	0.8250	84250	1359	206
14	0.8500	86500	1153	122
13	0.8650	87850	1031	120
12	0.8800	89200	911	119
11	0.8950	90550	792	271
10	0.9100	91900	675	154
9	0.9200	92800	598	153
8	0.9300	93700	521	152
7	0.9400	94600	445	151
6	0.9500	95500	369	149
5	0.9600	96400	294	74
4	0.9700	97300	220	74
3	0.9800	98200	146	73
2	0.9900	99100	73	44
1	0.9960	99640	29	29
0	1.0000	100000	0	0

5.2.2 CALMET Diagnostic Meteorological Modeling

The CALMET (Scire, 2000a) diagnostic meteorological model generates wind fields and other meteorological variables required by the CALPUFF LRT dispersion model in a two-step process.

In STEP 1, an initial first guess wind field is modified through parameterized diagnostic wind field effects due to terrain: blocking and deflection, channeling and slope flows. The first guess wind field can be provided using prognostic meteorological model output (e.g., MM5) or interpolated from observations. The resultant STEP 1 wind field is then modified in STEP 2 by incorporating (blending) surface and upper-air wind observations with the STEP 1 wind field in an Objective Analysis (OA) procedure. CALMET has numerous options on how to generate the STEP 1 wind field as well as how the STEP 2 OA procedure is performed. A series of CALMET sensitivity tests were performed to examine the efficacy of OA, optimal radii of influence for CALMET OA operations, and also to examine the role of horizontal grid resolution on performance of both the diagnostic meteorological model and the performance of the CALPUFF (Scire, 2000b) LRT dispersion model. CALMET was operated at three horizontal grid resolutions (18, 12 and 4 km) with input prognostic meteorological data at horizontal resolutions of 80 km (MM5 EXP1C), 36 km (MM5 EXP2H), and 12 km (MM5 EXP2H). Additionally, the Mesoscale Model Interface (MMIF) tool (Emery and Brashers, 2009) was also applied using MM5 output at 80 km (MM5 EXP1C), 36 km (MM5 EXP2H), and 12 km (MM5 EXP2H) for CTEX5. Since no 80 km MM5 data was available for CTEX3, MMIF was only used using the 36 and 12 km MM5 output for CTEX3. In addition, for CTEX5 MMIF was run using 4 km MM5 output that was generated in a “nest down” simulation from the 12 km MM5 simulation.

33 separate CALMET sensitivity tests were performed using MM5 output from the MM5 sensitivity simulations listed in Table 5-1 and the CALMET sensitivity test experimental configuration design given in Tables 5-4 and 5-5. The definitions of the 33 CALMET sensitivity tests are given in Table 5-6. CALPUFF sensitivity simulations were performed using a subset of the 33 CALMET sensitivity tests for the CTEX3 and CTEX5 tracer test field experiments. For both the CTEX3 and CTEX5 modeling periods, the CALMET EXP2 sensitivity test series was not run with CALPUFF, as well as the EXP1 series for CTEX5. The BASED CALPUFF simulation encountered an error in execution and failed to finish for the CTEX3 modeling period. The 80KM_MMIF was also not run for CTEX3 because MMIF was not designed to use MM4 data. For CTEX5, a 4 km MM5 nest down simulation was performed off of the MM5 EXP2H sensitivity test (see Figure 5-1) so that a 4KM_MMIF CALPUFF sensitivity test could also be performed.

Table 5-4. CALMET sensitivity test experiment configuration for grid resolution.

Experiment	CALMET Resolution (km)	MM5 Resolution (km)
BASE	18	80
EXP1	12	80
EXP2	4	80
EXP3	12	36
EXP4	12	12
EXP5	4	36
EXP6	4	12

Table 5-5. CALMET Objective Analysis (OA) sensitivity test configurations.

Experiment Series	RMAX1 (km)	RMAX2 (km)	NOOBS	Comment
A	500	1000	0	Use surface and upper-air met obs
B	100	200	0	Use surface and upper-air met obs
C	10	100	0	Use surface and upper-air met obs
D	0	0	2	Don’t use surface and upper-air met obs

Table 5-6. Definition of the CALMET sensitivity tests and data sources.

Sensitivity Test	MM5 Experiment and Resolution	CALMET Resolution	RMAX1/RMAX2	NOOBS	CTEX3	CTEX5
BASEA	EXP1C – 80 km	18 km	500/1000	0	Yes	Yes
BASEB	EXP1C – 80 km	18 km	100/200	0	Yes	Yes
BASEC	EXP1C – 80 km	18 km	10/100	0	Yes	Yes
BASED	EXP1C – 80 km	18 km	0/0	2	No	Yes
1A	EXP1C – 80 km	12 km	500/1000	0	Yes	No
1B	EXP1C – 80 km	12 km	100/200	0	Yes	No
1C	EXP1C – 80 km	12 km	10/100	0	Yes	No
1D	EXP1C – 80 km	12 km	0/0	2	Yes	No
2A	EXP1C – 80 km	4 km	500/1000	0	No	No
2B	EXP1C – 80 km	4 km	100/200	0	No	No
2C	EXP1C – 80 km	4 km	10/100	0	No	No
2D	EXP1C – 80 km	4 km	0/0	2	No	No
3A	EXP2H – 36 km	12 km	500/1000	0	Yes	Yes
3B	EXP2H – 36 km	12 km	100/200	0	Yes	Yes
3C	EXP2H – 36 km	12 km	10/100	0	Yes	Yes
3D	EXP2H – 36 km	12 km	0/0	2	Yes	Yes
4A	EXP2H – 12 km	12 km	500/1000	0	Yes	Yes
4B	EXP2H – 12 km	12 km	100/200	0	Yes	Yes
4C	EXP2H – 12 km	12 km	10/100	0	Yes	Yes
4D	EXP2H – 12 km	12 km	0/0	2	Yes	Yes
5A	EXP2H – 36 km	4 km	500/1000	0	Yes	Yes
5B	EXP2H – 36 km	4 km	100/200	0	Yes	Yes
5C	EXP2H – 36 km	4 km	10/100	0	Yes	Yes
5D	EXP2H – 36 km	4 km	0/0	2	Yes	Yes
6A	EXP2H – 12 km	4 km	500/1000	0	Yes	Yes
6B	EXP2H – 12 km	4 km	100/200	0	Yes	Yes
6C	EXP2H – 12 km	4 km	10/100	0	Yes	Yes
6D	EXP2H – 12 km	4 km	0/0	2	Yes	Yes
80KM_MMIF	EXP1C – 80 km	MMIF	NA	NA	No	Yes
36KM_MMIF	EXP2H – 36 km	MMIF	NA	NA	Yes	Yes
12KM_MMIF	EXP2H – 12 km	MMIF	NA	NA	Yes	Yes
4KM_MMIF	4 km EXP2H nest down	MMIF	NA	NA	No	Yes

5.3 QUALITY ASSURANCE

Quality assurance (QA) of the CALMET and CALPUFF sensitivity modeling was performed by analyzing the run control files to confirm that the intended options and inputs of each sensitivity test were used. For the MM5 datasets, performance for meteorological parameters of wind (speed and direction), temperature, and humidity (mixing ratio) are examined. For the CALMET experiments, just model estimated winds (speed and direction) were compared to observations because the two-dimensional temperature and relative humidity fields output are simple interpolated fields of the observations. Therefore, the performance evaluation for CALMET was restricted to winds where the majority of change can be induced by both diagnostic terrain adjustments and varying the OA strategy. Note that except for the NOOBS = 2 CALMET sensitivity tests (experiment K), surface meteorological observations are blended in the wind fields used in the CALMET STEP 2 OA procedure. Thus, this is not a true independent evaluation as the surface meteorological observations used in the evaluation were also used as input into CALMET.

The METSTAT software (Emery et al., 2001) was used to match MM5 output with observation data. The MMIFStat software (McNally, 2010) tool was used to match CALMET output with observation data. Emery and co-workers (2001) have developed a set of "benchmarks" for comparing prognostic meteorological model performance statistics metrics. These benchmarks were developed after examining the performance of the MM5 and RAMS prognostic meteorological models for over 30 applications. The purpose of the benchmarks is not to assign a passing or failing grade, rather it is to put the prognostic meteorological model performance in context. The surface meteorological model performance benchmarks from Emery et al., (2001) are displayed in Table 5-7. Note that the wind speed RMSE benchmark was also used for wind speed MNGE given the similarity of the RMSE and MNGE performance statistics. These benchmarks are not applicable for diagnostic model evaluations.

Table 5-7. Wind speed and wind direction benchmarks used to help judge the performance of *prognostic* meteorological models (Source: Emery et al., 2001).

Wind Speed	Root Mean Squared Error (RMSE) Mean Normalized Bias (NMB) Index of Agreement (IOA)	≤ 2.0 m/s ≤ ±0.5 m/s ≥ 0.6
Wind Direction	Mean Normalized Gross Error (MNGE) Mean Normalized Bias (MNB)	≤ 30° ≤ ±10°
Temperature	Mean Normalized Gross Error (MNGE) Mean Normalized Bias (NMB) Index of Agreement (IOA)	≤ 2.0 K ≤ ±0.5 m/s ≥ 0.8
Humidity	Mean Normalized Gross Error (MNGE) Mean Normalized Bias (NMB) Index of Agreement (IOA)	≤ 2.0 g/kg ≤ ±1.0 g/kg ≥ 0.6

The MM5 and CALMET comparisons to observations for CTEX3 and CTEX5 are provided in the Appendix. The key findings of the CTEX5 MM5 and CALMET model performance evaluation are as follows:

- The MM5 performance using the MRF PBL scheme (EXP2A-C) was extremely poor. For example the temperature exhibited an underestimation bias of over -4 °K, compared to the benchmark of ≤±0.5 °K. Thus, MM5 sensitivity simulations using MRF PBL scheme were discontinued.
- The MM5 wind speed, and especially wind direction, model performance is noticeably better when FDDA was utilized.
- The "A" series of CALMET runs (RMAX1/RMAX2 = 500/1000) always has a wind speed underestimation bias.
- The "C" and "D" series of CALMET sensitivity tests exhibit wind performance that is comparable to the MM5 simulation used as input to CALMET.
- The 36 km and 12 km MM5 simulations exhibit substantially better model performance than the 80 km MM5 simulation.

The CTEX3 and CTEX5 CALMET comparison for wind speed and direction needs to be viewed with the caveat that because the winds are used as input in some of the sensitivity tests, then this is not a true independent evaluation. Thus, it is at all not surprising that the CALMET wind performance at the monitor locations is improved in the CALMET sensitivity tests that used meteorological observations as input compared to those that used no observations. As clearly pointed out in the 2009 Revised IWAQM Guidance (EPA, 2009a), the better wind model performance at the monitors produced when CALMET blends observed surface wind data in the wind fields can produce unrealistic discontinuities and other artifacts in the wind fields.

5.4 CALPUFF MODEL PERFORMANCE EVALUATION FOR CAPTEX

CALPUFF was applied for the CTEX3 and CTEX5 tracer release field experiments using the meteorological inputs corresponding to each of the meteorological sensitivity tests given in Table 5-6. Figure 5-1, presented earlier, displays the locations of the CTEX3 (Dayton, Ohio) and CTEX5 (Sudbury, Ontario) tracer release sites and the tracer monitoring network in northeastern U.S. and southeastern Canada.

A common CALPUFF model configuration was used in all sensitivity tests. This was done to isolate the sensitivity of the model to the different meteorological inputs and not confound the interpretation by changing the CALPUFF model configuration. The CALPUFF model configuration used the options listed in Table 5-8. Mostly default options were utilized for CALPUFF. One parameter that was not the default value was for vertical puff splitting. The default for vertical puff splitting is to turn it on using the vertical puff splitting flag (IRESPLIT) for just hour 17. After the vertical puff splitting flag is turned on a puff performs vertical puff splitting if certain criteria are met based on criteria using the ZISPLIT and ROLDMAX parameters for which default values were specified (see discussion on CALPUFF puff splitting sensitivity tests for the ETEX experiment in Chapter 6 for more details). Once a puff splits in the vertical, the vertical puff splitting is turned off and the puff is not allowed to split until after the puff splitting flag is turned on again at hour 17. In the CTEX3 and CTEX5 CALPUFF sensitivity simulations, the IRESPLIT input was set to turn on the vertical puff splitting flag 24 hours a day so that vertical puff splitting flag for all puffs is always on so vertical puff splitting will always occur whenever the other criteria are met.

Table 5-8. CALPUFF model configuration used in the CTEX3 and CTEX5 sensitivity tests.

Option	Value	Comment
MGAUSS	1	Use Gaussian vertical distribution initially
MCTADJ	0	No terrain adjustment
MSLUG	0	Near-field puffs not modeled as slugs
MTRANS	1	Use transitional plume rise
MTIP	1	Use stack tip downwash
MBDW	1	Use ISC method to simulate building downwash
MSHEAR	1	Model vertical wind shear above stack top
MSPLIT	1	Use puff splitting
MCHEM	0	No chemistry
MWET	0	No wet deposition
MDRY	0	No dry deposition
MDISP	2	Dispersion from internally calculate sigma-y and sigma-z using turbulence
MTURBW	3	Both sigma-y and sigma-z from PROFILE.DAT
MDISP3	3	PG dispersion coefficients for rural areas
MCTURB	2	Use AERMOD subroutine for turbulence variables
MROUGH	0	Don't adjust sigma-y and sigma-z for roughness
MPARTL	1	Use partial plume penetration
MTINV	0	Compute strength of temperature inversion
MPDF	1	Use PDF for dispersion under convective conditions
NSPLIT	3	Split puff into 3 puffs when performing vertical puff splitting
IRESPLIT	24*1	Keep vertical puff splitting flag on all the time (default is just hour 17 = 1, rest 0)
ZISPLIT	100	Vertical splitting is allowed if mixing height exceeds 100 m.
ROLDMAX	0.25	Vertical splitting is allowed if ratio of maximum to current mixing height is > 0.25
NSPLITH	5	Number of puffs that result when horizontal splitting is performed
SYSPLITH	1.0	Minimum width of puff (in grid cells) before horizontal splitting
SHSPLITH	2.0	Minimum puff elongation factor for horizontal splitting
CNSPLITH	1.E-7	Minimum concentrations (g/m^3) in puff for horizontal splitting

5.4.1 CALPUFF CTEX3 Model Performance Evaluation

Because of the large number of CALPUFF sensitivity tests performed for the CTEX3 tracer test field experiment, they are first compared by groups that used a common MM5/MM4 prognostic meteorological grid resolution output as input into CALMET or MMIF. We then compare the CALPUFF sensitivity tests using different MM4/MM5 grid resolutions but common CALMET/MMIF configurations to determine the sensitivity of MM4/MM5 grid resolution on CALPUFF tracer model performance.

5.4.1.1 CALPUFF CTEX3 Model Evaluation using 80 km MM4 Data

Figure 5-2 displays the spatial model performance statistics metrics for the CALPUFF CTEX3 sensitivity tests that used the 80 km MM4 data. There are variations in the rankings across the spatial statistical performance metrics for the CALPUFF sensitivity tests using the 80 km MM4 data. These sensitivity tests use the finest CALMET grid resolution tested in this series (12 km vs. 18 km) and minimizes the influence of the meteorological observations either through the lowest RMAX1/RMAX2 values (EXP1C) or not using meteorological observations at all by running CALMET in the NOOBS = 2 mode (EXP1D).

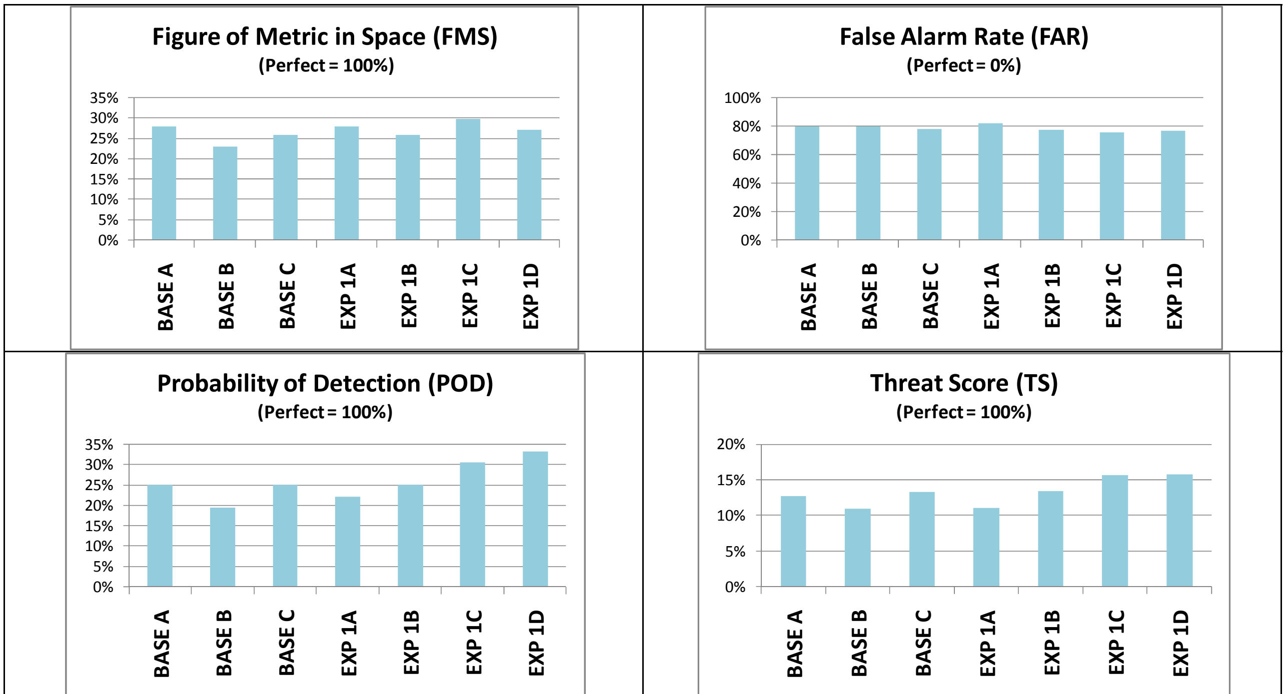


Figure 5-2. Spatial model performance statistics for the CTEX3 CALPUF sensitivity tests that used the 80 km MM4 data.

The global model performance statistics for the CALPUFF sensitivity tests using 80 km MM4 data are compared in Figure 5-3.

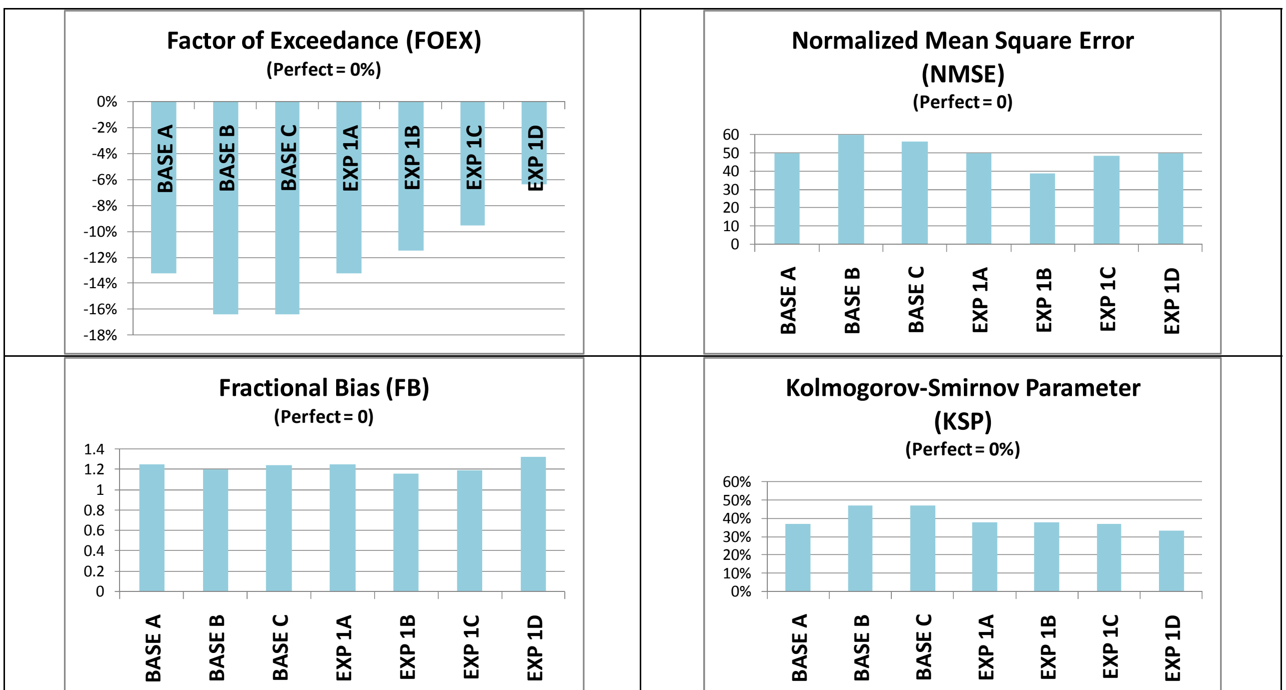
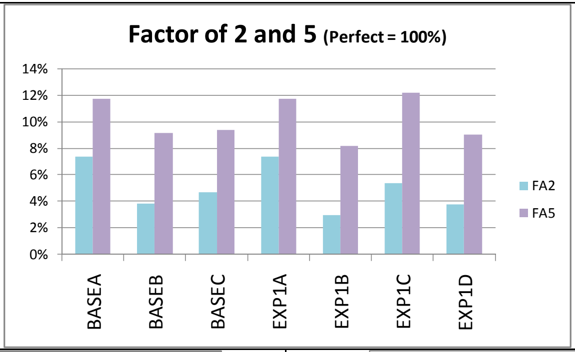
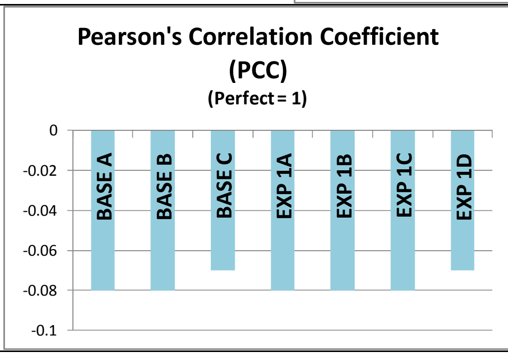


Figure 5-3a. Global model performance statistics for the CTEX3 CALPUFF sensitivity tests using the 80 km MM4 data.





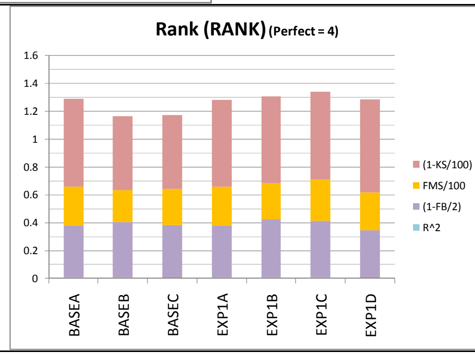


Figure 5-3b. Global model performance statistics for the CTEX3 CALPUFF sensitivity tests using the 80 km MM4 data.

5.4.1.2 CALPUFF CTEX3 Model Evaluation using 36 km MM5 Data

For the CTEX3 CALPUFF sensitivity tests using the 36 km MM5 data, there are 9 CALPUFF sensitivity tests 7 that use CALMET meteorological inputs with 12 and 4 km grid resolution and different OA options and one that uses MMIF meteorological inputs that as a MM5 “pass through” tool uses 36 km grid resolution.

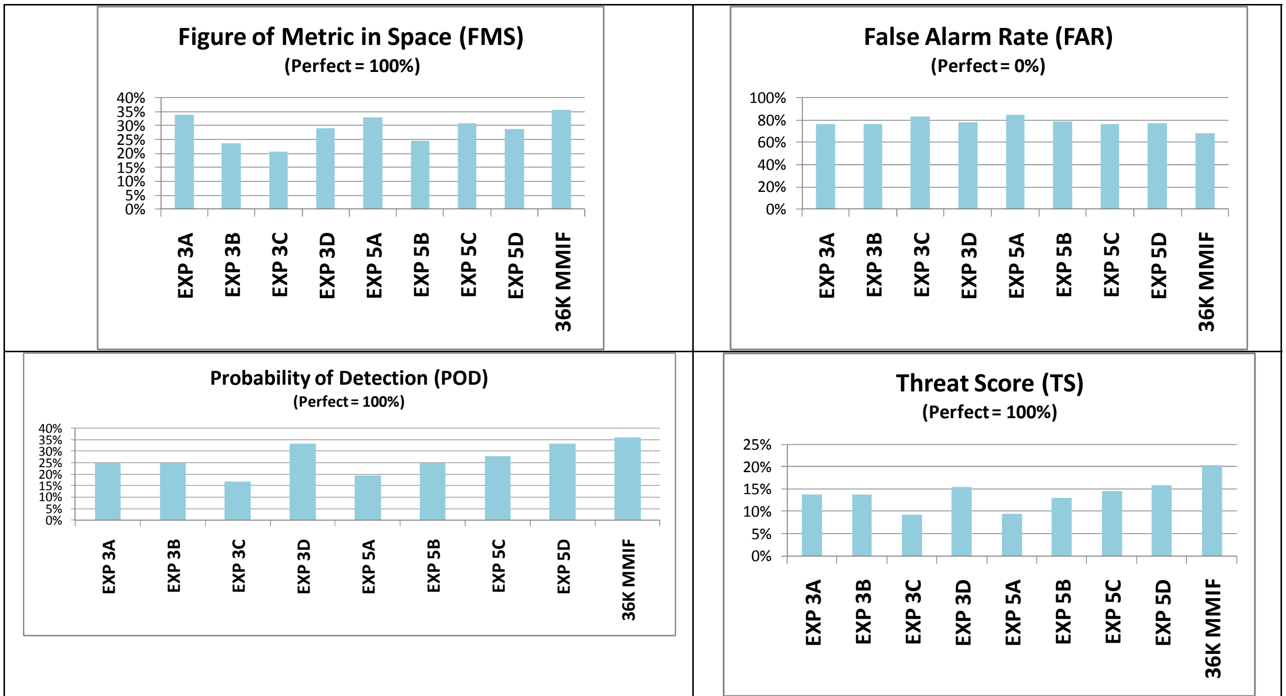


Figure 5-4. Spatial model performance statistics for the CTEX3 CALPUF sensitivity tests that used the 36 km MM5 data.

The global model performance statistics for the CALPUFF sensitivity tests using 36 km MM5 data are shown in Figure 5-5.

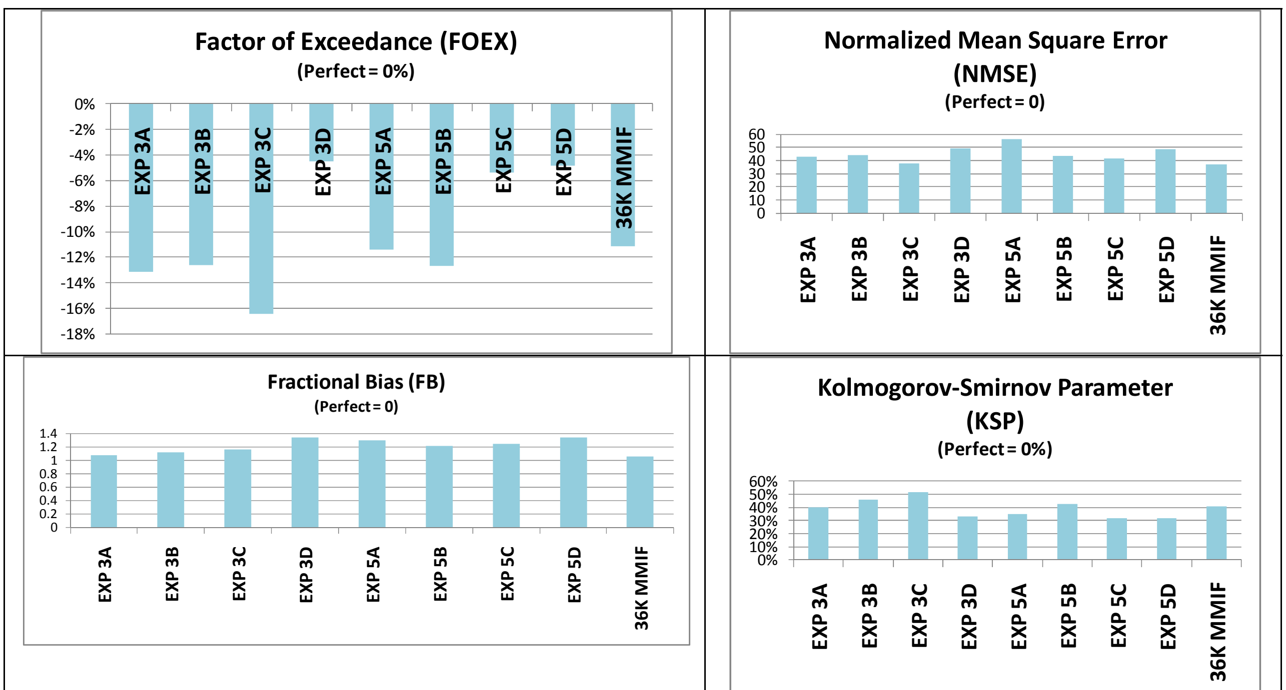
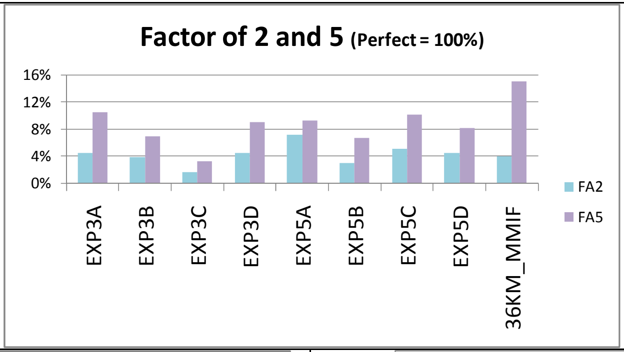
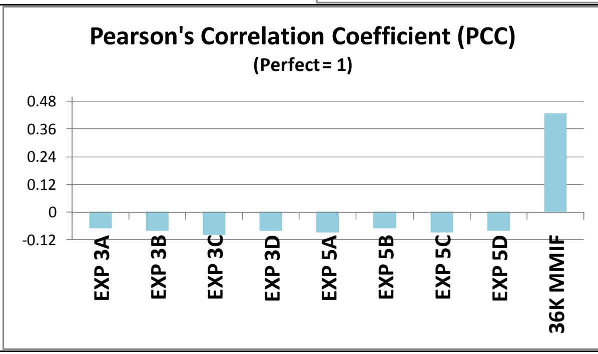


Figure 5-5a. Global model performance statistics for the CTEX3 CALPUFF sensitivity tests using the 36 km MM5 data.





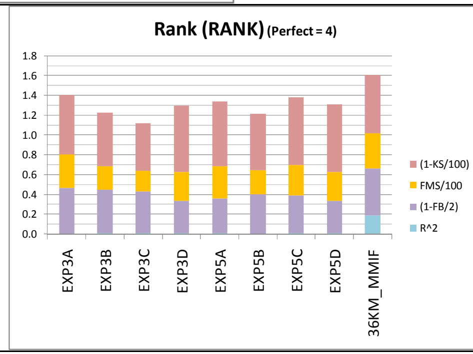


Figure 5-5b. Global model performance statistics for the CTEX3 CALPUFF sensitivity tests using the 36 km MM5 data.

5.4.1.3 CALPUFF CTEX3 Model Evaluation using 12 km MM5 Data

The spatial model performance statistical metrics for the CTEX3 CALPUFF sensitivity tests using 12 km MM5 data are shown in Figure 5-6.

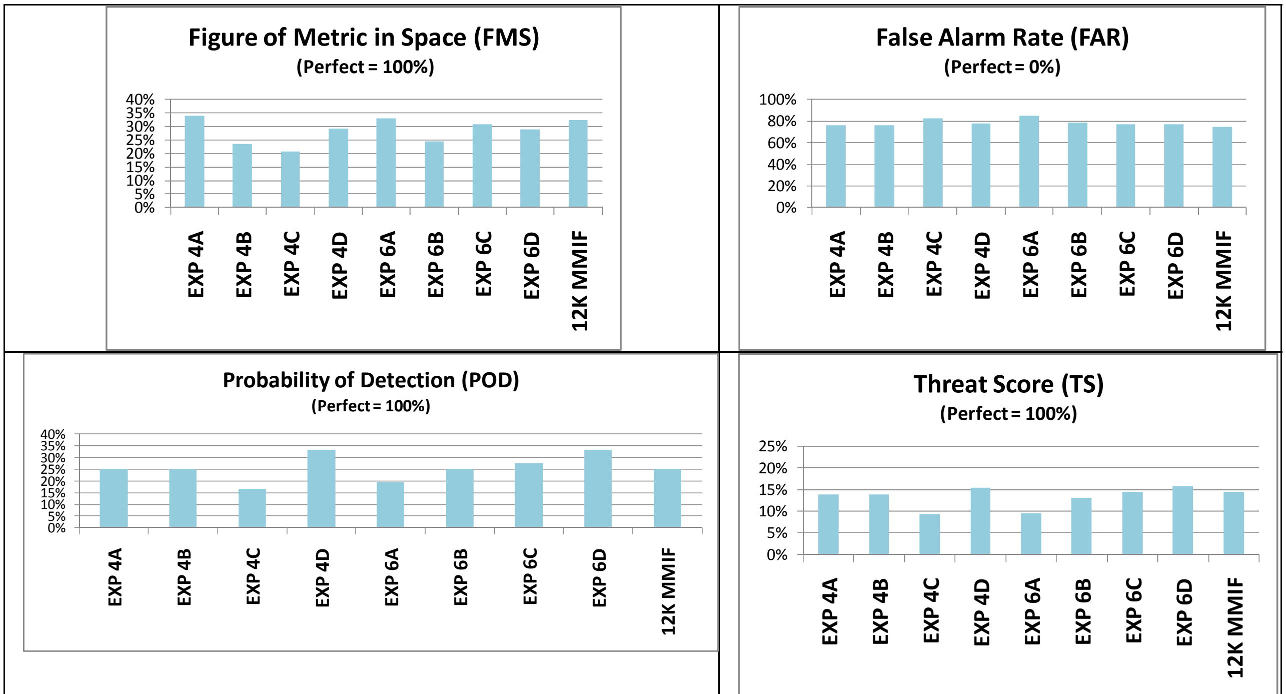


Figure 5-6. Spatial model performance statistics for the CTEX3 CALPUF sensitivity tests that used the 12 km MM5 data.

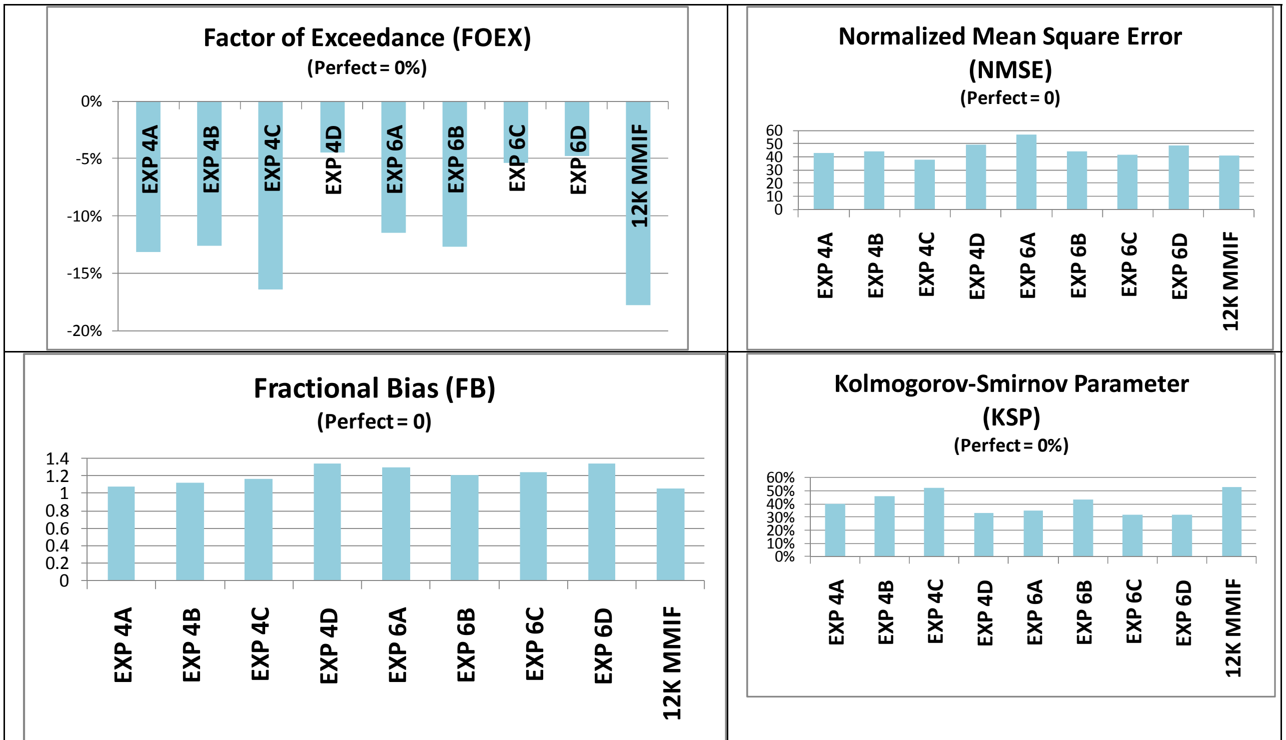


Figure 5-7a. Global model performance statistics for the CTEX3 CALPUFF sensitivity tests using the 12 km MM5 data.

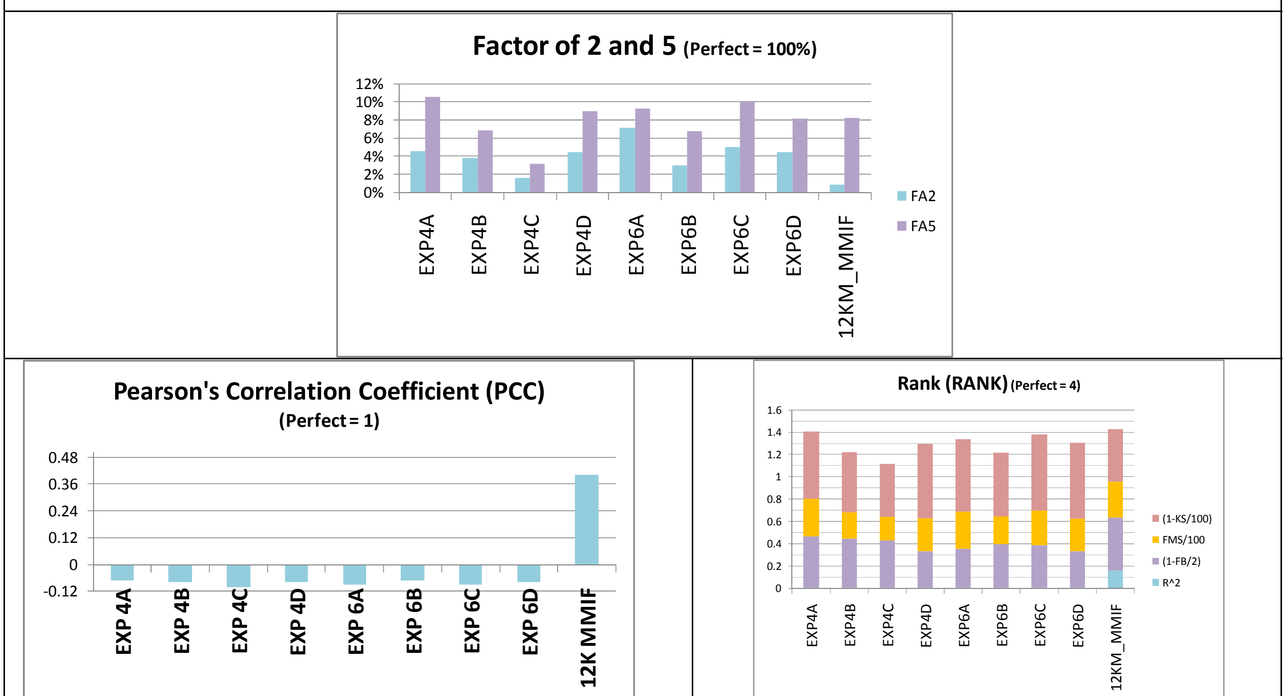


Figure 5-7b. Global model performance statistics for the CTEX3 CALPUFF sensitivity tests using the 12 km MM5 data (high scores indicate better model performance).

5.4.1.4 Comparison of CALPUFF CTEX3 Model Evaluation using Different MM4/MM5 Grid Resolutions

In the final series of CTEX3 CALPUFF sensitivity tests we grouped the “B” and “D” series of CALPUFF/CALMET sensitivity tests that use the EPA-FLM recommended RMAX1/RMAX2 settings (100/200) and no met observations, respectively, using the various MM5 data and grid resolutions in CALMET with the 12KM_MMIF and 36KM_MMIF CALPUFF sensitivity tests. The spatial model performance statistics are shown in Figure 5-8. The 36KM_MMIF and 12KM_MMIF have the best and second best FMS statistics (36% and 32%) followed by EXP3D and EXP6D (29%). The worst performing FMS statistics are given by the “B” series of CALPUFF/CALMET sensitivity tests with values ranging from 23% to 25%. The 36KM_MMIF has by far the lowest (best) FAR value (68%) followed by 12KM _MMIF (74%) with the “B” series of CALPUFF/CALMET sensitivity tests having the worst (highest) FAR values that approach 80%. A clear pattern is seen in the POD statistic for the CALPUFF/CALMET sensitivity tests with the “D” series using no met observations clearly performing better (33%) than the “B” series (19% to 25%). However, the best performing CALPUFF sensitivity test using the POD statistics is 36KM_MMIF (36%). Oddly, the 12KM_MMIF is one of the worst performing configurations with POD value the same as many of the “B” series (25%). 36KM_MMIF (20%) is also the best performing CALPUFF sensitivity test according to the TS statistic with the no met observations (“D” series) CALPUFF/CALMET sensitivity tests (15% to 16%) and 12KM_MMIF (15%) having better TS values than when met observations are used with CALMET (10% to 14%).

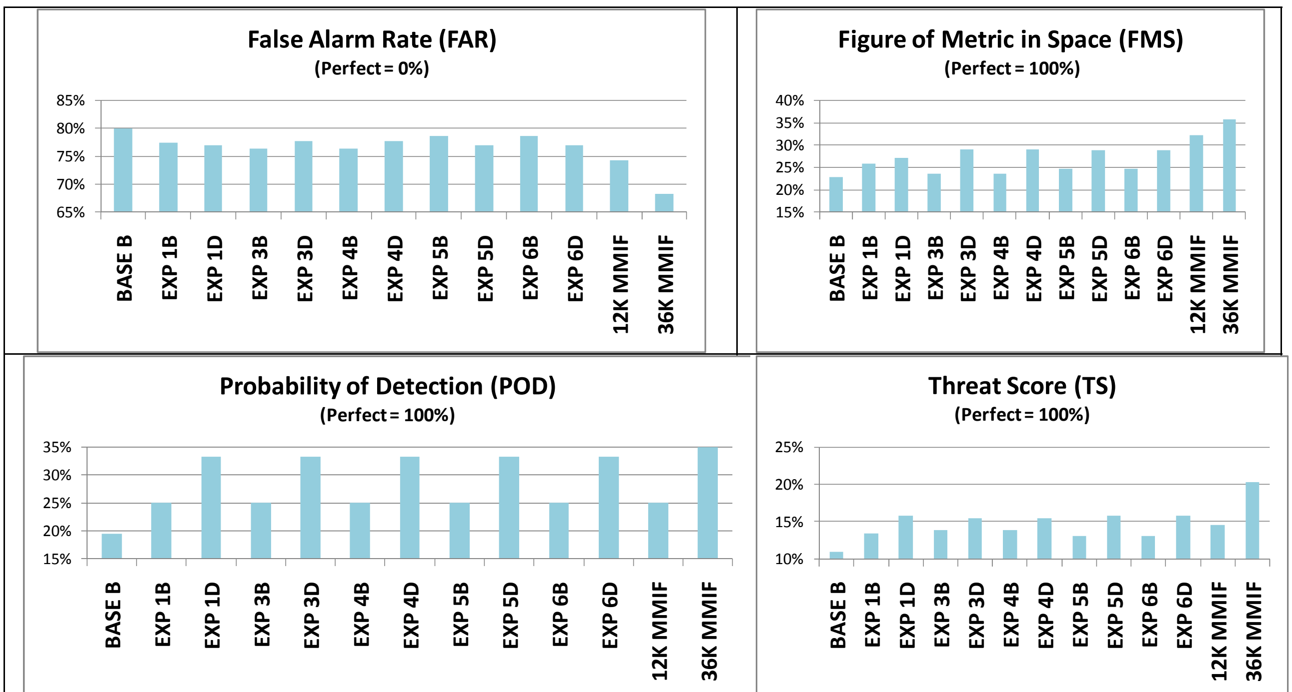


Figure 5-8. Spatial model performance statistics for the CTEX3 CALPUF sensitivity tests using different MM4/MM5 grid resolutions.

For the FOEX and KSP global statistical metrics, the “D” series of CALPUFF/CALPUFF sensitivity tests is clearly performing better than the “B” series with 12KM_MMIF one of the worst performing model configurations for these two statistics (Figure 5-9a). However, the “B” series of CALPUFF/CALMET sensitivity tests is exhibiting lower bias (FB) and error (NMSE) than the “D” series of CALPUFF/CALMET sensitivity tests with the 36KM_MMIF exhibiting the lowest bias and error statistics; 12KM_MMIF has the second lowest FB and third lowest NMSE. For the within a factor of 2 and 5 statistics the “D” series performs better than the “B” series of CALPUFF/CALMET sensitivity tests. The 12KM_MMIF has by far the lowest FA2 metric but has a FA5 metric that is comparable to the “D” series of CALPUFF/CALMET sensitivity tests. By far the best performing model configuration for the FA5 metric is 36KM_MMIF whose value (15%) is almost double the next best performing CALPUFF model configurations (7% to 9%). The 36KM_MMIF (0.43) followed closely by the 12KM_MMIF (0.40) are by far the best performing sensitivity tests according to the correlation coefficient statistical metric with the CALPUFF/CALMET tracer estimates showing a small negative correlation with the observations (-0.07 to -0.08). According to the composite RANK statistic, 36KM_MMIF (1.61) is the best performing CALPUFF sensitivity test of this group followed by 12KM_MMIF (1.43). The CALPUFF/CALMET RANK statistics range from 1.16 to 1.32 with the “D” series typically performing better (~1.3) than the “B” series (~1.2) with the exception of EXP1B (1.3).

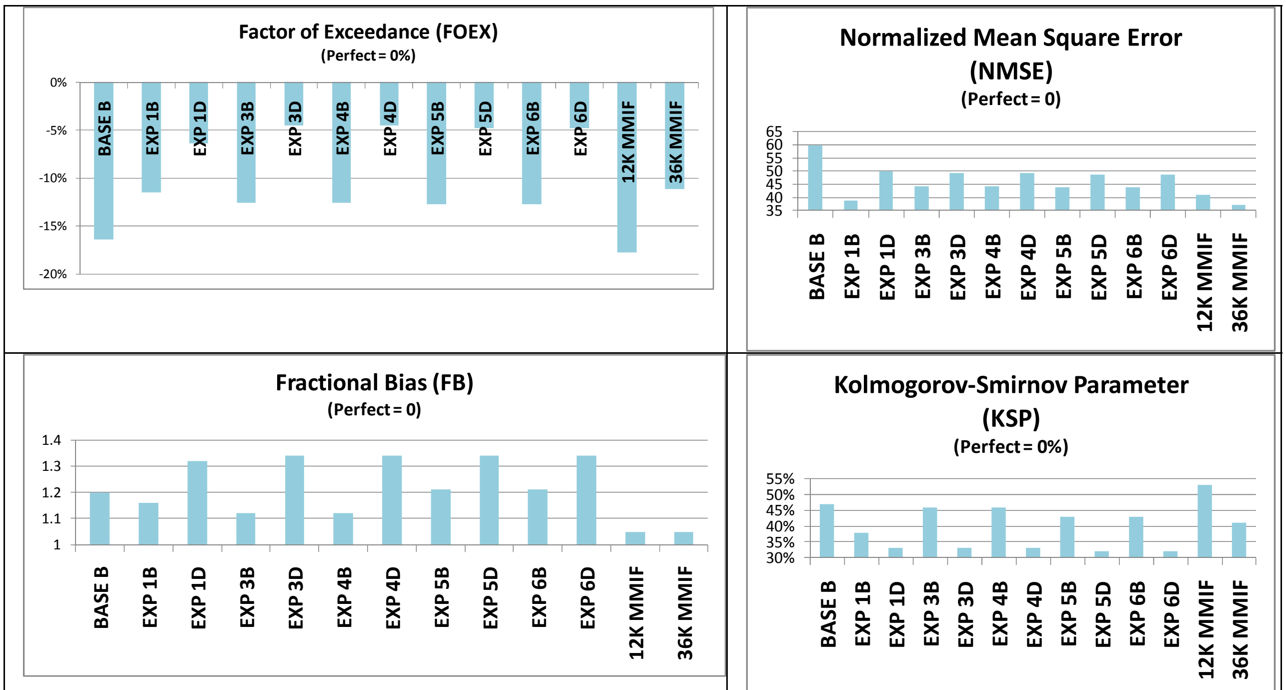


Figure 5-9a. Global model performance statistics for the CTEX3 CALPUFF sensitivity tests using different MM4/MM5 grid resolutions.

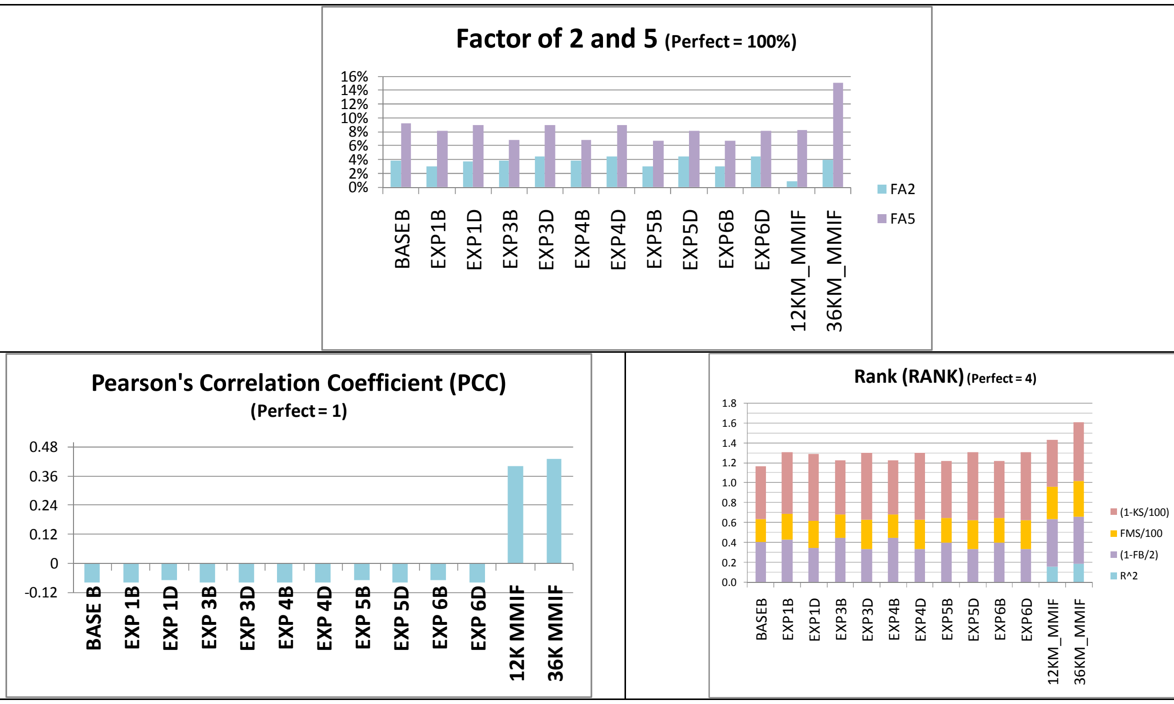


Figure 5-9b. Global model performance statistics for the CTEX3 CALPUFF sensitivity tests using different MM4/MM5 grid resolutions (high scores indicate better model performance).

5.4.1.5 Rankings of CTEX3 CALPUFF Sensitivity Tests using the RANK Statistic

The ranking of all of the CTEX3 CALPUFF sensitivity tests using the composite RANK model performance statistics is given in Table 5-9. The 36KM_MMIF (1.61) is the highest ranked CALPUFF sensitivity test using RANK followed by 12KM_MMIF (1.43) which is very close to EXP3A and EXP4A that are tied for third with a RANK value of 1.40. It is interesting to note that the EXP3A and EXP4A CALPUFF/CALMET sensitivity test that uses the, respectively, 36 km and 12 km MM5 data with 12 km CALMET grid resolution and RMAX1/RMAX2 values of 500/1000 is tied for third best performing CALPUFF/CALMET configuration using the RANK statistic, but the same model configuration with alternative RMAX1/RMAX2 values of 10/100 (EXP3C and EXP4C) degrades the model performance to the worst performing CALPUFF configuration according to the RANK statistics with a RANK value of 1.12.

Based on the RANK statistic and the CALPUFF sensitivity test rankings in Table 5-9 we conclude the following for the CTEX3 CALPUFF sensitivity tests:

- The CALPUFF MMIF sensitivity tests are the best performing configuration for the CTEX3 experiments.
- The CALPUFF/CALMET "B" series (RMAX1/RMAX2 = 100/200) appears to be the worst performing configuration for RMAX1/RMAX2.
- The CALMET/CALPUFF "A" series seems to be the best performing RMAX1/RMAX2 setting (500/1000) followed by the "C" series (10/100) then "D" series (no met observations).
- Ignoring the "B" series of sensitivity tests, the CALPUFF/CALMET sensitivity tests that use higher MM5 grid resolution (36 and 12 km) tend to produce better model performance than those that used the 80 km MM4 data.

- When using the "A" series model configuration, the use of higher CALMET resolution does not produce better CALPUFF model performance, however for the "C" and "D" series of CALMET runs use of higher CALMET grid resolution does produce better CALPUFF model performance.
- Note that the finding that CALPUFF/CALMET model performance using CALMET wind fields based on setting RMAX1/RMAX2 = 100/200 (i.e., the "B" series) produces worse CALPUFF model performance for simulating the observed atmospheric tracer concentrations is in contrast to the CALMET evaluation that found the "B" series produced winds closest to observations (see Appendices A and B). Since the CALPUFF tracer evaluation is an independent evaluation of the CALMET/CALPUFF modeling system, whereas the CALMET surface wind evaluation is not, the CALPUFF tracer evaluation may be a better indication of the best performing CALMET configuration. The CALMET "B" series approach for blending the wind observations in the wind fields may just be the best approach for getting the CALMET winds to match the observations at the monitoring sites, but at the expense of degrading the wind fields.

Table 5-9. Final Rankings of CALPUFF CTEX3 Sensitivity Tests.

Ranking	Sensitivity Test	RANK Statistics	MM5 (km)	CALGRID (km)	RMAX1/RMAX2	Met Obs
1	36KM_MMIF	1.610	36	--	--	--
2	12KM_MMIF	1.430	12	--	--	--
3	EXP3A	1.400	36	12	500/1000	Yes
4	EXP4A	1.400	12	12	500/1000	Yes
5	EXP5C	1.380	36	4	10/100	Yes
6	EXP6C	1.380	12	4	10/100	Yes
7	EXP1C	1.340	36	18	10/100	Yes
8	EXP5A	1.340	36	4	500/1000	Yes
9	EXP6A	1.340	12	4	500/1000	Yes
10	EXP5D	1.310	36	4	--	No
11	EXP6D	1.310	12	4	--	No
12	EXP1B	1.300	36	18	100/200	Yes
13	EXP3D	1.300	36	12	--	No
14	EXP4D	1.300	12	12	--	No
15	BASEA	1.290	80	18	500/1000	Yes
16	EXP1D	1.290	36	18	--	No
17	EXP1A	1.280	36	18	500/1000	Yes
18	EXP3B	1.220	36	12	100/200	Yes
19	EXP5B	1.220	36	4	100/200	Yes
20	EXP4B	1.220	12	12	100/200	Yes
21	EXP6B	1.220	12	4	100/200	Yes
22	BASEC	1.170	80	18	10/100	Yes
23	BASEB	1.160	80	18	100/200	Yes
24	EXP3C	1.120	36	12	10/100	Yes
25	EXP4C	1.120	12	12	10/200	Yes

5.4.2 CALPUFF CTEX5 Model Performance Evaluation

The model performance of the CALPUFF sensitivity tests for the CTEX5 (October 25, 1983) field experiment are presented below grouped by MM5 grid resolution. The MM5 output were used as input to the CALMET or MMIF meteorological drivers for CALPUFF, as was done for the

CTEX3 discussed in Section 5.4.1. As noted in Table 5-6, CTEX5 CALPUFF sensitivity tests were not performed for the EXP1 and EXP2 series of experiments.

5.4.1.1 CALPUFF CTEX5 Model Evaluation using 80 km MM5 Data

The spatial model performance statistics for the CTEX5 CALPUFF sensitivity tests using the 80 km MM5 data are shown in Figure 5-10. The BASEA and BASEB sensitivity tests are performing the best followed by BASEC, then BASED with 80KM_MMIF coming in last.

Figure 5-10. Spatial model performance statistics for the CTEX5 CALPUF sensitivity tests that used the 80 km MM5 data.

Although 80KM_MMIF has the lowest FOEX statistic, for all the other global statistic it is the worst or almost worst performing CALPUFF sensitivity test using 80 km MM5 data. BASEA has the best bias, error, FA2 and FA5 statistics of this group with either BASEB or BASEC coming in second and then BASED next to last and 80KM_MMIF last. The RANK composite statistics ranks BASEA (2.06) and BASEC (2.05) the highest followed by BASEB (1.82) and BASED (1.79) next and 80KM_MMIF (1.42) in last.

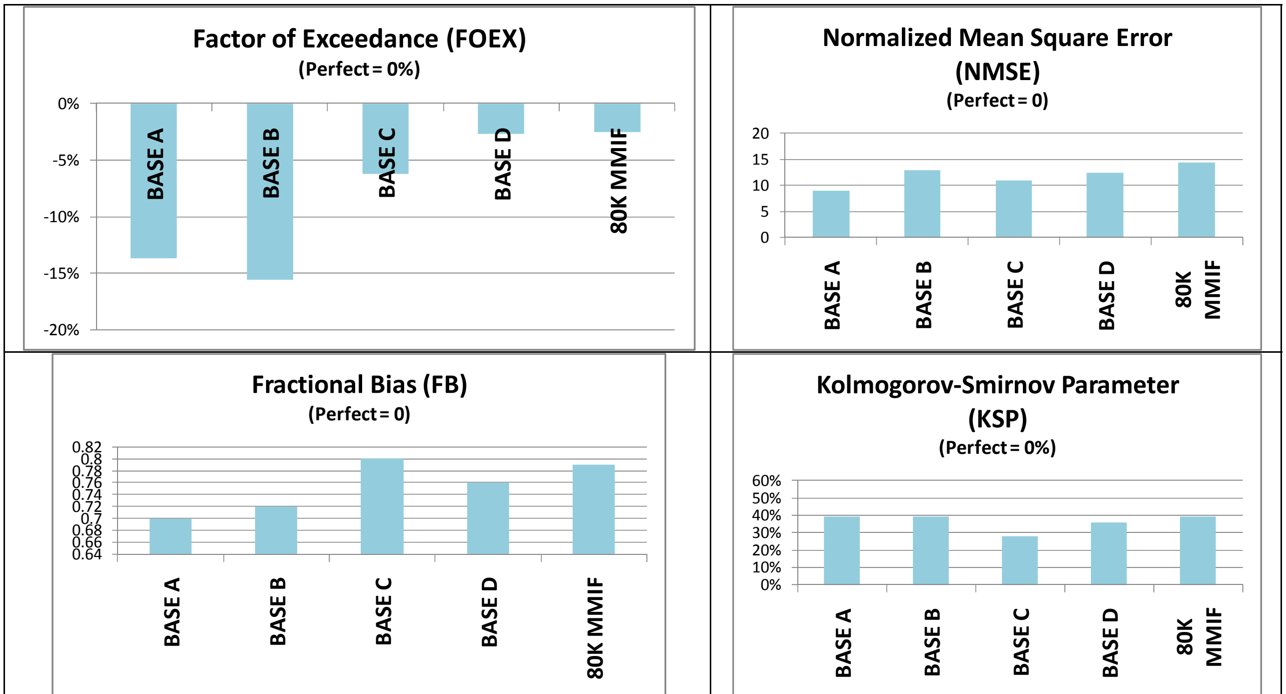


Figure 5-11a. Global model performance statistics for the CTEX5 CALPUFF sensitivity tests using the 80 km MM5data (lower values indicate better performance).

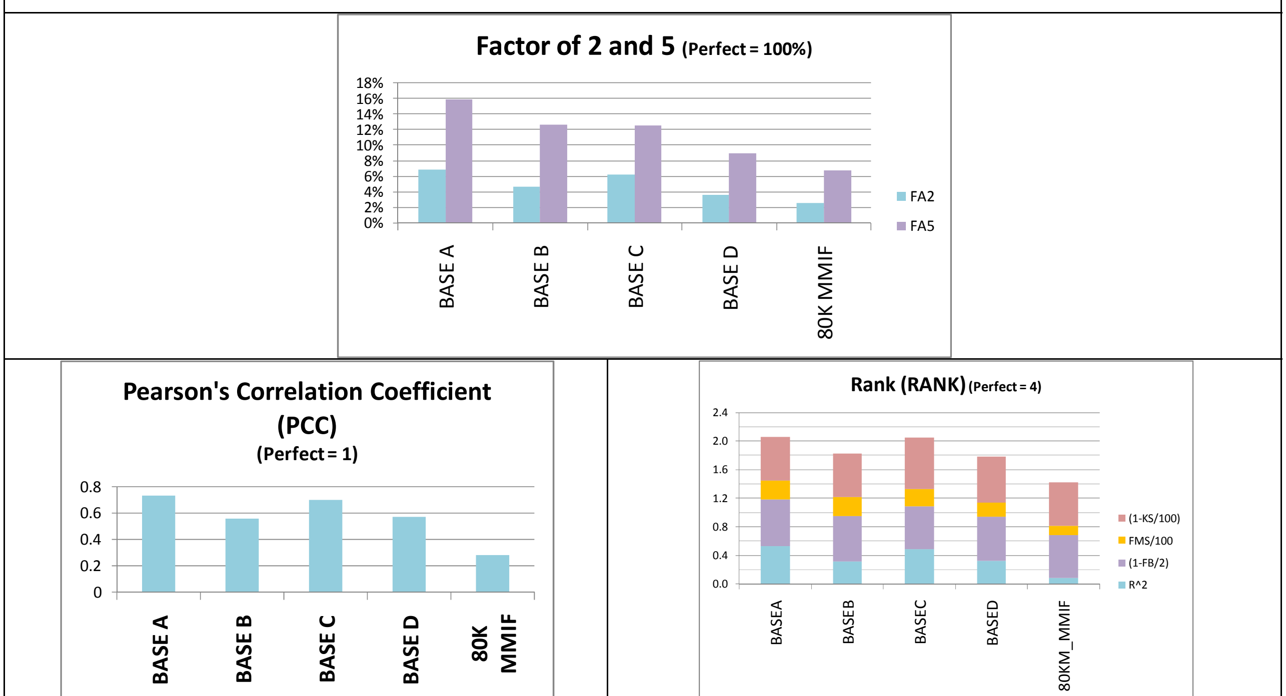


Figure 5-11b. Global model performance statistics for the CTEX5 CALPUFF sensitivity tests using the 80 km MM5 data (higher values indicate better performance).

<u>5.4.2.2 CALPUFF CTEX5 Model Evaluation using 36 km MM5 Data</u>

Figure 5-12 displays the spatial statistical metrics for the CTEX5 CALPUFF sensitivity tests using the 36 km MM5 data. Note that the CALMET simulation for EXP3D encountered an error in HTOLD so no CALPUFF sensitivity modeling results are available. The "A" and "B" series of

CALPUFF sensitivity simulations are performing best for the spatial performance statistics with the 36KM_MMIF performing worst.

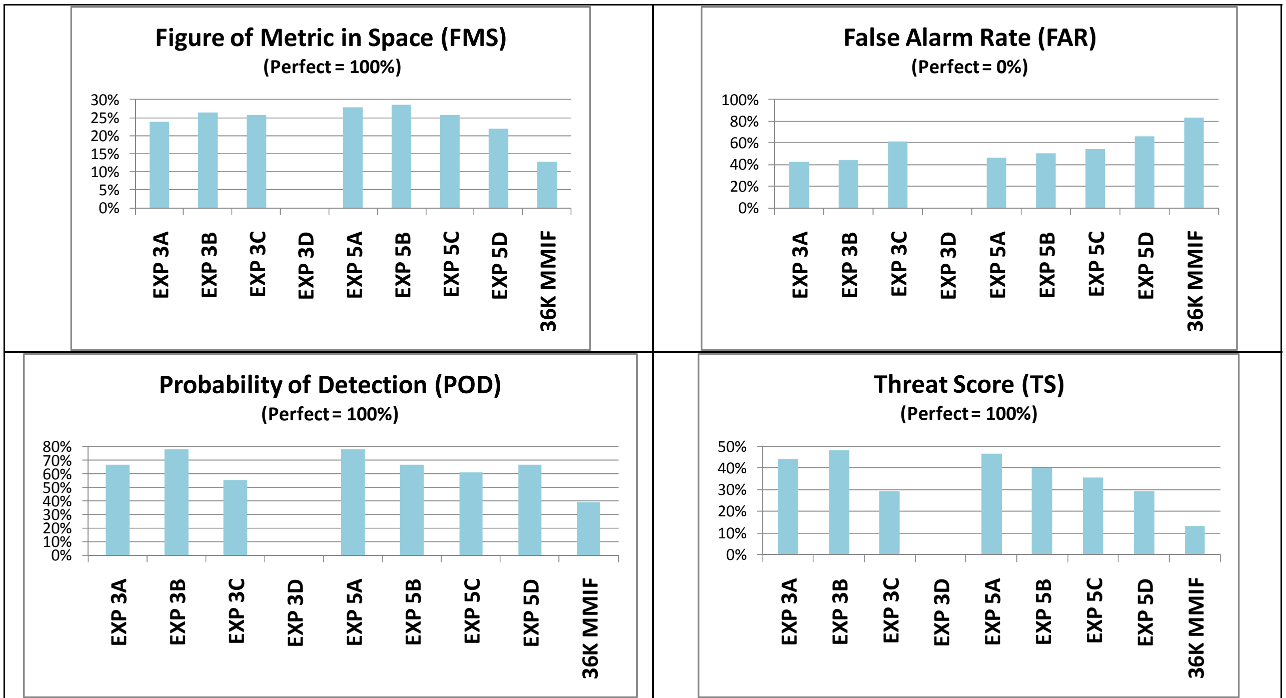


Figure 5-12. Spatial model performance statistics for the CTEX5 CALPUF sensitivity tests that used the 36 km MM5 data.

The global statistics for the CALPUFF sensitivity tests using the 36 km MM5 data are shown in Figure 5-13. EXP5D and 36KM_MMIF have the FOEX that is closest to zero. The EXP5B and EXP5D sensitivity simulations have the lowest bias and error followed by EXP3C with 36KM-MMIF having the worst bias and error metrics. The lowest (best) KSP statistics is given by EXP5D followed by 36KM_MMIF and EXP3C. EXP3B and EXP5A have the best FA2 and FA5 values, with 36KM_MMIF having the worst ones. EXP3A, EXP3C and EXP5A all have correlation coefficients above 0.7 with 36km_MMIF having the lowest correlation coefficient that is below 0.3. Using the overall composite RANK statistics, EXP3C and EXP5D (2.1) are ranked first followed by EXP3A and EXP5A (2.0) with 36KM_MMIF (1.4) having the lowest RANK statistic.

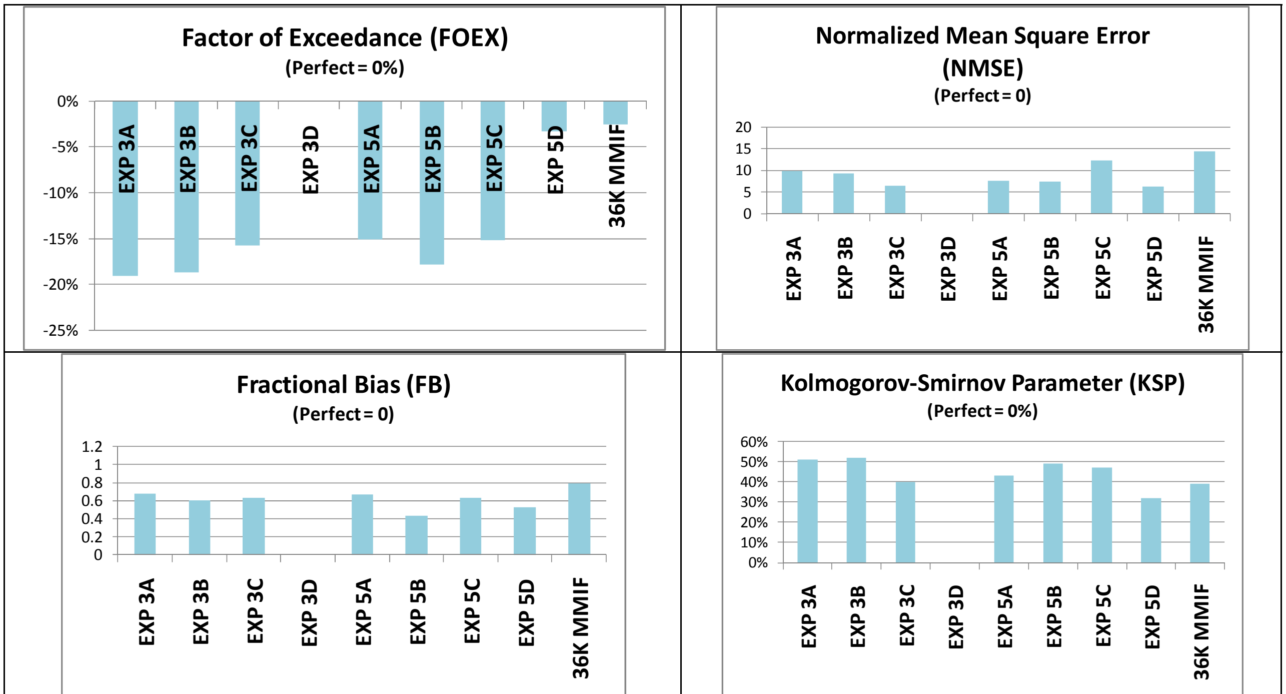


Figure 5-13a. Global model performance statistics for the CTEX5 CALPUFF sensitivity tests using the 36 km MM5 data.

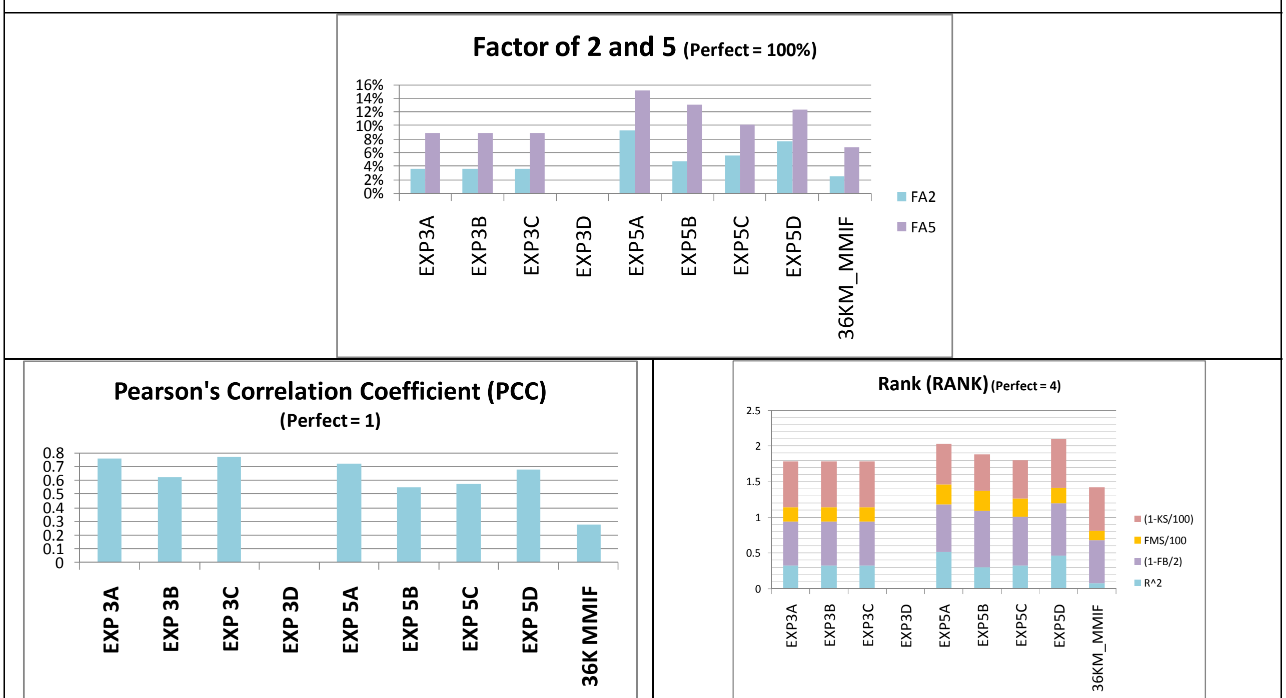


Figure 5-13b. Global model performance statistics for the CTEX5 CALPUFF sensitivity tests using the 36 km MM5 data (higher values indicate better performance).

5.4.2.3 CALPUFF CTEX5 Model Evaluation using 12 and 4 km MM5 Data

The spatial statistics for the CALPUFF/CALMET and CALPUFF/MMIF sensitivity tests using the 12 km MM5 data along with the 4 km MM5 CALPUFF/MMIF sensitivity test are given in Figure 5-

14. Across all the spatial statistics, EXP6A performs the best with EXP4A, EXP4B, EXP6B and 4KM_MMIF next best and 12KM_MMIF being worst.

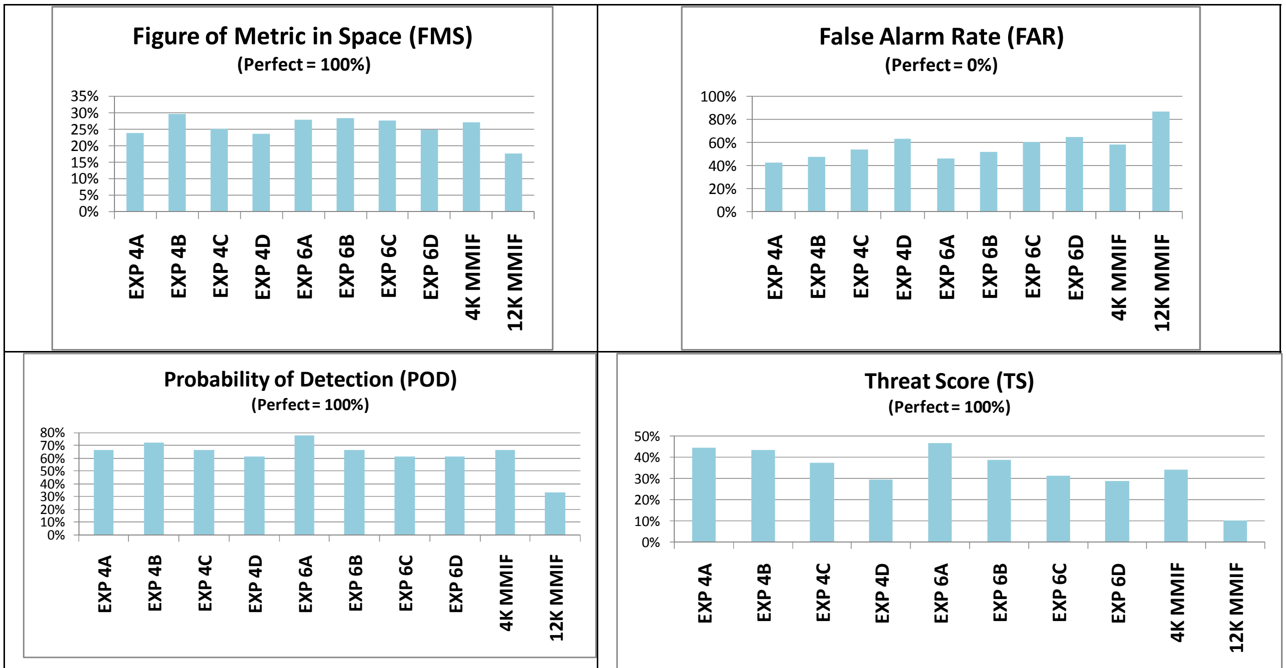


Figure 5-14. Spatial model performance statistics for the CTEX5 CALPUF sensitivity tests that used the 12 and 4 km MM5 data.

The lowest error of the 12 km MM5 CALPUFF sensitivity tests is given by EXP4B and EXP6A-C, with 12KM_MMIF having the highest error (Figure 5-15). EXP6B has the lowest bias follows by EXP6C and EXP4B, with 12KM_MMIF having the largest bias. EXP6A and EXP6B have the most model predictions within a factor of 2 of the observations and EXP4C has the most within a factor of 5. The CALMET/CALPUFF correlation coefficients range from 0.57 to 0.76 with EXP4A (0.76) and EXP6C (0.75) have the highest values and EXP6B (0.57) having the lowest value. The 4KM_MMIF has an even lower correlation coefficient (0.48) with the 12KM_MMIF having no to slight anti-correlation with the observed values (-0.07). According to the RANK composite statistics the best performing 12 km CALPUFF sensitivity test in EXP6C (2.19) followed by EXP6A (2.02) and EXP4A (1.98) with 12KM_MMIF (1.28) performing worst.

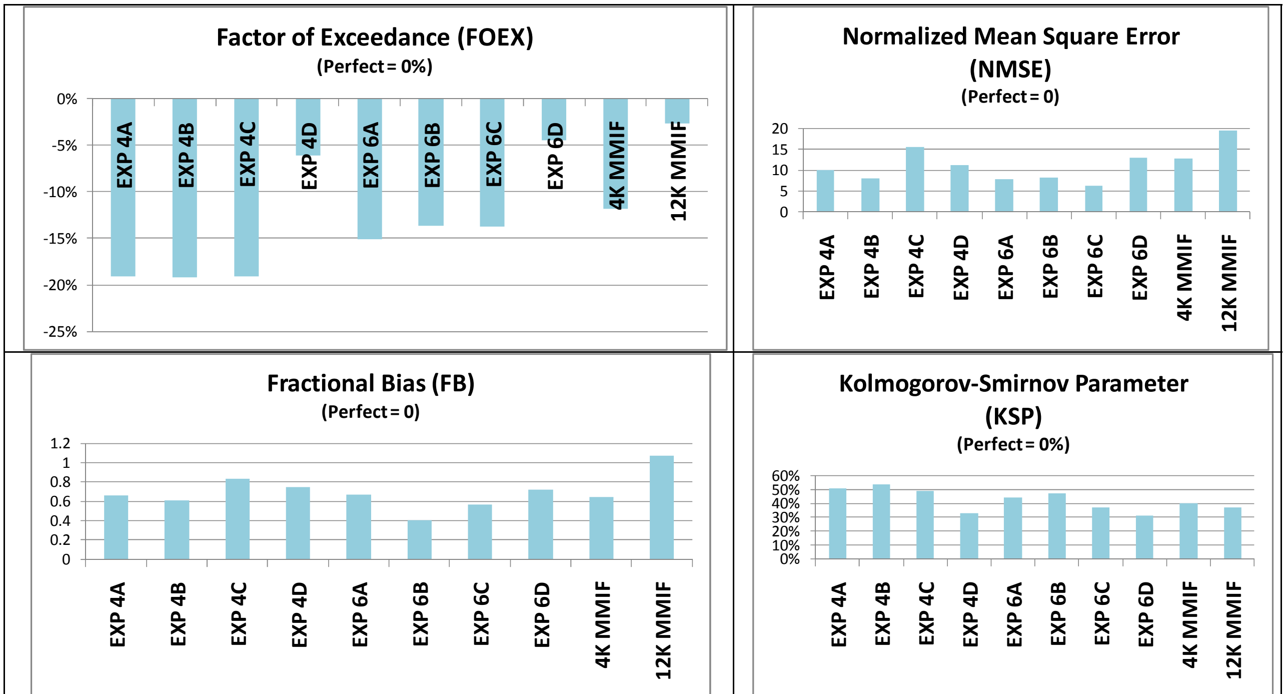


Figure 5-15a. Global model performance statistics for the CTEX5 CALPUFF sensitivity tests using the 12 km MM5 data.

Figure 5-15b. Global model performance statistics for the CTEX5 CALPUFF sensitivity tests using the 12 km MM5 data (higher values indicate better performance).

5.4.2.4 Comparison of CALPUFF CTEX5 Model Evaluation using Different MM5 Grid Resolutions

This section analyzes the CALPUFF model performance across different MM5 and CALMET grid resolutions using the "B" and "D" series of CALPUFF/CALMET and the CALPUFF/MMIF sensitivity tests. The "B" series (EXP4B, EXP5B, EXP6B and EXP3B) and 4KM_MMIF have the highest FMS values between 25% and 30% with 36KM_MMIF and 80KM_MMIF have the lowest FMS scores between 10% and 15%. Again the "B" series of CALPUFF/MMIF sensitivity tests have the best FAR scores with the worst scores given by the 12KM, 36KM and 80KM MMIF sensitivity tests. The "D" series using no met observations has the worst (highest) FAR scores of the CALPUFF/CALMET sensitivity tests. EXP3B has the best POD value follows by EXP4B with EXP5B, EXP5D, EXP6B and 4KM_MMIF ties for third best; the 12KM, 36KM and 80KM MMIF CALPUFFs have the worst FAR scores. Similar results are seen with the TS statistics with the four top performing sensitivity tests ordered by EXP4B, EXP5B, EXP6B and 4KM_MMIF,

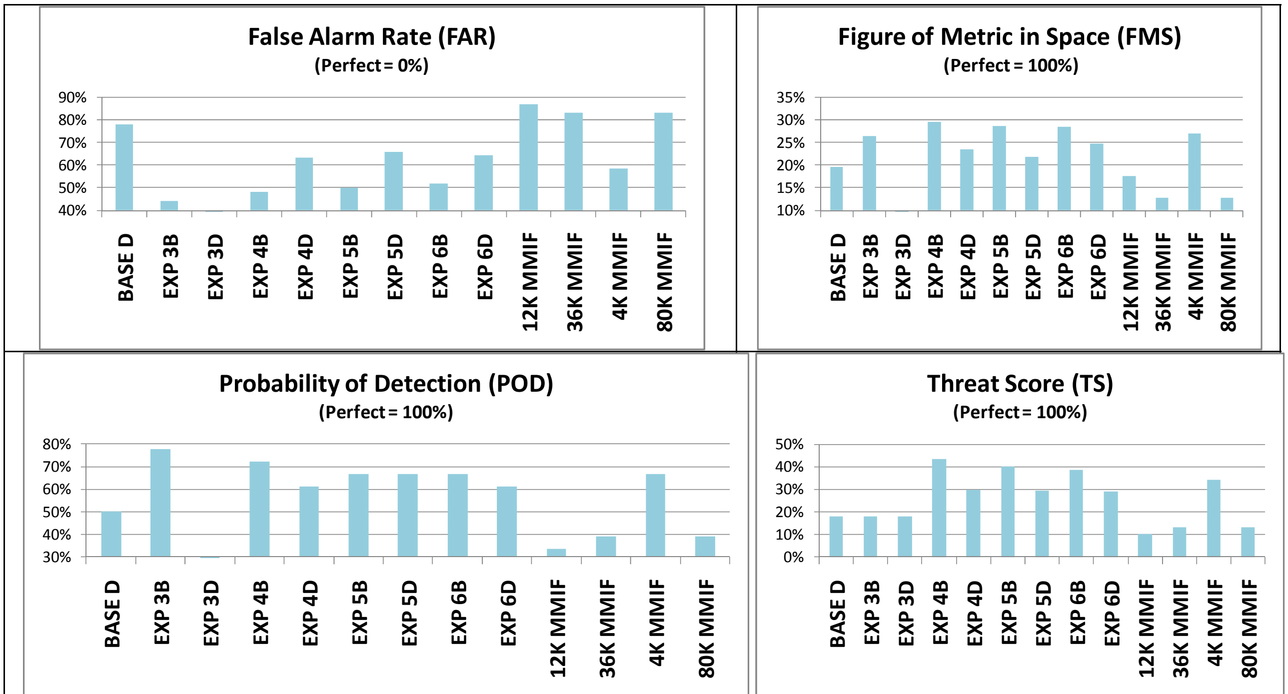


Figure 5-16. Spatial model performance statistics for the CTEX5 CALPUF sensitivity tests using different MM4/MM5 grid resolutions.

Although EXP5D has the lowest error, the "B" series of sensitivity tests consistency have the lowest bias and error (Figure 5-17). The 12KM_MMIF has the highest bias and error followed by the 80KM_MMIF sensitivity test. The "D" series of sensitivity tests have the best (lowest) KS parameter at ~30% with the "B" series of tests have the worst (highest) KSP at ~50% with the other sensitivity test in between.

The best sensitivity test for predicting the observed tracer within a factor of 2 and 5 is EXP3B followed by EXP6B with the 12KM, 36KM and 80KM MMIF runs being the worst. The correlation coefficients for the CALPUFF/CALMET CTEX sensitivity tests in this group range from 0.57 to 0.69 with 4km_MMIF being the best performing MMIF configuration with a 0.48 PCC with the other MMIF runs being much worse. The composite RANK statistics scores the CALPUFF/CALMET and 4KM_MMIF sensitivity tests in the 1.8 to 2.1 range with EXP5D (2.1) scoring the highest followed by EXP4D (1.99), EXP6D (1.99), EXP6B (1.94), EXP5B (1.89) and EXP4B (1.86). The 12KM, 36KM and 80KM CALPUFF/MMIF sensitivity tests have the lowest RANK scores (1.28 to 1.42).

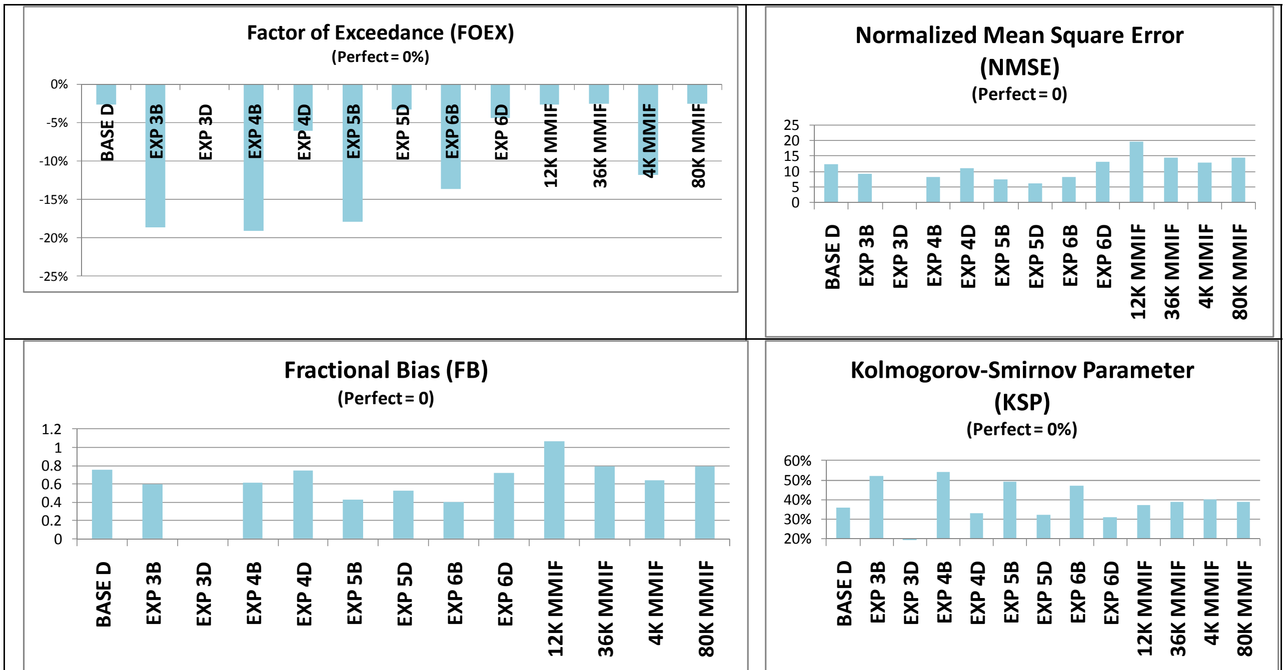


Figure 5-17a. Global model performance statistics for the CTEX5 CALPUFF sensitivity tests using different MM4/MM5 grid resolutions.

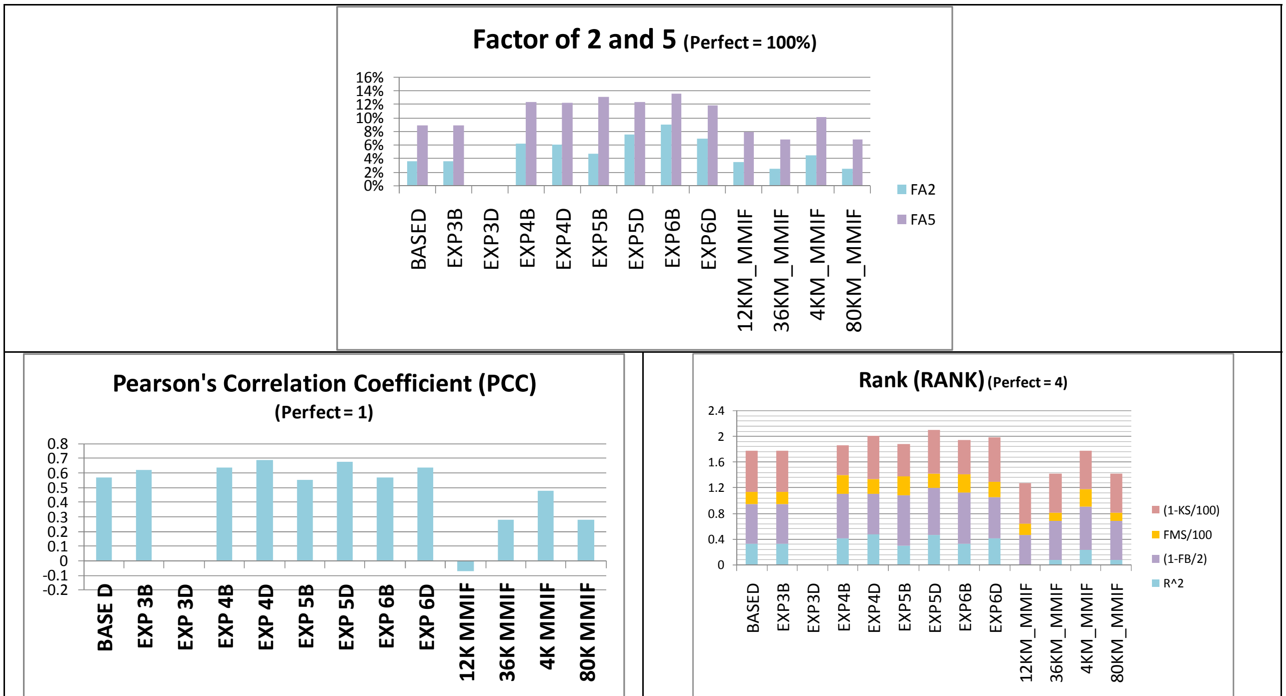


Figure 5-17b. Global model performance statistics for the CTEX5 CALPUFF sensitivity tests using different MM4/MM5 grid resolutions (higher values indicate better performance).

5.4.2.5 Rankings of CTEX5 CALPUFF Sensitivity Tests using the RANK Statistic

Table 5-10 ranks the model performance of the CTEX5 CALPUFF sensitivity tests using the RANK composite statistic. Outside of the 12KM, 36KM and 80KM MMIF CALPUFF sensitivity tests being by far the worst performing configurations with RANK values in the 1.28 to 1.42 range, the remaining sensitivity tests have RANK values in the 1.7 to 2.2 range, with the 4KM_MMIF run being in the lower end of this range. Examining trends in the CALPUFF sensitivity tests, the EXP6 series that uses the highest MM5 (12 km) and CALMET (4 km) grid resolution tends to have better model performance, whereas the "B" series of sensitivity tests tends to have worst model performance. Although the BASEA scenario is ranked 4th, the other BASE series using the 80 km MM5 and 18 km CALMET grid resolution have RANK scores on the lower end of the distribution. Based on these results we conclude the following for the CTEX5 sensitivity tests:

- Use of higher MM5 grid resolution (12 km) produces better CALPUFF model performance using both CALMET and MMIF.

5.5 CONCLUSIONS OF THE CAPTEX TRACER SENSITIVITY TESTS

There are some differences and similarities in CALPUFF's ability to simulate the observed tracer concentrations in the CTEX3 and CTEX5 field experiments. The overall conclusions of the evaluation of the CALPUFF model using the CAPTEX tracer test field experiment data can be summarized as follows:

- Regarding use of CALMET versus MMIF as a meteorological driver for CALPUFF, no definitive conclusion can be made since the CALPUFF/MMIF was the best performing model configuration for CTEX3 and the worst performing configuration for CTEX5.

Table 5-10. Final Rankings of CALPUFF CTEX5 Sensitivity Tests using the RANK statistic.

Ranking	Sensitivity Test	RANK Statistics	MM5 (km)	CALGRID (km)	RMAX1/RMAX2	Met Obs
1	EXP6C	2.19	12	4	10/100	Yes
2	EXP5D	2.10	36	4	--	No
3	BASEA	2.06	80	18	500/1000	Yes
4	BASEC	2.05	80	18	10/100	Yes
5	EXP5A	2.03	36	4	500/1000	Yes
6	EXP6A	2.02	12	4	500/1000	Yes
7	EXP4D	2.00	12	12	--	No
8	EXP6D	1.99	12	4	--	No
9	EXP4A	1.98	12	12	500/1000	Yes
10	EXP6B	1.94	12	4	100/200	Yes
11	EXP5B	1.89	36	4	100/200	Yes
12	EXP4B	1.86	12	12	100/200	Yes
13	BASEB	1.82	80	18	100/200	Yes
14	EXP5C	1.80	36	4	10/100	Yes
15	BASED	1.79	80	18	--	No
16	EXP3A	1.79	36	12	10/100	Yes
17	EXP3B	1.79	36	12	100/200	Yes
18	EXP3C	1.79	36	12	500/1000	Yes
19	EXP3D	1.79	36	12	--	No
20	4KM_MMIF	1.78	4	--	--	No
21	EXP4C	1.72	12	12	10/100	Yes
22	36KM_MMIF	1.42	36	--	--	No
23	80KM_MMIF	1.42	80	--	--	No
24	12KM_MMIF	1.28	12	--	--	No

- The use of 12 to 36 km resolution MM5 data tends to produce better CALPUFF model performance than using coarse grid data (e.g., 80 km).
- Regarding the effects of the RMAX1/RMAX2 parameters on CALPUFF/CALMET model performance, the “A” series (500/1000) is performing best for CTEX3 but the “C” series (10/100) is performing best for CTEX5 with both CTEX3 and CTEX5 agreeing that the “B” series (100/200) is the worst performing setting for RMAX1/RMAX2.
  - This is in contrast to the CALMET surface wind model evaluation that found the EPA-FLM Clarification Memorandum recommended settings used in the “B” series of CALMET experiments produced the wind fields that most closely matched observations (see Appendices A and B).
  - However, the CALMET surface wind evaluation was not a valid independent evaluation since surface wind observations are also used as input to CALMET for some of the experiments.

6.0 1994 EUROPEAN TRACER EXPERIMENT

6.1 DESCRIPTION OF THE 1994 EUROPEAN TRACER EXPERIMENT

The European Tracer Experiment (ETEX) was initiated in 1992 by the European Commission (EC), International Atomic Energy Agency (IAEA), and World Meteorological Organization (WMO) to address many of the questions that arose from the 1986 Chernobyl accident regarding the capabilities of LRT models and the ability to properly handle and disseminate large volumes of data. ETEX was designed to validate long-range transport models used for emergency response situations and to develop a database which could be used for model evaluation and development purposes.

6.1.1 ETEX Field Study

Two releases of a perflurocarbon tracer called perfluromonomethylcyclohexane (PMCH) were made in October and November 1994 from France. For this evaluation, model simulations are focused upon the first PMCH release. The first ETEX release has been used extensively to evaluate operational LRT models for numerous countries so was also used in this study. In many ways, it represents an ideal database for LRT evaluation because of the volume and high frequency of observations taken.

The PMCH was released at a constant rate of approximately 8 g/s (340 kg total) for 12 hours beginning at 1600 UTC on 23 October 1994 from Monterfil, France. The release of PMCH was a dynamic release, with an outlet temperature of 84°C and velocity of 47.6 m/s (JRC, 2008). Air concentrations were sampled at 168 monitoring sites in 17 European countries with a sampling frequency of every three hours for approximately 90 hours. Figure 6-1 displays the location of the PMCH release point in northwestern France and the array of sampling receptors.

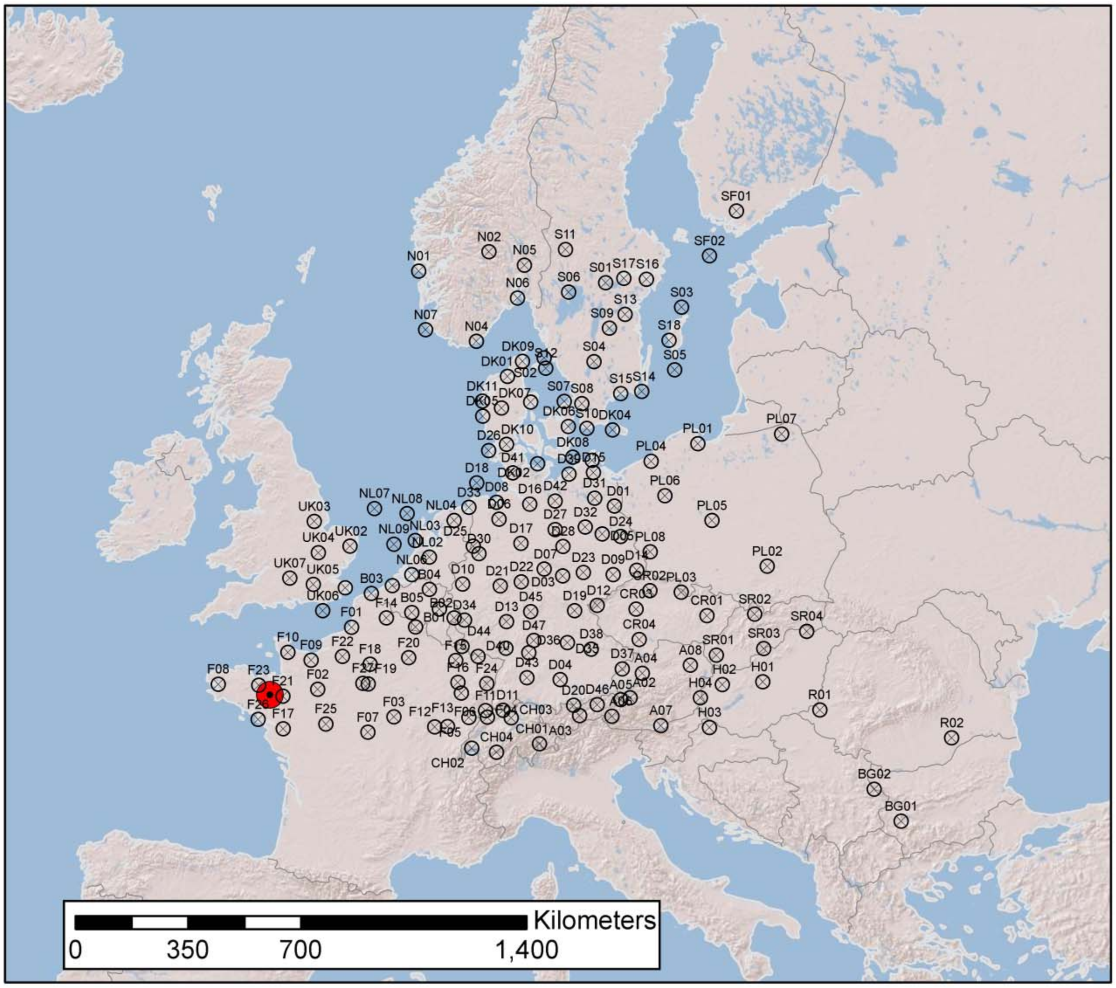


Figure 6-1. Locations of the PMCH tracer release point in Monterfil , France and sampling receptors for the 1994 European Tracer Experiment (ETEX).

6.1.2 Synoptic Conditions

Numerous synoptic surface and upper air observations were made by participating meteorological agencies as part of this experiment. Two separate extratropical cyclonic systems were present over the European continent at the time of the release. A strong extratropical cyclone was located over the North Sea with a central pressure of 980 mb. A second, significantly weaker, extratropical cyclone was located near the Balkan Peninsula over the Black Sea, having a central pressure of 1010 mb. These cyclonic systems were important to the transport of the PMCH tracer cloud. Figure 6-2 depicts the locations of the extratropical cyclonic systems during the ETEX field study.

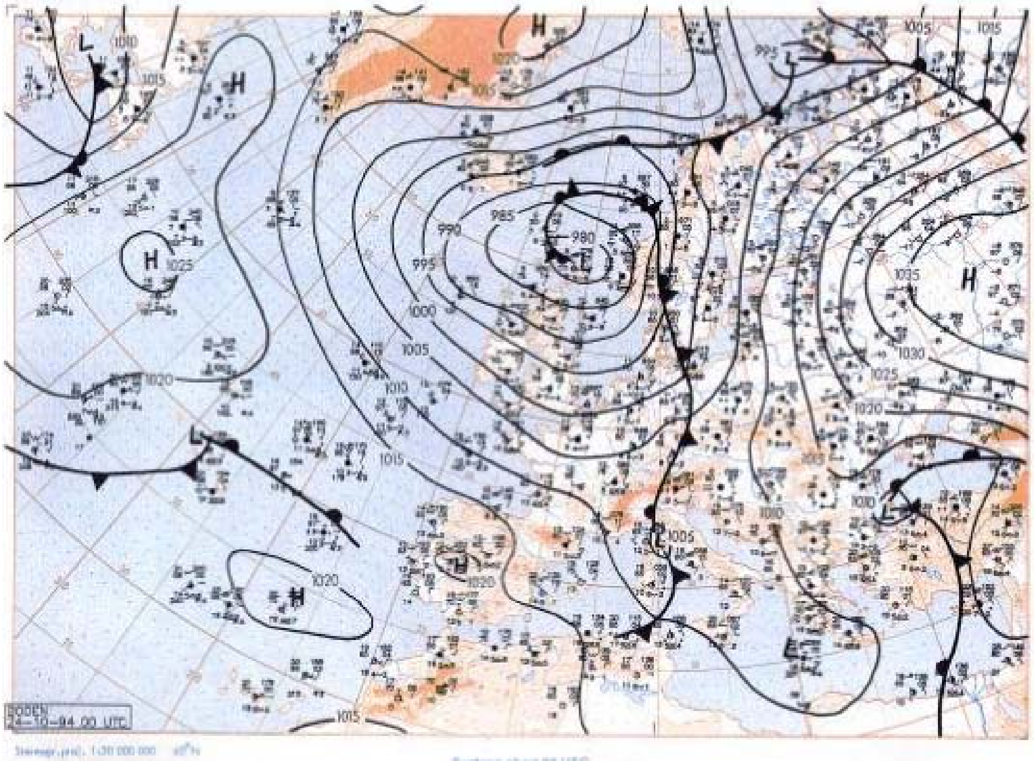


Figure 6-2a. Surface synoptic meteorological conditions for Europe at 0000 UTC on October 24, 1994 eight hours after the release of the PMCH tracer in ETEX (Source: http://rem.jrc.ec.europa.eu/etex/).

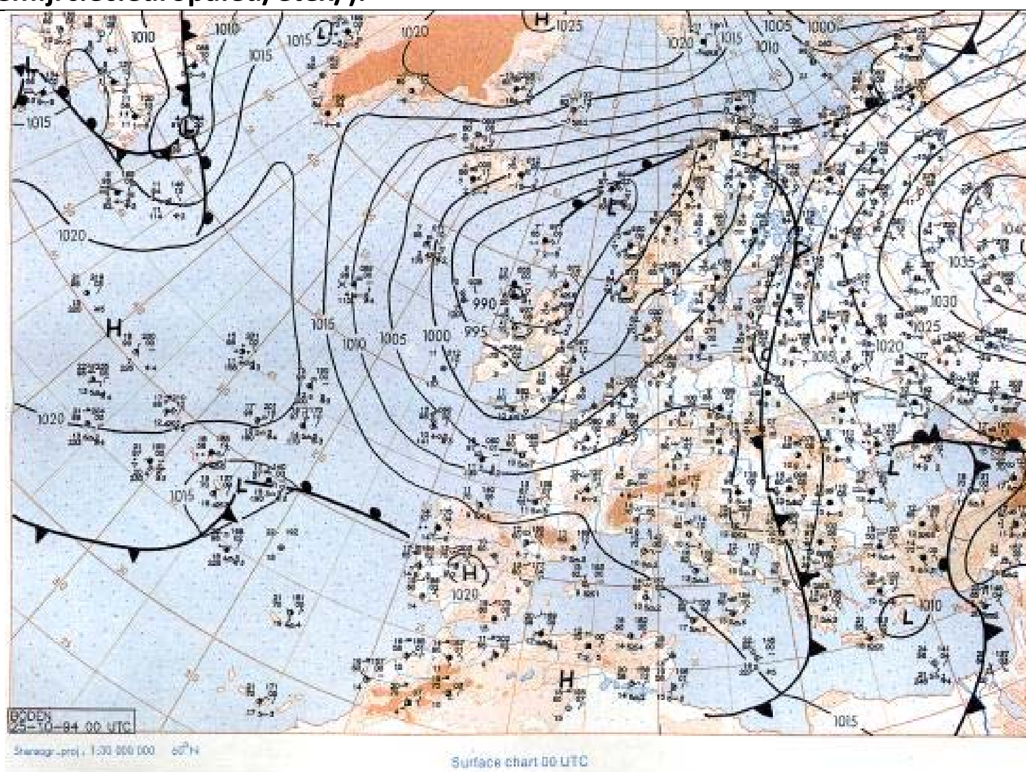


Figure 6-2b. Surface synoptic meteorological conditions for Europe at 0000 UTC on October 25, 1994 32 hours after the release of the PMCH tracer in ETEX (Source: http://rem.jrc.ec.europa.eu/etex/).

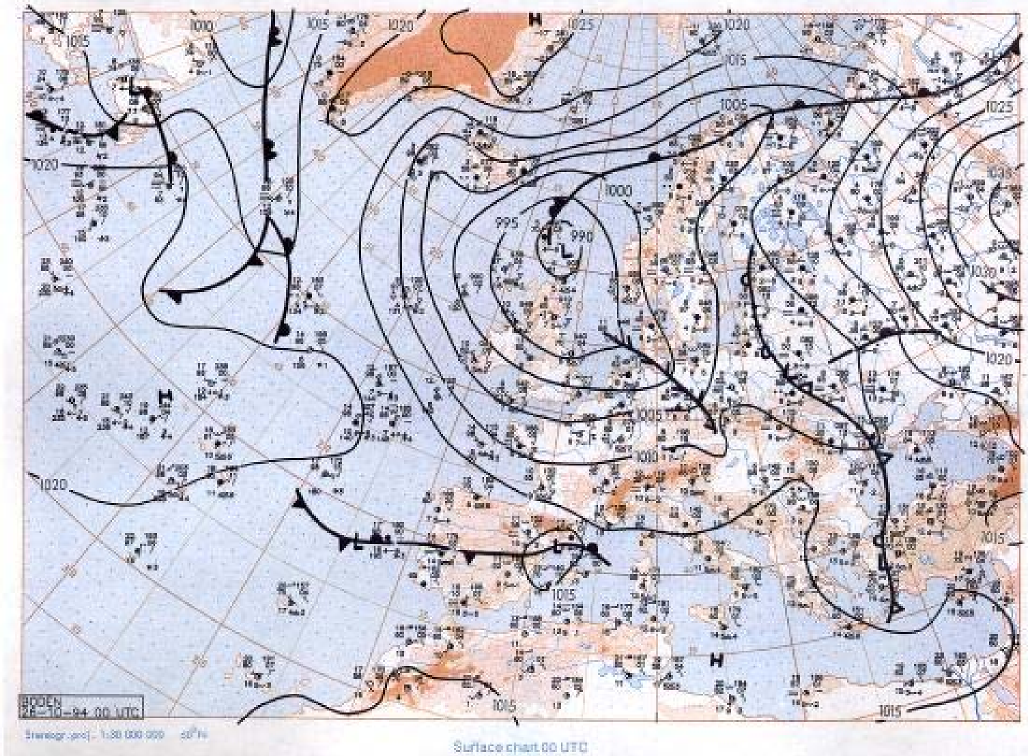


Figure 6-2c. Surface synoptic meteorological conditions for Europe at 0000 UTC on October 26, 1994 56 hours after the release of the PMCH tracer in ETEX (Source: http://rem.jrc.ec.europa.eu/etex/).

Figure 6-3 displays the spatial distribution of the observed PMCH tracer concentration in pico-grams per cubic meter (pgm^{-3}) 24, 36, 48 and 60 hours after the release in Monterfil, France. During the first 24 hours after the release of the PMCH, the tracer cloud was advected generally east-northeast from the release point in northwestern France into the Netherlands and Luxembourg and into western Germany. By 36 hours after the initial release, the tracer cloud had advected well into Germany (Figure 6-3, top right). In this region, the wind flow split between the two cyclonic systems northwest and southeast of Germany (see Figure 6-2), causing the tracer cloud to essentially bifurcate, with one portion advecting around the core of the cyclonic system over the North Sea, and the other portion advecting southeast towards the cyclonic system in the Balkan Peninsula region. 48 and 60 hours after the tracer release (Figure 6-3, lower panels), the tracer cloud stretches from Norway to the Black Sea in a narrow northwest to southeast orientation.

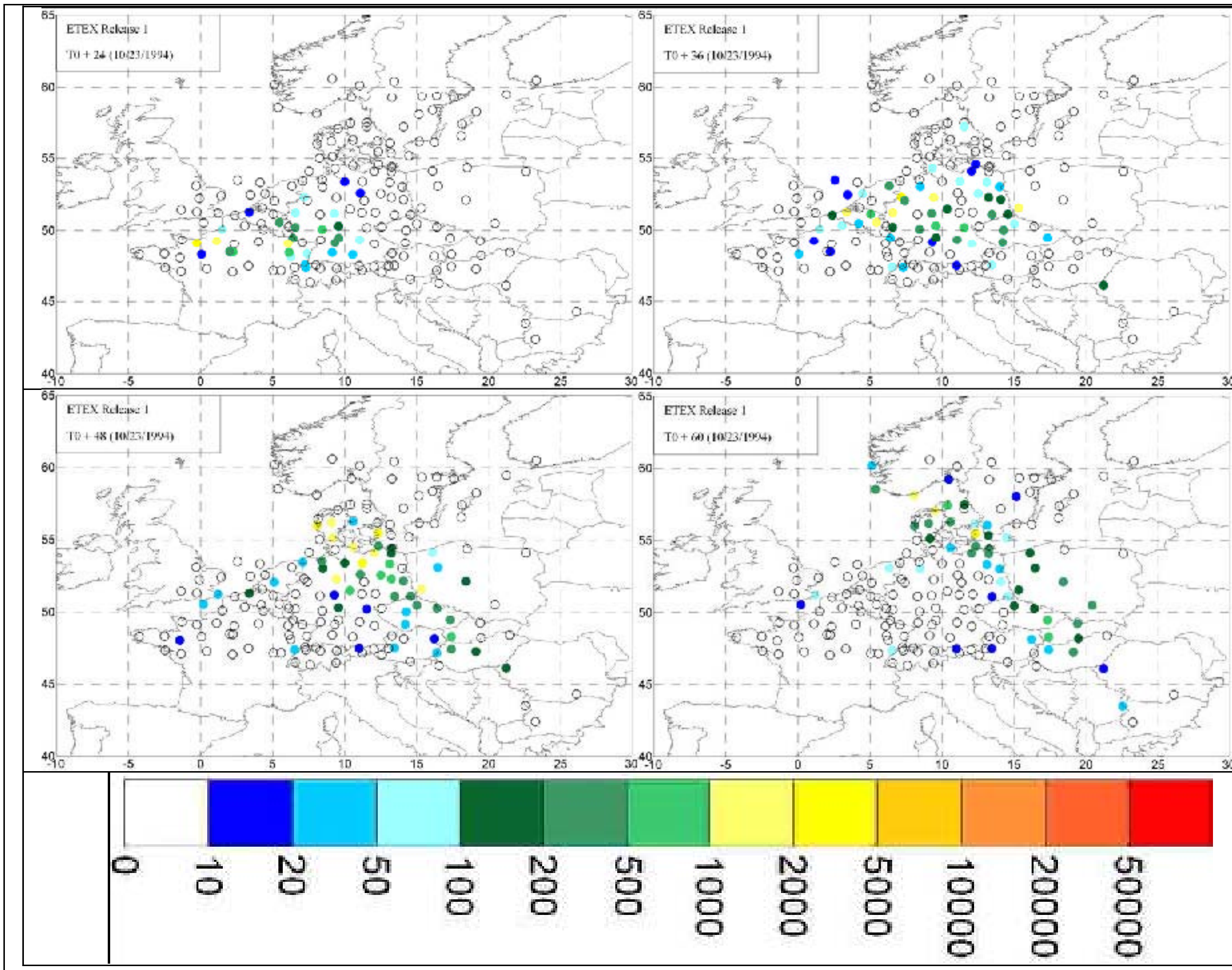


Figure 6-3a. Distribution of the observed PMCH tracer concentrations (pgm^{-3}) 24 (top right), 36 (top right), 48 (bottom left) and 60 (bottom right) hours after the release.

6.2 MODEL CONFIGURATION AND APPLICATION

6.2.1 Experimental Design

The objectives of the LRT model evaluation using the ETEX field study database was somewhat different than the other three tracer test evaluations. In the GP80, SRL75 and CAPTEX tracer test LRT model evaluations, one major objective was an evaluation of the CALPUFF LRT dispersion model using two different sets of meteorological inputs, one based on the CALMET diagnostic wind model and the other using the MMIF WRF/MM5 pass-through tool. However, in the ETEX LRT model tracer test evaluation an objective was to use the same meteorological inputs in all of the LRT dispersion models. This approach is similar to the one taken by Chang and co-workers (2003) who conducted an evaluation of three Lagrangian puff models (HPAC/SCIPUFF, VLSTRACK, and CALMET/CALPUFF). While all three puff models are based on a Gaussian puff formulation, these models varied significantly in terms of the level of sophistication of their technical formulation. Chang and co-workers (2003) proposed a framework to perform an objective and meaningful evaluation when such models vary significantly in their formulation. A primary focus of their model evaluation framework centered upon the use of the same observed meteorological data and similar modeling domains. To the extent practical, default model options were selected for all models in their evaluation. Reflecting that evaluation paradigm, a major focus of the LRT model evaluation using the ETEX database in this study was to provide a common source of meteorological fields to each of the dispersion models evaluated.

Five different LRT dispersion models were evaluated using the ETEX database. Each of the LRT models in this exercise requires three-dimensional meteorological fields as input to the model. For the majority of these models, meteorological fields from prognostic meteorological models are the primary source of the meteorological inputs. However, CALPUFF and SCIPUFF typically rely upon their own diagnostic meteorological models to provide three-dimensional meteorological fields to the dispersion model. In cases where prognostic meteorological model data are ingested to set the initial conditions within the diagnostic meteorological model, much of the original prognostic meteorological data is not preserved, and key parameters are rediagnosed. This compromises a key component of the evaluation paradigm of Chang et al. (2003) that we have adopted for the ETEX evaluation, namely a common meteorological database. The Mesoscale Model Interface (MMIF) software program (Emery and Brashers, 2009) was developed to facilitate direct ingestion of prognostic meteorological model data by the LRT dispersion model, bypassing the diagnostic meteorological model component and rediagnosing algorithms effectively overcoming the challenge to this evaluation paradigm.

6.2.2 Meteorological Inputs

During the original ATMES-II project, participating agencies during ETEX were required to calculate concentration fields for their respective models using analysis fields from the European Center for Medium-Range Weather Forecasts (ECMWF). ECMWF analysis fields were available at 6-hour intervals and a horizontal resolution of 0.5° (~50 km) latitude-longitude (D'Amours, 1998). Participating agencies could also submit results obtained using different meteorological analyses. Van Dop et al. (1998) and Nasstrom et al. (1998) found that increasing the resolution of the input meteorological fields enhanced the performance of the dispersion models evaluated in the ATMES-II study. Similarly, Deng et al. (2004) found that SCIPUFF model performance for the Cross-Appalachian Tracer Experiment (CAPTEX) improved by increasing meteorological model horizontal and vertical resolution, use of four dimensional data assimilation (FDDA), and more advanced meteorological model physics. However, they also noted that use of the more advanced physics options were responsible for more improvement in model performance than merely increasing horizontal grid resolution.

For the LRT model evaluation exercise using the ETEX database presented in this report, meteorological inputs were generated using a limited-area mesoscale meteorological model to produce higher temporally and spatially resolved meteorological data than used in the ATMES-II project. By producing more accurate meteorological fields, it should be possible to maximize performance of the LRT models under evaluation in this study. Furthermore, by using a common source of meteorological data between each of the five modeling systems, it reduces the potential contribution of differences in meteorological data on dispersion model performance and facilitates a more direct intercomparison of dispersion model results.

Hourly meteorological fields were derived from the PSU/NCAR Mesoscale Meteorological Model (MM5) Version 3.74 (Grell et al., 1995). MM5 was initialized with National Center for Environmental Prediction (NCEP) reanalysis data (NCAR, 2008). NCEP reanalysis fields are available every 6 hours on a 2.5° x 2.5° (~275 km) grid. The MM5 horizontal grid resolution was

36 kilometers and the vertical structure contained 43 vertical layers. Physics options were not optimized for northern European operations, but were based upon more advanced physics options available in MM5, reflecting the findings of Deng et al. (2004). Key MM5 options included:

- ETA Planetary Boundary Layer (PBL) scheme;
- Kain-Fritsch II cumulus parameterization (Kain, 2004);
- Rapid Radiative Transfer Model (RRTM) radiation scheme (Mlawer et al. 1997);
- NOAH land surface model (LSM) (Chen et al. 2001); and
- Dudhia Simple Ice microphysics scheme (Dudhia, 1989).

Four dimensional data assimilation (FDDA) (Stauffer et al. 1990, 1991) was employed for this study. "Analysis nudging" based upon the NCEP reanalysis fields were used with default values for nudging strengths.

6.2.3 LRT Model Configuration and Inputs

Three distinct classes of LRT dispersion models were included as part of the ETEX tracer evaluation including four Lagrangian models and one Eulerian model. CALPUFF Version 5.8 (Scire et al. 2000b) and SCIPUFF Version 2.303 (Sykes et al., 1998) are Lagrangian Gaussian puff models. HYSPLIT Version 4.8 (Draxler 1997) and FLEXPART Version 6.2 (Siebert 2006) are Lagrangian particle models. CAMx Version 5.2 (ENVIRON, 2010) is an Eulerian grid model. The respective user's guides provide a complete description of the technical formulations of each of these models.

Both CALPUFF and SCIPUFF are based upon Gaussian puff formulation. The two puff models have the advantage of more robust capabilities for source characterization, having the ability to treat dispersion for point, area, or line sources. Furthermore, these models can more accurately characterize dynamic releases of pollutants by accounting for initial plume rise of the pollutant. Conversely, the two particle models are very limited in their capability to characterize sources, having no direct ability to account for variations in source configurations or consider plume rise. The CAMx grid model is limited in its ability to simulate "plumes" by the grid resolution specified. CAMx includes a subgrid-scale Plume-in-Grid (PiG) module to treat the early evolution, transport and dispersion of point source plumes whose effect on model performance was investigated using sensitivity tests.

Since plume rise varies from hour-to-hour as a function of ambient temperature, wind speed and stability it is not possible to define a release height which would reflect this variation. Therefore, a constant release height of 10 meters was assigned for the two particle models in this study. This limitation of the particle models is problematic when comparing against models such as CALPUFF, SCIPUFF and CAMx that can simulate dynamic releases of emissions and calculate hour-specific plume rise using hourly meteorological data. Iwasaki et al. (1998) found that the initial release height assigned to the Japan Meteorological Agency (JMA) particle model had a large impact on the predicted ground level concentrations. Investigation of initial release height sensitivity of the two particle models was beyond the scope of this evaluation. However, this limitation should be noted when considering the uncertainty of concentration estimates from the two particle models.

Each of the four models requires gridded meteorological fields for dispersion calculations. CALPUFF normally uses output from the CALMET diagnostic wind field model (Scire et al., 2000a). SCIPUFF also has its own simplified mass-consistent wind field processor referred to as MC-SCIPUFF (Sykes et al., 1998). Gridded meteorological fields are normally supplied to HYSPLIT and FLEXPART using software that converts prognostic meteorological data into formats that are directly ingested into the respective dispersion models. The CAMx model also uses software to reformat output from a prognostic meteorological model into the variables and formats used by CAMx.

Use of a diagnostic wind field model (DWM) as the primary method to supply meteorological data to the dispersion models under review creates additional uncertainty in the intercomparison of the five dispersion models. DWM's, such as CALMET, have the ability to ingest prognostic data from models such as the PSU/NCAR MM5 (Grell et al.,1995) or the Advanced Research Weather Research and Forecasting (WRF-ARW) (Skamarock et al. 2008) as its first guess wind field. However, this method of using the prognostic meteorological data as the first guess field for the DWM does not preserve the integrity of the original meteorological field. For example, the CALMET DWM adjusts the wind fields for kinematic and thermodynamic effects of terrain and also rediagnoses key meteorological parameters such as planetary boundary layer heights. Thus, to conduct a proper evaluation of the dispersion models on the same basis, each of the models should be operated with the same meteorological dataset. In order to maintain consistency with this study objective, it would not have been appropriate to use either MC-SCIPUFF or CALMET to produce three-dimensional meteorological fields for their respective dispersion model.

In order to facilitate direct intercomparison of models using a common prognostic meteorological dataset, it is necessary to supply meteorological fields to CALPUFF and SCIPUFF in the same manner as the particle models and grid model included in this study. SCIPUFF has the ability to ingest prognostic data sets directly in either MEDOC (Multiscale Environmental Dispersion Over Complex terrain) (Sykes et al., 1998) or HPAC formats. The Pennsylvania State University developed the MM5SCIPUFF utility program (A. Deng, pers. comm.) to convert MM5 fields into the MEDOC format which is directly ingested into the SCIPUFF. Similarly, the US EPA developed the Mesoscale Model Interface (MMIF) software to convert MM5 fields into the CALPUFF meteorological input format (Emery and Brashers, 2009). With these two utility programs, it was now possible to evaluate the five LRT models using a consistent set of meteorological inputs.

Due to the inherent differences that exist between each of the five LRT models, it was not possible to standardize dispersion model options. Rather, options selected for each class of models were similar to the extent possible. For example, more advanced model features (turbulence dispersion, puff splitting) were used for CALPUFF simulations as these represent the state-of-the-practice for puff dispersion models and are most consistent with the capabilities of the SCIPUFF modeling system, helping to facilitate greater inter-model consistency for this evaluation.

CALPUFF is typically only recommended to distances of about 300 km or less (EPA, 2003). This would effectively limit the useful range of CALPUFF to the first 24-36 hours of ETEX simulation. However, recent enhancements to the CALPUFF modeling system include both horizontal and vertical puff splitting, incorporating the effects of wind shear on puff growth, potentially allowing for use of CALPUFF at distances greater than the nominal recommended limit of about 300 km, and allowing for more direct intercomparison with the two particle models and one grid model used in this study which are free of this restriction. The default method for CALPUFF vertical puff splitting is to allow for splitting to occur once per day by turning on the puff splitting flag near sunset (hour 17), artificially limiting the number of split puffs that are generated by the model. However, for the ETEX evaluation puff-splitting was enabled for each simulation hour instead of the default option of once per day in order to allow for full treatment of wind shear. The puff splitting feature of the CALPUFF modeling system does not have a complementary puff "merging" feature which aggregates puffs according to specified rules when they occupy the same space. Without the complementary puff merging capability, the number of puffs generated by puff-splitting can rapidly increase, resulting in extensive computational requirements of the model and eventual simulation termination once the maximum number of puffs allowed by the model is exceeded. Since the ETEX CALPUFF application was of short duration, the number of puffs allowed was increased so no termination occurred. However, the use of all hour puff splitting with CALPUFF in an annual simulation could be problematic. The SCIPUFF Lagrangian puff model also performs puff splitting when a sheared environment is encountered, however it can perform puff merging when two puffs occupy the "same" space so does not suffer from the extensive computer time of CALPUFF when aggressive puff splitting is desired.

The horizontal and vertical grid structures of CALPUFF were similar to the parent MM5 data. Twenty-seven (27) vertical levels were used in CALPUFF with each of the first 27 MM5 layers matched explicitly to the CALPUFF vertical structure, through the lowest 4,900 m vertical depth of the atmosphere. Additionally, 168 discrete receptors were included in the modeling analysis, with the location of each corresponding to the location and elevation of the ETEX monitors. AERMOD (EPA, 2004) turbulence coefficients, no complex terrain adjustment, and puff-splitting were selected for this analysis. A constant emission rate of 7.95 g/s was assigned for twelve hours of release of the PMCH tracer. Plume rise and momentum were also simulated in CALPUFF according to the release characteristics detailed on the ETEX website. CALPUFF results were integrated for 90 hours, and model results were post-processed in order to generate 30 three (3) hour averages for each of the 168 discrete receptors.

For SCIPUFF simulations, the horizontal and vertical grid structures of the extracted MM5 data were similar to the original MM5 data. Twenty-eight (28) vertical levels were extracted, encompassing a depth of approximately 5,000 m, similar to the CALPUFF simulations. Plume rise and momentum were also simulated in SCIPUFF in the same manner as the CALPUFF simulations. SCIPUFF results were also integrated for 90 hours, and model results were post-processed in order to generate 30 three (3) hour averages for each of the same 168 discrete receptors.

FLEXPART simulations used a 375 x 175 horizontal grid at a resolution 0.16° (~18 km) latitude/longitude. All MM5 vertical layers were extracted for the transport simulation. The FLEXPART concentration grid consisted of 15 vertical levels from the surface to 1,500 m with 9 layers below the first 500 m. Emissions were released at 10 meters. Concentrations were bi-linearly interpolated to grid cells corresponding to the 168 ETEX monitoring locations that were used.

HYSPLIT simulations used a 60 x 60 concentration grid with a horizontal resolution 0.25° (~28 km) latitude/longitude, consistent with NOAA's model configuration for ETEX described on the DATEM website. All MM5 vertical layers to 5000 meters were extracted for the transport simulation. Emissions were released at 10 meters. The gridded concentration output was linearly interpolated to the sampling locations utilizing software from NOAA's Data Archive of Tracer Experiments and Meteorology (DATEM) project. HYSPLIT was configured as a puff-particle hybrid (same used by the NOAA ARL for their ETEX evaluation) was used for the model intercomparison (i.e., INITD = 104)

Note that the FLEXPART and HYSPLIT meteorological inputs were based on the 36 km MM5 meteorological model output, so they used the same transport conditions and resolution as the other LRT models. The FLEXPART (~18 km) and HYSPLIT (~28 km) horizontal grid resolution is used to convert the particles (mass) to concentrations (mass divided by volume).

CAMx was operated on a 148 x 112 horizontal grid with 36 km grid resolution with 25 vertical layers up to a 50 mb pressure level (~15 km). CAMx is a photochemical grid model that includes state-of-science gas, aerosol and aqueous phase chemistry modules and dry and wet deposition algorithms. However, for the ETEX tracer modeling CAMx was operated with no chemistry and no wet or dry removal mechanisms. The MM5CAMx processor was used to process the MM5 output to the variables and formats required by CAMx. CAMx has several options for vertical mixing (from MM5CAMx), horizontal advection as well as a subgrid-scale Plume-in-Grid (PiG) module. Several alternative configurations of CAMx were investigated using sensitivity tests. When comparing with the other LRT models, we used a CAMx configuration with the following attributes, which are fairly typical for many CAMx simulations:

- CMAQ-like vertical diffusion coefficients from MM5CAMx;
- Piecewise Parabolic Method (PPM) horizontal advection solver; and
- No PiG module.

6.3 QUALITY ASSURANCE

Quality assurance (QA) of the LRT dispersion runs was conducted by evaluating the MM5 meteorological model output against surface meteorological observations and by examining of the LRT model inputs and outputs, as available, to assure that the intended options and configurations were used.

6.3.1 Quality Assurance of the Meteorological Inputs

A limited statistical evaluation of the MM5 simulation for the ETEX period was conducted as part of this evaluation. The meteorological observations collected at the 168 sampling stations during the ETEX exercise were not used as part of the MM5 data assimilation strategy; therefore, these observations could reliably be used to provide an independent evaluation of the MM5 simulation.

MM5 model performance evaluation results are presented in Figure 6-4. The MM5 performance statistics presented in Figure 6-4 are compared to performance criteria typically recommended for meteorological model applications for regional air quality studies in the United States (Emery et al. 2001) that were presented previously in Table 5-7. In general, MM5 verification scores indicate a persistent negative bias and higher error for both wind speed (-1.67 m/s and 4.73 m/s, respectively) and temperature (-1.1 °K and 2.36 °K, respectively) averaged across all 168 sites that are outside of target performance benchmark values for each of these meteorological parameters. Wind direction bias and error were within the performance benchmarks. Typically, these performance statistics would likely cause the modeler to consider experimenting with additional physics configurations and/or altering the data assimilation strategy to enhance meteorological model verification statistics. However, the MM5 simulation was not optimized for this project for several reasons:

- First, from an operational perspective, the meteorological model errors are likely consistent with the magnitude of model prediction errors that would have been experienced during the original ETEX exercise if forecast fields rather ECMWF analysis fields had been employed. Additionally, the MM5 simulation has the added advantage of data assimilation to constrain the growth of forecast error as a function of time.

- Second, since each of the five LRT model platforms evaluated in this project are presented with the same meteorological database; a systemic degradation of performance due to advection error would have been observed if the meteorology was a primary source of model error. However, since poor model performance was only noted in one of the five models, meteorological error was not considered the primary cause of poor performance.
- Finally, since wind direction is likely one of the key meteorological parameters for LRT simulations, the operational decision to use the existing MM5 forecasts was made because the MM5 wind direction forecasts were within acceptable statistical limits.

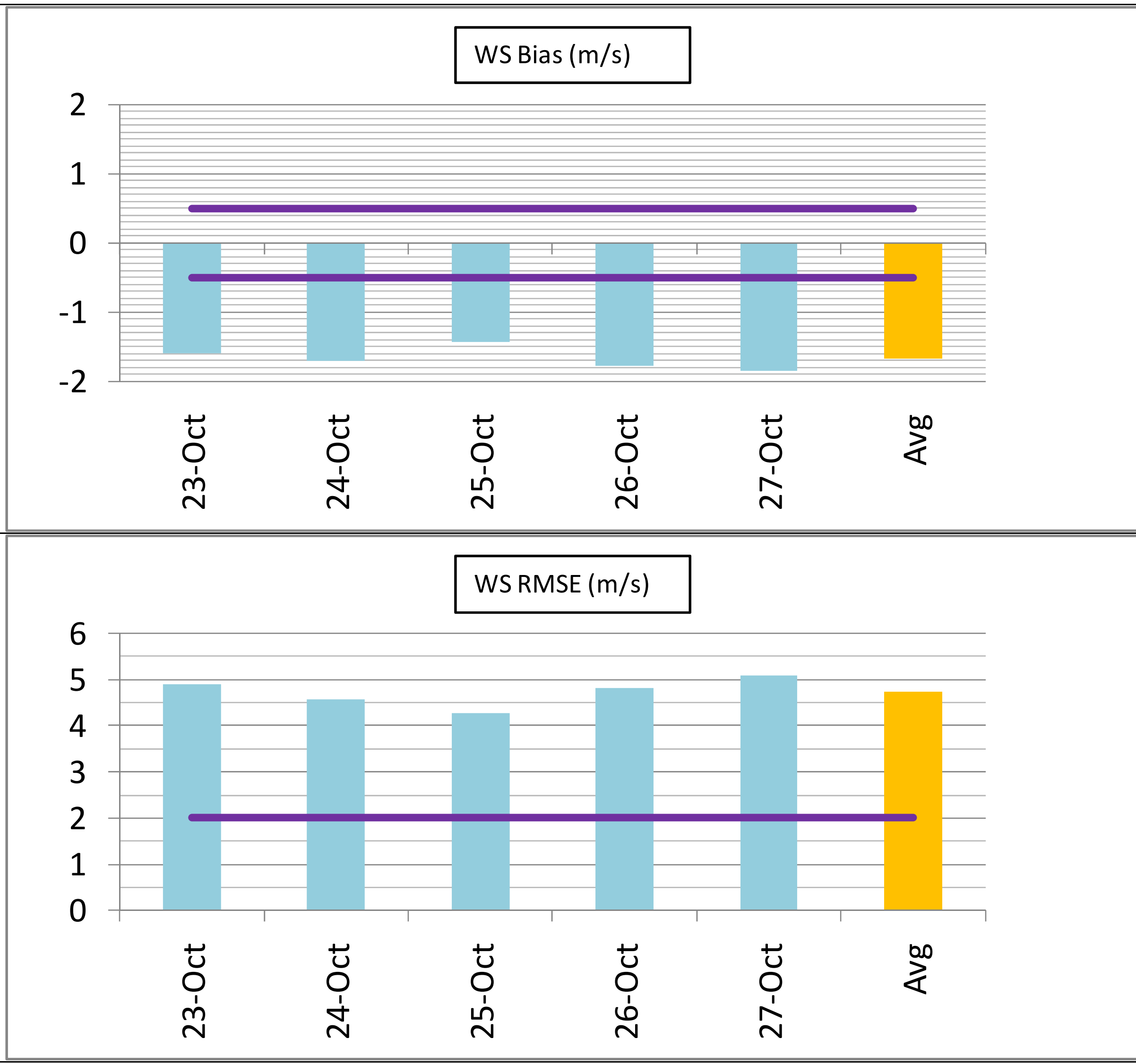
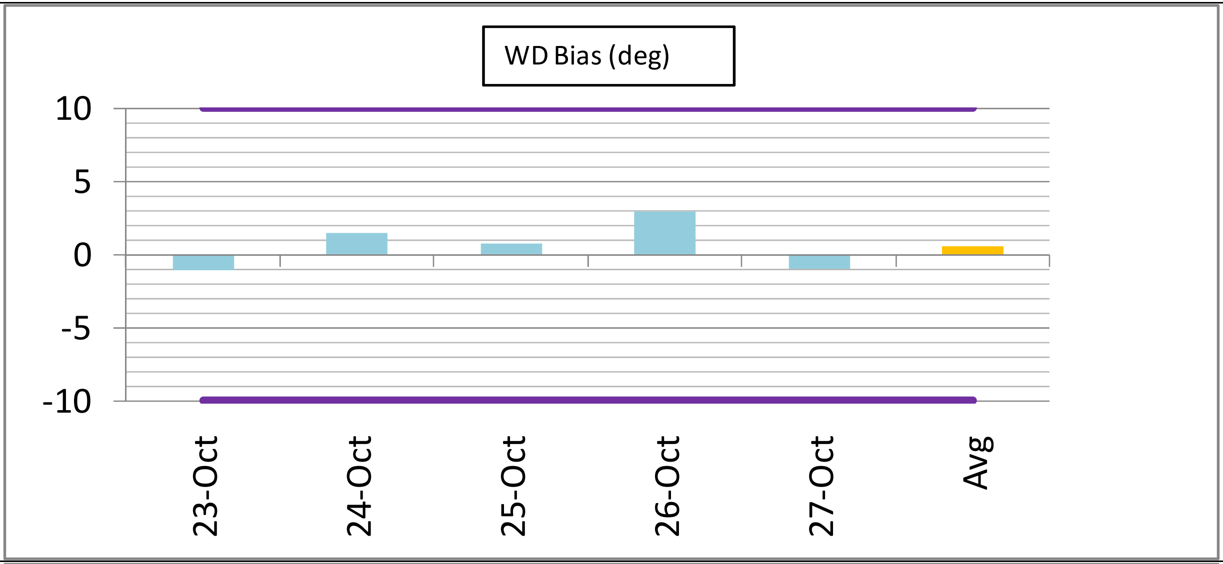


Figure 6-4a. ETEX MM5 model performance statistics of Bias (top) and RMSE (bottom) for wind speed and comparison with benchmarks (purple lines).



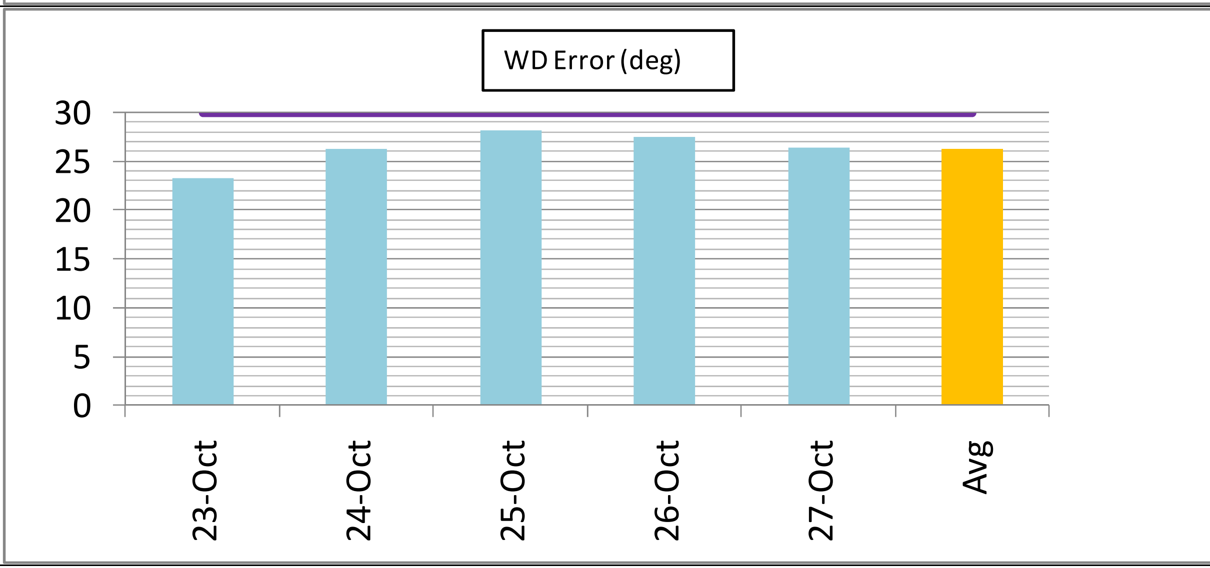


Figure 6-4b. ETEX MM5 model performance statistics of Bias (top) and Error (bottom) for wind direction and comparison with benchmarks (purple lines).

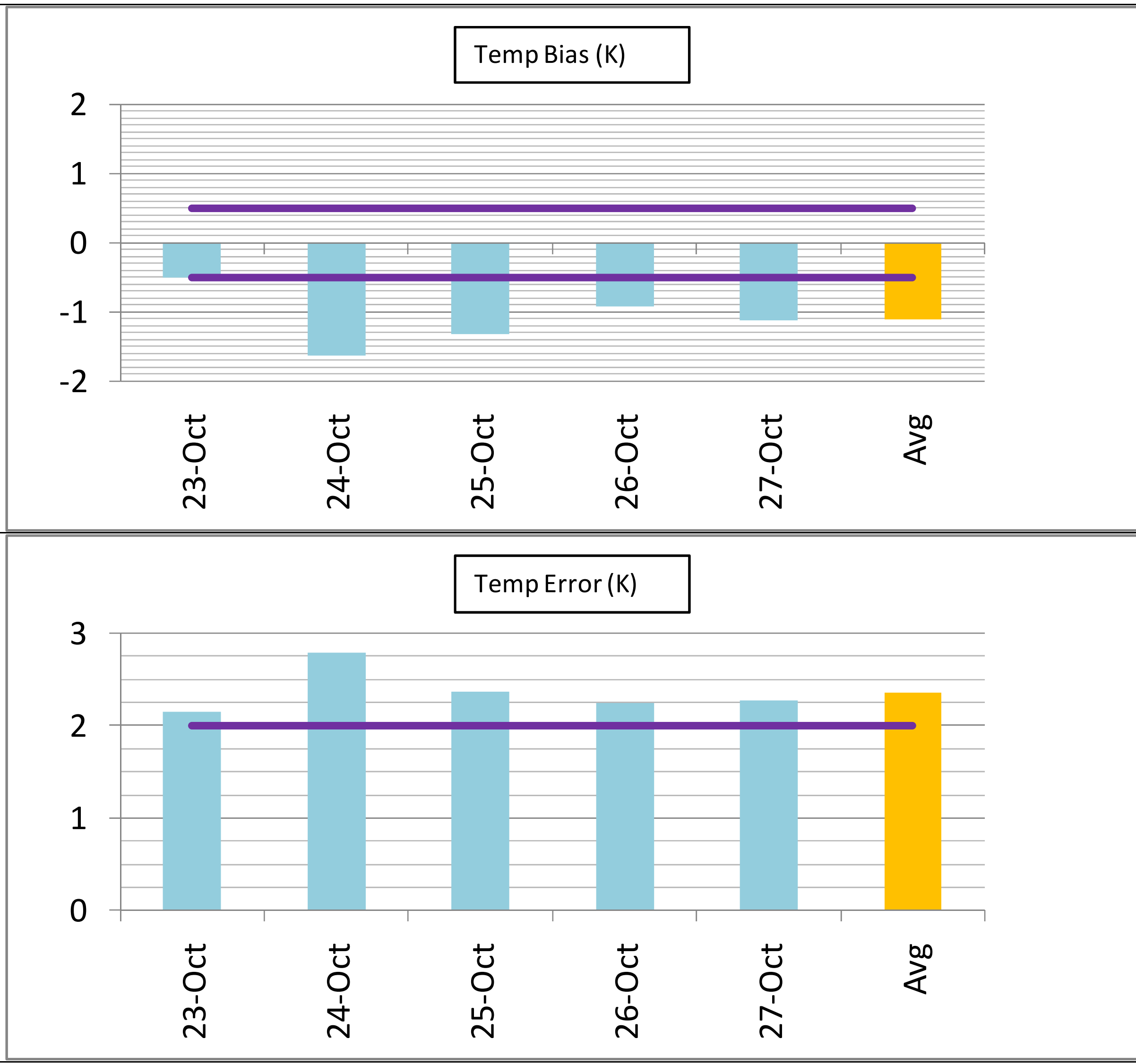


Figure 6-4c. ETEX MM5 model performance statistics of Bias (top) and Error (bottom) for temperature and comparison with benchmarks (purple lines).

6.3.2 Quality Assurance of the LRT Model Inputs

The input control files for the five LRT dispersion models were examined to assure that the intended model options were used in each of the simulations.

6.4 MODEL PERFORMANCE EVALUATION

The model performance of the five LRT dispersion models are evaluated using statistical measures as used in the ATMES-II study (Mosca et al., 1998) and recommended by DATEM (Draxler, Heffter and Rolph, 2002). Graphical comparisons are generated of the predicted and observed tracer spatial distributions.

6.4.1 Statistical Model Performance Evaluation

The spatial, temporal and global model performance of the five LRT models is evaluated using the statistical model performance metrics described in Section 2.4.

6.4.1.1 Spatial Analysis of Model Performance

Four spatial analysis model performance statics have been identified and are discussed in this section: FMS, FAR, POD and TS. Figure 6-5 displays the FMS spatial analysis performance metrics for the five LRT models and the ETEX tracer study field experiment. Recall that the FMS statistic is define as the overlap divided by the union of the predicted and observed tracer clouds with a perfect model receiving an FMS score of 100%.

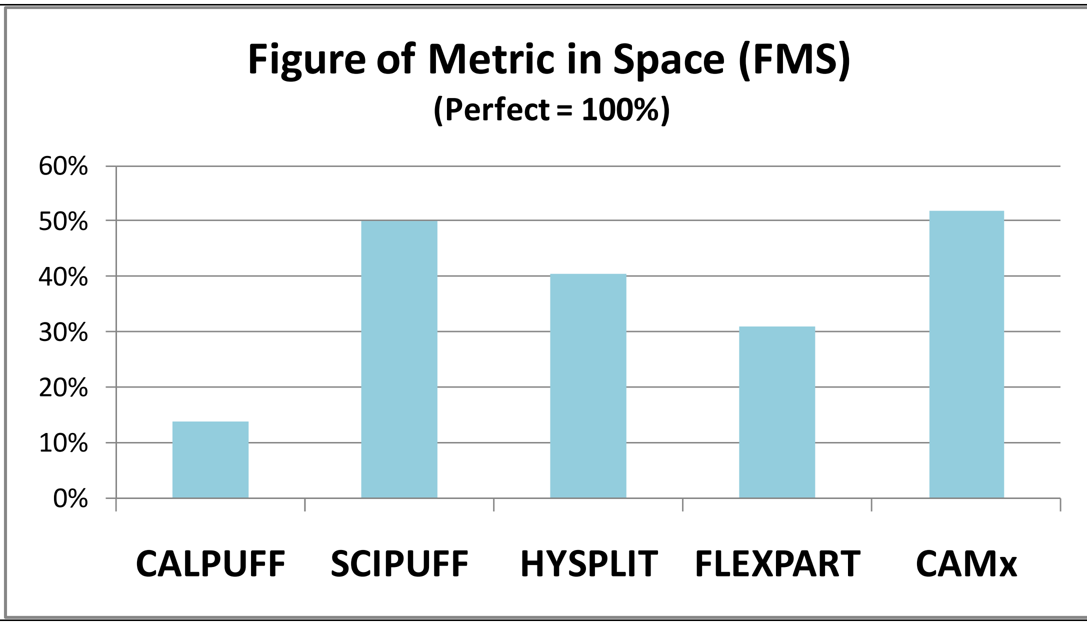


Figure 6-5. Figure of Merit in Space (FMS) statistical performance metric for the five LRT models and the ETEX tracer field experiment.

Figure 6-6 displays the False Alarm Rate (FAR) performance metrics. The FAR metric is defined by the number of times that a tracer concentration was predicted to occur at a monitor-time when no tracer was observed (i.e., a miss) divided by the number of times a tracer was predicted to occur at a monitor-time (i.e., sum of misses and hits); a perfect model (i.e., one that had no misses) would have a FAR score of 0%.

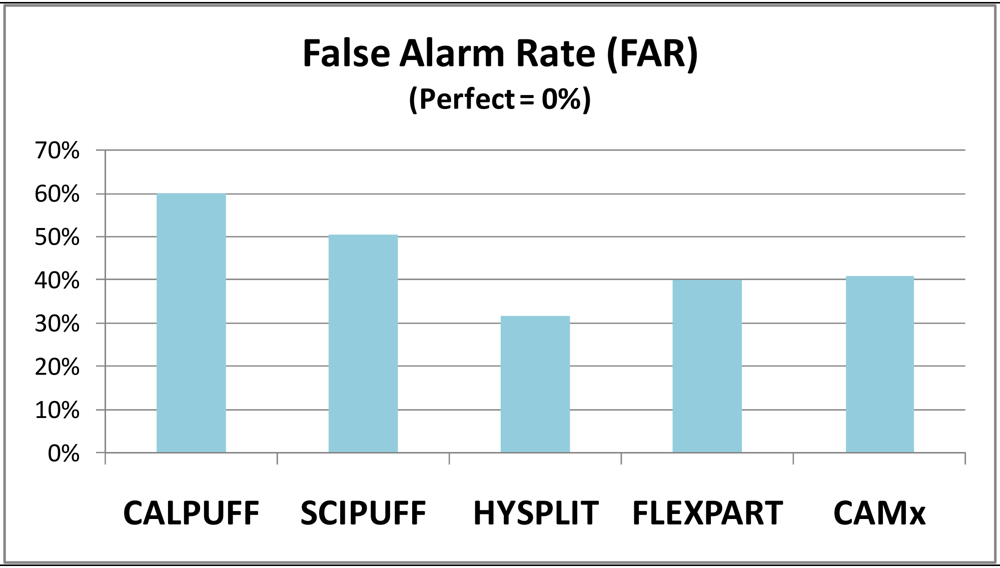


Figure 6-6. False Alarm Rate (FAR) statistical performance metric for the five LRT models and the ETEX tracer field experiment.

The Probability of Detection (POD) performance statistic is defined as the percent of the time the predicted and observed tracer both occurred at a monitor-time (i.e., a hit of tracer concentrations greater than 1 ngm^{-3}) divided by the number of times that the tracer was observed at any monitor-time (i.e., sum of hits and misses); a perfect model POD score would be 100% (i.e., anytime there was observed tracer at a monitor there was also predicted tracer at the monitor).

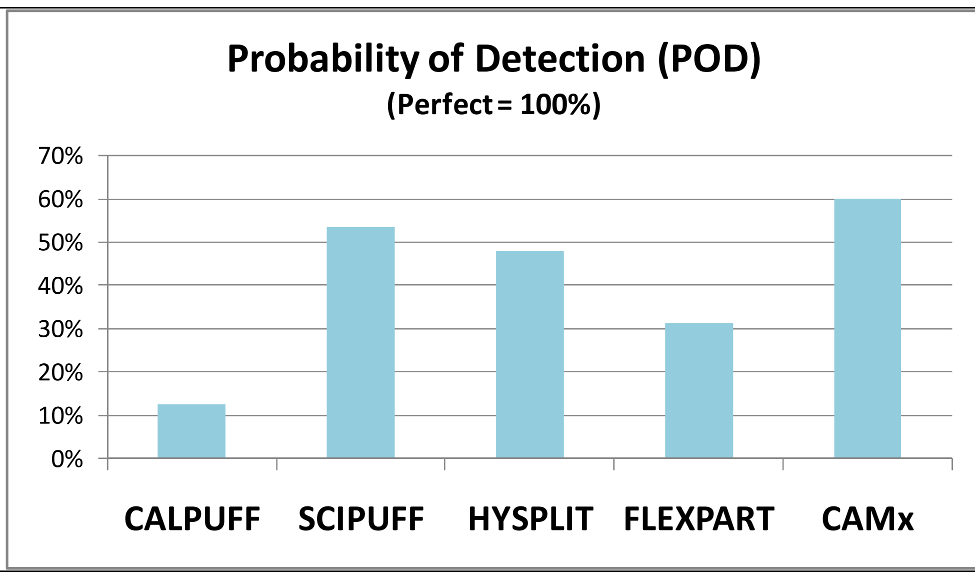


Figure 6-7. Probability of Detection (POD) statistical performance metric for the five LRT models and the ETEX tracer field experiment.

The Threat Score (TS) is the ratio of the number of times that a tracer is both predicted and observed at a monitor-time at the same time (i.e., common hits among the predictions and observations) divided by the number of monitor-time events that either a prediction or observed tracer occurred at a monitor (i.e., either a predicted or observed hits), with a perfect score of 100% (which means there were no occurrences when there was a predicted hit but an observed miss and vice versa).

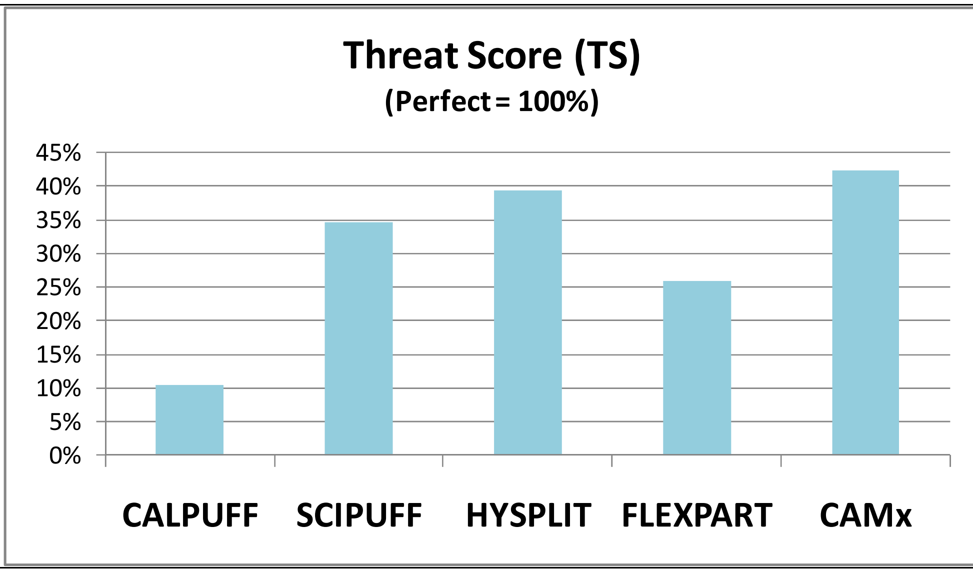


Figure 6-8. Threat Score (TS) statistical performance metric for the five LRT models and the ETEX tracer field experiment.

6.4.1.2 Global Analysis of Model Performance

Eight global statistical analysis metrics are used to evaluate the five LRT model performance using the ETEX data base that are described in Section 2.4 and consist of the FOEX, FA2, FA5, NMSE, PCC, FB, KS and RANK statistical metrics.

The Factor of Exceedance (FOEX) gives a measure of the scatter of the modeled predicted and observed and a level of underestimation versus overestimation of the model. FOEX is bounded by -50% to +50%. The within a Factor of α (FAα), where we used within a Factor of 2 (FA2) and 5 (FA5), also gives an indication of the amount of scatter in the predicted and observed tracer pairs, but no information on whether the model is over- or under-predicting. A perfect model would have an FAα score of 100%. A good performing model would have a FOEX score near zero and high FAα values. A model with a large negative FOEX and low FAα values would indicate an under-prediction tendency. Whereas a model with a large positive FOEX and low FAα would suggest a model that over-predicts.

Figure 6-9 displays the FOEX performance metrics for the five LRT models and the ETEX modeling period.

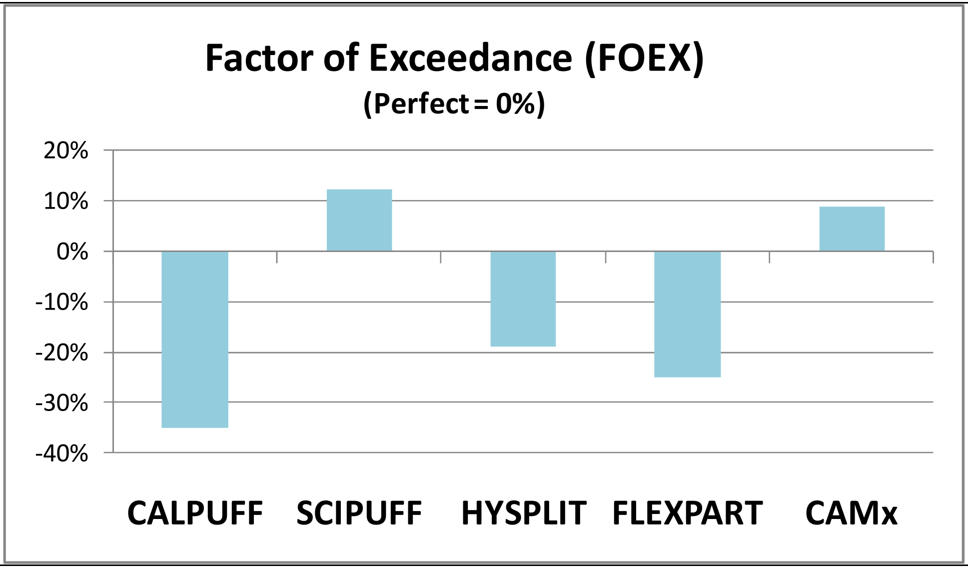


Figure 6-9. Factor of Exceedance (FOEX) statistical performance metric for the five LRT models and the ETEX tracer field experiment.

The rankings of the five LRT models are the same whether using the FA2 or FA5 performance metric.

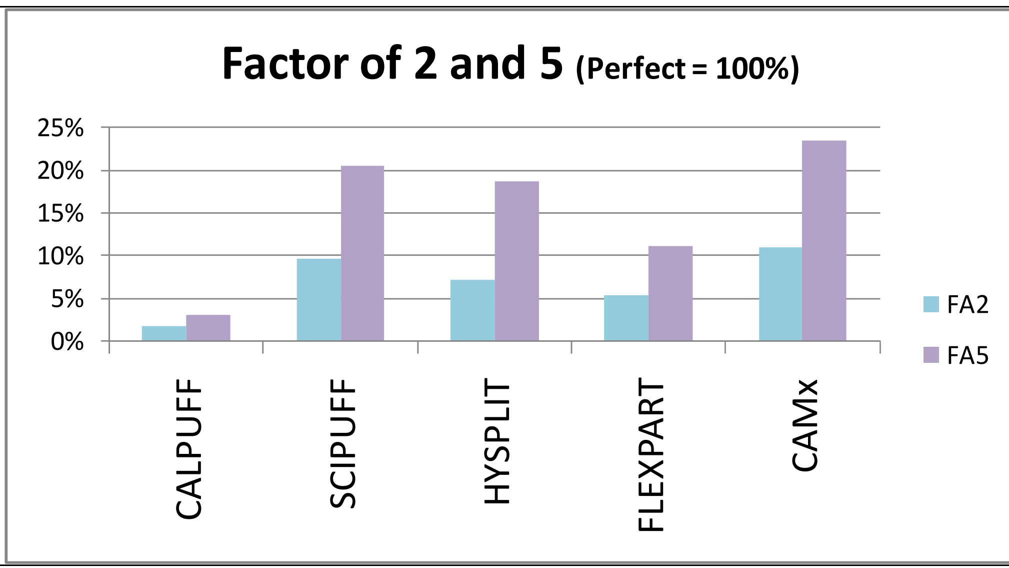


Figure 6-10. Factor of 2 (FA2, top) and Factor of 5 (FA5, bottom) statistical performance metric for the five LRT models and the ETEX tracer field experiment.

The scores for the Normalized Mean Squared Error (NMSE) statistical metrics for the five LRT models are given in Figure 6-11. The NMSE provides an indication of the deviations between the predicted and observed tracer concentrations paired by time and location with a perfect model receiving a 0.0 score.

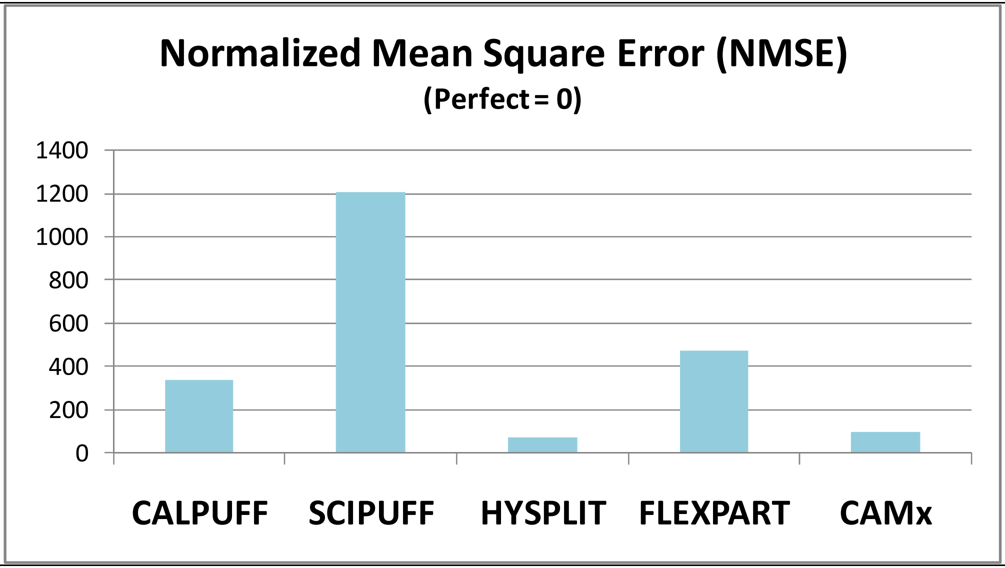


Figure 6-11. Normalized Mean Square Error (NMSE) statistical performance metric for the five LRT models and the ETEX tracer field experiment (pgm^{-3}).

The Pearson's Correlation Coefficient (PCC or R) ranges between -1.0 and +1.0, a model that has a perfect correlation with the observations would have a PCC value of 1.0. The PCC values for the five LRT models are shown in Figure 6-12. All of the models have positive PCCs so none are negatively correlated with the observe data.

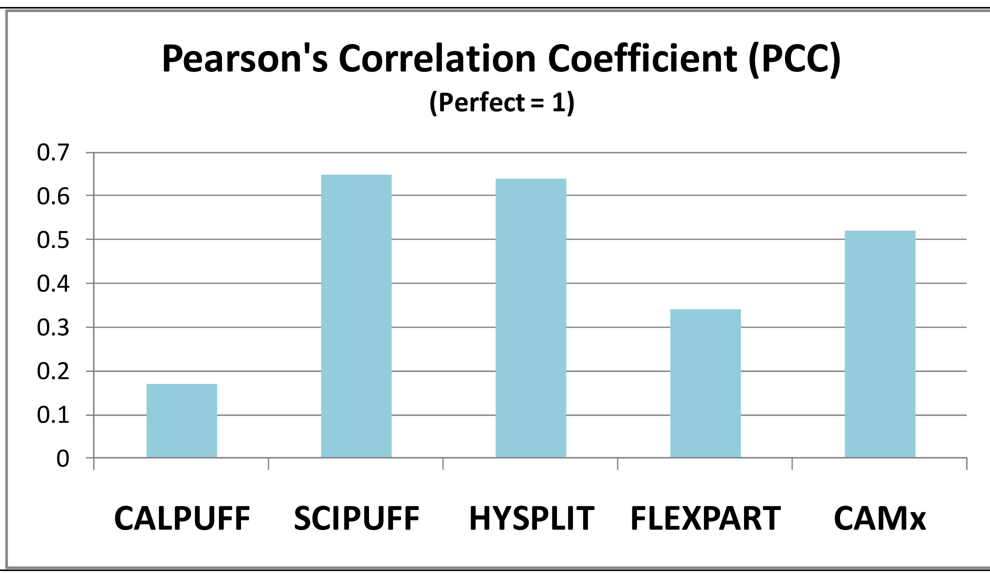


Figure 6-12. Pearson's Correlation Coefficient (PCC) statistical performance metric for the five LRT models and the ETEX tracer field experiment.

The Fractional Bias (FB) is a measure of bias in the deviations between the predicted and observed paired tracer concentrations and ranges from -2.0 to +2.0 with a perfect model receiving a 0.0 score. Figure 6-13 displays the FB parameter for the five LRT models. All five models exhibit a positive FB, which suggests an overestimation tendency.

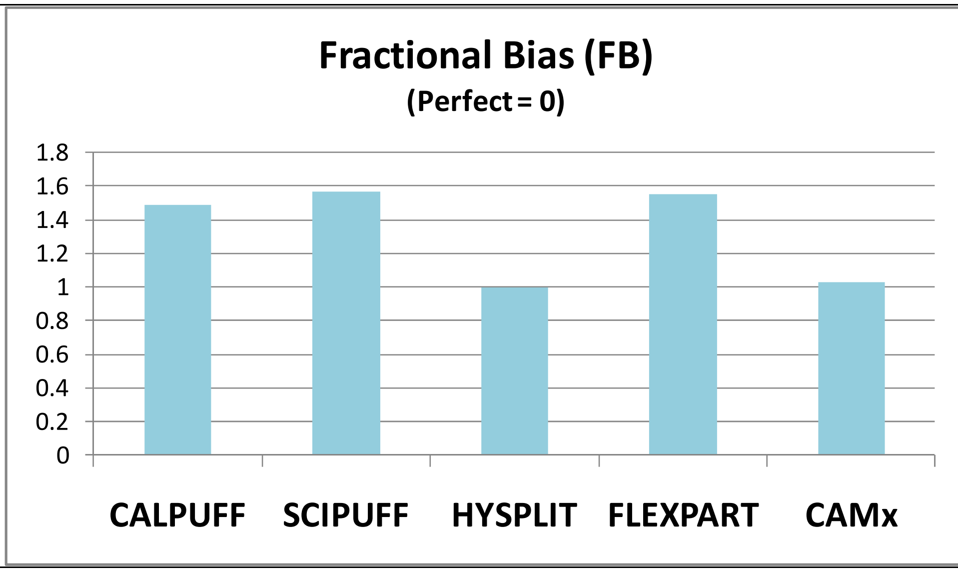


Figure 6-13. Fractional Bias(FB) statistical performance metric for the five LRT models and the ETEX tracer field experiment.

The Kolmogorov-Smirnoff (KS) parameter compares the frequency distributions of the predicted and observed tracer concentrations unmatched by time and location. It is the only unpaired statistical metric in the global statistics. The KS parameter ranges from 0% to 100% with a perfect model receiving a score of 0%. The KS parameters for the five LRT models and the ETEX modeling are shown in Figure 6-14.

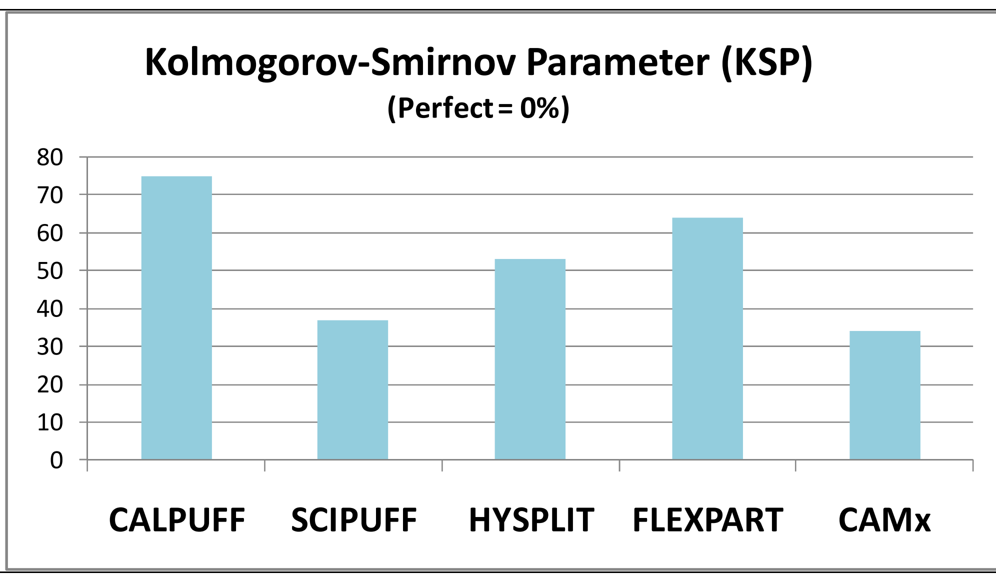


Figure 6-14. Kolmogorov – Smirnov Parameter (KSP) statistical performance metrics for the five LRT models and the ETEX tracer field experiment.

The RANK statistical performance metric was proposed by Draxler (2001) as a single model performance metric that equally ranks the combination of performance metrics for correlation (PCC or R), bias (FB), spatial analysis (FMS) and unpaired distribution comparisons (KS). The RANK metrics ranges from 0.0 to 4.0 with a perfect model receiving a score of 4.0. Figure 6-15 lists the RANK model performance statistics for the five LRT models. CAMx is the highest ranked model using the RANK metric with a value of 1.9. Note that CAMx scores high in all four areas of model performance (correlation, bias, spatial and cumulative distribution). The next highest ranking models according to the RANK metric are SCIPUFF and HYSPLIT with a score of 1.8.

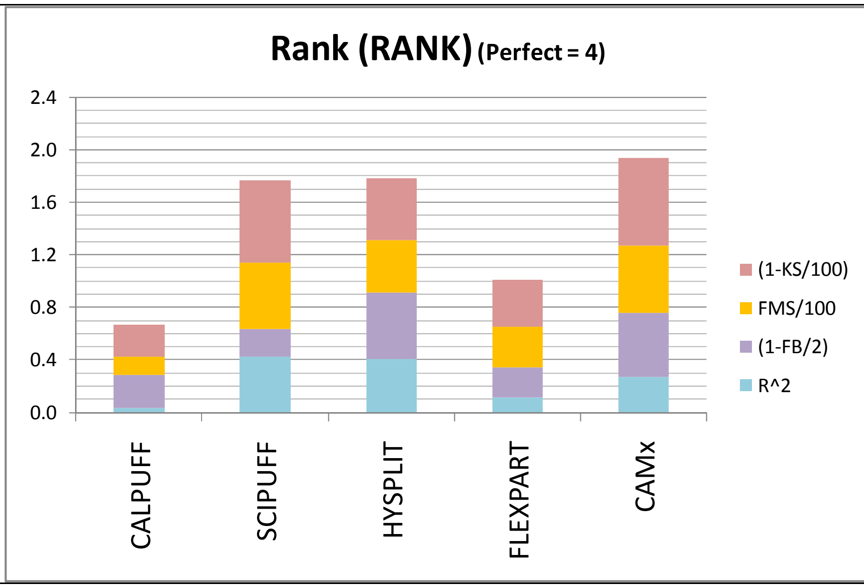


Figure 6-15. RANK statistical performance metric for the five LRT models and the ETEX tracer field experiment.

6.4.1.3 Summary of Model Ranking using Statistical Performance Measures

Table 6-1 summarizes the rankings between the five LRT models for the 11 performance statistics analyzed. Depending on the statistical metric, three different models were ranked first for a particular statistic with CAMx being ranked first most of the time (64%) and HYSPLIT ranked first second most (27%). In order to come up with an overall rank across all eleven statistics we average the modeled ranking order in order to come up with an average ranking that listed CAMx first, HYSPLIT second, SCIPUFF third, FLEXPART fourth and CALPUFF the fifth. This is the same ranking as produced by the RANK integrated statistics that combines the four statistics for correlation (PCC), bias (FB), spatial (FMS) and cumulative distribution (KS) giving credence that the RANK statistic is a potentially useful performance statistic for indicating over all model performance of a LRT dispersion model.

Table 6-1. Summary of model ranking using the statistical performance metrics.

Statistic	1st	2nd	3rd	4th	5th
FMS	CAMx	SCIPUFF	HYSPLIT	FLEXPART	CALPUFF
FAR	HYSPLIT	FLEXPART	CAMx	SCIPUFF	CALPUFF
POD	CAMx	SCIPUFF	HYSPLIT	FLEXPART	CALPUFF
TS	CAMx	HYSPLIT	SCIPUFF	FLEXPART	CALPUFF
FOEX	CAMx	SCIPUFF	HYSPLIT	FLEXPART	CALPUFF
FA2	CAMx	SCIPUFF	HYSPLIT	FLEXPART	CALPUFF
FA5	CAMx	SCIPUFF	HYSPLIT	FLEXPART	CALPUFF
NMSE	HYSPLIT	CAMx	CALPUFF	FLEXPART	SCIPUFF
PCC or R	SCIPUFF	HYSPLIT	CAMx	FLEXPART	CALPUFF
FB	HYSPLIT	CAMx	CALPUFF	FLEXPART	SCIPUFF
KS	CAMx	SCIPUFF	HYSPLIT	FLEXPART	CALPUFF
Avg. Ranking	CAMx	HYSPLIT	SCIPUFF	FLEXPART	CALPUFF
Avg. Score	1.55	2.27	2.73	3.82	4.64
RANK Ranking	CAMx	HYSPLIT	SCIPUFF	FLEXPART	CALPUFF

6.4.2 Spatial Displays of Model Performance

Figure 6-16 displays the observed tracer distribution 24, 36, 48 and 60 hours after the beginning of the tracer release as well as the predicted tracer distribution by CALPUFF, SCIPUFF, FLEXPART and CAMx. Note that the observed tracer spatial distribution plots in Figure 6-16 are color coded at the monitoring sites. Previously the spatial distribution of the observed tracer distribution was also presented using spatial interpolation from the monitoring sites in Figure 6-3b. However, such an interpolation is in itself a model and may not be correct, so in Figure 6-16 the observed tracer concentrations at the monitoring sites is presented for comparison with the five LRT models.

24 hours after the tracer release, the observed tracer was advected to the east-northeast and was present across northern France and Germany (Figure 6-16a, top left). CALPUFF advected the tracer with a more northeasterly direction than observed and underestimated the plume spread thereby missing the observed tracer concentrations in southern Germany (Figure 6-16a, top right). SCIPUFF (Figure 6-16a, middle left) also appeared to advect the tracer with more of a northeast direction than observed, but had more plume spread so was better able to capture the occurrence of observed tracer concentrations in southern Germany. FLEXPART (Figure 6-16a, middle right) and HYSPLIT (Figure 6-16a, bottom left) both correctly advect the tracer initially in the east-northeast direction, but FLEXPART greatly underestimates the observed plume spread on the ground with HYSPLIT also underestimating the plume spread but not as much as FLEXPART. CAMx also appears to initially transport the tracer with more of a northeasterly than east-northeast direction as seen with SCIPUFF. Like SCIPUFF, the CAMx tracer plume has a southerly bulge that begins to capture the occurrence of the observed tracer concentrations in southern Germany that the other three LRT dispersion models miss completely. All of the models fail to reproduce the leading edge of the observed tracer cloud in northeastern Germany, with SCIPUFF and CAMx best able to simulate the observed front of the tracer cloud. The LRT dispersion models underestimation of the location of the leading edge of the observed tracer cloud is likely related to the MM5 model wind speed underestimation bias (see Figure 6-4a). SCIPUFF tends to have an overestimation bias of both concentrations and spatial extend of the observed tracer 24 hours after its release.

The predicted and observed tracer distribution 36 hours after its release is shown in Figure 6-16b. The observed tracer plume moved eastward and traverses Germany 36 hours after the start of the release and is stretched from the west coast of Sweden in the north to Hungary in the South. CALPUFF is displacing the tracer too far to the northeast with the centerline over the North Sea stretching from the northern tip of France to southern tip of Sweden and missing most of the observed tracer concentrations in France, Germany and Czechoslovakia. SCIPUFF covers the spatial extent of the observed tracer cloud, and then some, correctly estimating the coverage across Germany and Czechoslovakia. FLEXPART reproduces the easterly transport of the observed tracer clouds 36 hours after the start of the release, but greatly underestimates the ground level plume spread. HYSPLIT also reproduces the easterly transport of the observed tracer plume but also understates the plume spread missing the observed tracer concentrations in southern Germany and Czechoslovakia. CAMx has a similar distribution as SCIPUFF with less of an overestimation bias locating the tracer center of mass slightly too far north. After 36 hours from the start of the tracer release the leading edge of the observed tracer is just entering Poland from Germany, which is reproduced well by SCIPUFF, HYSPLIT and CAMx with FLEXPART having a lag and CALPUFF locating the leading edge of the tracer too far north.

By 48 hours after the beginning of the tracer release, the observed tracer cloud is exhibiting a northwest to southeast orientation stretching from Denmark in the northwest to Hungary in the southeast (Figure 6-16c). The CALPUFF tracer plume, however, is advected too far north into the North Sea and southern Finland with a circular Gaussian puff distribution. SCIPUFF correctly reproduces the northwest to southeast orientation of the observed tracer cloud and almost completely covers the observed tracer cloud but appears to overestimate the spatial extent and concentrations of the observed tracer. HYSPLIT and FLEXPART also are exhibiting a northwest to southeast orientation of the observed tracer cloud but both models, and especially FLEXPART, understate the spatial spread of the observed ground level tracer concentrations. CAMx reproduces the northwest to southeast orientation of the observed tracer distribution and appears to better match the observed tracer plume spread than SCIPUFF (overstated) and FLEXPART and HYSPLIT (understated).

After 60 hours after the beginning of the tracer release, the observed tracer cloud still has the northwest to southeast orientation that stretches from southern Finland in the northwest to the most western point of Romania. The CALPUFF model has advected its circular puffs to the north with the center over the North Sea just west of southern Finland almost completely missing the spatial extent of the observed tracer. The other four LRT dispersion models are correctly estimating the northwest to southeast orientation of the observed tracer pattern 60 hours after the beginning of the tracer release. However, the remaining four LRT models (less CALPUFF) estimate different amounts of plume spread with FLEXPART estimating a very narrow predicted tracer cloud that understates the observed spread of the tracer footprint. SCIPUFF estimated the largest spatial extent of the tracer cloud that is much larger than observed. HYSPLIT and CAMx estimated tracer spread that is closer to what was observed.

The comparison of the spatial distribution of the predicted and observed tracer concentrations from the ETEX1 experiment helps explain the statistical model performance presented earlier. The poor performance of the CALPUFF model is because it keeps the tracer in a circular Gaussian plume distribution that is advected too far north and fails to reproduce the elongation and stretching of the observed tracer cloud in the northwest to southeast orientation. The other four LRT dispersion models do allow the predicted tracer cloud to take on the northwest to southeast distribution matching the basic features of the observed tracer footprint well, but with different amounts of plume spread. FLEXPART greatly understates the amount of tracer plume spread and observed surface concentrations, whereas SCIPUFF overstates the amount of plume spread as well as the surface concentrations.

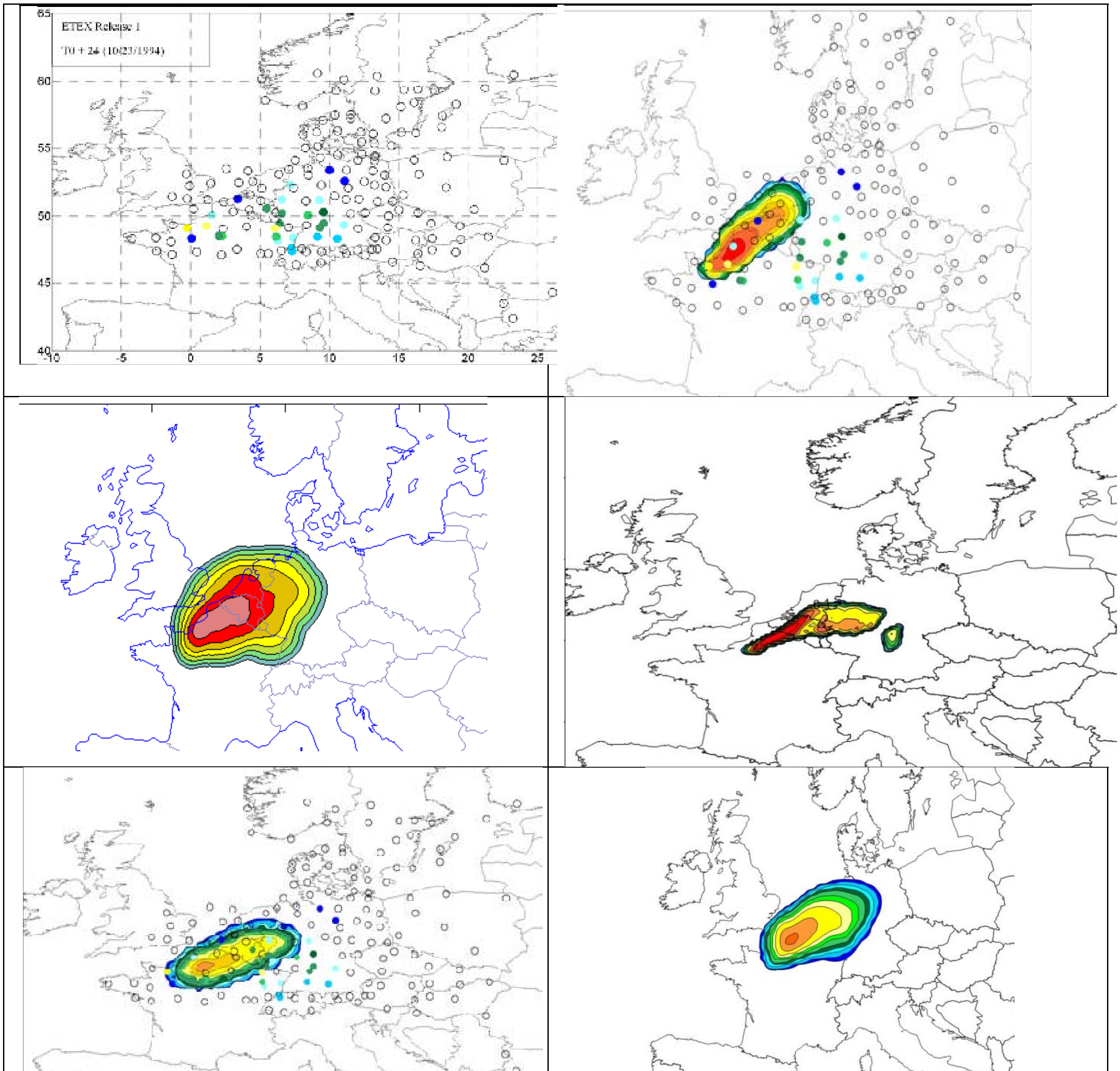


Figure 6-16a. Comparison of spatial distribution of the ETEX tracer concentrations 24 hours after release for the observed (top left), CALPUFF (top right), SCIPUFF (middle left), FLEXPART (middle right), HYSPLIT (bottom left) and CAMx (bottom right).

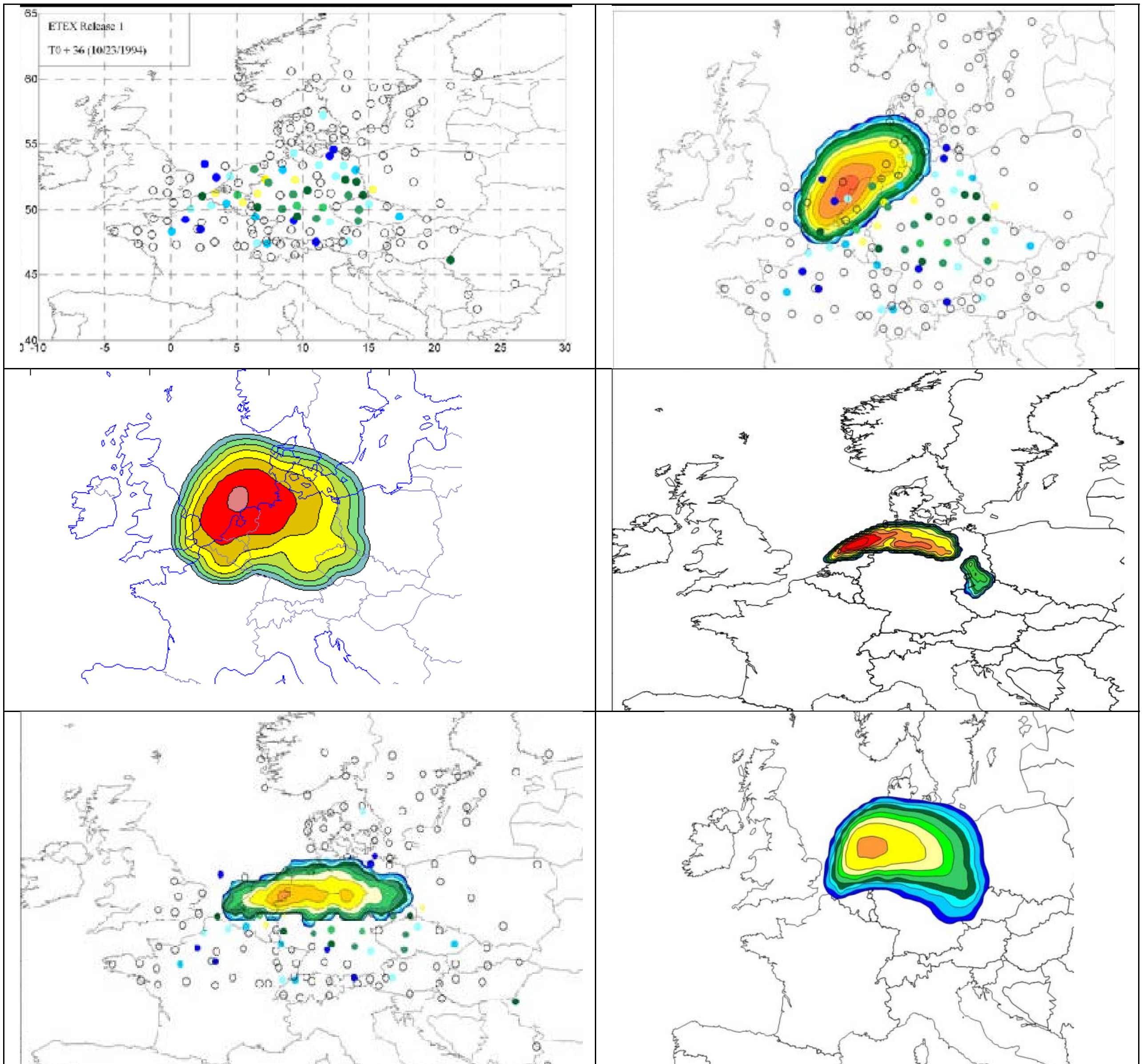


Figure 6-16b. Comparison of spatial distribution of the ETEX tracer concentrations 36 hours after release for the observed (top left), CALPUFF (top right), SCIPUFF (middle left), FLEXPART (middle right), HYSPLIT (bottom left) and CAMx (bottom right).

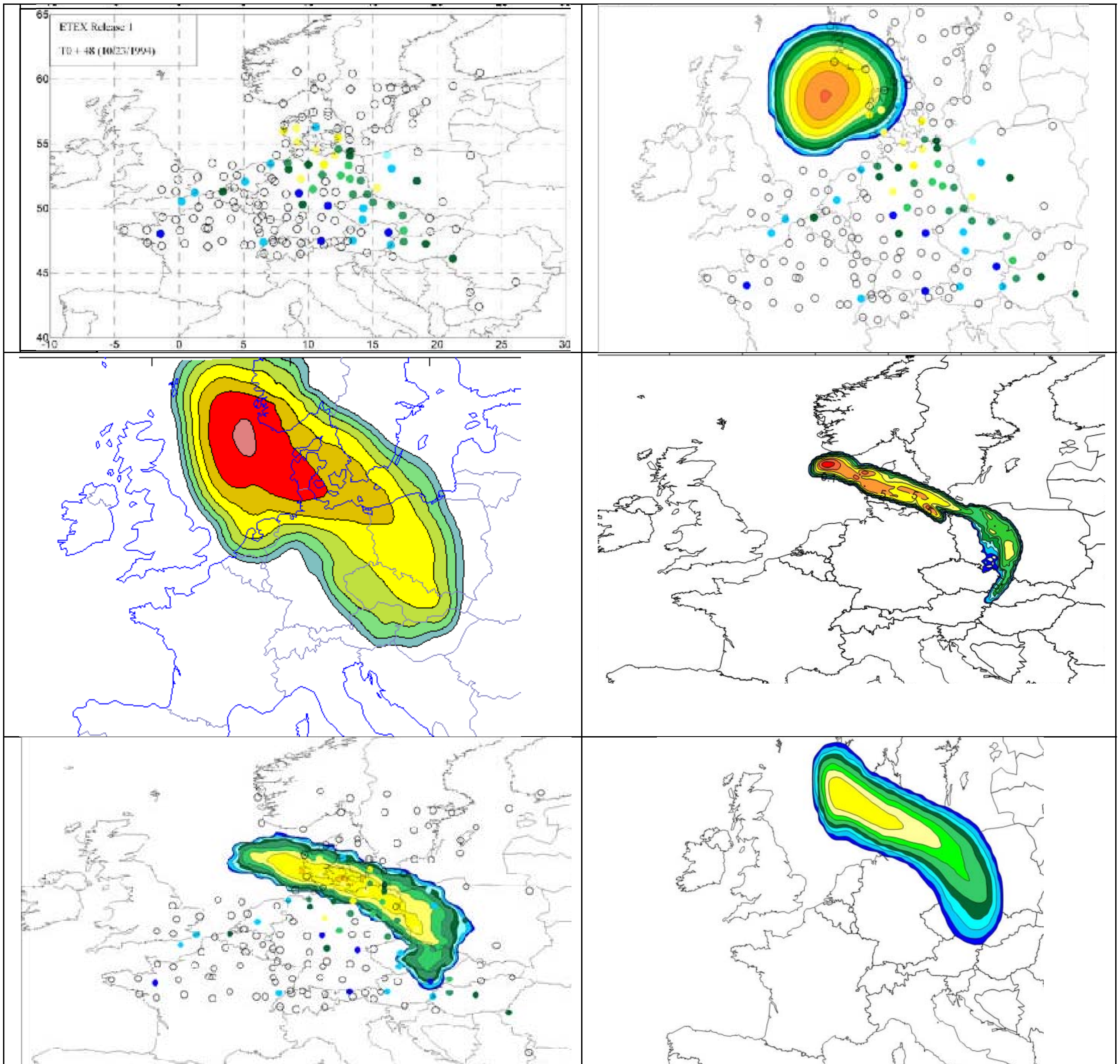


Figure 6-16c. Comparison of spatial distribution of the ETEX tracer concentrations 48 hours after release for the observed (top left), CALPUFF (top right), SCIPUFF (middle left), FLEXPART (middle right), HYSPLIT (bottom left) and CAMx (bottom right).

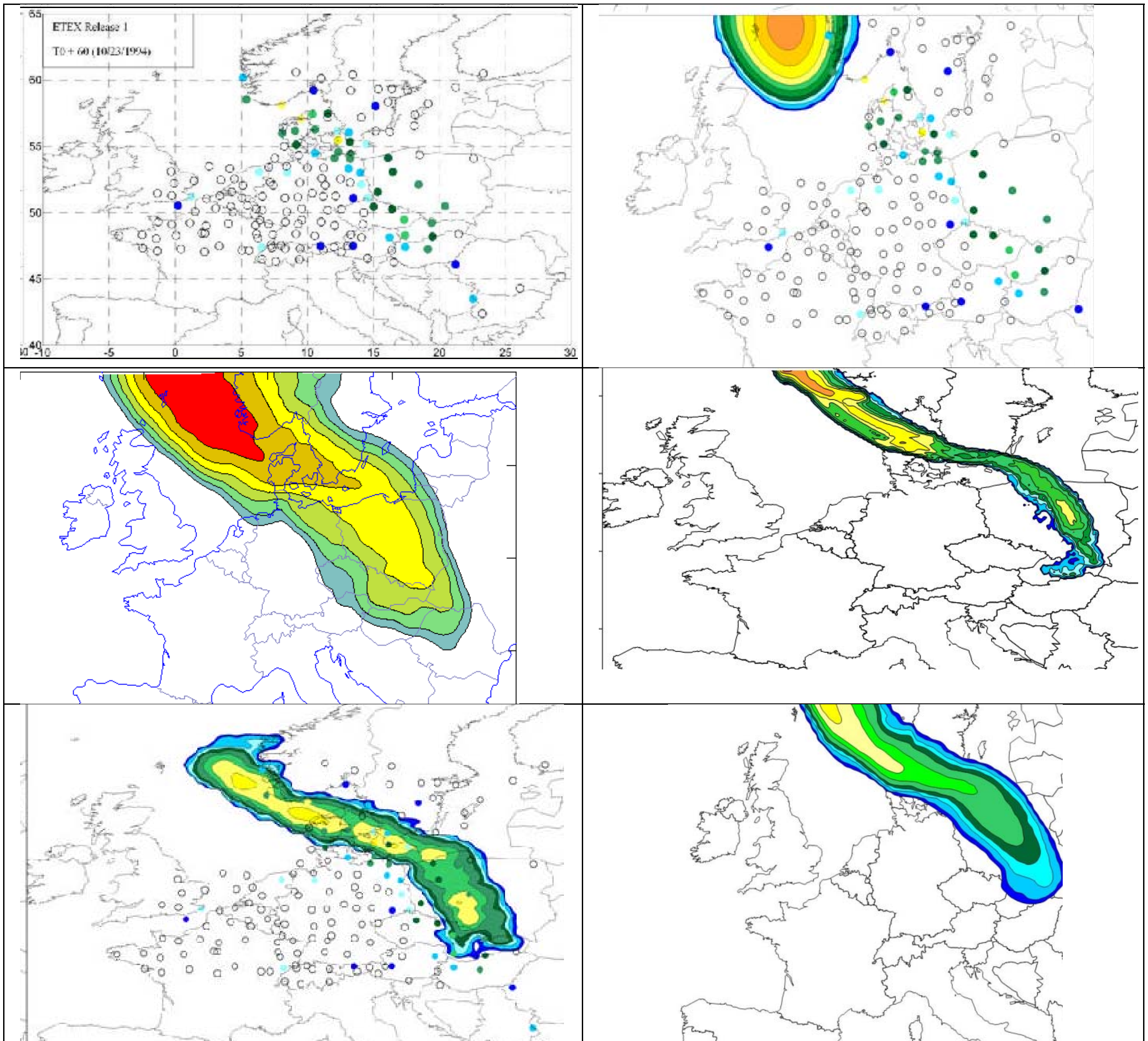


Figure 6-16d. Comparison of spatial distribution of the ETEX tracer concentrations 60 hours after release for the observed (top left), CALPUFF (top right), SCIPUFF (middle left), FLEXPART (middle right), HYSPLIT (bottom left) and CAMx (bottom right).

6.4.3 CAMx Sensitivity Tests

Sixteen CAMx sensitivity tests were conducted to investigate the effects of vertical diffusion, horizontal advection solvers and use of the sub-grid scale Plume-in-Grid (PiG) module on the model performance for the ETEX tracer experiment.

<u>Plume-in-Grid (PiG) Module</u>: The PiG module treats the near-source plume dispersion (and chemistry if applicable) of a point source plume using a subgrid-scale Lagrangian puff module. The mass from the PiG puff module is transferred to the grid model when the plume size is commensurate with the grid cell size used in the CAMx simulation. Two types of PiG sensitivity tests were conducted in this study to investigate the effects of the PiG module on model performance:

- NoPiG: The tracer emissions were released directly into the CAMx 36 km grid cell containing the tracer release location calculating plume rise using the local meteorological conditions to inject the emissions into the appropriate vertical layer.
- PiG: Calculate plume rise using local meteorological conditions and simulate the early evolution of plume dispersion using the PiG module.

Vertical Diffusion Coefficients (Kz): The Kz coefficients define the rate of vertical mixing in a column of grid cells in CAMx. MM5 meteorological model does not directly output Kz, thus the MM5CAMx pre-processor has several different algorithms for diagnosing the Kz coefficients. Four different Kz algorithms were evaluated in the CAMx sensitivity tests in this study:

- OB70: O'Brien 1970 algorithm for calculation Kz values by diagnosing them from the MM5 output.
- TKE: The Eta planetary boundary layer (PBL) scheme used in the ETEX MM5 meteorological modeling has a Turbulent Kinetic Energy (TKE) formulation. When using a TKE PBL scheme, MM5CAMx can calculate the Kz coefficients directly from the TKE values, rather than diagnosing them from the other meteorological variables in the MM5 output.
- ACM2: The Asymmetric Convective Mixing (ACM2) algorithm has two components: a standard Kz scheme that calculates diffusion between two adjacent grid cells in a column; and a non-local diffusion scheme that can calculate diffusion between grid cells in a column that are not adjacent. In CAMx, the ACM2 scheme will deduce when convective activity is present in a column of grid cells and add the non-local diffusion to the standard local diffusion based on the Kz coefficients.
- CMAQ: Use the algorithm for calculating Kz from the CMAQ modeling system (Byun and Ching, 1999).

Horizontal Advection Solver: Horizontal advection (transport) is solved in CAMx using finite difference algorithms that were explicitly developed for simulating transport and limit numerical diffusion that can artificially reduce concentration peaks. Two horizontal transport algorithms are implemented in CAMx and their effect on model performance for the ETEX experiment was evaluated:

Bott: The Bott (1989) scheme is a positive definite transport scheme that limits numerical diffusion.

PPM: The Piecewise Parabolic Method (PPM; Colella and Woodward, 1984) is a higher order positive definite transport scheme that is also designed to limit numerical diffusion.

The configuration of CAMx presented in the previous sections comparing model performance against the other four LRT models was a standard configuration used in many regional model applications:

- Don't use PiG subgrid-scale puff module (NoPiG)
- Use of CMAQ-like Kz vertical diffusion coefficients (CMAQ)
- Use of PPM horizontal advection solver (PPM)

6.4.3.1 NoPiG CAMx Sensitivity Tests

Figure 6-17 displays the CAMx spatial model performance statistics for the sensitivity tests that were run without using the PiG subgrid-scale puff module. For the FMS statistic, the CMAQ Kz and PPM horizontal transport sensitivity test (CMAQ/PPM) is performing the best with a FMS value of 51.8% followed by CMAQ/Bott (50.9%) and ACM2/PPM (50.8%). Vertical diffusion has the biggest effect with the ranking of the algorithms from best to worst using the FMS statistic being CMAQ, ACM2, TKE and OB70. Whereas, for the horizontal advection solver the PPM algorithm performs slightly better than Bott using the FMS statistic.

For the FAR statistic, CMAQ/Bott has the best score (39.0%) followed by CMAQ/PPM (41.0%). Overall CMAQ is the best performing vertical diffusion formulation and Bott performs better than PPM for horizontal advection using the FAR statistic.

For the POD and TS spatial statistics, the CMAQ and TKE vertical diffusion algorithms perform substantially better than the OB70 and ACM2 approaches. There are much smaller differences in the model performance using the two advection solvers for the POD and TS statistics.

In summary, based on the spatial statistics, the CMAQ Kz algorithm appears to be the best performing approach for vertical mixing followed by TKE. And with the exception of the FAR statistic, PPM produces slightly better spatial model performance statistics than the Bott horizontal advection solver. The differences in vertical diffusion algorithms has a greater effect on CAMx model performance than the differences in horizontal advection solvers.

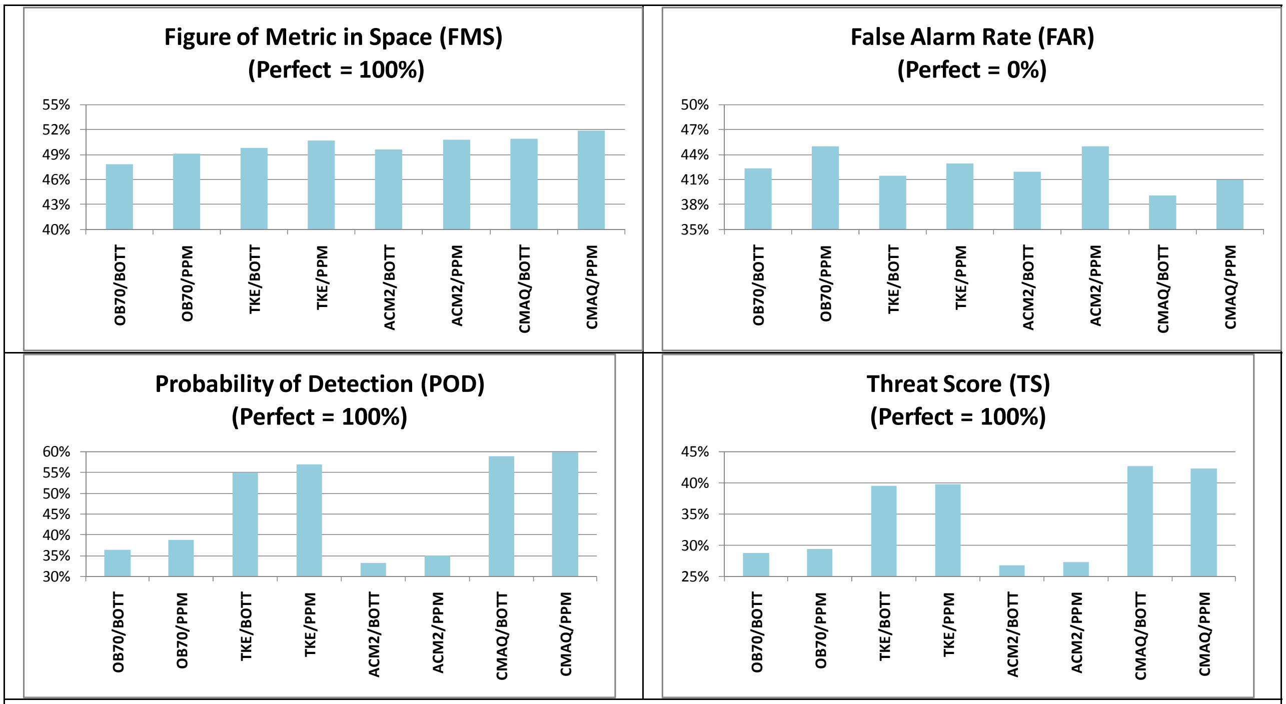


Figure 6-17. Spatial model performance statistics for the CAMx sensitivity tests without using the PiG subgrid-scale puff module (NoPiG).

Figure 6-18 displays the global statistics for the CAMx NoPiG sensitivity tests with Figures 6-18a and 6-18b containing the statistical metrics where the best performing model has the, respectively, lowest and highest score. For the FOEX metric, the vertical diffusion algorithm has the biggest effect with the ACM2 scoring the best with an essentially zero FOEX score followed by OB70 with values -2.4% (OB70/Bott) and -3.4% (OB70/PPM). The TKE (8.5%) and PPM (8.7% and 9.1%) have the highest (worst) FOEX scores. The FOEX metrics using the two alternative horizontal advection algorithms are essentially the same.

Using the NMSE statistical performance metric, the CMAQ vertical diffusion scheme performs best with OB70 and TKE producing very similar results next, with the ACM2 exhibiting the worst NMSE performance results (Figure 6-18a, top right). The PPM horizontal advection scheme is performing slightly better than the Bott algorithm based on the NMSE metric.

The CMAQ vertical diffusion scheme is also the best performing method according to the FB metrics followed by the TKE then ACM2 and then OB70 in last. According to the FB metrics, PPM performs slightly better than Bott.

For the KS parameter, the OB70 is the best vertical mixing method with CMAQ barely beating out ACM2 in second and TKE slightly worse. The PPM horizontal advection solver is performing slightly better than Bott for the KS parameter.

For the within a factor of 2 and 5 metrics (FA2 and FA5, Figure 6-18b, top), the CMAQ and TKE vertical mixing approaches are clearly performing better than the OB70 and ACM2 methods and the PPM horizontal advection solver is clearly performing better than Bott. For the FA2, the TKE/PPM is the best performing configuration (11.4%) followed by CMAQ/PPM (10.9%), Whereas for the FA5 the reverse is true with CMAQ/PPM being the best performing configuration (23.4%) followed by TKE/PPM (22.2%).

There is essentially no difference in the PCC statistic using the two horizontal advection solvers (Figure 6-18b, bottom right). According to the PCC metric, CMAQ is the best performing vertical diffusion approach (0.52) followed by TKE (0.37 and 0.38), OB70 (0.35) and ACM2 (0.26 and 0.27).

The final panel in Figure 6-18b (bottom right) displays the overall RANK statistic. The RANK statistics orders the model performance of the CAMx configurations without PiG as follows:

1. CMAQ/PPM (1.94)
2. CMAQ/Bott (1.90)
3. TKE/PPM (1.70)
4. OB70/PPM (1.66)
5. TKE/Bott (1.65)
6. ACM2/PPM (1.60) (tied)
7. OB70/Bott (1.60) (tied)
8. ACM2/Bott (1.54)

Based on this analysis the CMAQ Kz coefficients is the best performing vertical diffusion approach followed by TKE and the PPM horizontal advection algorithm is performing slightly better than Bott. The vertical diffusion algorithm has a greater effect on CAMx model performance compared to the choice of horizontal advection solvers.

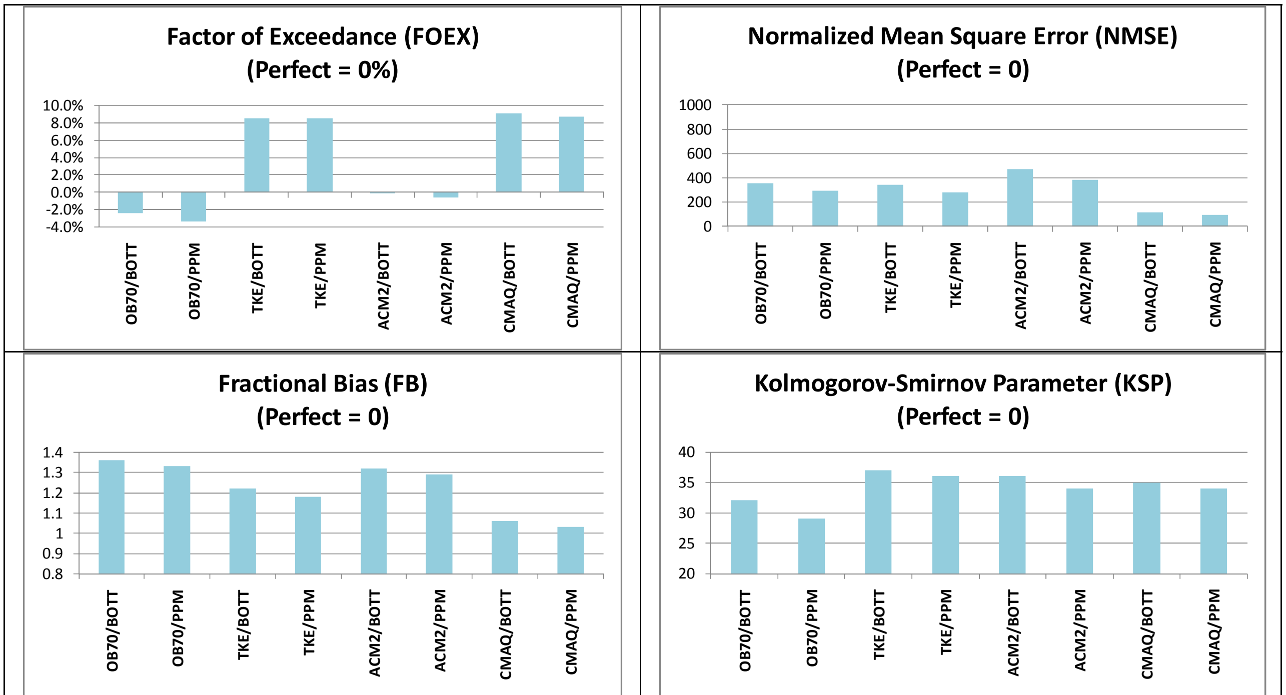


Figure 6-18a. Global model performance statistics for the CAMx sensitivity tests without using the PiG subgrid-scale puff module.

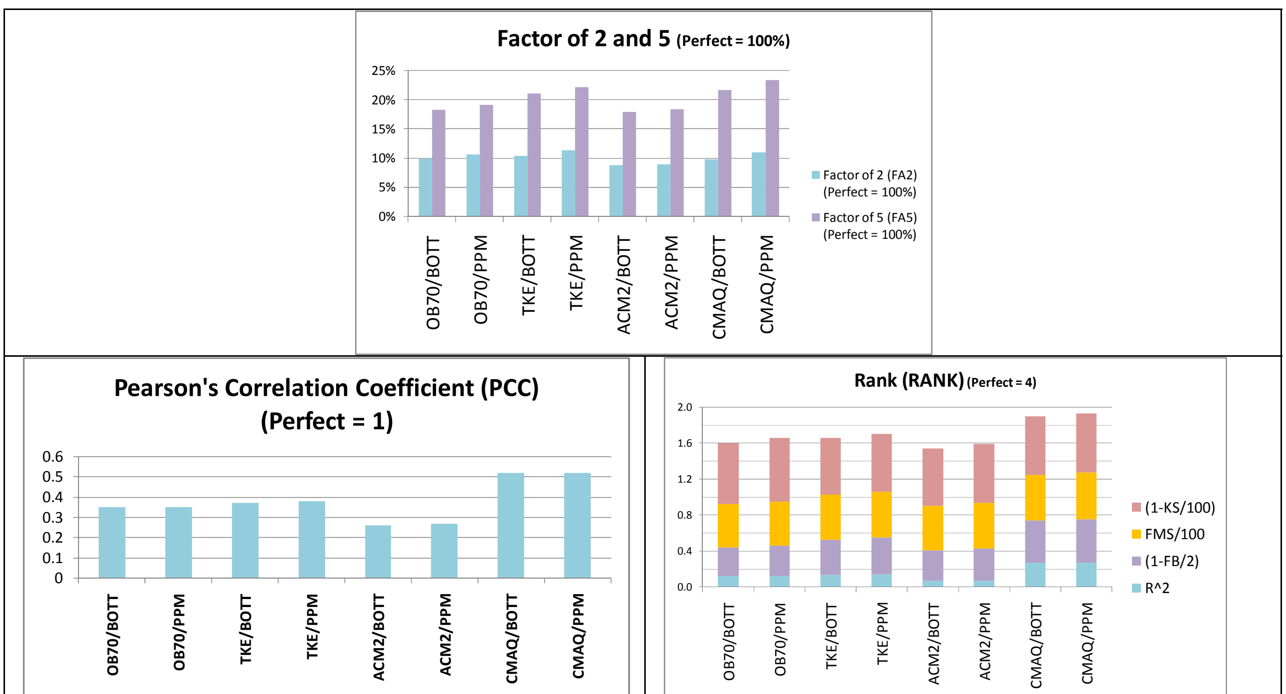


Figure 6-18b. Global model performance statistics for the CAMx sensitivity tests without using the PiG subgrid-scale puff module.

6.4.3.2 Effect of PiG on Model Performance

Whether better model performance is obtained using the PiG module or not frequently depends on the statistical metric being analyzed and the CAMx model configuration (vertical diffusion algorithm and horizontal advection solver). However, whether the PiG is used or not has very little difference on the rankings of the CAMx model performance using the alternative vertical mixing and horizontal advection approaches. In general, it appears that the CAMx model performance without the PiG is performing slightly better than its performance using the PiG.

The spatial performance statistics are sometimes improved and sometimes degraded when the PiG module is invoked. For the global statistics, the PCC performance statistic is degraded by -11% to -37% (-0.03 to -0.13 points) when the PiG module is invoked. Similarly, use of the PiG versus NoPiG module increases (degrades) the FB metric by 5 to 18 percent and also increases (degrades) the NMSE metrics for all model configurations.

Table 6-2 summarized the RANK model performance statistic for the different CAMx model configurations with and without the PiG module. For each model vertical diffusion/horizontal advection configuration, using the PiG module always results in slightly lower RANK statistics that are from -3.9% to -8.5% lower than when the PiG module is not used. The ranking of the top four CAMx vertical diffusion/horizontal advection configurations remains unchanged whether the PiG module is used or not. And by far the most important parameter examined in regards to the RANK model performance statistics for the ETEX experiment in the CAMx sensitivity tests is the vertical mixing algorithm, with the CMAQ Kz parameterization producing the best four RANK model performance statistics out of the 16 sensitivity tests: (1) NoPiG/CMAQ/PPM; (2) NoPiG/CMAQ/Bott; (3) PiG/CMAQ/PPM; and (4) PiG/CMAQ/Bott.

Table 6-2. CAMx RANK model performance statistic and model rankings for different model configurations with and without using the PiG subgrid-scale puff model.

Model Configuration	Without PiG Module		With PiG Module		PiG-NoPiG	
	RANK	Model Ranking	RANK	Model Ranking	ΔRANK	Percent
OB70/BOTT	1.60	7[a]	1.53	6[a]	-0.07	-4.4%
OB70/PPM	1.66	4	1.55	4	-0.11	-6.6%
TKE/BOTT	1.65	5	1.51	7	-0.14	-8.5%
TKE/PPM	1.70	3	1.56	3	-0.14	-8.2%
ACM2/BOTT	1.54	8	1.48	8	-0.06	-3.9%
ACM2/PPM	1.60	6[a]	1.53	5[a]	-0.07	-4.4%
CMAQ/BOTT	1.90	2	1.76	2	-0.14	-7.4%
CMAQ/PPM	1.94	1	1.80	1	-0.14	-7.2%
[a] tied						

6.4.4 CALPUFF Sensitivity Tests

Most CALPUFF applications have limited the distance downwind that the model is applied for to less than 300 km from the source. However, the evaluation of CALPUFF in the ETEX study has applied the model to much farther downwind distances. The issue of the downwind applicability of the CALPUFF model was raised in the FLAG (2000) report and EPA's June 26-27, 2000 7th Conference on Air Quality Modeling[19] that proposed to list CALPUFF as an EPA recommended model for far-field applications. However, when CALPUFF was designated an EPA recommended far-field model in a 2003 Federal Register (FR) notice, EPA noted that "*…since the 7th Modeling Conference, enhancements were made to CALPUFF that allow puffs to be split both horizontally (to address wind direction shear) and vertically (to address spatial variation in meteorological conditions). These enhancements likely will extend the system's ability to treat transport and dispersion beyond 300 km*" (68 FR 18441). EPA goes on to further state that "*…Future performance comparisons for transport beyond 300 km are likely to extend the applicability and use of the modeling system, and we intend to watch for such evaluations very diligently. In an effort to keep the public abreast with the latest findings, EPA requests that evaluation results of the CALPUFF modeling system be sent to us (SCRAM webmaster) in an electronic format suitable for distribution, or that citations be provided for copyrighted material. EPA will post this information on its website for review and assessment*" (EPA, 2003).

Despite the passage of eight years since EPA's request for CALPUFF evaluation regarding its suitability for application beyond 300 km, no such documentation has been submitted. Thus, the ETEX CALPUFF evaluation serves as an important source of information on the downwind applicability of CALPUFF. In this section we present two types of performance analysis:

- Analyze the CALPUFF model performance as a function of distance from the source to determine whether the poor performance of CALPUFF relative to the other LRT models is related to applying the model beyond its downwind distance of applicability; and
- Perform CALPUFF puff splitting sensitivity tests to determine whether puff splitting can increase the downwind distance applicability of CALPUFF, as suggested in the 2003 Federal Register notice.

6.4.4.1 Time Dependent Model Performance

Figure 6-19 displays the FMS model performance statistic for the five LRT models as a function of time from the beginning of the tracer release in the ETEX experiment. Although the CALPUFF model performance does degrade with time (distance), even close to the source it is performing worse than the other LRT models. This was also seen in the spatial maps of the model performance presented previous in Figure 6-16 where the CALPUFF model had spatial alignment problems compared with the observed tracer 24 hours after the tracer was released. Thus, CALPUFF does not perform comparably to the other evaluated LRT models even within 300 km of the source.

19 http://www.epa.gov/ttn/scram/7thmodconf.htm

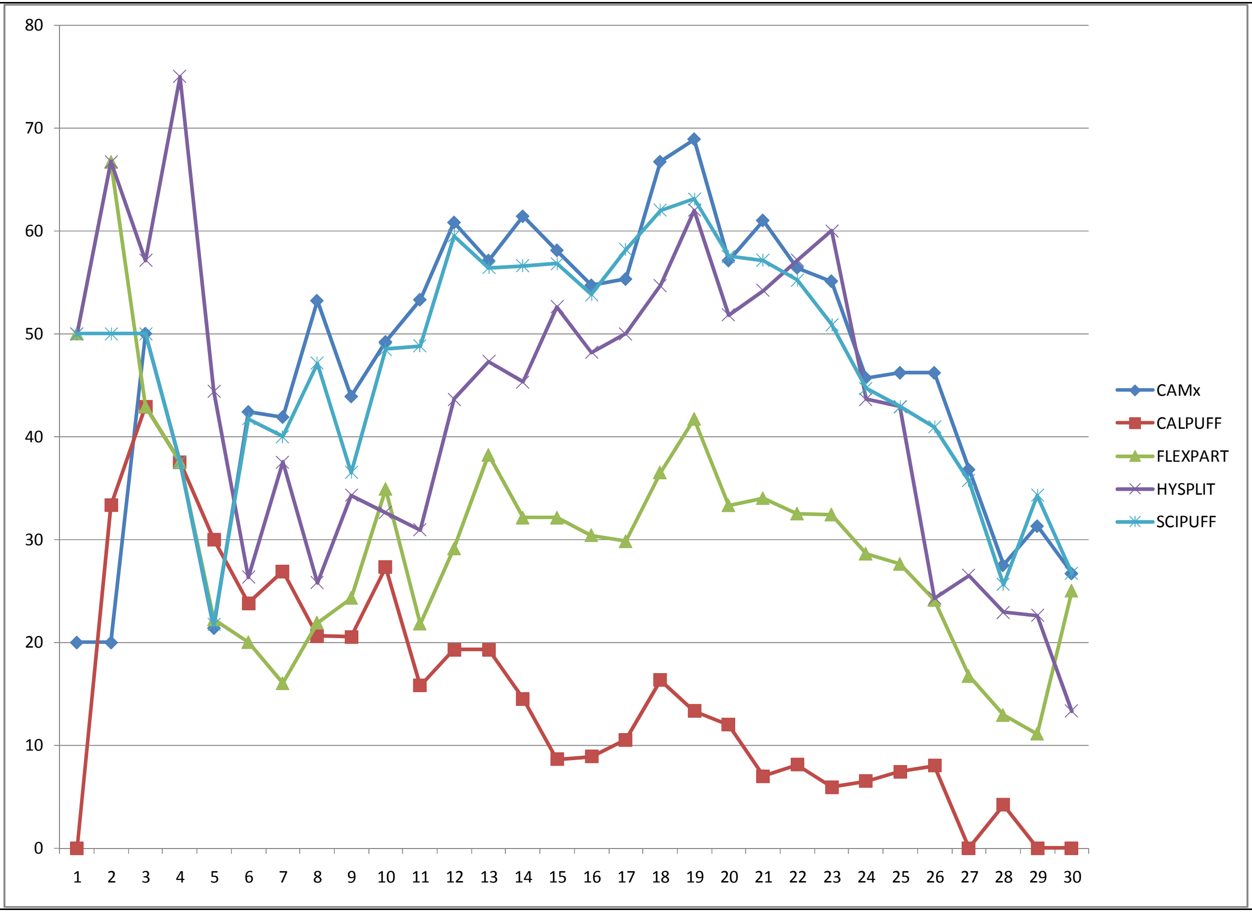


Figure 6-19. Figure of Merit (FMS) spatial model performance statistics as a function of time since the beginning of the tracer release.

6.4.4.2 CALPUFF Puff Splitting Sensitivity Tests

The CALPUFF puff splitting algorithm is controlled by several model options that are defined in the CALPUFF control input file. Two types of puff splitting may be invoked in CALPUFF: (1) vertical puff splitting when vertical wind shear is present across vertical layers in a well-mixed puff; and (2) horizontal puff splitting when there is sufficient horizontal wind shear across the horizontal extent of the puff.

The MSPLIT control option turns on puff splitting when set to 1, when MSPLIT is 0 no vertical or horizontal puff splitting is allowed to occur.

Four criteria must occur in order for vertical puff splitting to occur in CALPUFF:

1. The puff must be in contact with the ground.
2. The puff splitting flag must be turned on (i.e., IRESPLIT = 1).
3. The previous hours mixing height must be above a certain height (mixing height > ZISPLIT).
4. The ratio of the last hours mixing height to the maximum mixing height encountered by the puff is less than a maximum value (current mixing height/maximum mixing height > ROLDMAX).

The puff splitting flag (item 2) is turned on using the IRESPLIT input option. IRESPLIT consists of 24 values corresponding to the hour of the day with values that are either 0 or 1, where 1 turns on the puff splitting flag for puffs. Once the puff splitting flag is turned on, it remains on until the puff splitting occurs at which point the puff splitting flagged is turned off until it is turned back on again by IRESPLIT. The default setting for IRESPLIT is to have all hours zero except for setting hour 17 to 1. The reasoning behind this is to invoke puff splitting in the evening when a nocturnal inversion occurs and there is a decoupling of the winds between the nocturnal inversion layer and above the nocturnal inversion (i.e., the residual "mixed layer"). Setting IRESPLIT to all zeros will result in the puffs never performing vertical puff splitting and setting IRESPLIT to all ones will result in the puff splitting flag always turned on and puffs will always split when the other three criteria for vertical puff splitting are met.

The default value for the previous hours minimum mixing height value (item 3) is ZISPLIT = 100 m. This minimum value is used to assure that the current mixing height is not negligible.

The ratio of the previous hours mixing height to maximum mixing height encountered by the puff (item 4) is controlled by the ROLDMAX parameter with a default value of 0.25.

When vertical puff splitting occurs in CALPUFF, the number of puffs that the puff is split into is controlled by the NSPLIT parameter that has a default value of 3.

Horizontal puff splitting occurs when the puff concentrations are above a minimum value (CNSPLITH), the puff has a minimum width that is defined by its sigma-y in grid cell units (SYSPLITH) and the minim puff elongation rate (SYSPLITH per hour) is above a SHSPLITH factor. The default minimum concentration is CNSPLITH = 10^{-7} g/m^3 (0.1 µg/m^3). Default SYSPLITH value is 1.0 and default SHSPLITH factor is 2.0. When horizontal puff splitting occurs in CALPUFF the number of puffs the puff is split into is controlled by the NSPLITH parameter that has a default of 5.

Eight CALPUFF puff splitting sensitivity tests were conducted, which are defined in Table 6-3. When vertical and horizontal puff splitting occurs in CALPUFF, the default number of puffs to split into was used in the CALPUFF sensitivity tests (i.e., NSPLIT = 3 and NSPLITH = 5). The NOSPLIT sensitivity test set MSPLIT = 0 so no vertical or horizontal puff splitting was allowed to occur. The DEFAULT puff splitting turned on puff splitting (MSPLIT = 1) but only turned on the vertical puff splitting flag at hour 17 every day. Whereas, the ALLHRS sensitivity test made sure that the vertical puff splitting flag was turned on all the time (i.e., IRESPLIT = 24*1) removing criteria 2 from the vertical puff splitting requirement. The ZISPLIT sensitivity test set ZISPLIT to zero thereby removing criteria 3 in the vertical puff splitting, as well as requirement 2 (like ALLHRS). ROLD relaxed the minimum ratio of the previous hours to maximum mixing height for vertical puff splitting from 0.25 to 0.50. The SYS sensitivity test allows horizontal puff splitting to occur more frequently by allowing puff splitting to occur with a puff sigma-y value is greater than SYSPLITH values of 0.1 (2.6 km) versus the default 1.0 (36 km) value. The last sensitivity test combines the ROLD and SYS sensitivity tests.

Table 6-3. Summary of CALPUFF puff splitting sensitivity tests performed using the ETEX database.

Sensitivity Test	MSPLIT	NSPLIT	IRESPLT	ZISPLIT	ROLDMAX	NSPLITH	SYSPLITH	CNSPLITH
NOSPLIT	0	NA	NA	NA	NA	NA	NA	NA
DEFAULT	1	3	Hr 17=1	100	0.25	5	1.0	10^{-7}
ALLHRS	1	3	24*1	100	0.25	5	1.0	10^{-7}
CNSMIN	1	3	24*1	100	0.25	5	1.0	10^{-20}
ZISPLIT	1	3	24*1	0	0.25	5	1.0	10^{-20}
ROLD	1	3	24*1	0	0.50	5	1.0	10^{-20}
SYS	1	3	24*1	0	0.25	5	0.1	10^{-20}
SYSROLD	1	3	24*1	0	0.50	5	0.1	10^{-20}

Figure 6-20 displays the spatial model performance statistics for the CALPUFF puff splitting sensitivity tests. The DEFAULT, ALLHRS and CNSMIN CALPUFF sensitivity tests obtained the exactly same model performance statistics indicating that CALPUFF model performance was not affected by the IRESPLT and CNSMIN puff splitting parameters. There are some small difference in the spatial model performance statistics for the other CALPUFF puff splitting sensitivity tests with the ROLD parameter having the biggest effect when changed from 0.25 to 0.50 that improved model performance a couple of percentage points for the FMS, POD and TS spatial statistics but degraded the FAR spatial statistic by several percentage points.

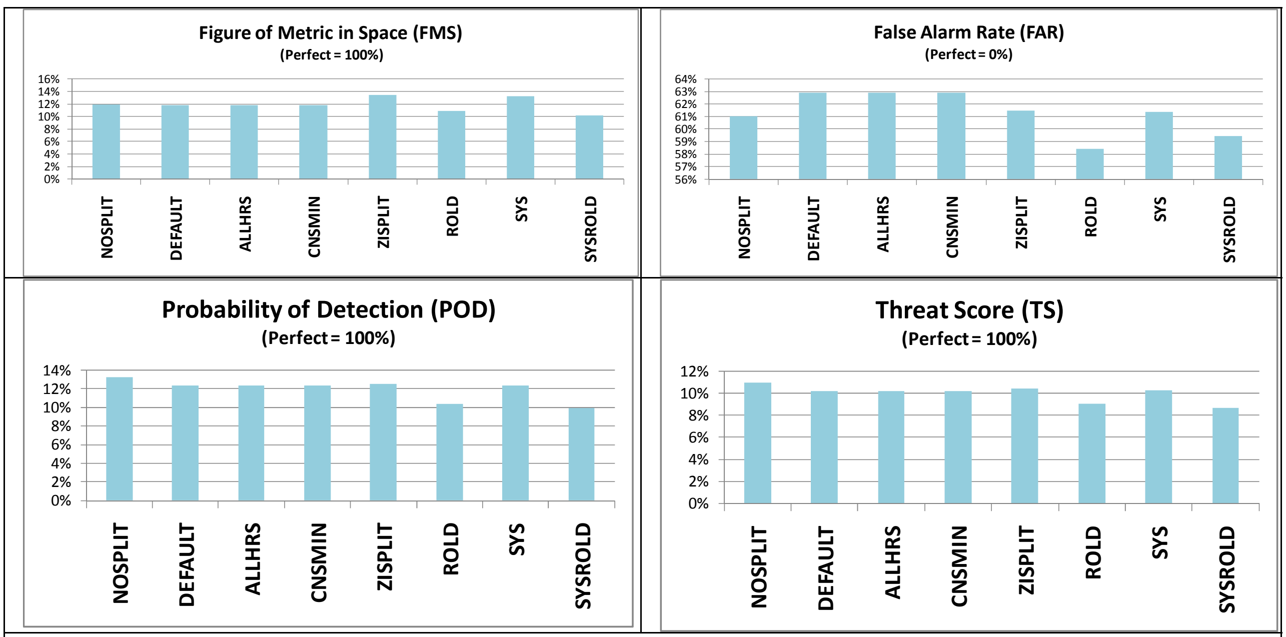


Figure 6-20. Spatial model performance statistics for the CALPUFF puff splitting sensitivity tests.

The global model statistics for the CALPUFF puff splitting sensitivity tests are shown in Figure 6-20, with Figures 6-21a and 6-21b displays statistics where the best performing model configuration has the lowest and highest score, respectively. The puff splitting sensitivity tests have a very small effect on the CALPUFF model performance. Again, the biggest effect on CALPUFF performance of all the puff splitting parameters comes from changing ROLD from 0.25 to 0.50, which appears to slightly degrade most CALPUFF model performance metrics with the exception of bias and error that are improved. Again, in terms of the CALPUFF global model performance versus other four LRT dispersion models (Figures 6-9 through 6-15), the CALPUFF puff splitting sensitivity tests are exhibiting by far the worst model performance. For example, the RANK model performance statistic varies from 0.6 to 0.7 across the CALPUFF puff splitting sensitivity tests as compared to much higher values for CAMx (1.9), SCIPUFF (1.8), HYPLIT (1.8) and FLEXPART (1.0).

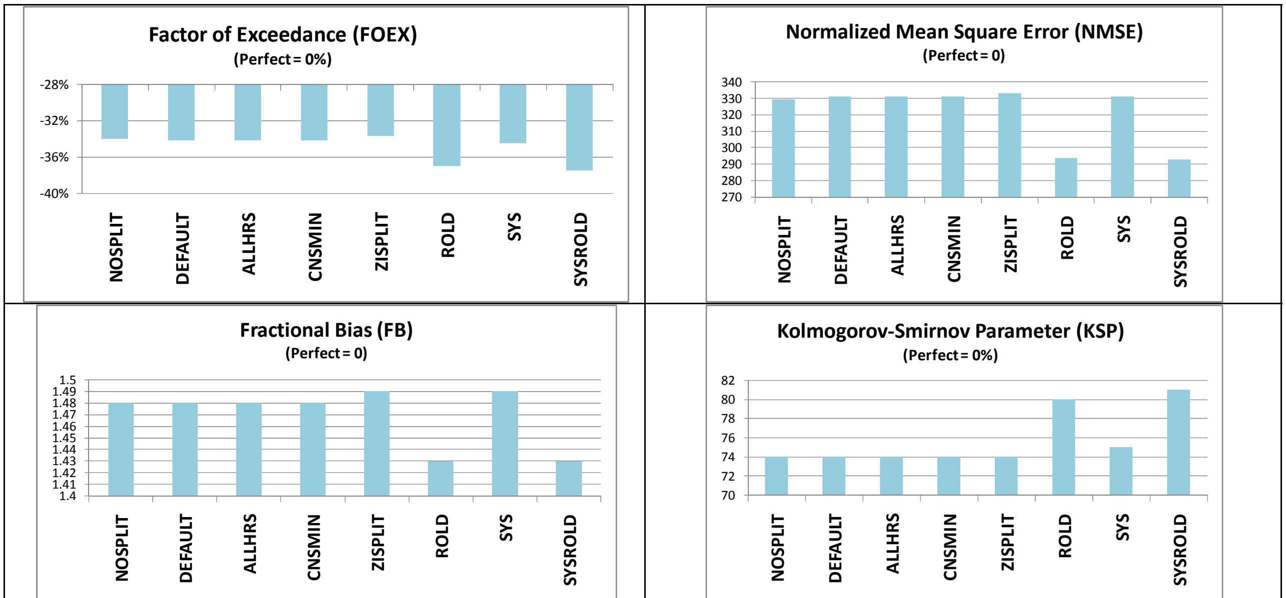


Figure 6-21a. Global model performance statistics for the CALPUFF puff splitting sensitivity tests.

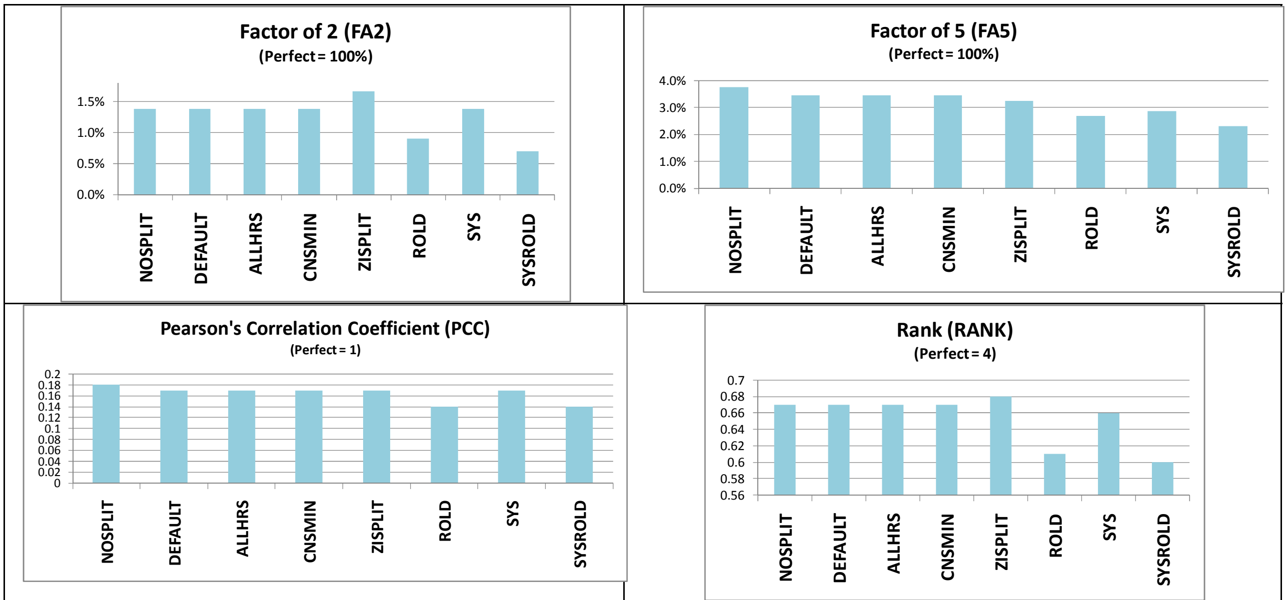


Figure 6-21b. Global model performance statistics for the CALPUFF puff splitting sensitivity tests.

In conclusion, the CALPUFF puff splitting sensitivity tests did not have any significant effect on CALPUFF model performance. Whether puff splitting was used or not produced essentially identical model performance for the ETEX experiment and certainly did not improve the CALPUFF model performance.

6.4.5 HYSPLIT Sensitivity Tests

HYSPLIT is unique among the models analyzed in this project in that its configuration is highly flexible, allowing for treatment of atmospheric dispersion purely as a Lagrangian particle model (default configuration), puff-particle hybrid model, or purely as a puff model. Nine sensitivity analyses were conducted against the ETEX database to provide information about the various configurations of HYSPLIT, but more importantly to provide additional information regarding the two distinct classes (puff and particle) of Lagrangian models evaluated as part of this project. Model configuration (puff, particle, puff-particle hybrid) are governed through the HYSPLIT parameter INITD. A description of the INITD variable options is provided in Table 6-4.

Model configuration options for the nine sensitivity runs are detailed in Table 6-5. In general, model control options were held to default values with two notable exceptions, the INITD and NUMPAR variables. HYSPLIT performance is highly sensitive to the number of particles released in the simulation. The HYSPLIT parameter NUMPAR controls the number of particles released over the duration of the emissions release. The default value for NUMPAR is set to 2500, but the user must take caution to insure that a sufficient number of particles are released to provide a "smooth temporal change" in concentration fields (NOAA, 2009). The original NOAA configuration for HYSPLIT was for INITD = 104 that is a particle/puff hybrid configuration (3D part – THh-Pv) with NUMPAR set to 1500. Original sensitivity runs found that the concentration fields were spotty; therefore, NUMPAR was set to 10000 to provide for smoother temporal evolution of the concentration fields.

Table 6-4. HYSPLIT INITD options and descriptions.

INITD Value	Description
0 (Default)	3D Particle Horizontal and Vertical
1	Gaussian horizontal and top-hat vertical puff (Gh-THv)
2	Top-hat horizontal and vertical puff (THh-THv)
3	Gaussian horizontal puff and vertical particle distribution (Gh-Pv)
4	Top-hat horizontal puff and vertical particle distribution (THh-Pv)
103	3D particle (#0) converts to Gh-Pv (#3)
104	3D particle (#0) converts to THh-Pv (#4)
130	Gh-Pv (#3) converts to 3D particle (#0)
140	THh-Pv (#4) converts to 3D particle (#0)

Table 6-5. HYSPLIT sensitivity runs and relevant configuration parameters.

Sensitivity Test	INITD	NUMPAR	ISOT	KSPL	FRHS	FRVS	FRTS	FRME
INITD0	0	10000	1	NA	NA	NA	NA	NA
INITD1	1	10000	1	1	1.0	0.01	0.10	0.10
INITD2	2	10000	1	1	1.0	0.01	0.10	0.10
INITD3	3	10000	1	1	1.0	0.01	0.10	0.10
INITD4	4	10000	1	1	1.0	0.01	0.10	0.10
INITD103	103	10000	1	1	1.0	0.01	0.10	0.10
INITD104	104	10000	1	1	1.0	0.01	0.10	0.10
INITD130	130	10000	1	1	1.0	0.01	0.10	0.10
INITD140	140	10000	1	1	1.0	0.01	0.10	0.10

Figure 6-22 displays the spatial model performance statistics for the HYSPLIT INITD sensitivity tests. Wide variation in spatial performance is noted across the nine runs and requires closer examination. For example, the two puff based configurations (INITD1 and INITD2) showed the poorest spatial performance of all of the runs with low POD and TS values and much higher FAR values compared to all other configurations. The 3D particle based configuration (INITD0) had higher POD, TS, and lower FAR in comparison, yet it had a comparably low FMS to INITD1 and INITD2. Since the FMS score examines all model/observed values greater than 0 and the additional spatial metrics use a contingency level of 100 pg m^{-3}, it can be interpreted that the 3D particle configuration performed significantly better at concentration levels above 100 pg m^{-3}, but its spatial performance degraded with concentration ranges below the contingency level. The puff-particle hybrid configurations (INITD3, INTID4, INITD103, INITD104) performed consistently better overall across all four spatial metrics.

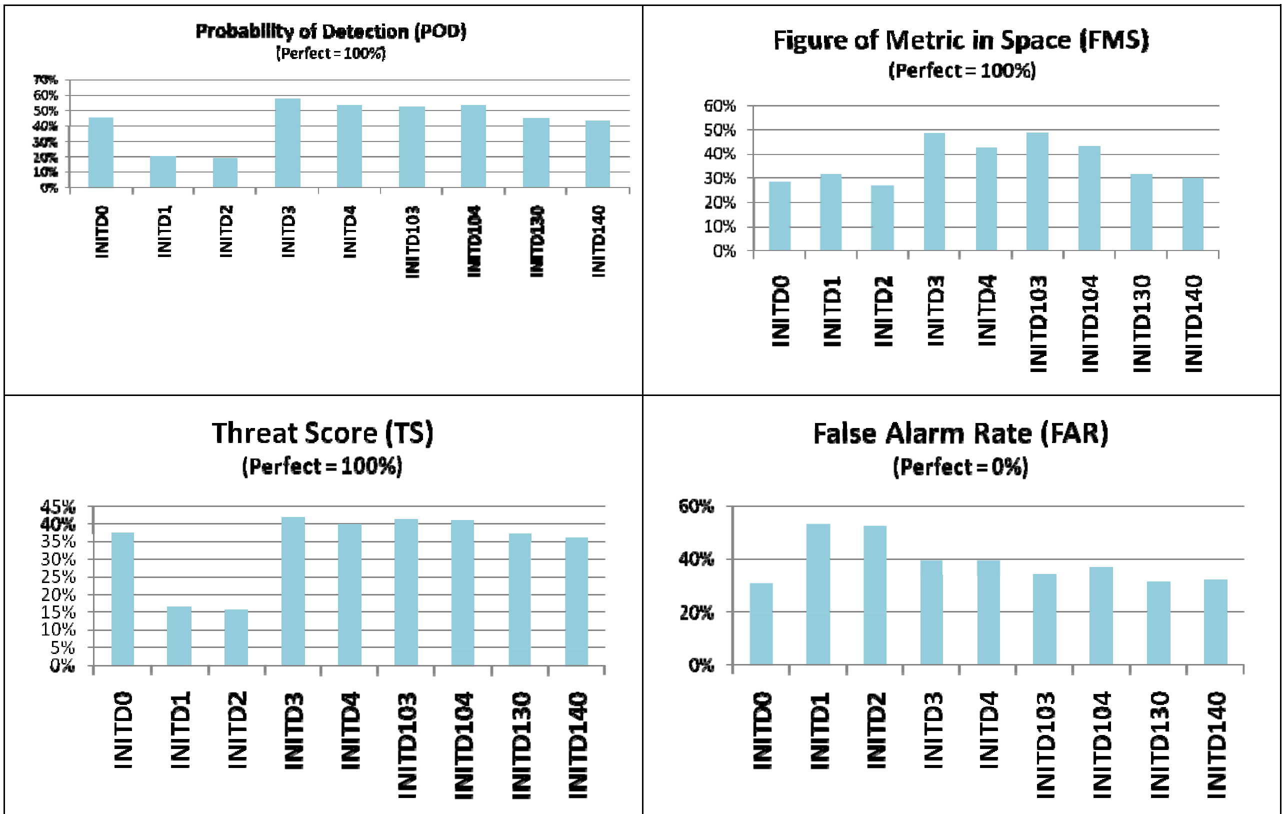


Figure 6-22. Spatial model performance statistics for nine HYSPLIT INITD sensitiviity experiments.

Figure 6-23 displays the global statistics for the HYSPLIT sensitivity tests with Figures 6-23a and 6-23b containing the statistical metrics where the best performing model has the, respectively, lowest and highest score. For the FOEX metrics, the INITD3 scores the best with a 3.4% FOEX score followed by INITD4 (-7%), INITD104 (-8.6%), and finally INITD103 (-9.5%). INITD2 scored worst with a -28.9%. INITD0, 1, 130, and 140 performed nearly as poorly with scores ranging between -21.9% to -24%. Using the NMSE statistical performance metric, the best performing configuration was INITD130, 140, and 3 with values of 17, 18, 19 pg m^{-3} respectively. The model configurations with the highest predicted error were INITD1 and INITD2 with values of approximately 325 and 333 pg m^{-3}. For the KS parameter, the four puff-particle model configuration options (INITD3,4,103,104) again showed the best scores.

For the within a factor of 2 and 5 metric (FA2 and FA5, Figure 6-23b, top), the hybrid puff-particle configurations INITD3 and INITD4 and their counterpart particle-puff configurations INITD103 and INITD104 are clearly performing better than pure particle (INITD0) or puff (INITD1 and INITD2) configurations. For the PCC metric, INITD140 had the highest (0.69) followed by INITD104 (0.64) and INITD0 and 103 (0.63). Interestingly, it appears that the higher PCC score for INITD103 is the main reason for the highest overall model RANK as both INITD3 and 103 had nearly identical spatial performance while INITD3 had slightly better KS scores.

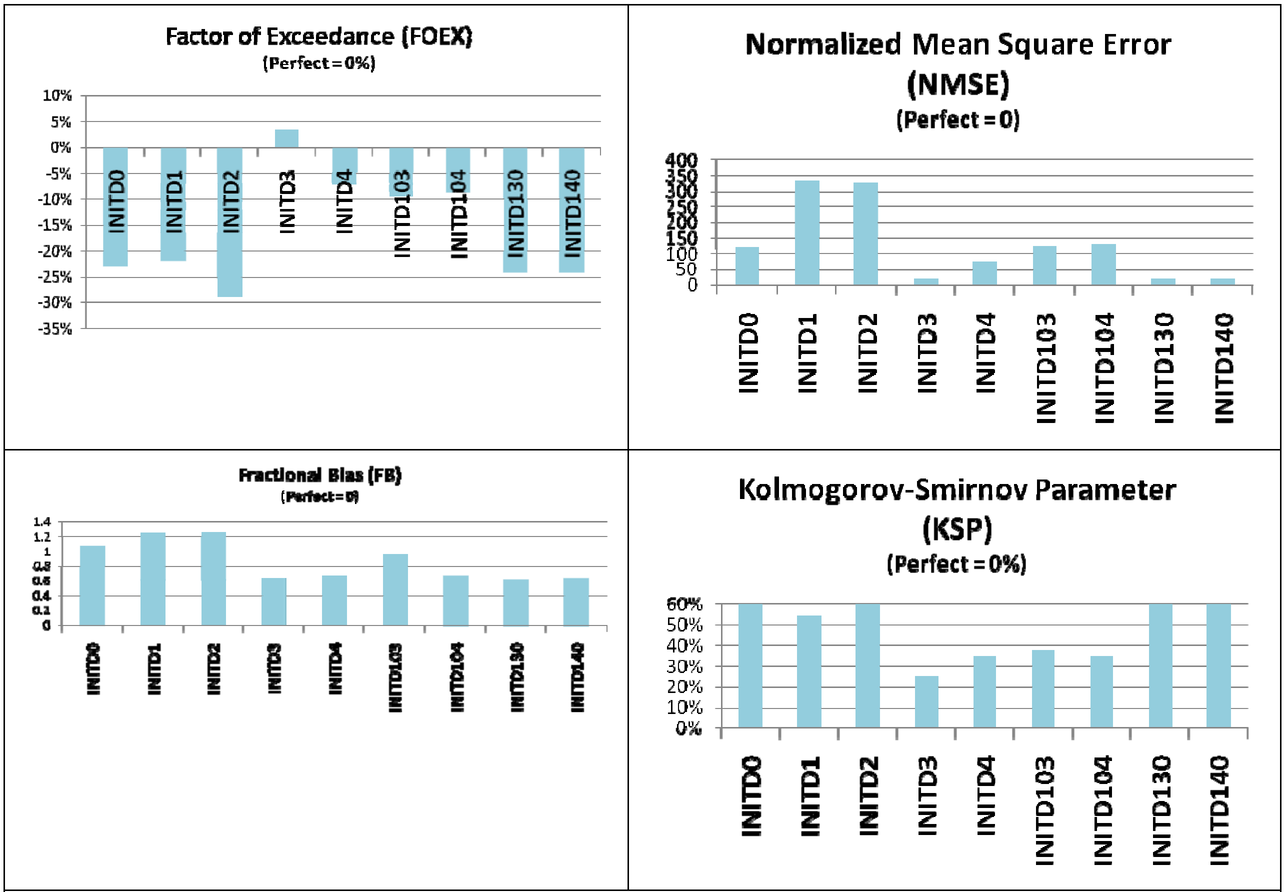


Figure 6-23a. Global model performance statistics for nine HYSPLIT INITD sensitivity tests.

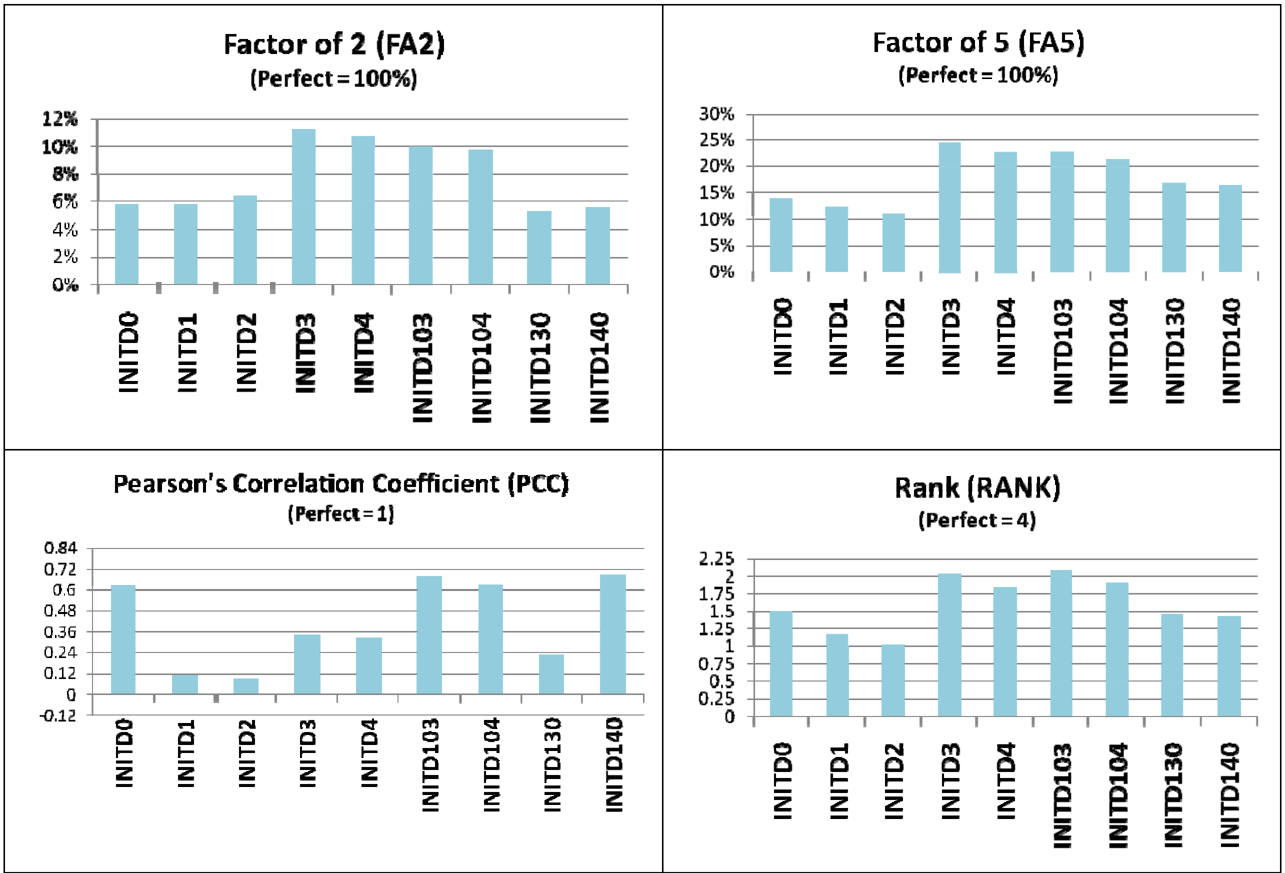


Figure 6-23b. Global model performance statistics for nine HYSPLIT INITD sensitivity tests.

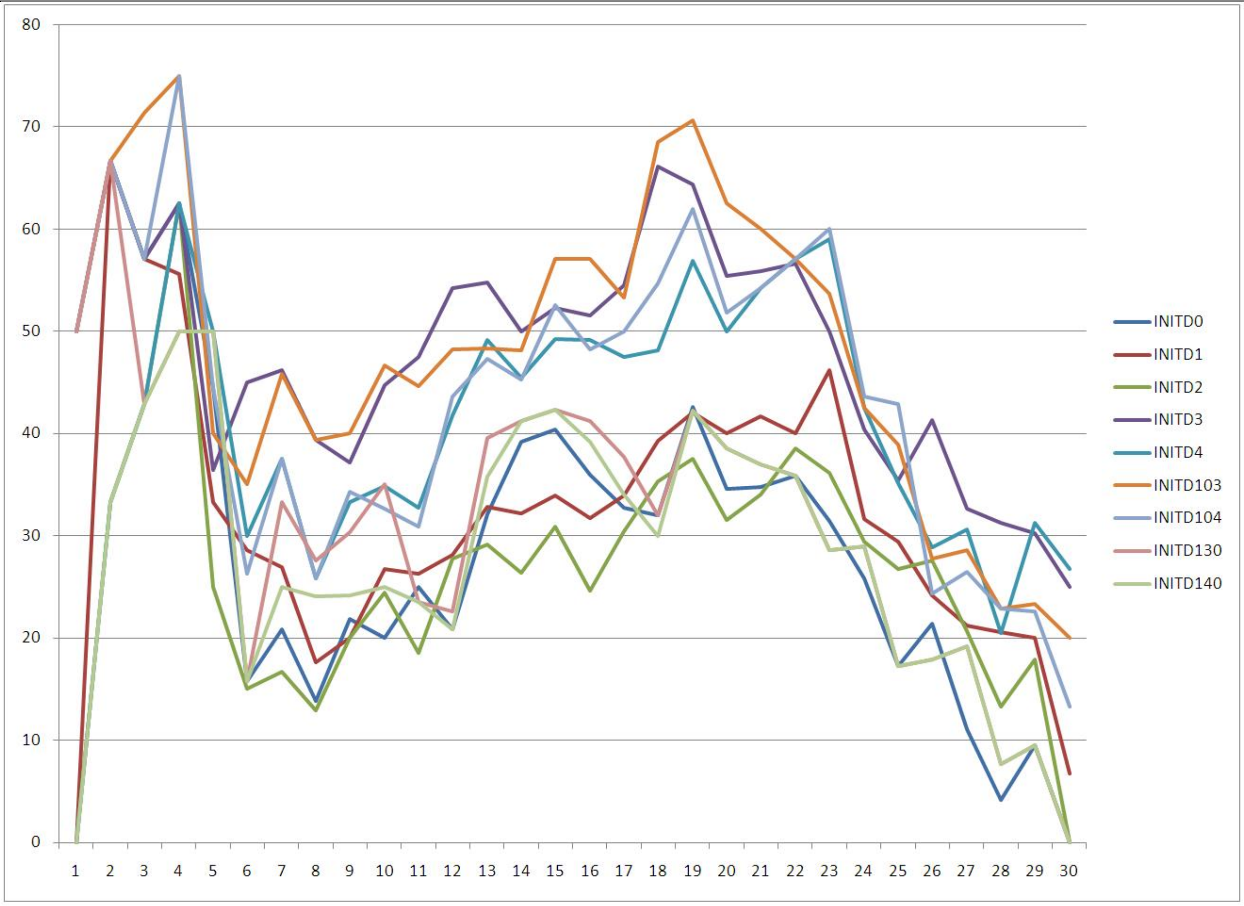


Figure 6-24. Figure of Merit (FMS) spatial model performance statistics as a function of time since the beginning of the tracer release for HYSPLIT INITD sensitivity analyses.

The final panel in Figure 6-23b (bottom right) displays the overall RANK statistic. The RANK statistics orders the model performance of the HYSPLIT INITD configurations are as follows:

1. INITD103 (2.09)
2. INITD3 (2.03)
3. INITD104 (1.91)
4. INITD4 (1.85)
5. INITD0 (1.50)
6. INITD130 (1,47)
7. INITD140 (1.44)
8. INITD1 (1.16)
9. INITD2 (1.01)

Based on this analysis the puff-particle and particle-puff hybrid configurations of the HYSPLIT system are clearly the best performing, indicating a distinct operational advantage over pure puff or particle configurations.

6.5 CONCLUSIONS OF THE MODEL PERFORMANCE EVALUATION OF THE LRT DISPERSION MODELS USING THE ETEX TRACER EXPERIMENT FIELD STUDY DATA

The evaluation of the five LRT dispersion models using a common MM5 dataset and the ETEX database has provided interesting results about the current capability of LRT models to reproduced observed tracer concentrations. Four of the five LRT models were able to reproduce the observed tracer bifurcation at the farther downwind distances. The CALPUFF model was unable reproduce the observed bifurcation of the tracer cloud and kept the estimated tracer cloud in a circular Gaussian distribution that was advected too far north. CALPUFF puff splitting sensitivity tests were performed to determine whether it would help simulate the bifurcation of the tracer cloud but puff splitting had little effect on the CALPUFF predictions.

CAMx sensitivity tests were conducted to examine vertical mixing and horizontal advection solvers and the best performing CAMx model configuration was the one that is most frequently used in applications, which includes using the CMAQ-like vertical diffusion coefficients in MM5CAMx and the PPM advection solver. The vertical diffusion algorithm had a much bigger effect on CAMx model performance than the choice of horizontal advection solver.

The HYSPLIT sensitivity tests with different particle-puff variations resulted in a wide range of model performance with RANK scores that varied from 1.01 to 2.09.

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Appendix A

Evaluation of the MM5 and CALMET Meteorological Models Using the CAPTEX CTEX5 Field Experiment Data

EVALUATION OF THE MM5 AND CALMET METEOROLOGICAL MODELS USING THE CAPTEX CTEX5 FIELD EXPERIMENT DATA

Statistical evaluation of the prognostic (MM5) and diagnostic (CALMET) meteorological model applications for the CTEX5 CAPTEX release was conducted using surface meteorological measurements. For the MM5 datasets, performance for meteorological parameters of wind (speed and direction), temperature, and humidity (mixing ratio) was examined. For the CALMET experiments, CALMET estimated winds (speed and direction) were examined because the two-dimensional temperature and relative humidity fields output are simple interpolated fields of the observations. Therefore, the evaluation for CALMET was restricted to winds where the majority of change can be induced by both diagnostic terrain adjustments and varying the OA strategy. Note that except for the NOOBS = 2 CALMET sensitivity tests (i.e., the "D" series of CALMET sensitivity tests), surface meteorological observations are blended with the wind fields in the CALMET STEP2 objective analysis (OA) procedure. Thus, the evaluation of the CALMET wind fields is not a true independent evaluation as the surface meteorological observations used in the evaluation are also used as input into CALMET. So we expect the CALMET wind fields to compare better with observations than MM5, but that does not mean that CALMET is producing better meteorological fields. As clearly shown by EPA (2009a,b), the CALMET diagnostic (STEP1) and blending of observations using the STEP2 OA procedure can introduce discontinuities and artifacts in the wind fields generated by the MM5/WRF prognostic meteorological model that is used as input to CALMET, even though the CALMET winds may match the observed surface winds at the locations of the monitoring sites does not necessarily mean that CALMET is performing better than MM5/WRF.

The METSTAT software (Emery et al., 2001) was used to match MM5 output with observation data. The MMIFStat software (McNally, 2010) tool was used to match CALMET output with observation data. Emery and co-workers (2001) have developed a set of "benchmarks" for comparing prognostic meteorological model performance statistics metrics. These benchmarks were developed after examining the performance of the MM5 and RAMS prognostic meteorological models for over 30 applications. The purpose of the benchmarks is not to assign a passing or failing grade, rather it is to put the prognostic meteorological model performance in context. The surface meteorological model performance benchmarks from Emery et al., (2001) are displayed in Table A-1. Note that the wind speed RMSE benchmark was also used for wind speed MNGE given the similarity of the RMSE and MNGE performance statistics. These benchmarks are not applicable for diagnostic model evaluations.

Table A-1. Wind speed and wind direction benchmarks used to help judge the performance of prognostic meteorological models (Source: Emery et al., 2001).

Wind Speed	Root Mean Squared Error (RMSE) Mean Normalized Bias (NMB) Index of Agreement (IOA)	≤ 2.0 m/s ≤ ±0.5 m/s ≥ 0.6
Wind Direction	Mean Normalized Gross Error (MNGE) Mean Normalized Bias (MNB)	≤ 30° ≤ ±10°
Temperature	Mean Normalized Gross Error (MNGE) Mean Normalized Bias (NMB) Index of Agreement (IOA)	≤ 2.0 K ≤ ±0.5 m/s ≥ 0.8
Humidity	Mean Normalized Gross Error (MNGE) Mean Normalized Bias (NMB) Index of Agreement (IOA)	≤ 2.0 g/kg ≤ ±1.0 g/kg ≥ 0.6

Table A-2 lists the CTEX5 MM5 sensitivity tests that are evaluated in this section. For the first set of MM5 experiments (EXP1) MM5 was configured as it would be run during the late 1980s and early 1990s using only 16 vertical layers, a single 80 km grid resolution and older (Blackadar) planetary boundary layer (PBL) and land soil module (LSM). There were several four dimensional data assimilation (FDDA) experiments using this first MM5 configuration from none (EXP1A) to analysis nudging above the PBL and at the surface (EXP1C).

The second set of MM5 experiments (EXP2A-C) used a more recent MRF PBL scheme and 33 vertical layers with three levels of grid nesting (108/26/12 km) and was meant to represent the way MM5 was run in the late 1990s/early 2000s. Three different levels of FDDA were used with this MM5 configuration: none (EXP2A), analysis nudging above the PBL (EXP2B) and analysis nudging above the PBL as well as at the surface (EXP2C). Note that additional sensitivity experiments were planned using this second MM5 configuration (e.g., EXP2D and EXP2E), but the MM5 model performance using the MRF PBL scheme was so poor that this MM5 configuration was abandoned.

The third set of MM5 experiments (EXP2F-J) used a MM5 configuration similar to the second set of MM5 experiments only with more vertical layers (43) and going back to the Blackadar PBL scheme due to the poor performance of MRF. Additional FDDA sensitivity tests were performed that increased the FDDA nudging strength by a factor of 2 and then added in observation nudging. The final MM5 configuration (EXP3) was exactly the same as the third configuration MM5 experiment EXP2H, only using the Pleim-Xiu PBL/LSM scheme.

The CALMET sensitivity tests are listed in Table A-3. The MM5 output from either MM5 EXP1C (80 km) or MM5 EXP2H (36 and 12 km) were used as initial guess winds in the CALMET experiments. The CALMET sensitivity tests varied by the CALMET grid resolution, the source and grid resolution of the MM5 output data used and how the surface and upper-air meteorological data were blended into the STEP1 wind fields in the STEP2 OA procedure. There were seven basic CALMET configurations:

BASE	Use 80 km MM5 data from EXP1C and 18 km CALMET grid resolution.
1.	Use 80 km MM5 data from EXP1C and 12 km CALMET grid resolution.
2.	Use 80 km MM5 data from EXP1C and 4 km CALMET grid resolution.
3.	Use 36 km MM5 data from EXP2H and 12 km CALMET grid resolution.
4.	Use 12 km MM5 data from EXP2H and 12 km CALMET grid resolution.
5.	Use 36 km MM5 data from EXP2H and 4 km CALMET grid resolution.
6.	Use 12 km MM5 data from EXP2H and 4 km CALMET grid resolution.

The variations in the CALMET STEP2 OA procedures in the CALMET sensitivity test were as follows:

A. Use meteorological observations with RMAX1/RMAX2 = 500/1000.
B. Use meteorological observations with RMAX1/RMAX2 = 100/200.
C. Use meteorological observations with RMAX1/RMAX2 = 10/100.
D. Don't use any meteorological observations (NOOBS = 2).

Table A-2. Summary of CTEX5 MM5 sensitivity tests.

Sensitivity Test	Horizontal Grid	Vertical Layers	PBL	LSM	FDDA Used
1A_80km	80 km	16	BLKDR	5LAY	No FDDA
1B_80km	80 km	16	BLKDR	5LAY	Analysis Nudging
1C_80km	80 km	16	BLKDR	5LAY	Analysis Nudging Surface Analysis Nudging
2A_36km 2A_12km	108/36/12km	33	MRF	5LAY	No FDDA
2B_36km 2B_12km	108/36/12km	33	MRF	5LAY	Analysis Nudging
2C_36km	108/36/12km	33	MRF	5LAY	Analysis Nudging Surface Analysis Nudging
2F_36km 2G_12km	108/36/12km	43	BLKDR	5LAY	No FDDA
2G_36km 2G_12km	108/36/12km	43	BLKDR	5LAY	Analysis Nudging
2H_36km 2H_12km	108/36/12km	43	BLKDR	5LAY	Analysis Nudging Surface Analysis Nudging
2I_36km 2I_12km	108/36/12km	43	BLKDR	5LAY	Analysis Nudging Surface Analysis Nudging FDDA x 2 strength
2J_36km 2J_12km	108/36/12km	43	BLKDR	5LAY	Analysis Nudging Surface Analysis Nudging FDDA x 2 strength Observational Nudging
4_36km 4_12km	108/36/12km	43	PX	PX	Analysis Nudging Surface Analysis Nudging

Table A-3. Definition of the CTEX5 CALMET sensitivity tests and data sources.

Sensitivity Test	MM5 Experiment and Resolution	CALMET Resolution	RMAX1/RMAX2	NOOBS[A]
BASEA	EXP1C – 80 km	18 km	500/1000	0
BASEB	EXP1C – 80 km	18 km	100/200	0
BASEC	EXP1C – 80 km	18 km	10/100	0
BASED	EXP1C – 80 km	18 km	NA	2
1A	EXP1C – 80 km	12 km	500/1000	0
1B	EXP1C – 80 km	12 km	100/200	0
1C	EXP1C – 80 km	12 km	10/100	0
1D	EXP1C – 80 km	12 km	NA	2
2A	EXP1C – 80 km	4 km	500/1000	0
2B	EXP1C – 80 km	4 km	100/200	0
2C	EXP1C – 80 km	4 km	10/100	0
2D	EXP1C – 80 km	4 km	NA	2
3A	EXP2H – 36 km	12 km	500/1000	0
3B	EXP2H – 36 km	12 km	100/200	0
3C	EXP2H – 36 km	12 km	10/100	0
3D	EXP2H – 36 km	12 km	NA	2
4A	EXP2H – 12 km	12 km	500/1000	0
4B	EXP2H – 12 km	12 km	100/200	0
4C	EXP2H – 12 km	12 km	10/100	0
4D	EXP2H – 12 km	12 km	NA	2
5A	EXP2H – 36 km	4 km	500/1000	0
5B	EXP2H – 36 km	4 km	100/200	0
5C	EXP2H – 36 km	4 km	10/100	0
5D	EXP2H – 36 km	4 km	0/0	2
6A	EXP2H – 12 km	4 km	500/1000	0
6B	EXP2H – 12 km	4 km	100/200	0
6C	EXP2H – 12 km	4 km	10/100	0
6D	EXP2H – 12 km	4 km	NA	2
6K	EXP2H – 12 km	4 km	NA	2

A. NOOBS = 0 use surface and upper-air meteorological observations
NOOBS = 2 do not use surface and upper-air meteorological observations
NOOBS = 1 use surface but not upper-air meteorological observations

Figure A-1 compares the MM5 model estimated wind fields. Figures A-2 and A-3 display the temperature and humidity model performance for the MM5 simulations. As shown in Figure A-2, the temperature performance for the three MM5 sensitivity tests using the MRF PBL scheme (2A, 2B and 2C) is extremely poor using either the 36 or 12 km grid resolution having an underestimation bias greater than -4 degrees that does not meet the temperature bias performance goal (≤±0.5 degrees).

The wind speed and, especially, the wind direction performance of the MM5 simulations with no FDDA (1A, 2A and 2F) is noticeably worse than when FDDA is used with the wind direction bias and error exceeding the performance benchmarks when no FDDA is used. With the exception of the EXP2H temperature underestimation tendency that barely exceeds the performance benchmark, the MM5 EXP1C and EXP2H MM5 sensitivity tests that were used in the CALMET sensitivity tests achieve the model performance benchmarks for wind speed, wind direction, temperature and humidity.

Tables A-4 and A-5 show CALMET estimated winds compared to observations. The “A” series of CALMET sensitivity tests (RMAX1/RMAX2 =500/1000) tends to have a wind speed underestimation bias compared to the other RMAX1/RMAX2 settings for most of the base CALMET settings (Figure A-1). The “A” and “B” series of CALMET runs tend to have the winds that closest match observations compared to the “C” (RMAX1/RMAX2 = 10/100) and “D” (no observations) series of CALMET runs. The use of 12 km CALMET grid resolution appears to improve the CALMET model performance slightly compared to 80 and 36 km. The CALMET runs using the MM5 EXP2H 36/12 km data appear to perform better than the ones that used the MM5 EXP1C 80 km data. CALMET tends to slow down the MM5 wind speeds with the slowdown increasing going from the “D” to “C” to “B” to “A” series of CALMET configurations such that the “A” series has a significant wind speed underestimation tendency.

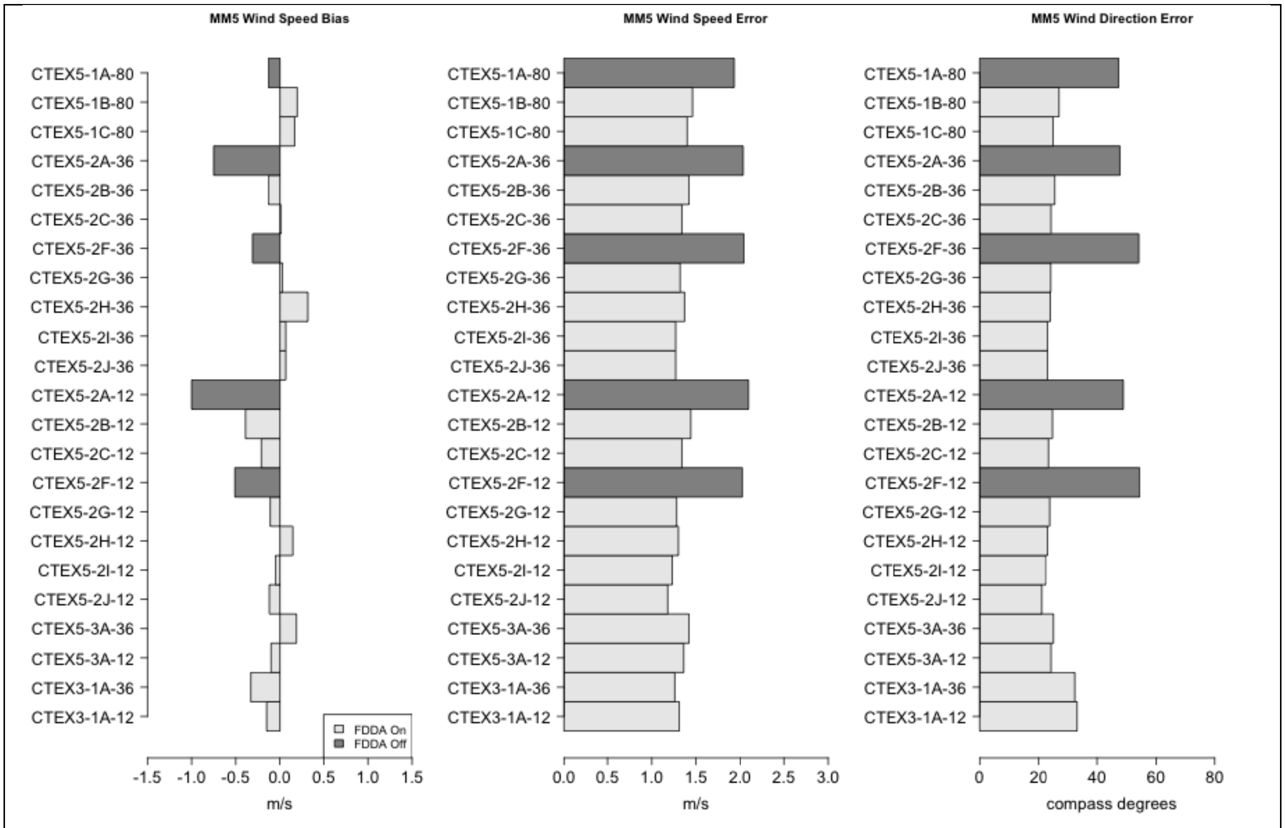

Figure A-1. Wind speed bias (m/s), wind speed error (m/s) and wind direction error (degrees) for MM5 runs.

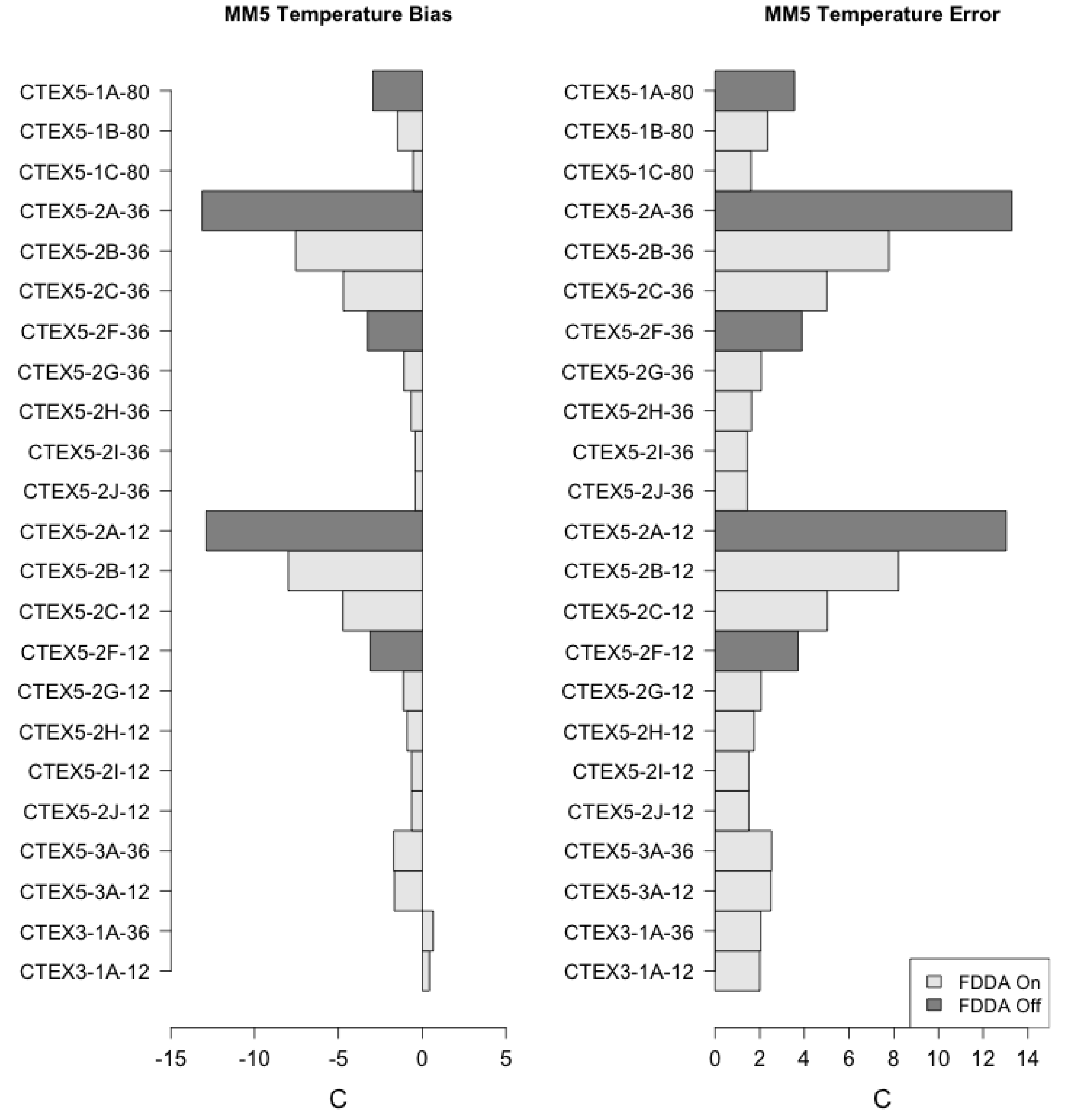

Figure A-2. Temperature bias and error (degrees K) of the CTEX5 MM5 meteorological modeling.

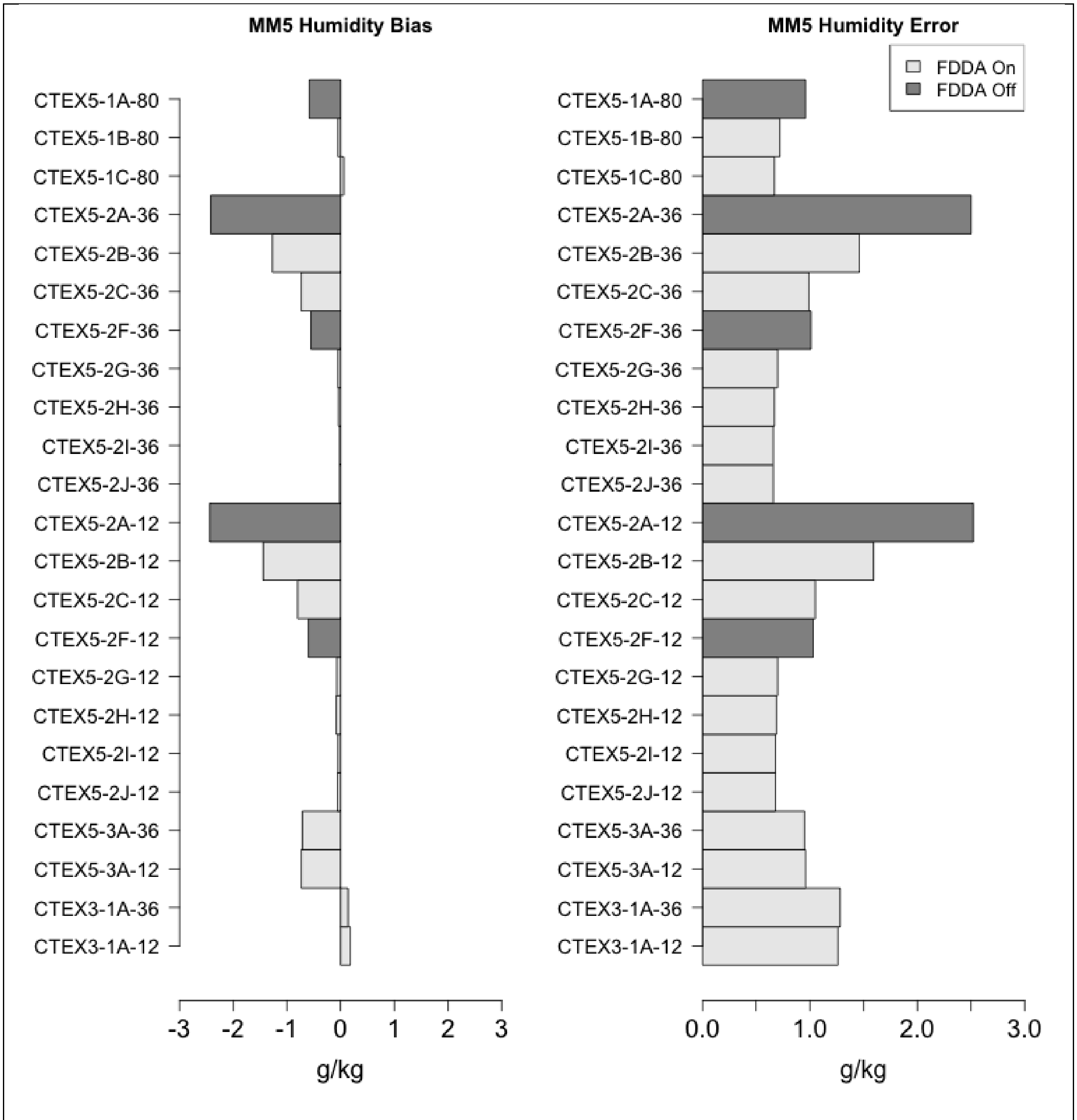

Figure A-3. Humidity bias and error (g/kg) of the CTEX5 MM5 meteorological modeling.

Table A-4. Comparison of CTEX5 MM5 meteorological simulation EXP1C and CALMET simulations using EXP1C MM5 80 km data as input.

	Wind Speed (m/s)			Wind Direction (°)	
	Bias	**Error**	**RMSE**	**Bias**	**Error**
Benchmark	≤±0.5	≤2.0	≤2.0	≤±10	≤30
MM5_EXP1C	0.17	1.40	1.83	4.52	25.1
CALMET					
BASEA	-0.35	0.89	1.38	-0.42	15.9
BASEB	-0.11	0.84	1.32	1.01	15.2
BASEC	-0.01	1.26	1.67	4.26	23.8
BASED	0.03	1.34	1.76	4.53	25.1
1A	-0.29	0.82	1.36	-0.56	14.9
1B	0.06	0.78	1.3	0.67	14.3
1C	-0.03	1.22	1.62	3.80	22.9
1D	0.02	1.34	1.77	4.45	25.1
2A	-0.21	0.71	1.33	-0.78	13.9
2B	-0.02	0.69	1.29	0.31	13.3
2C	-0.08	0.96	1.40	2.28	17.9
2D	0.00	1.34	1.77	4.08	25.0

Table A-5. Comparison of CTEX5 MM5 meteorological simulation EXP2H and CALMET simulations using EXP2H MM5 36 and 12 km data as input.

	Wind Speed (m/s)			Wind Direction (°)	
	Bias	**Error**	**RMSE**	**Bias**	**Error**
Benchmark	≤±0.5	≤2.0	≤2.0	≤±10	≤30
MM5_EXP2H	0.32	1.37	1.78	5.07	24.2
CALMET					
3A	-0.29	0.82	1.35	-0.56	14.9
3B	-0.01	0.78	1.29	0.83	14.2
3C	0.17	1.20	1.59	4.50	22.0
3D	0.24	1.34	1.74	5.13	24.1
4A	-0.29	0.82	1.35	-0.56	14.9
4B	-0.03	0.76	1.25	0.36	14.0
4C	0.07	1.16	1.54	3.36	21.4
4D	0.13	1.28	1.67	3.83	23.5
5A	-0.21	0.71	1.33	-0.78	13.9
5B	0.03	0.69	1.28	0.50	13.2
5C	0.08	0.95	1.39	2.87	17.4
5D	0.21	1.33	1.75	4.79	24.1
5K	0.04	0.69	1.28	0.47	13.2
6A	-0.21	0.71	1.33	-0.79	13.9
6B	-0.05	0.67	1.24	0.04	13.0
6C	-0.02	0.92	1.33	1.84	16.7
6D	-0.26	1.33	1.77	4.67	24.5
6K	0.00	0.66	1.23	0.00	13.0

Appendix B

EVALUATION OF VARIOUS CONFIGURATIONS OF THE CALMET METEOROLOGICAL MODEL USING THE CAPTEX CTEX3 FIELD EXPERIMENT DATA

B.1 CALMET MODEL EVALUATION TO IDENTIFY RECOMMENDED CONFIGURATION

The CAPTEX Release #3 (CTEX3) meteorological database was used to evaluate different configurations of the CALMET meteorological model for the purposes of helping to identify a recommended configuration for regulatory far-field CALMET/CALPUFF modeling. The results from these CALMET CTEX3 sensitivity tests were used in part to define the recommended CALMET model options in the August 31, 2009 Memorandum from the EPA/OAQPS Air Quality Modeling Group "Clarifications on EPA-FLM Recommended Settings for CALMET (i.e., the 2009 Clarification Memorandum). The EPA Clarification Memorandum on CALMET settings (EPA, 2009a) was a follow-up to a draft May 27, 2009 document: "Reassessment of the Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 Summary Report: Revisions to Phase 2 Recommendations" (EPA, 2009a). The IWAQM Phase 2 Reassessment Report recommended settings for CALMET that were intended to facilitate the direct "pass through" of prognostic meteorological model (e.g., MM5 and WRF) output to CALPUFF as much as possible. However, in subsequent testing of the new recommended CALMET settings in the IWAQM Phase 2 Reassessment Report using the CTEX3 database, the performance of CALMET degraded compared to some other settings. This led to the August 31, 2009 Clarification Memorandum of recommended CALMET settings for regulatory far-field modeling.

EPA examined 31 different configurations of the CALMET diagnostic meteorological model using the CTEX3 database. The resultant CALMET wind fields were paired in space and time with observations using the CALMETSTAT tool. CALMETSTAT is an adaptation of the METSTAT program that is typically used to evaluate the MM5 and WRF prognostic meteorological models against surface meteorological observations.

Note that since CALMET uses some of the same meteorological observations as input as used in the evaluation database, this is not a true evaluation as by design CALMET's STEP2 objective analysis (OA) will modify the wind field to make the winds better match the observations at the locations of the monitoring sites. But as noted by EPA (2009a,b), this can be at the expense of degrading the wind fields.

Table B-1 lists the 31 CALMET sensitivity tests that were performed using the CTEX3 modeling database. These CALMET sensitivity tests differed in the following aspects:

- The resolution of the CALMET gridded fields (18, 12 and 4 km);
- The resolution of the MM5 prognostic meteorological model output used as input to CALMET (80, 36 and 12 km);
- How the MM5 data was used in CALMET (i.e., as a first guess field prior to the STEP 1 diagnostic effects, as the STEP 1 wind fields prior to STEP 2 blending (objective analysis or OA) of observations or the MM5 data are not used at all); and
- Whether the surface and upper-air meteorological observations were used (NOOBS=0) or not (NOOBS=2).

Table B-1. CTEX3 CALMET sensitivity simulations performed for the CTEX3 database.

RUN	CALMET Resolution	MM4/MM5 Resolution	NOOBS	RMAX1/RMAX2	IPROG
BASE A	18-km	80-km MM4	0	500/1000	STEP 1
BASE B	18-km	80-km MM4	0	500/1000	First Guess
BASE C	18-km	80-km MM4	0	10/100	First Guess
BASE D	18-km	80-km MM4	0	100/200	First Guess
BASE E	18-km	80-km MM4	0	10/100	STEP 1
BASE F	18-km	80-km MM4	0	10/100	First Guess
BASE G[A]	18-km	80-km MM4	2	NA	First Guess
BASE H	18-km	NA	0	500/1000	NA
BASE I	18-km	NA	0	100/200	NA
BASE J	18-km	NA	0	10/100	NA
BASE K	18-km	80-km MM4	0	100/200	First Guess[B]
EXP 1A	18-km	36-km MM5	0	500/1000	First Guess
EXP 1B	18-km	36-km MM5	0	100/200	First Guess
EXP 1C	18-km	36-km MM5	0	10/100	First Guess
EXP 1D	18-km	36-km MM5	2	NA	First Guess
EXP 3A	12-km	36-km MM5	0	500/1000	First Guess
EXP 3B	12-km	36-km MM5	0	100/200	First Guess
EXP 3C	12-km	36-km MM5	0	10/100	First Guess
EXP 3D	12-km	36-km MM5	2	NA	First Guess
EXP 4A	12-km	12-km MM5	0	500/1000	First Guess
EXP 4B	12-km	12-km MM5	0	100/200	First Guess
EXP 4C	12-km	12-km MM5	0	10/100	First Guess
EXP 4D	12-km	12-km MM5	2	NA	First Guess
EXP 5A	4-km	36-km MM5	0	500/1000	First Guess
EXP 5B	4-km	36-km MM5	0	100/200	First Guess
EXP 5C	4-km	36-km MM5	0	10/100	First Guess
EXP 5D	4-km	36-km MM5	2	NA	First Guess
EXP 6A	4-km	12-km MM5	0	500/1000	First Guess
EXP 6B	4-km	12-km MM5	0	100/200	First Guess
EXP 6C	4-km	12-km MM5	0	10/100	First Guess
EXP 6D	4-km	12-km MM5	2	NA	First Guess

A. Base G CALMET simulation obtained an Error in MIXDT2 – HTOLD so run not completed
B. Base K did not do any diagnostic adjustments to the wind fields

Figure B-1 displays the wind speed and direction model performance statistical metric for the Base A through Base K CALMET sensitivity test simulations that used either the 80 km MM4 or no prognostic meteorological model data as input. The dark gray bar represents the CALMET model configuration that is consistent with the recommendations in the August 31, 2009 Clarification Memorandum. The numerical values of the model performance statistics are provided in Table B-2. CALMET sensitivity simulations Base D, H, I and K are the best performing simulations for winds from this group. Base D is the current recommended CALMET settings, whereas Base H and I use no MM4 data and Base K is like Base D only CALMET does not perform any diagnostic wind field adjustments. The wind speed statistics for Base D and K are identical, whereas the ones for Base H and I are slightly worse than Base D and K. The wind direction statistics for Base D and K are almost identical and again the ones for Base H and I are slightly worse.

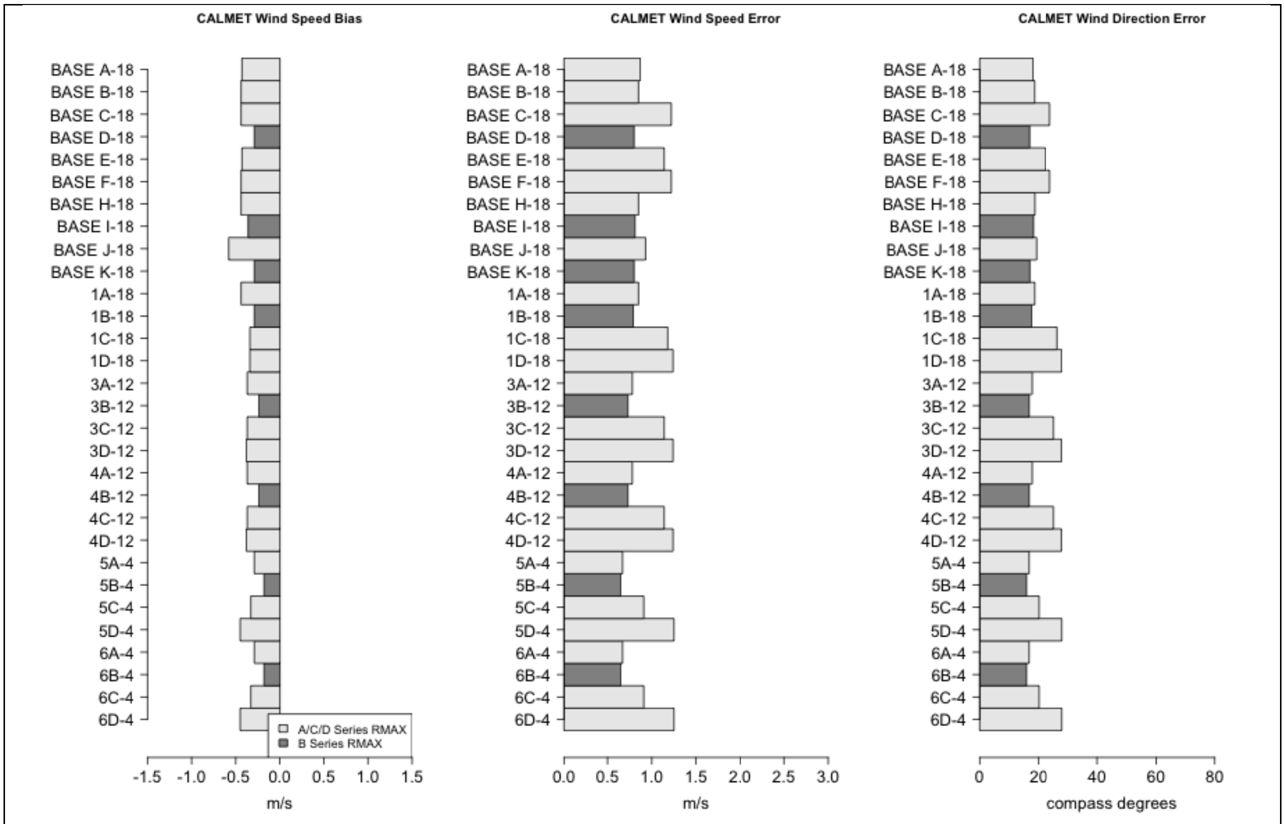

Figure B-1. Wind speed and wind direction comparisons with observations for CTEX3 CALMET sensitivity simulations.

Figure B-1 displays the wind speed and direction performance metrics for the second group of CALMET sensitivity tests that uses CALMET grid resolutions of 18 km (EXP1) and 12 km (EXP3 and EXP4) and uses 36 km MM5 (EXP1 and EXP3) and 12 km MM5 (EXP4) data as input to CALMET. EXP1B, EXP3B and EXP4B CALMET sensitivity tests all conform to the recommended settings in the Clarification Memorandum. The “B” series most closely matches observation data.

The CALMET model performance statistics for the final group of CTEX3 sensitivity tests corresponding to the EXP5 and EXP6 series of experiments are shown in Figure B-1. These experiments correspond to using a 4 km grid resolution in CALMET, which is the finest scale recommended in the Clarification Memorandum. They differ in the resolution of MM5 data used as input (36 or 12 km) and how observations are blended into the wind fields (different RMAX1/RMAX2 or no observations). When looking across all wind speed and direction statistics, the CALMET sensitivity simulations that conform to the CALMET settings in the August 2009 Clarification Memorandum (EXP5B and EXP6B) compare most closely to observations.

Figure B-1 displays the CALMET model performance statistics for all sensitivity tests that conform to the recommended CALMET settings in the Clarification Memorandum. The Clarification Memorandum specifies that prognostic meteorological model output data should be used as a first guess wind field in CALMET (IPROG = 14), but doesn’t specify the resolution that the prognostic meteorological model should be run at. For the CALMET grid resolution, the Clarification Memorandum just specifies that it should be ≥ 4 km. Thus these CALMET sensitivity tests vary by grid resolution used in the prognostic meteorological model (80, 36 and 12 km) whose output is used as input to CALMET and the CALMET grid resolution (18, 12 and 4 km).

Table B-2a. Summary wind speed model performance statistics for the CALMET CTEX3 sensitivity tests.

RUN	WS Gross Error (ms^{-1})	WS Bias (ms^{-1})	WS RMSE (ms^{-1})	IOA
BASE A	0.87	-0.43		0.81
BASE B	0.85	-0.44	1.60	0.82
BASE C	1.22	-0.44	1.62	0.63
BASE D	0.80	-0.29	1.23	0.83
BASE E	1.14	-0.43	1.52	0.68
BASE F	1.22	-0.44	1.62	0.63
BASE G	NA	NA	NA	NA
BASE H	0.85	-0.44	1.30	0.82
BASE I	0.81	-0.36	1.30	0.82
BASE J	0.93	-0.58	1.36	0.80
BASE K	0.80	-0.29	1.23	0.83
EXP 1A	0.85	-0.44	1.29	0.82
EXP 1B	0.79	-0.29	1.22	0.83
EXP 1C	1.18	-0.34	1.57	0.68
EXP 1D	1.24	-0.34	1.64	0.65
EXP 3A	0.78	-0.37	1.26	0.83
EXP 3B	0.73	-0.24	1.20	0.85
EXP 3C	1.14	-0.37	1.52	0.70
EXP 3D	1.24	-0.38	1.64	0.65
EXP 4A	0.78	-0.37	1.26	0.83
EXP 4B	0.73	-0.24	1.20	0.85
EXP 4C	1.14	-0.37	1.52	0.70
EXP 4D	1.24	-0.38	1.64	0.65
EXP 5A	0.67	-0.29	1.24	0.84
EXP 5B	0.65	-0.18	1.19	0.85
EXP 5C	0.91	-0.33	1.31	0.80
EXP 5D	1.25	-0.45	1.25	0.65
EXP 6A	0.67	-0.29	1.24	0.84
EXP 6B	0.65	-0.18	1.19	0.85
EXP 6C	0.91	-0.33	1.31	0.80
EXP 6D	1.25	-0.45	1.66	0.65

Table B-2b. Summary wind direction model performance statistics for the CALMET CTEX3 sensitivity tests.

RUN	WD Gross Error (deg.)	WD Bias (deg.)
BASE A	18.06	0.73
BASE B	18.62	-0.74
BASE C	23.91	2.63
BASE D	16.92	0.40
BASE E	22.31	2.68
BASE F	23.91	2.63
BASE G	NA	NA
BASE H	18.70	-0.79
BASE I	18.22	-0.65
BASE J	19.30	-0.85
BASE K	16.97	0.38
EXP 1A	18.64	-0.72
EXP 1B	17.59	1.15
EXP 1C	26.43	2.99
EXP 1D	27.99	3.11
EXP 3A	17.80	-0.82
EXP 3B	16.75	0.98
EXP 3C	25.25	2.57
EXP 3D	27.93	2.94
EXP 4A	17.80	-0.82
EXP 4B	16.75	0.98
EXP 4C	25.25	2.57
EXP 4D	27.93	2.94
EXP 5A	16.73	-1.00
EXP 5B	15.85	0.72
EXP 5C	20.11	1.42
EXP 5D	28.05	2.43
EXP 6A	16.73	-1.00
EXP 6B	15.85	0.72
EXP 6C	20.11	1.42
EXP 6D	28.05	2.43

B.2 CONCLUSIONS OF CTEX3 CALMET SENSITIVITY TESTS

The evaluation of the CALMET modeling system using the CTEX3 field experiment database is not a true independent evaluation because some of the surface meteorological observations used as the evaluation database are also used as input into CALMET. Thus, care should be taken in the interpretation of the CALMET meteorological model evaluation. In fact, EPA has demonstrated that CALMET's blending of meteorological observations with MM5 prognostic meteorological model fields can actually produce unrealistic results in the wind fields (e.g., discontinuities around the wind observation sites) at the same time as improving the CALMET statistical model performance at the meteorological monitoring sites.

Given these caveats, when looking at the alternative CALMET settings for RMAX1/RMAX2 the CALMET configuration that best matches observed winds is with the 100/200 RMAX1/RMAX2 setting as recommended in the 2009 Clarification Memorandum. Other recommended settings in the 2009 Clarification Memorandum (e.g., use of prognostic meteorological data as the initial first guess wind field) are supported by the CALMET CTEX3 model evaluation. Note that better wind field comparisons using the 2009 Clarification Memorandum recommended settings for RMAX1/RMAX2 was also seen for the CTEX5 CALMET evaluation presented in Appendix A.

Although the CALMET meteorological model performance evaluation for alternative model settings support the recommended 100/200 CALMET settings for RMAX1/RMAX2 in the Clarification Memorandum, the evaluation of the CALPUFF/CALMET modeling system for the CTEX3 and CTEX5 field experiments against observed tracer data presented in Chapter 5 come to an alternative conclusion. The CALPUFF/CALMET evaluation against the observed tracer observations in the CTEX3 and CTEX5 experiments found that different RMAX1/RMAX2 configurations produced better CALPUFF/CALMET tracer model performance for the two CAPTEX experiments, but that the 100/200 recommended setting always produced the worst CALPUFF/CALMET model performance. Given the large differences in the in the rankings of the ability of the CALPUFF to reproduce the observed tracer concentrations across the different meteorological model configurations in the two CAPTEX field experiments, it is unclear whether a third experiment would produce another set of rankings.

Appendix C

INTERCOMPARISON OF SIX LRT MODELS AGAINST THE CAPTEX RELEASE 3 AND RELEASE 5 FIELD EXPERIMENT DATA

C.1 INTRODUCTION

In this section, the evaluation of six LRT dispersion models (CALPUFF, SCIPUFF, HYSPLIT, FLEXPART, CAMx, and CALGRID) against the Cross Appalachian Tracer Study (CAPTEX) (Section 5) is presented. The ATMES-II evaluation framework described in Section 2.4.3.1 and 2.4.3.3 are utilized to conduct this evaluation. The CAPTEX evaluations generally follow the ETEX evaluation paradigm, all models presented in this section use a common 36 km MM5 meteorological data source. Thus the results from the CALMET/CALPUFF sensitivities are not presented because they are not within the scope of this evaluation framework. However, we do wish to note that CALPUFF/CALMET performance for CAPTEX-5 (EXP6C) was quite good, and exceeded that of the other models involved in the model intercomparison portion of this section; however, due to a different source of meteorology, only the MMIF/CALPUFF results for the same MM5 run and grid resolution are included.

In addition to the six model intercomparison, sensitivities of the HYSPLIT INITD and CAMx vertical diffusion and horizontal advection solver (Kz/advection solver) combinations are also presented. The best performing INITD and Kz/advection solver combinations are presented for purposes of model intercomparison.

C.2 HYSPLIT SENSITIVITY TESTS

Consistent with the approach taken for evaluating HYSPLIT for the European Tracer Experiment discussed in Section 6.4.5, HYSPLIT was evaluated using each of the nine INITD model configurations. The HYSPLIT INITD option defines the technical formulation of the dispersion model from fully particle to fully Lagrangian puff with several hybrid particle/puff combinations. A description of the INITD variable options is provided in Table 6-4. The HYSPLIT configurations for each INITD option are presented in Table C-1.

Table C-1. HYSPLIT sensitivity runs and relevant configuration parameters.

Sensitivity Test	INITD	NUMPAR	ISOT	KSPL	FRHS	FRVS	FRTS	FRME
INITD0	0	10000	1	NA	NA	NA	NA	NA
INITD1	1	10000	1	1	1.0	0.01	0.10	0.10
INITD2	2	10000	1	1	1.0	0.01	0.10	0.10
INITD3	3	10000	1	1	1.0	0.01	0.10	0.10
INITD4	4	10000	1	1	1.0	0.01	0.10	0.10
INITD103	103	10000	1	1	1.0	0.01	0.10	0.10
INITD104	104	10000	1	1	1.0	0.01	0.10	0.10
INITD130	130	10000	1	1	1.0	0.01	0.10	0.10
INITD140	140	10000	1	1	1.0	0.01	0.10	0.10

C.2.1 HYSPLIT SPATIAL PERFORMANCE FOR CAPTEX RELEASE 3

Figure C-1 displays the spatial model performance statistics for the HYSPLIT INITD sensitivity tests. Unlike the results from the HYSPLIT sensitivities from ETEX, the variation in spatial performance is much smaller. While the puff based INITD configurations showed slightly lower scores for POD, their scores for all other spatial categories is nearly identical to the other INITD configurations. INITD3 has the highest FMS score (34%) with INITD1 nearly the same at 33%. Consistent with the ETEX results, the puff configuration INITD1 (Gh-Thv) yielded slightly better performance statistics across spatial categories than the INITD2 puff configuration (Thh-Thv). Overall for CAPTEX Release 3, there appears to be little advantage of one INITD configuration over another for the four spatial categories of model performance metrics.

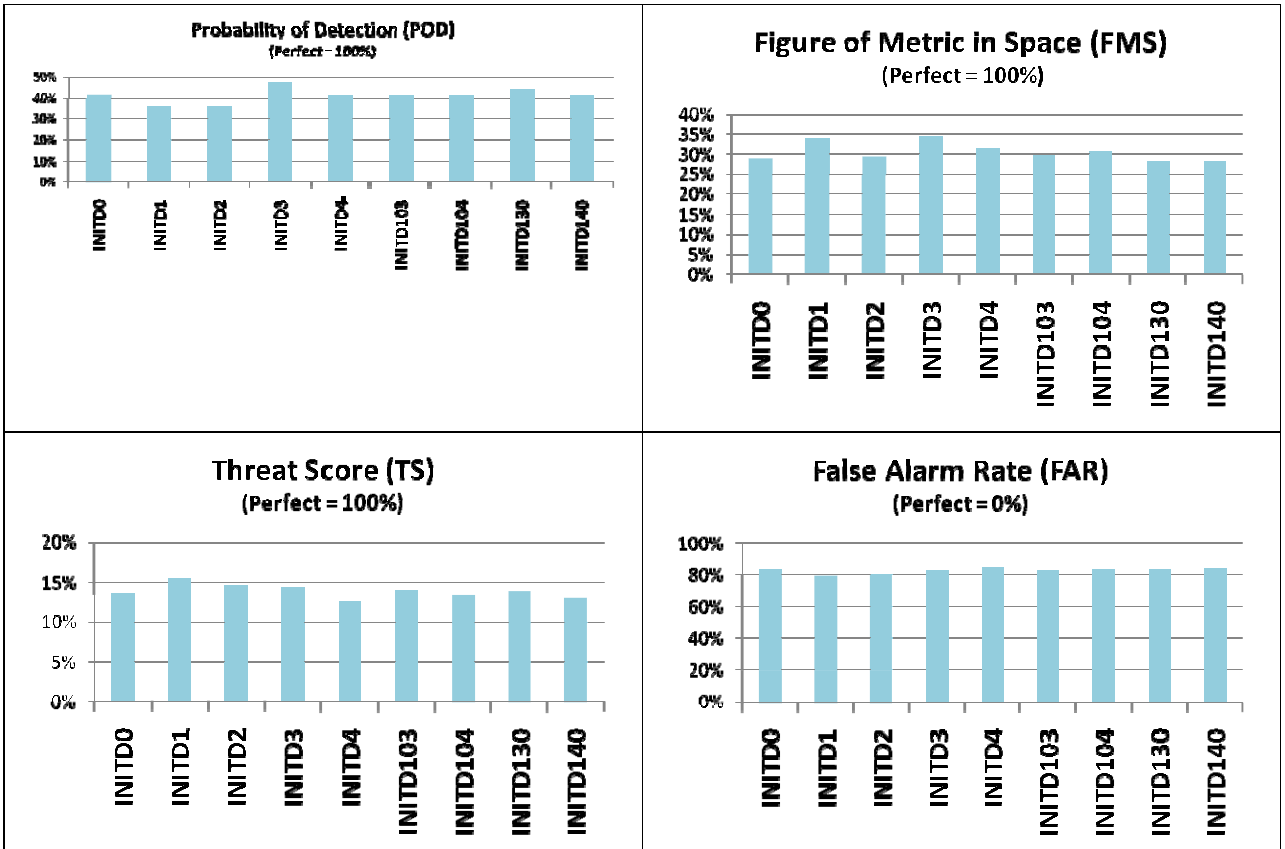

Figure C-1. Spatial model performance statistics for nine HYSPLIT INITD sensitiviity experiments for CAPTEX Release 3.

C.2.2 HYSPLIT GLOBAL STATISTICS FOR CAPTEX RELEASE 3

Figures C-2 and C-3 display the global statistics for the HYSPLIT sensitivity tests with Figures C-2 and C-3 containing the statistical metrics where the best performing model has the, respectively, lowest and highest score. For the FOEX metrics, INITD140 scores the best with nearly 0%, followed closely by INITD1 and INITD2. INITD3 scores the poorest with a 21% FOEX score followed by INITD4. The two puff configurations had the poorest NMSE and FB statistical performance metrics (with values of approximately 127 and 130 pg m^{-3} for error and 1.56 and 1.57 for FB). The four puff-particle model configuration options (INITD3,4,103,104) exhibited the best overall scores for both NMSE and FB. INITD1 and INITD2 exhibited the best overall KSP score with 30% and 31% respectively, with the poorest performing being INITD3 with 49%.

For the within a factor of 2 and 5 metric (FA2 and FA5, Figure C-3, top), the hybrid puff-particle configurations INITD3 and INITD4 and their counterpart particle-puff configurations INITD103 and INITD104 perform slightly better than the other configurations. For the PCC metric (PCC, Figure C.2.2-2, bottom left), all of the HYSPLIT configurations show a slight negative correlation ranging from -0.04 to -0.09.

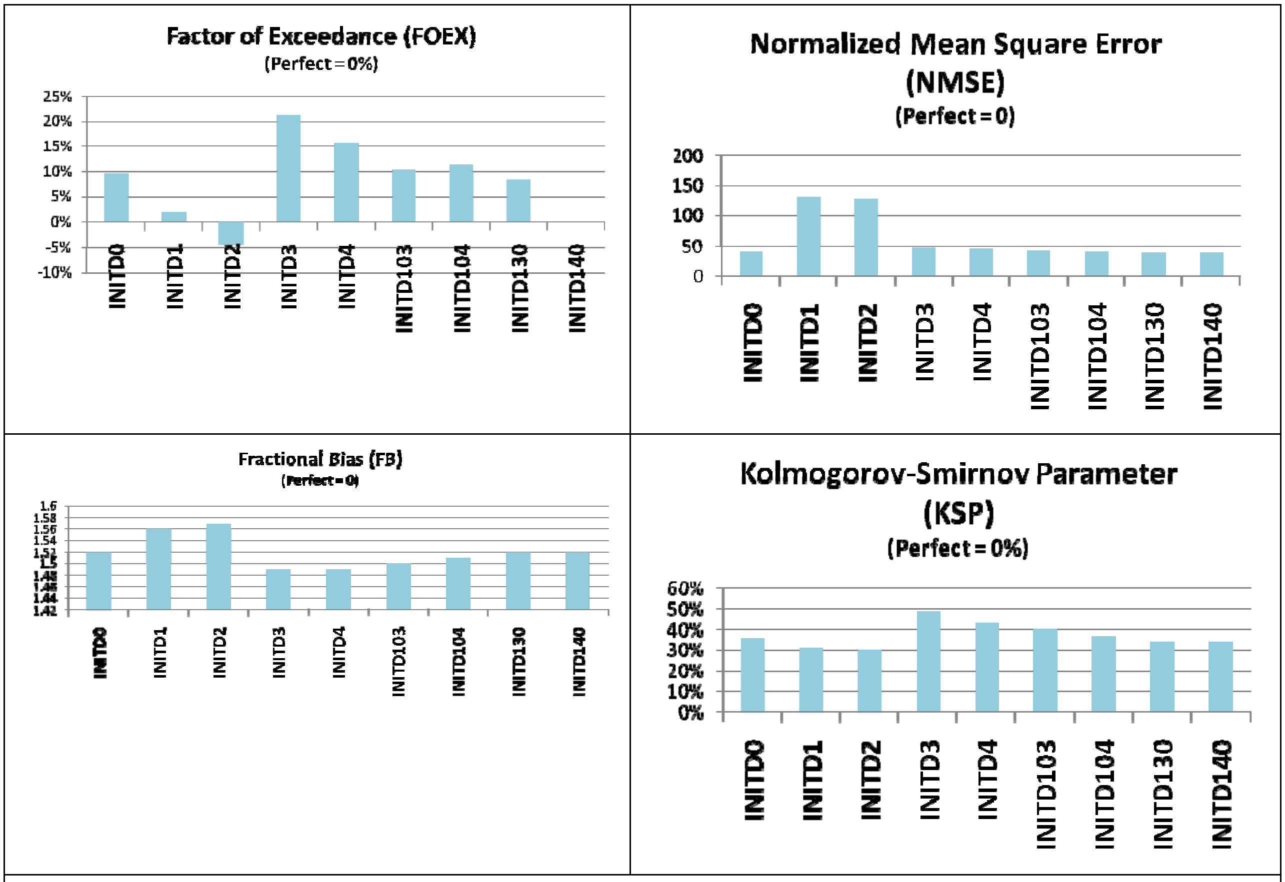

Figure C-2. Global model performance statistics for nine HYSPLIT INITD sensitivity tests for CAPTEX Release 3.

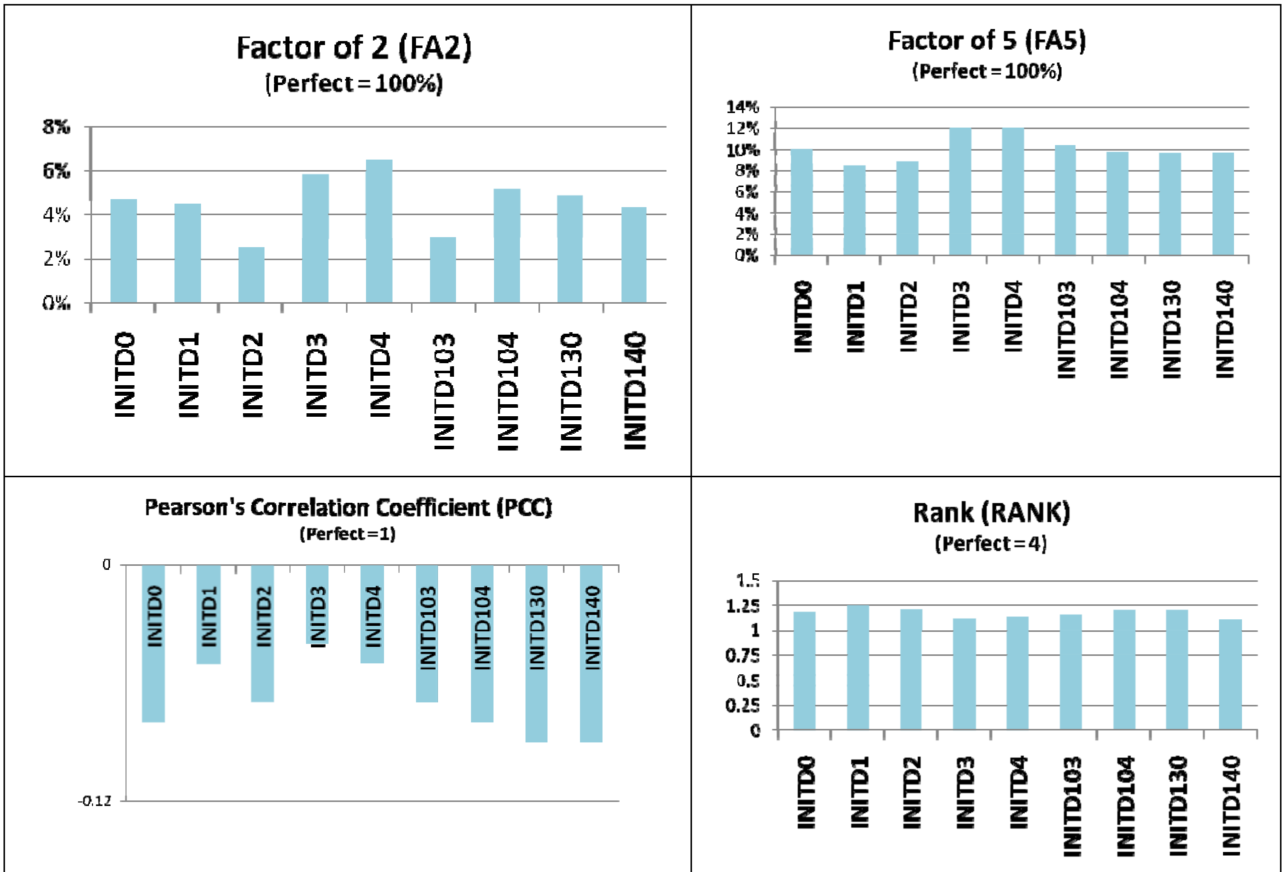

Figure C-3. Global model performance statistics for nine HYSPLIT INITD sensitivity tests for CAPTEX Release 3.

The final panel in Figure C-3 (bottom right) displays the overall RANK statistic. The RANK statistics orders the model performance of the HYSPLIT INITD configurations as follows:

1. INITD1 (1.25)
2. INITD2 (1.21)
3. INITD104 (1.19)
4. INITD130 (1.19)
5. INITD0 (1.18)
6. INITD103 (1.15)
7. INITD4 (1.14)
8. INITD3 (1.11)
9. INITD140 (1.10)

The RANK performance statistics results presented above raise some interesting questions about the RANK metric. The puff based configurations (INITD1 and INITD2) are the highest ranking with scores using the RANK metric with values of 1.25 and 1.21 respectively. However, each of these options had the worst (highest) NMSE and FB scores, while puff-particle configurations ranking slightly less using the RANK metric (1.1 to 1.19) have NMSE scores that are much better (only one-third) those for the puff configurations as well as slightly lower FB scores. On the basis of RANK scores, the INITD1 and INITD2 configurations are the best performing, but based upon other model performance statistics that are not included as the four statistical metrics that make up the RANK metric (i.e., PCC, FB, FMS and KSP), the puff-particle hybrid configurations are better performing. Thus care must be taken in interpreting model performance based solely on the RANK score and its use in performing model intercomparisons and we recommend examining the whole suite of statistical performance metrics, as well as graphical representation of model performance, to come to conclusions regarding model performance.

C.2.3 HYSPLIT SPATIAL STATISTICS FOR CAPTEX RELEASE 5

Figure C-4 displays the spatial model performance statistics for the HYSPLIT INITD sensitivity tests for CAPTEX Release 5. Overall, the spatial performance for this experiment is very similar to the results obtained from the ETEX INITD sensitivities for HYSPLIT. The puff configurations (INITD1 and INITD2) exhibited the poorest performance across all of the spatial statistics. INITD2 had the poorest FMS score with 5%, followed by INITD1 with 9.6%. INITD3 had the best FMS score of 19.66%, but less than 2% separated all of the remaining particle and puff-particle INITD configurations. The particle mode (INITD0) exhibited the best TS with 24.4% with less than 1.5% separating INITD103, 130, and 140 from INITD0. Consistently, the puff configurations exhibited the lowest TS among the nine configurations, both with 7.9%.

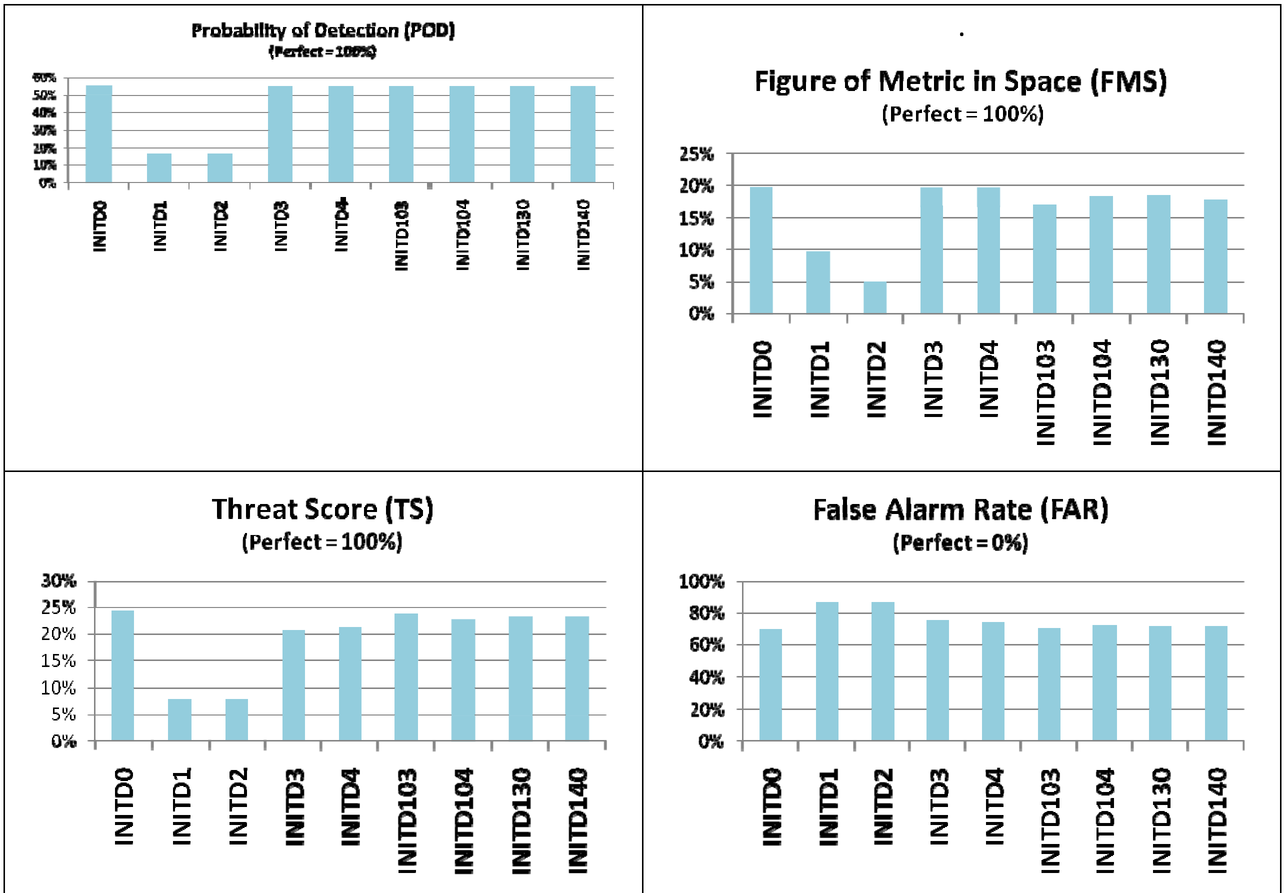

Figure C-4. Spatial model performance statistics for nine HYSPLIT INITD sensitiviity experiments for CAPTEX Release 5.

C.2.4 HYSPLIT GLOBAL STATISTICS FOR CAPTEX RELEASE 5

Figures C-5 and C-6 display the global statistics for the HYSPLIT sensitivity tests for CAPTEX Release 5 where the two figures containing the statistical metrics where the best performing model has the, respectively, lowest and highest score. For the FOEX metrics (Figure C-5, top left), INITD3 and INITD4 showed the best scores with -3% and -7.9% respectively. INITD2 scored the poorest with a -22% FOEX score followed by INITD1 with -18.3%. The two puff configurations had the poorest NMSE and FB statistical performance metrics (with values of approximately 72.7 and 63.6 pg m^{-3} for error and 1.45 and 1.41 for FB). INITD3 exhibited the best overall scores for both NMSE and FB (16.6 pg m^{-3} and 0.88 respectively. INITD1 and INITD2 exhibited the poorest KSP scores with 44% and 48% respectively. INITD104 had the best KSP score with 28%, followed by INITD4 (30%), INITD0 and INIT130 (31%), and INITD140 (32%).

For the within a factor of 2 and 5 metric (FA2 and FA5, Figure C-6, top), the puff INITD configurations performed the poorest with scores between 0% - 1% for FA2 and 1% - 4.8% for FA5. INITD0 showed the best FA2/FA5 scores with 6.9%/11.8%, followed by INITD130 and INITD140 for FA2 and INITD3 and INITD4 for FA5. Curiously, INITD3 and INITD4 had slightly lower FA2 scores (3.4%/2.8%) than the other puff-particle hybrid configurations, but higher FA5 scores. For the PCC metric (PCC, Figure C-6, bottom left), INITD3 had the highest score with 0.63, followed closely by the other puff-particle or particle configurations ranging from 0.51 (INITD0) to 0.62 (INITD2).

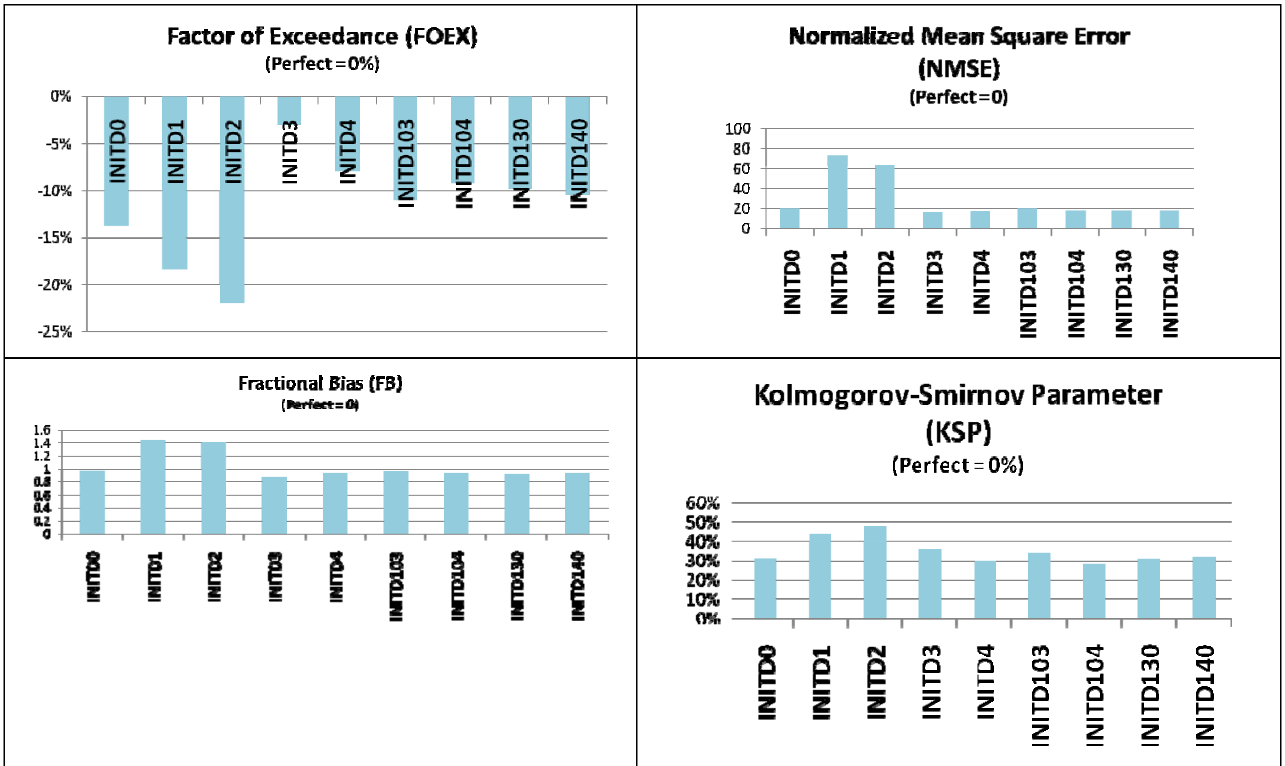

Figure C-5. Global model performance statistics for nine HYSPLIT INITD sensitivity tests for CAPTEX Release 5.

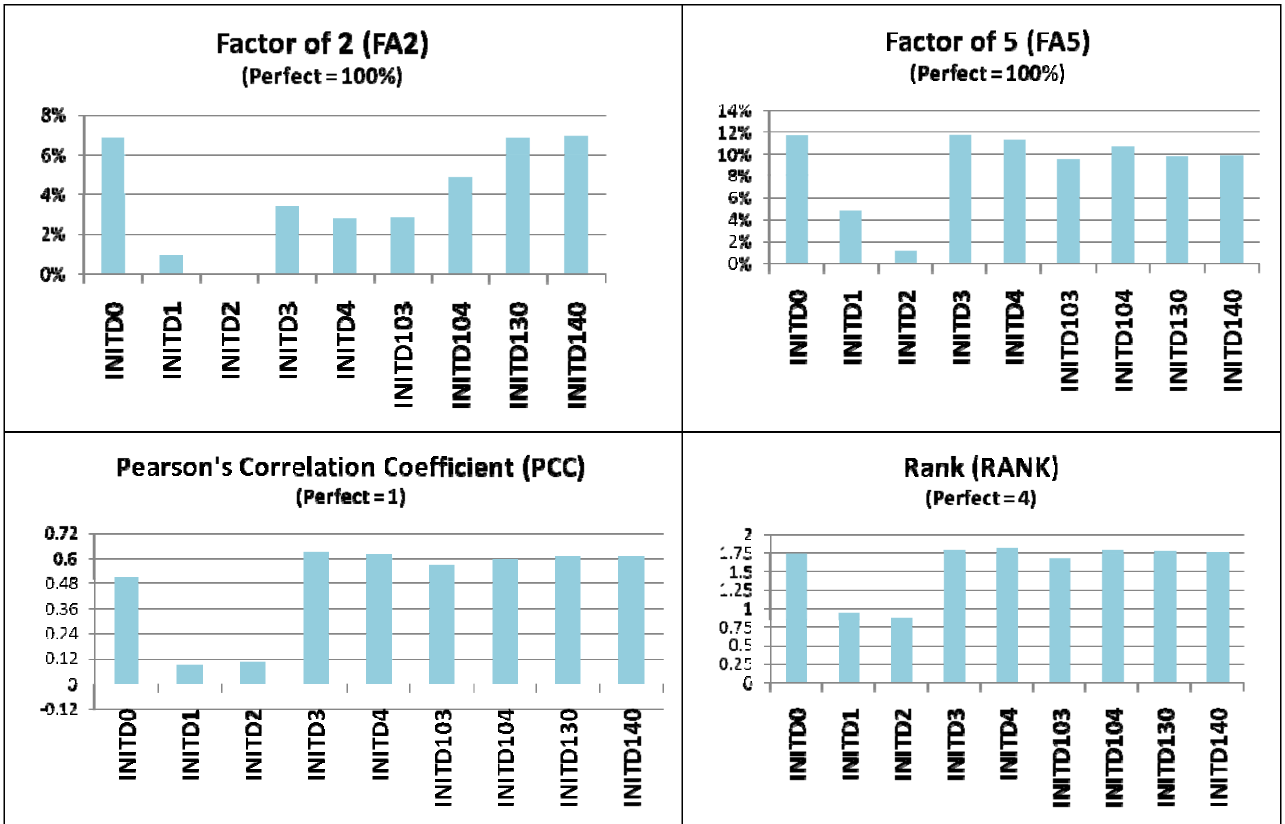

Figure C-6. Global model performance statistics for nine HYSPLIT INITD sensitivity tests for CAPTEX Release 5.

The final panel in Figure C-6 (bottom right) displays the overall RANK statistic. The RANK statistics orders the model performance of the HYSPLIT INITD configurations are as follows:

1. INITD4 (1.82)
2. INITD104 (1.80)
3. INITD3 (1.79)
4. INITD130 (1.78)
5. INITD140 (1.76)
6. INITD0 (1.75)
7. INITD103 (1.68)
8. INITD1 (0.94)
9. INITD2 (0.88)

C.3 CAMX SENSITIVITY TESTS

Following the general design of the study for the ETEX tracer database, CAMx sensitivity tests described in Section 6.4.3, thirty-two CAMx sensitivity tests were conducted to investigate the effects of vertical diffusion, horizontal advection solvers and use of the sub-grid scale Plume-in-Grid (PiG) module on the model performance for the CAPTEX tracer experiment releases 3 and 5. In addition to the sixteen sensitivities conducted for ETEX, a similar set of sensitivity analyses were conducted using the newer ACM2 vertical diffusion scheme (Pleim, 2007; ENVIRON, 2010) introduced into CAMx as of Version 5.20 as an alternative to the more traditional fully K-theory vertical diffusion schemes that were the only options available in previous versions of CAMx.

C.3.1 SPATIAL PERFORMANCE FOR CTEX3 NOPIG EXPERIMENTS

Figure C-7 displays the CAMx spatial model performance statistics for the sensitivity tests that were run without using the PiG subgrid-scale puff module. For the FMS statistic, the ACM2, TKE, and CMAQ Kz exhibit very similar performance (40.9%, 40.9%, and 39.4% respectively). OB70 exhibits the poorest performance with 33.5% for FMS.

For the FAR statistic, ACM2/Bott has the best score (55.6%) followed by TKE/PPM and ACM2/PPM (tied at 58.5%). Overall ACM2 is the best performing vertical diffusion formulation and PPM performs better than BOTT for horizontal advection using the FAR statistic.

For the POD and TS spatial statistics, the CMAQ, TKE, and ACM2 vertical diffusion algorithms perform similarly, and all are substantially better than the OB70 approach (15% lower than other vertical diffusion schemes). ACM2/BOTT has the best TS score with 28.6% followed by ACM2/PPM and TKE/PPM (tied at 28.33%). CMAQ/PPM exhibits the best POD score with 52.8% followed by CMAQ/BOTT, ACM2/PPM, and TKE/PPM (tied at 47.2%). Consistent with the ETEX spatial results, there are much smaller differences in the model performance using the two advection solvers for the POD and TS statistics compared to differences between Kz options.

In summary, based on the spatial statistics, the ACM2, CMAQ, and TKE Kz algorithms appear to be performing similarly, with the older OB70 option exhibiting much poorer overall performance. The differences in vertical diffusion algorithms have a greater effect on CAMx model performance than the differences in horizontal advection solvers.

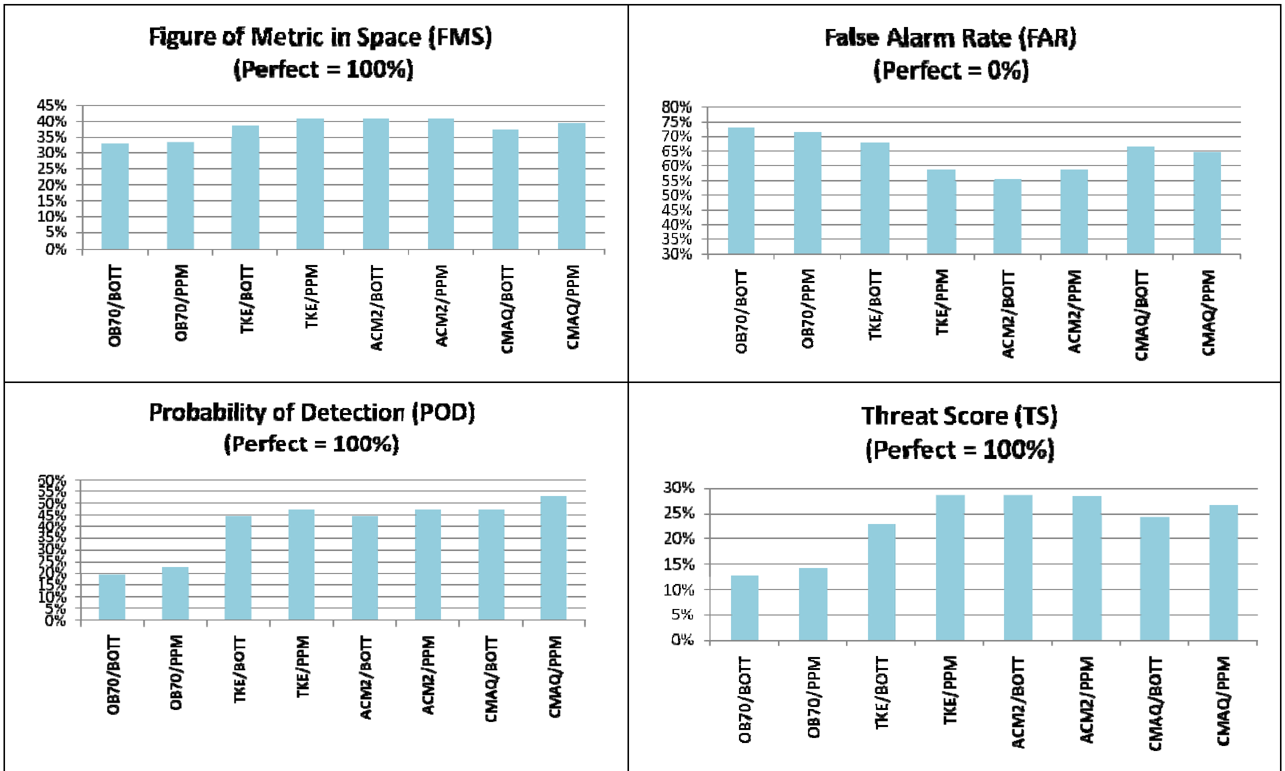

Figure C-7. Spatial model performance statistics for the CAMx sensitivity tests without using the PiG subgrid-scale puff module (NoPiG) for CAPTEX Release 3.

C.3.2 Global Statistical Performance for CTEX3 NoPiG Experiments

Figures C-8 and C-9 displays the global statistics for the CAMx NoPiG sensitivity and contain the statistical metrics where the best performing model has the, respectively, lowest and highest score. For the FOEX metric, the vertical diffusion algorithm that has the best score was the ACM2 algorithm with scores of 3.26% (ACM2/BOTT) and 3.6% (ACM2/PPM). The next best vertical diffusion algorithm/advection solver combination was OB70/BOTT with a -3.8% FOEX score. The CMAQ/BOTT (9.1%) and CMAQ/PPM (9.6%) have the highest (worst) FOEX scores.

For the NMSE statistical performance metric, the ACM2 and TKE vertical diffusion schemes perform best (28 to 30 pgm^{-3}) (Figure C-8, top right). Both OB70 scenarios yielded the poorest NMSE scores with error values more than twice that of the other Kz/advection solver configurations. Consistent with both FOEX and NMSE, the ACM2 vertical diffusion scheme is also the best performing method according to the FB and KSP metrics followed by the TKE scheme (Figure C-8, bottom left). The OB70 vertical diffusion algorithm performs the poorest for both of the FB and KSP metrics.

For the within a factor of 2 and 5 metrics (FA2/FA5, Figure C-9, top), the ACM2 combinations are the best performing with values of 8.8%/17.1% and 8.2%/16.3%. The TKE and CMAQ combinations perform similarly, with the TKE options having slightly higher FA2 percentages, but the CMAQ combinations exhibit higher FA5 percentages than the TKE.

For the PCC metric, the CMAQ and TKE combinations yield the best correlation performance with values ranging from 0.54 to 0.63 with CMAQ having slightly higher correlation values overall. Interestingly, for most other spatial and global statistical categories for the NoPiG tests

ACM2 Kz combinations rank as the best performing. However, the ACM2 Kz combinations have the lowest PCC correlation values of the four Kz combinations, with values of 0.22 and 0.30.

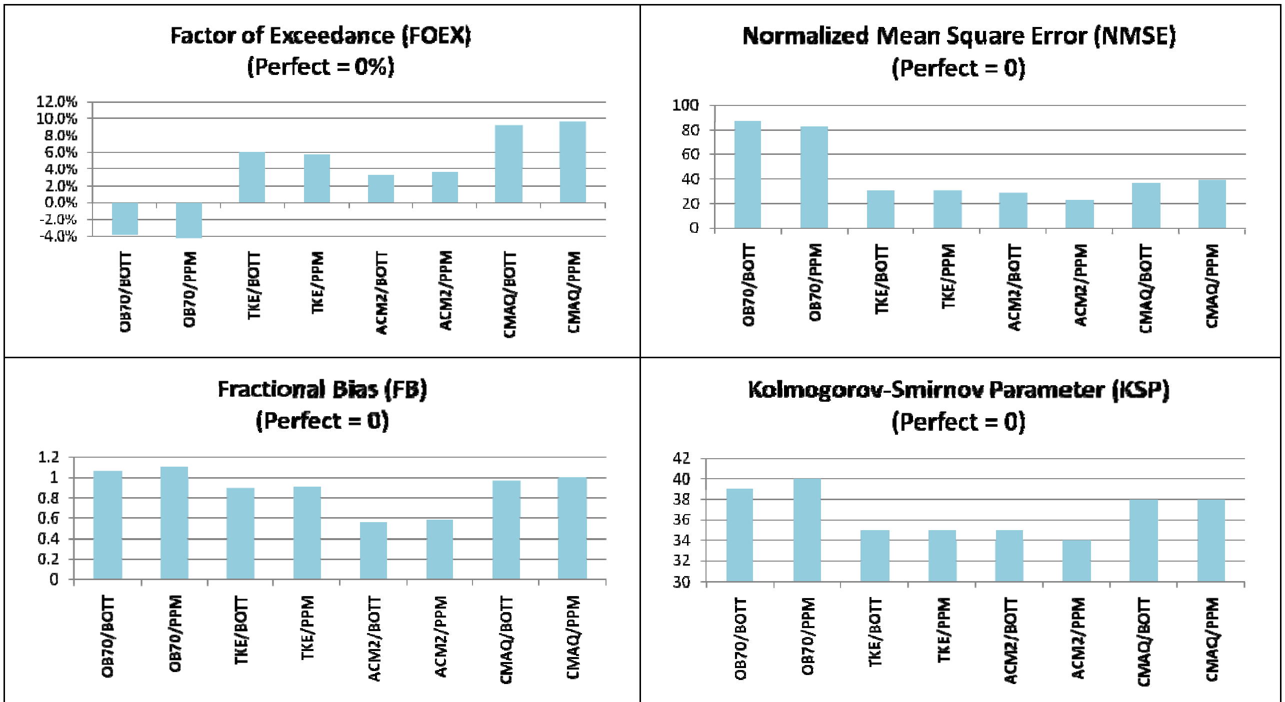

Figure C-8. Global model performance statistics for the CAMx sensitivity tests without using the PiG subgrid-scale puff module for CAPTEX Release 3.

The final panel in Figure C-9 (bottom right) displays the overall RANK statistic. The RANK statistics orders the model performance of the CAMx configurations without PiG as follows:

1. TKE/PPM (1.97)
2. CMAQ/PPM (1.91)
3. TKE/BOTT (1.89)
4. ACM2/PPM (1.87)
5. CMAQ/BOTT (1.83) (tied)
6. ACM2/BOTT (1.83) (tied)
7. OB70/PPM (1.67)
8. OB70/BOTT (1.56)

Based on this analysis, the TKE Kz coefficients is the best performing vertical diffusion approach followed closely by CMAQ. As noted previously, the vertical diffusion algorithm has a greater effect on CAMx model performance compared to the choice of horizontal advection solvers.

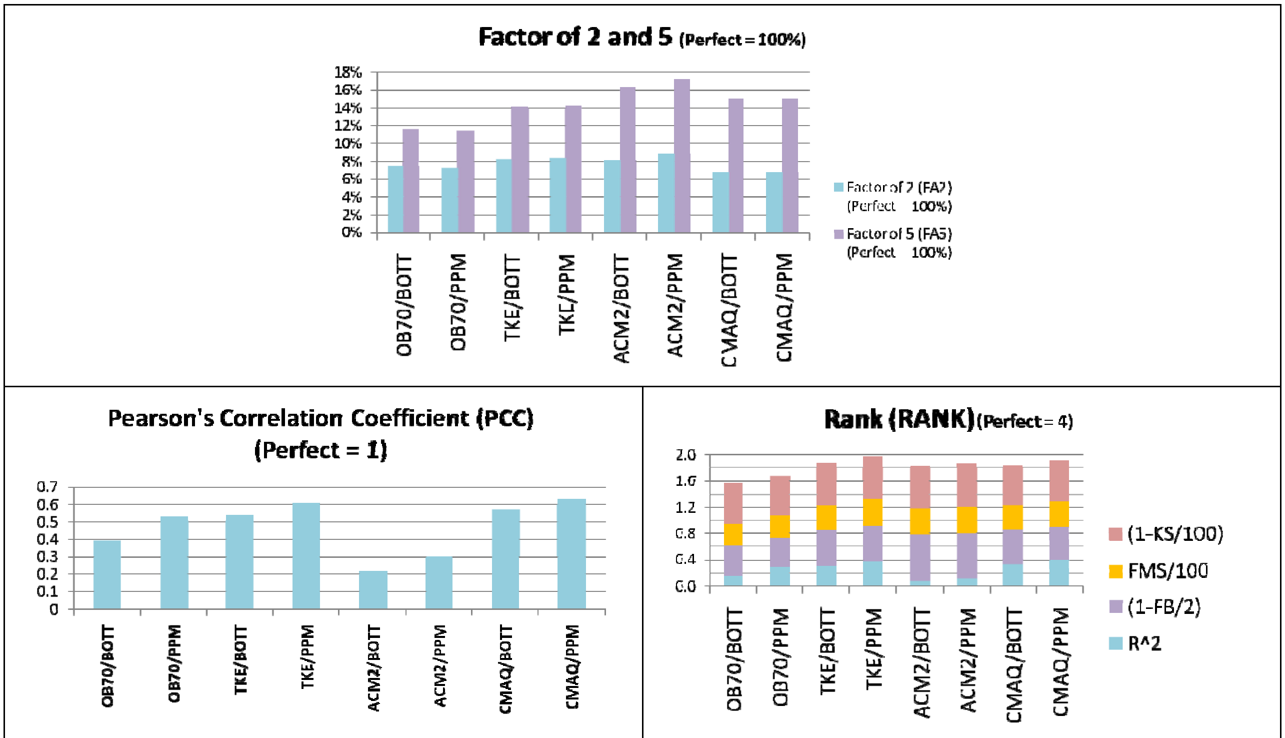

Figure C-9. Global model performance statistics for the CAMx sensitivity tests without using the PiG subgrid-scale puff module for CAPTEX Release 3.

C.3.3 SPATIAL PERFORMANCE FOR CTEX3 PIG EXPERIMENTS

Figure C-10 displays the CAMx spatial model performance statistics for the sensitivity tests that were run using the PiG subgrid-scale puff module. For the FMS statistic, the CMAQ Kz/BOTT combination has the best performance at 36.2%. TKE/BOTT and TKE/PPM followed closely with FMS scores of 36% and 35.6% respectively. OB70 exhibits the poorest performance with 23.5% for FMS.

For the FAR statistic, ACM2/Bott has the best score (61.5%) followed by TKE/BOTT and ACM2/PPM (62.8% and 63% respectively). OB70 exhibited the poorest performance with a 72% FAR. For the POD metric, the TKE/BOTT combination performs substantially better than the other Kz/advection solver combinations (44.4%). Both OB70 scenarios showed the poorest performance at 13.9%. For the TS spatial metric, the CMAQ/PPM exhibits the best score with 30.6% followed by TKE/BOTT and CMAQ/BOTT(25.4% and 23.3% respectively). OB70 again performs poorest with a TS value of 10.2% for both advection solver combinations. Consistent with the ETEX spatial results, there are much smaller differences in the model performance using the two advection solvers for the POD and TS statistics compared to differences between Kz options.

In summary, the effect of using the CAMx subgrid scale puff module appears to slightly degrade performance in comparison to the NoPiG experiments. A similar pattern was noted in the spatial statistics compared to the NoPiG experiments with the ACM2, CMAQ, and TKE Kz algorithms performing similarly, with the older OB70 option exhibiting much poorer overall performance.

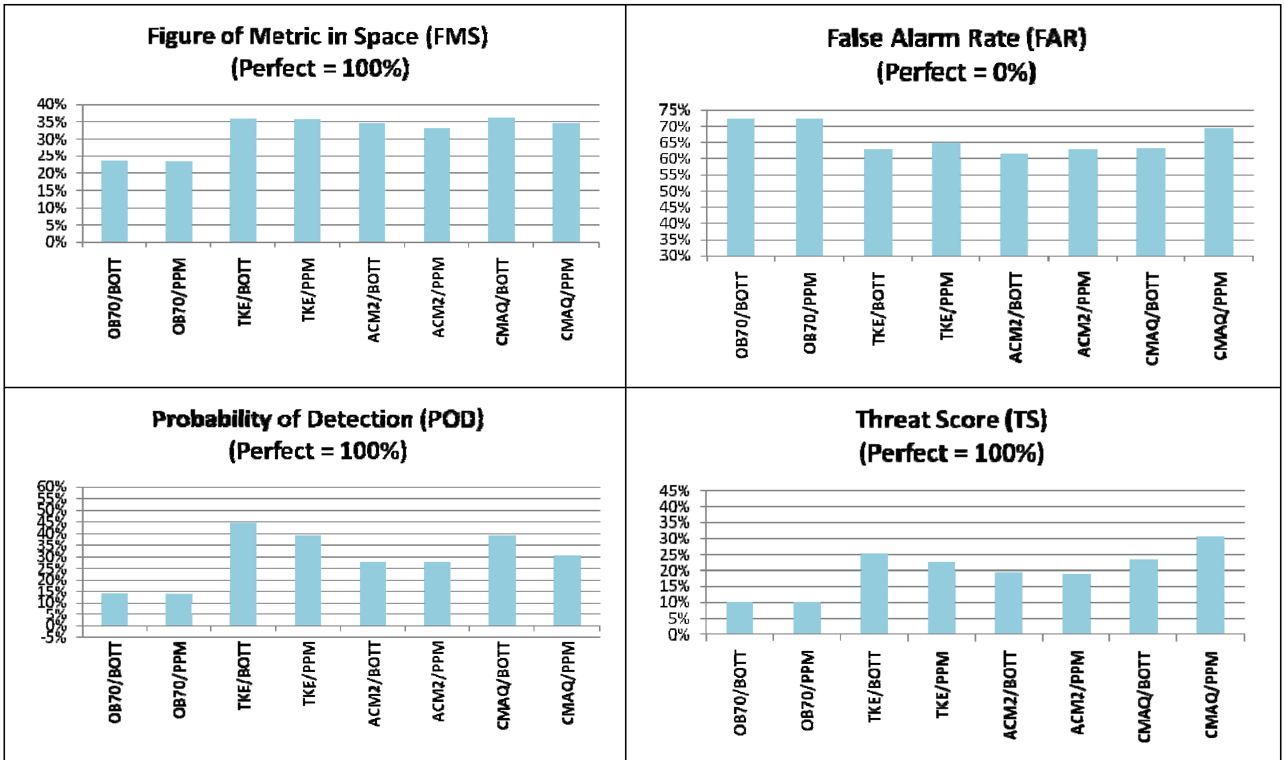

Figure C-10. Spatial model performance statistics for the CAMx CTEX3 sensitivity tests using the PiG subgrid-scale puff module (PiG).

C.3.4 GLOBAL STATISTICAL PERFORMANCE FOR CTEX3 CAMX PIG SENSITIVITY TESTS

Figures C-11 and C-12 displays the global statistics for the CAMx NoPiG sensitivity tests with the two figures containing the statistical metrics where the best performing model has the, respectively, lowest and highest score. For the FOEX metric, the vertical diffusion algorithm has the biggest effect was the TKE and CMAQ algorithms with scores near zero. The OB70 combinations exhibit significantly poorer FOEX performance with values of -13.6% (OB70/BOTT) and -16.9% (OB70/PPM).With the NMSE statistical performance metric, the ACM2 and TKE vertical diffusion schemes performs best (38 – 42 pgm^{-3}) (Figure C-11, top right). Both OB70 scenarios yielded the poorest scores with error values more than twice that of the other Kz/advection solver configurations (111 – 116 pgm^{-3}). For fractional bias (Figure C-11, bottom left), the ACM2 combinations have the best scores with 0.58/0.59 (BOTT/PPM). TKE Kz combinations follow with values 0.82/0.83 (BOTT/PPM). OB70 again has the poorest FB performance with values of 1.18/1.19 (BOTT/PPM).

For the within a factor of 2 and 5 metrics (FA2 and FA5, Figure C-12, top), ACM2, TKE, and CMAQ are very similar for FA2, but the TKE Kz option clearly performs best for the FA5 metric, followed by CMAQ. There is essentially no difference in the PCC statistic using the two horizontal advection solvers. According to the PCC metric (Figure C-11, bottom right), CMAQ is the best performing vertical diffusion approach (0.52/0.59 – BOTT/PPM) followed by TKE (0.33/0.44 – BOTT/PPM)ACM2 has the lowest PCC values with scores 0.17 – 0.23 (BOTT/PPM).

The final panel in Figure C-12 (bottom right) displays the overall RANK statistic. The RANK statistics orders the model performance of the CAMx configurations with PiG as follows:

1. CMAQ/PPM (1.86)

2. TKE/PPM (1.83)
3. CMAQ/BOTT (1.81)
4. TKE/BOTT (1.74)
5. ACM2/BOTT (1.69)
6. ACM2/PPM (1.68)
7. OB70/PPM (1.26)
8. OB70/BOTT (1.25)

Based on this analysis, the CMAQ Kz coefficients are the best performing vertical diffusion approach followed closely by TKE. Consistent with the NoPiG experiments, the vertical diffusion algorithm has a greater effect on CAMx model performance compared to the choice of horizontal advection solvers.

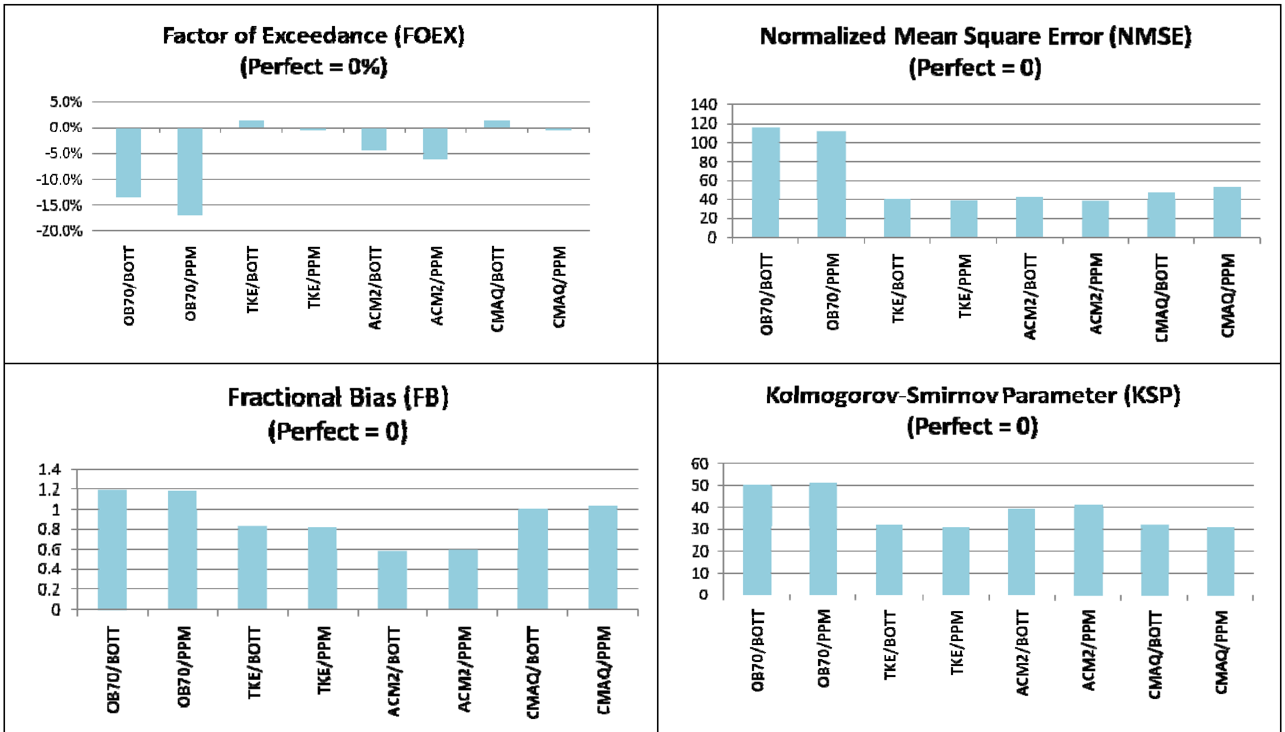

Figure C-11. Global model performance statistics for the CAMx CTEX3 sensitivity tests using the PiG subgrid-scale puff module.

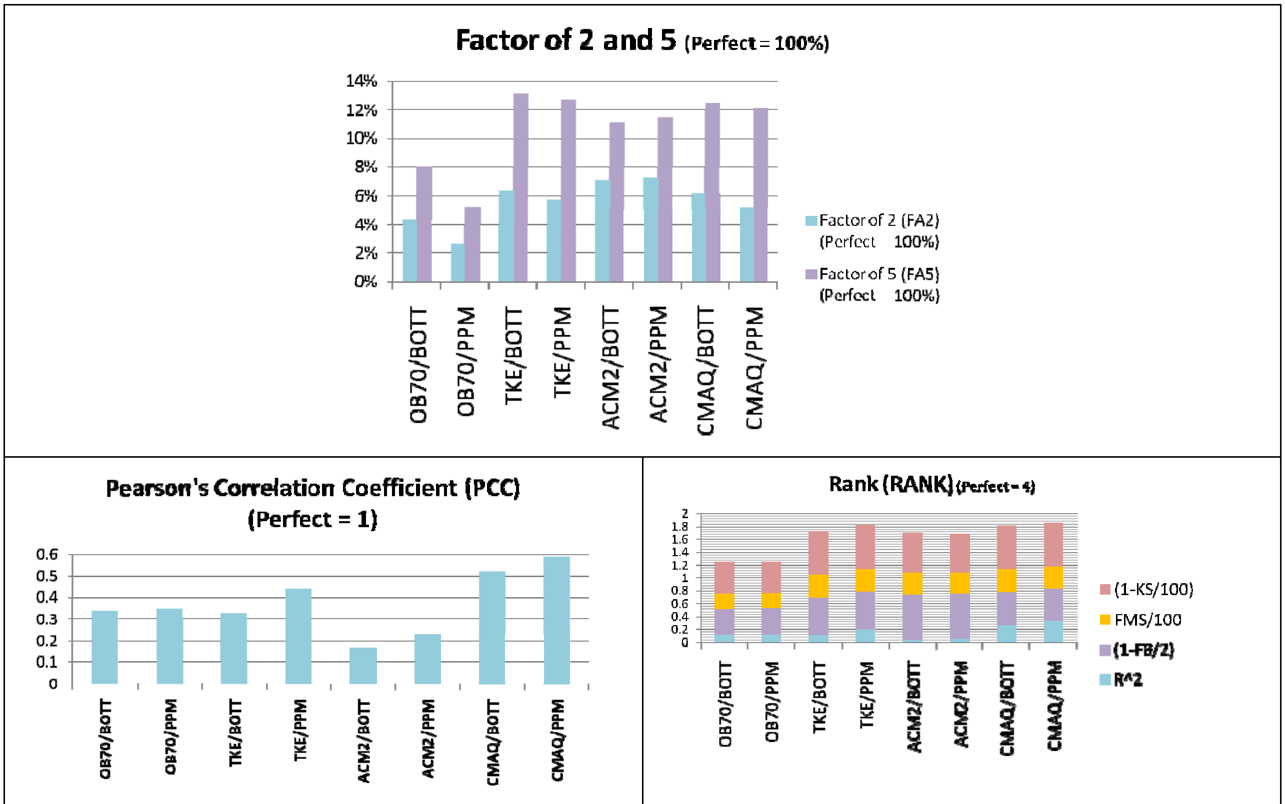

Figure C-12. Global model performance statistics for the CAMx CTEX3 sensitivity tests using the PiG subgrid-scale puff module.

C.3.4.1 EFFECT OF PIG ON MODEL PERFORMANCE

The effect of using the PiG module versus NoPiG results in similar results as seen in the ETEX experiments for CAMx; use of the subgrid-scale PiG module has very little effect on the CAMx model performance and the rankings of the CAMx model performance using the alternative vertical mixing and horizontal advection approaches. In general, it appears that the CAMx model performance without the PiG is performing slightly better than its performance using the PiG.

The spatial performance statistics are sometimes improved and sometimes degraded when the PiG module is invoked. For the global statistics, the PCC performance statistic is degraded by -11% to -37% (-0.03 to -0.13 points) when the PiG module is invoked. Similarly, use of the PiG versus NoPiG module increases (degrades) the FB metric by 5 to 18 percent and also increases (degrades) the NMSE metrics for all model configurations.

Table C-2 summarizes the RANK model performance statistic for the different CAMx model configurations with and without the PiG module. For each model vertical diffusion/horizontal advection configuration, using the PiG module always results in slightly lower RANK statistics that are from -3.9% to -8.5% lower than when the PiG module is not used.

Table C-2. CTEX3 CAMx RANK model performance statistic and model rankings for different model Kz/advection solver configurations with and without using the PiG subgrid-scale puff model.

Model Configuration	Without PiG Module		With PiG Module		PiG-NoPiG	
	RANK	Model Ranking	RANK	Model Ranking	ΔRANK	Percent
OB70/BOTT	1.56	8	1.25	8	-0.41	-26.4%
OB70/PPM	1.67	7	1.26	7	-0.41	-24.5%
TKE/BOTT	1.89	3	1.74	4	-0.15	-8.0%
TKE/PPM	1.97	1	1.83	2	-0.14	-7.1%
ACM2/BOTT	1.83	6[a]	1.69	5	-0.14	-7.6%
ACM2/PPM	1.87	4	1.68	6	-0.19	-10.1%
CMAQ/BOTT	1.83	5[a]	1.81	3	-0.02	-1.0%
CMAQ/PPM	1.91	2	1.86	1	-0.05	-2.6%

[a] tied

C.3.5 SPATIAL PERFORMANCE FOR CTEX5 NOPIG EXPERIMENTS

Spatial performance for CTEX5 and the NoPiG CAMx sensitivities posed a slightly more difficult challenge to interpret due to similarities amongst the Kz/advection solver options for the FMS metric (Figure C-13). The range of difference for the FMS between the minimum and maximum for all of the eight combinations was less than 2.1%, with all in the range of 22% to 24%. This would indicate that each of the model configurations performs similarly across all concentration ranges. However, in the extended spatial statistics of FAR, POD, and TS, greater differentiation in model spatial performance metrics are seen. For example, for POD and TS, the CMAQ Kz combinations perform best of all of the vertical diffusion options, and have POD/TS statistics that are nearly twice as good as the OB70 diffusion combinations with POD/TS values of ~60%/~22% for CMAQ versus ~33%/~10% for OB70 diffusion algorithm options. Since these statistics are valid for concentration ranges above the 100 pg m^{-3} concentration level, similarity in model performance for the FMS metric is likely due to better performance of OB70 and ACM2 at levels below the threshold concentration used for the FAR, POD and TS statistics. Above the concentration threshold spatial performance for OB70 and ACM2 lags behind that of the TKE and CMAQ, indicating that the TKE and CMAQ Kz options perform better across all concentration ranges compared to similar performance at the lower concentration levels below the threshold. Overall, it appears that the CMAQ Kz option yields the best performance of the diffusion options when examining the performance across all of the spatial metrics.

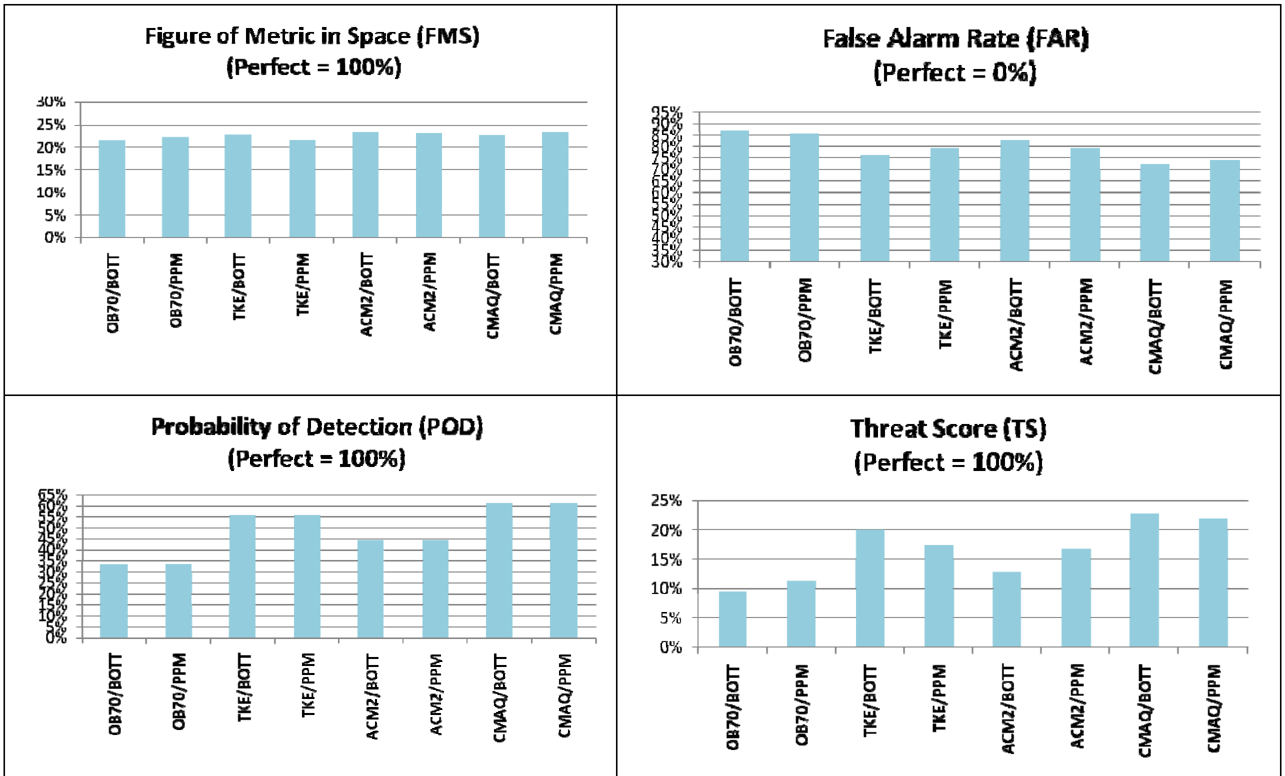

Figure C-13. Spatial model performance statistics for the CAMx CTEX5 sensitivity tests without using the PiG subgrid-scale puff module (NoPiG).

C.3.6 Global Statistical Performance for CTEX5 NoPiG Experiments

Figures C-14 and C-15 displays the global statistics for the CAMx NoPiG CTEX5 sensitivity tests for the statistical metrics with the best performing model has the, respectively, lowest and highest score. For the FOEX metric, all of the Kz/advection solver options are within 4% of each other (1% - 5%), with the best performance coming from OB70 and TKE options and degrading slightly across the ACM2 and CMAQ options.

The NMSE, FB, and PCC metrics provide clear differentiation in performance across the Kz options, with the TKE and CMAQ options yielding significantly better performance than either OB70 or ACM2. For NMSE, the CMAQ combinations have the best scores with 9.3 – 9.4 pg m^{-3}, followed by the TKE combinations with 12.6 – 13.6 pg m^{-3}. NMSE values are nearly double that for OB70 and ACM2. A similar relationship is found with the FB and PCC metrics, with the CMAQ and TKE performing significantly better than either ACM2 or OB70.

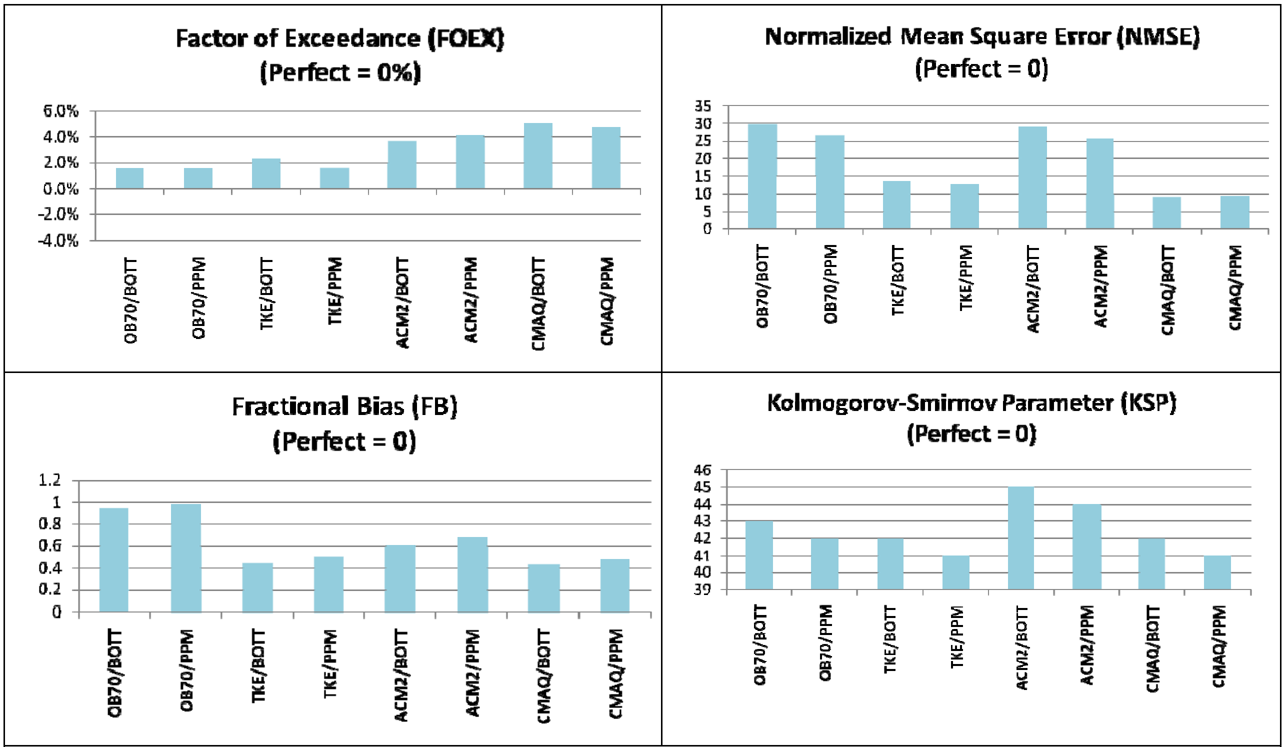

Figure C-14. Global model performance statistics for the CAMx CTEX5 sensitivity tests using the PiG subgrid-scale puff module.

The final panel in Figure C-15 (bottom right) displays the overall RANK statistic. The RANK statistics orders the model performance of the CTEX5 CAMx configurations without PiG as follows:

1. CMAQ/PPM (1.92) (tied)
2. CMAQ/BOTT (1.92) (tied)
3. TKE/PPM (1.73)
4. TKE/BOTT (1.71)
5. ACM2/BOTT (1.50)
6. ACM2/PPM (1.48)
7. OB70/PPM (1.34)
8. OB70/BOTT (1.33)

As with CTEX3, for the CTEX5 experiment the CMAQ Kz algorithm is the best performing vertical mixing approach in CAMx based on both the spatial and global statistical analyses. What differs in the CAMx CTEX3 and CTEX5 NoPiG sensitivity test performance is the composition of the RANK metric. Spatial performance for CTEX3 was significantly better than for CTEX5 (10% - 15% greater), thus FMS contributes less to the RANK statistical metric for CTEX5 compared to CTEX3. Similarly, the PCC metric is much more variable across the Kz options with CTEX5 experiment, with essentially no contribution of PCC to the RANK score for OB70 and ACM2 Kz options in CTEX5. Additionally, the KSP scores comprise a much greater portion of the RANK scores for CTEX5.

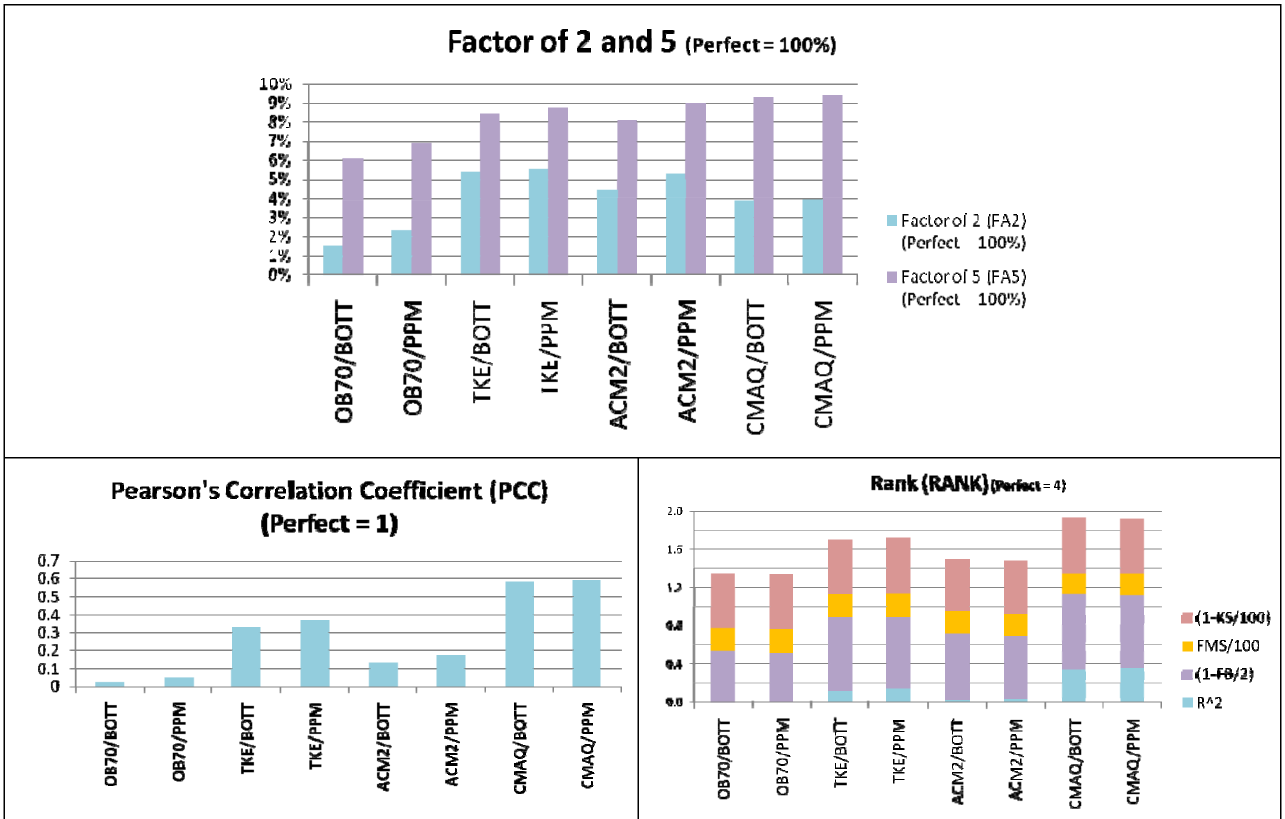

Figure C-15. Global model performance statistics for the CAMx sensitivity tests without using the PiG subgrid-scale puff module for CAPTEX Release 5 (NoPiG).

C.3.7 SPATIAL PERFORMANCE FOR CTEX5 PIG EXPERIMENTS

As with the CTEX5 NoPiG experiments, interpretation of the spatial performance for CTEX5 for the PiG CAMx sensitivities posed a slightly more difficult challenge to interpret due to similarities amongst the Kz/advection solver options for the FMS metric (Figure C-16). The range of difference for the FMS between the minimum and maximum for all of the eight combinations was less than 2%, with all in the range of 21.5% - 23.3%, noting a slight degradation across the board from the corresponding NoPiG experiments (0.2% - 3.1%).

Examination of the extended spatial statistics reveals a similar pattern in performance compared to the NoPiG equivalent tests. Greater differences in performance are observed across the various Kz/advection solver combinations, especially for the POD and TS metrics. For both of these metrics, the CMAQ Kz combinations clearly yield better spatial performance than the other Kz options (5% - 10% better for POD and 2% - 5% for TS than the second best Kz option (TKE)).

Consistent with results from the NoPiG scenarios, the CMAQ Kz option appears to perform best across the majority of the spatial metrics. The largest difference in spatial performance is determined by the user's selection of the Kz option than either the choice of advection solver or use of the subgrid scale PiG module in CAMx.

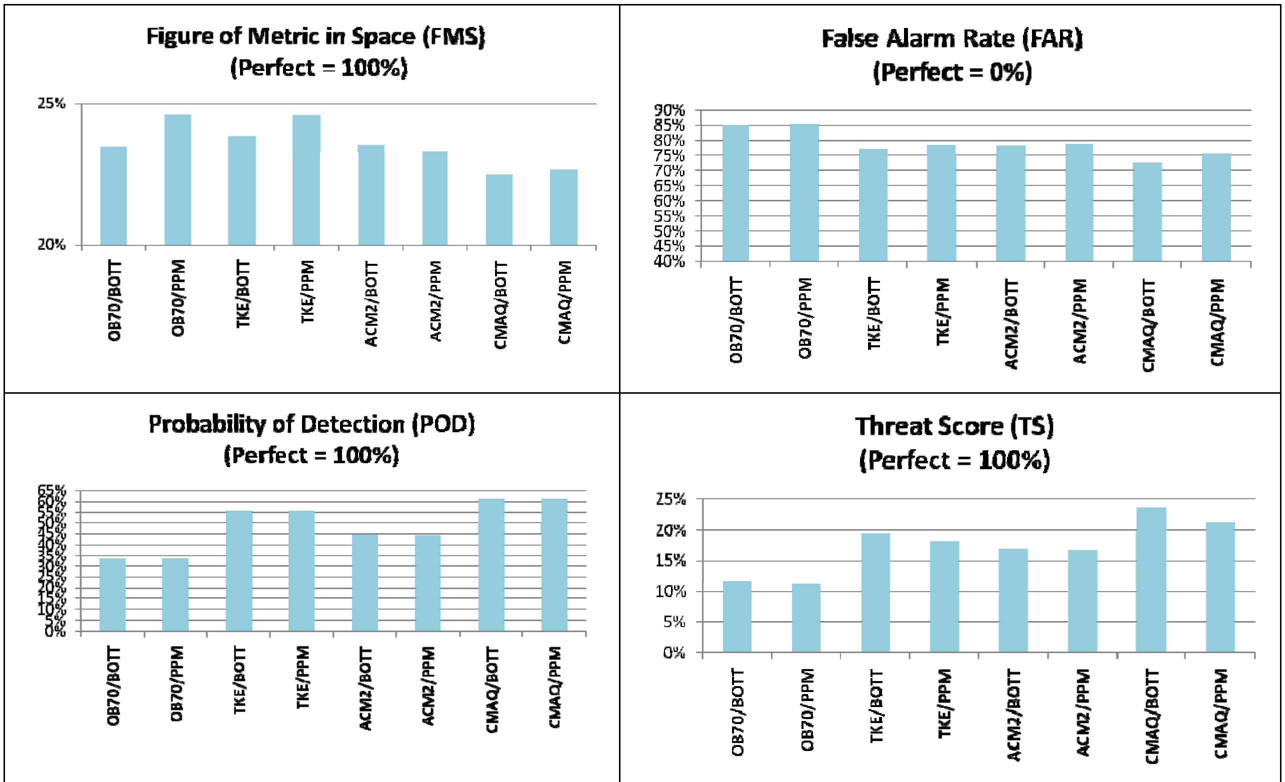

Figure C-16 Spatial model performance statistics for the CAMx CTEX5 sensitivity tests using the PiG subgrid-scale puff module (PiG).

C.3.8 Global Statistical Performance for CAMx CTEX5 PiG Experiments

Figures C-17 and C-18 displays the global statistics for the CAMx sensitivity tests using the PiG module with statistical metrics for the best performing model has the, respectively, lowest and highest score. For the FOEX metric, all of the Kz/advection solver options are within 5% - 6% of each other (-1.2% - 4.7%), with the best performance coming from OB70 and TKE options and degrading slightly across the ACM2 and CMAQ options, which is largely consistent with the equivalent NoPiG scenarios.

For NMSE and KSP, the CMAQ and TKE options perform better than either OB70 or ACM2. The CMAQ Kz option has the best NMSE values with 9.9 – 10.8 pg m^{-3} (PPM/BOTT), followed by TKE with values of 14.2 – 15.8 pg m^{-3} (PPM/BOTT). The TKE/PPM combination had the best scores for KSP, followed by CMAQ/PPM. All of the Kz options save OB70 had very similar FB and FA2/5 scores. OB70 consistently scored the poorest across all of the global statistical metrics.

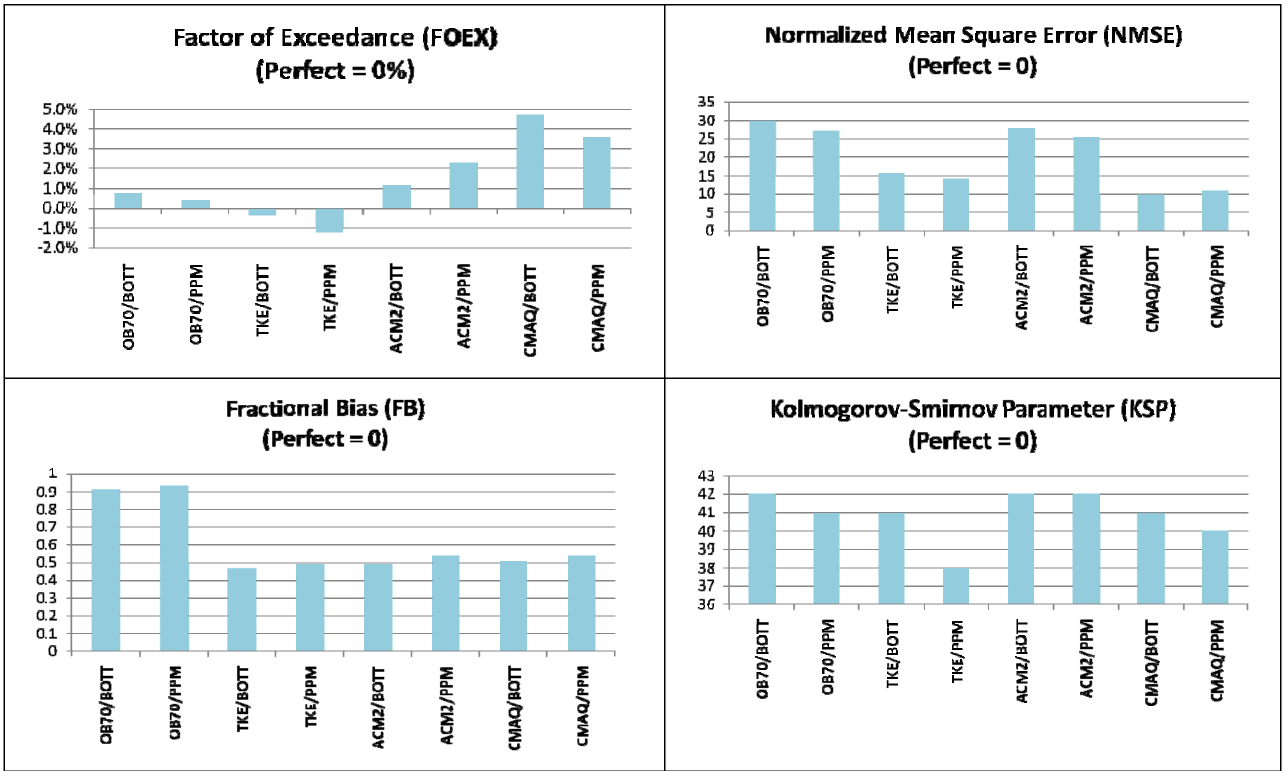

Figure C-17. Global model performance statistics for the CAMx sensitivity tests using the PiG subgrid-scale puff module for CAPTEX Release 5.

The final panel in Figure C-17 (bottom right) displays the overall RANK statistical metric. The RANK statistics orders the model performance of the CAMx configurations using the PiG module as follows:

1. CMAQ/BOTT (1.95)
2. CMAQ/PPM (1.92)
3. TKE/PPM (1.67)
4. TKE/BOTT (1.65)
5. ACM2/BOTT (1.58)
6. ACM2/PPM (1.56)
7. OB70/PPM (1.35)
8. OB70/BOTT (1.34)

Consistent with the NoPiG scenarios for CTEX5, CAMx performance using the CMAQ Kz option for vertical mixing is the best performing vertical diffusion algorithm overall for both the spatial and global statistical analyses and the choice of advection solver has a much smaller effect on model performance compared to vertical diffusion.

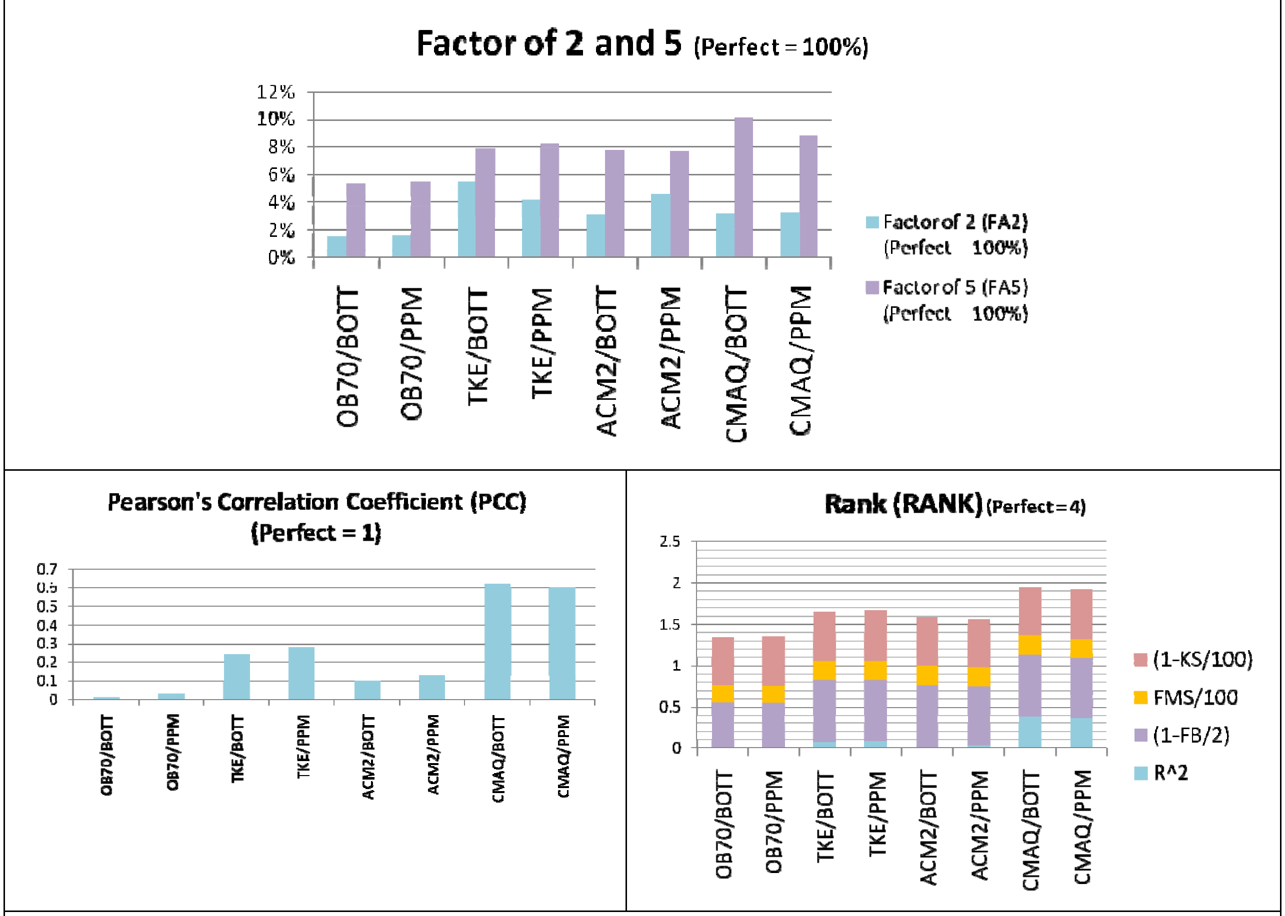

Figure C-18. Global model performance statistics for the CAMx sensitivity tests using the PiG subgrid-scale puff module for CAPTEX Release 5 (PiG).

C.3.8.1 EFFECT OF PIG ON MODEL PERFORMANCE FOR CTEX5

Similar to the results from the ETEX and CTEX3 experiments for CAMx, whether the PiG is used or not has very little effect on the CAMx model performance and the rankings of the CAMx model performance using the alternative vertical mixing and horizontal advection solver options. In general, it appears that the CAMx model performance without the PiG is performing slightly better than its performance using the PiG.

The spatial performance statistics are sometimes improved and sometimes degraded when the PiG module is invoked. Table C-3 examines the effect of PiG treatment of the tracer using two of the four spatial statistics, FMS and POD. Slight degradation of spatial performance when the PiG module is invoked is noted using the OB70, TKE, and ACM2 Kz diffusion combinations (from -3.1% to -0.2% for FMS and from -11.1% to 0% for POD). However, CAMX using the CMAQ Kz diffusion/advection solver combinations experienced a 0.2% to 0.5% improvement for FMS and no change for POD.

Table C-3. CAMx FMS and POD spatial performance statistic and model rankings for different model configurations with and without using the PiG subgrid-scale puff model for CAPTEX Release 5.

Model Configuration	Without PiG Module		With PiG Module		NoPiG-PiG	
	FMS	POD	FMS	POD	ΔFMS	ΔPOD
OB70/BOTT	23.48	33.33	21.54	27.78	-1.9%	-5.6%
OB70/PPM	24.62	33.33	22.05	33.33	-2.6%	0%
TKE/BOTT	23.85	55.56	22.83	55.56	-1.0%	0%
TKE/PPM	24.6	55.56	21.49	50	-3.1%	-5.6%
ACM2/BOTT	23.53	44.44	23.26	33.33	-0.3%	-11.1%
ACM2/PPM	23.31	44.44	23.08	44.44	-0.2%	0%
CMAQ/BOTT	22.48	61.11	22.66	61.11	0.2%	0%
CMAQ/PPM	22.66	61.11	23.2	61.11	0.5%	0%

Table C-4 summarizes the RANK model performance statistic for the different CAMx model configurations with and without using the PiG module. The results for the global statistics are somewhat varied across the Kz/advection solver configurations. OB70, ACM2, and CMAQ/BOTT showed slight improvements in their RANK score when using the PiG module (improvements ranged from 0.7% to 5.4%). However, the TKE combinations experienced performance degradations with changes ranging from -3.5% to 4.0%.

Table C-4. CAMx RANK model performance statistic and model rankings for different model configurations with and without using the PiG subgrid-scale puff model for CAPTEX Release 5.

Model Configuration	Without PiG Module		With PiG Module		PiG-NoPiG	
	RANK	Model Ranking	RANK	Model Ranking	ΔRANK	Percent
OB70/BOTT	8	1.33	1.34	8	+0.01	+0.7%
OB70/PPM	7	1.34	1.35	7	+0.01	+0.7%
TKE/BOTT	4	1.71	1.65	4	-0.06	-3.5%
TKE/PPM	3	1.73	1.67	3	-0.07	-4.0%
ACM2/BOTT	5	1.50	1.58	5	+0.08	+5.0%
ACM2/PPM	6	1.48	1.56	6	+0.08	+5.4%
CMAQ/BOTT	1[a]	1.92	1.95	1	+0.03	+1.5%
CMAQ/PPM	2[a]	1.92	1.92	2	0.0	0.0%

[a] tied

In general, it is difficult to discern a consistent pattern of performance across the Kz/advection solver combinations when using the CAMx subgrid scale PiG module or not. There appears to be only modest benefit in cases where performance improvement is detected and only modest degradation in model performance when the PiG module causes a worsening of model performance. The CAMx PiG module was originally developed primarily to treat the near-source chemistry of large point source plumes that can be quite different from its surrounding environment. The decision to employ the CAMx puff module relates not so much in improvement advection and diffusion performance, but rather whether or not it is appropriate to allow emissions of ozone and secondary $PM_{2.5}$ precursors from large point sources to be instantaneously mixed into the grid and what impact this would have on local chemical reactions.

C.4 COMPARISON OF SIX LRT DISPERSION MODELING USING CAPTEX RELEASE 3

The model performance of six LRT dispersion models (CALPUFF, SCIPUFF, HYSPLIT, FLEXPART, CAMx and CALGRID) are evaluated using common MM5 meteorological inputs and the CAPTEX Release 3 tracer experiment.

C.4.1 SPATIAL ANALYSIS OF MODEL PERFORMANCE

The performance of the six LRT dispersion models using the four spatial analysis model performance statics that were defined in Section 2.4 are discussed in this section. Figure C-19 displays the FMS spatial performance metrics for the six LRT models and the CTEX3 tracer study field experiment. The CAMx (39.4%) and SCIPUFF (35.2%) models are the two best performing models for the FMS statistic. They are followed by HYSPLIT (33.9%), CALPUFF (32.2%), and FLEXPART (32.1%). CALGRID has the poorest score for the FMS statistics with a value of only 24.1%.

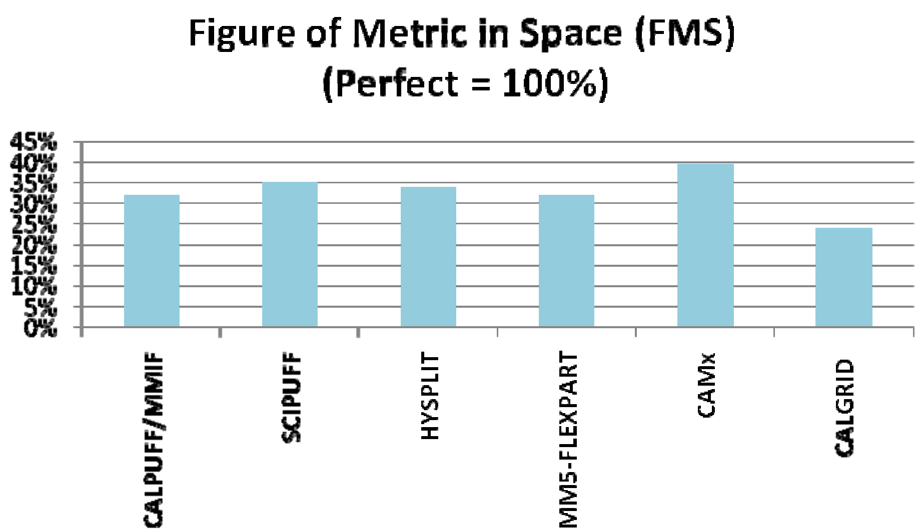

Figure C-19. Figure of Merit in Space (FMS) statistical performance metric for the six LRT models and CAPTEX Release 3.

Figure C-20 displays the FAR performance metric for the six LRT models. FLEXPART was the best performing model using the FAR statistics with a score of 54.1%. The next two best performing models using the FAR was CAMx (64.8%) and SCIPUFF (71.2%). CALPUFF and HYSPLIT exhibited similar performance for the FAR metric with values of 74.3% and 79.3% respectively. CALGRID had the worst FAR score with a value of 91.7%.

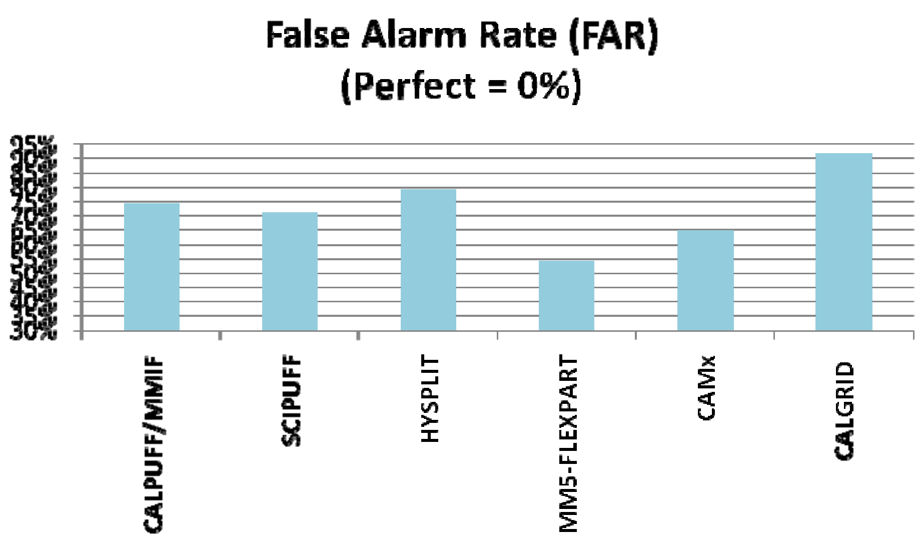

Figure C-20. False Alarm Rate (FAR) statistical performance metric for the six LRT models and CAPTEX Release 3.

Results for the Probability of Detection (POD) metric are presented in Figure C-21. CAMx was the best performing model using the POD performance statistic with a value of 52.6%. It is followed closely by FLEXPART with a score of 47.2%. SCIPUFF (41.7%) and HYSPLIT (36.1%) were in the middle, and CALPUFF and CALGRID had the worst POD score with a value of 25%.

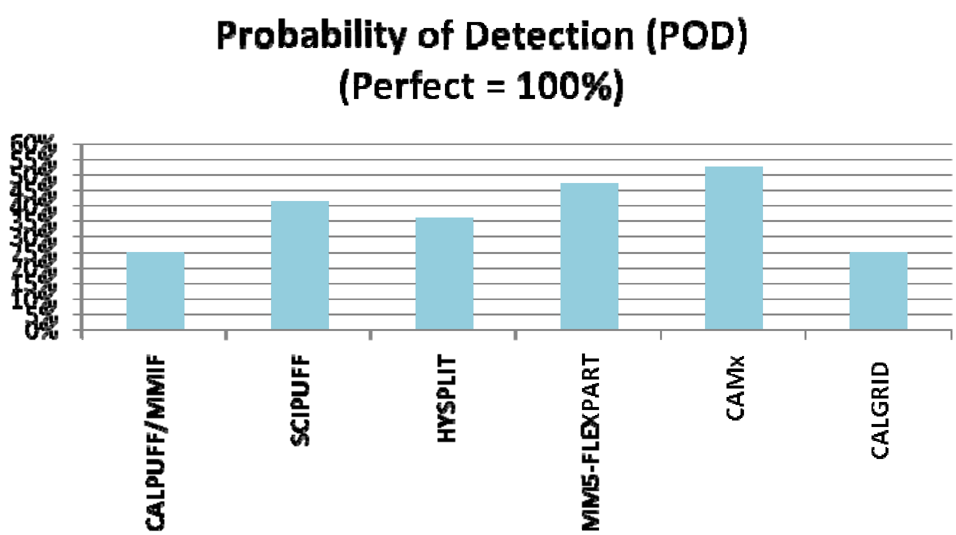

Figure C-21. Probability of Detection (POD) statistical performance metric for the six LRT models and CAPTEX Release 3.

Results for the TS metric and the six LRT models are presented in Figure C-22. FLEXPART had the highest TS statistics with a score with a value of 30.4% and was followed closely by CAMx

(26.8%). SCIPUFF (20.6%), HYSPLIT (15.1%), and CALPUFF (14.1%) were in the middle, and CALGRID exhibited the poorest TS performance with a score of 6.7%.

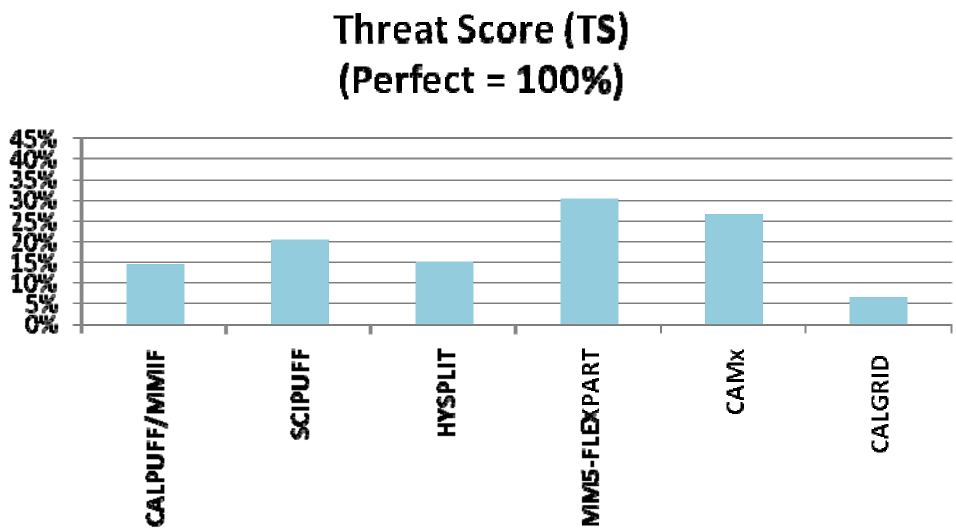

Figure C-22. Threat Score (TS) statistical performance metric for the six LRT models and CAPTEX Release 3.

Overall spatial performance was relatively equal between FLEXPART and CAMx, with CAMx having the best performance for the FMS and POD statistics and FLEXPART having better performance in the FAR and TS categories. CALPUFF, SCIPUFF, and HYSPLIT were comparable in their spatial performance for the CTEX3 experiment, with SCIPUFF showing marginally better scores in all of the four spatial performance metrics. CALGRID exhibited the poorest performance across all four spatial metrics.

C.4.2 GLOBAL ANALYSIS OF MODEL PERFORMANCE

Eight global statistical analysis metrics are used to evaluate the five LRT model performance using the ETEX data base that are described in Section 2.4 and consist of the FOEX, FA2, FA5, NMSE, PCC, FB, KS and RANK statistical metrics.

Figure C-23 displays the FOEX performance metrics for the six LRT models. HYSPLIT has the best FOEX score with a value of 2.0% that is closest to zero. The second best performing model using the FOEX metric is CAMx (9.6%) that is followed by SCIPUFF (11.5%). CALGRID has the poorest FOEX score with 20.6%.

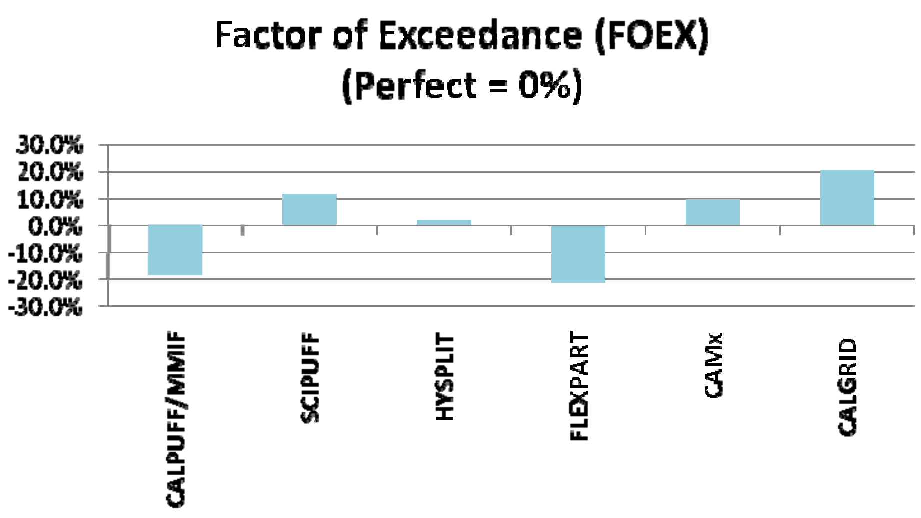

Figure C-23. Factor of Exceedance (FOEX) statistical performance metric for the six LRT models and CAPTEX Release 3.

FA2 and FA5 scores are presented in Figure C.-24. CAMx and SCIPUFF have nearly identical FA2 and FA5 scores with values of 6.6% - 6.7% (FA2) and 15% (FA5). The third best performing model for the FAα statistics is FLEXPART (5.3% and 12.2%) followed by HYSPLIT (4.5% and 8.5%). CALPUFF and CALGRID flip positions in FA2 and FA5 for the final position, with CALPUFF having a lower FA2 (0.8%) and a higher FA5 (8.2%) compared to CALGRID (FA2 – 1.05% and FA5 – 4.6%).

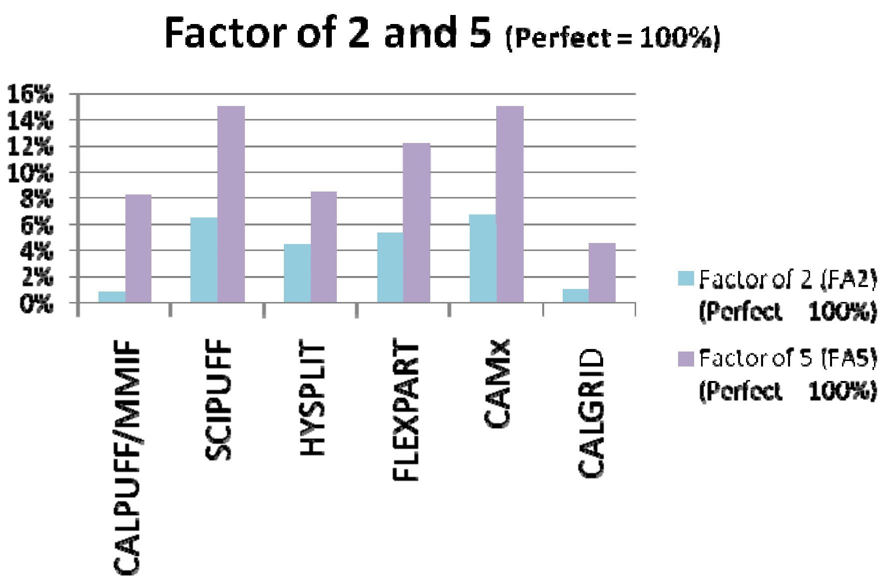

Figure C-24. Factor of 2 (FA2) and Factor of 5 (FA5) statistical performance metric for the six LRT models and CAPTEX Release 3.

The scores for the Normalized Mean Squared Error (NMSE) statistical metrics for the six LRT models are given in Figure C-25. The NMSE provides an indication of the deviations between the predicted and observed tracer concentrations paired by time and location with a perfect model receiving a 0.0 score. FLEXPART is the best performing model using the NMSE metric with a score of 21.4 pg m^{-3} followed closely by CAMx (38.9 pg m^{-3}) and CALPUFF (40.9 pg m-3). The worst performing LRT model according to the NMSE metric is HYSPLIT (130.5 pg m^{-3}).

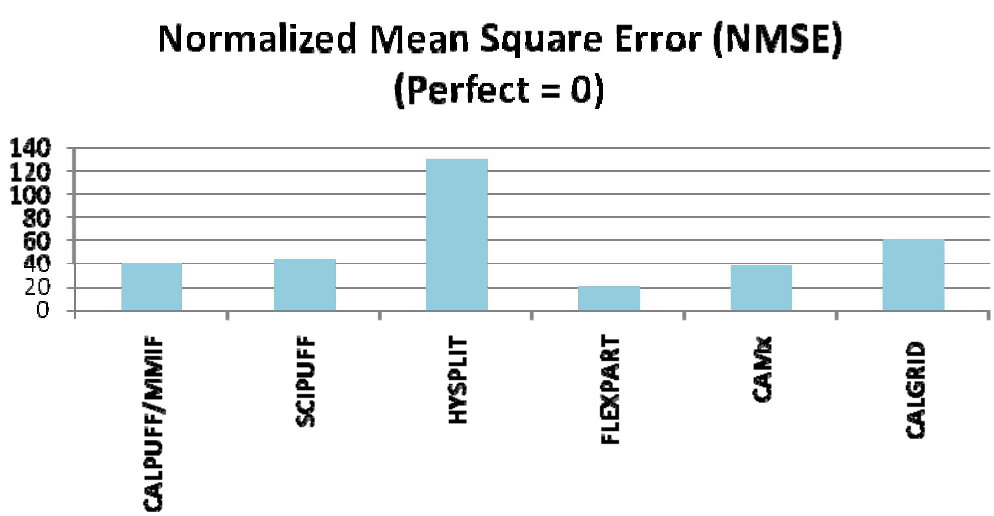

Figure C-25. Normalized Mean Square Error (NMSE) statistical performance metric for the six LRT models for CAPTEX Release 3. Values are expressed in pg m^{-3}.

The PCC values for the six LRT models are shown in Figure C-26. All models but HYSPLIT have positive correlation coefficients. The two best models according to the PCC statistical metric are CAMx (0.63) and SCIPUFF (0.56). The middle group of models consists of CALPUFF (0.4), CALGRID (0.23), and FLEXPART (0.19). The model with the least correlation with the observations is HYSPLTI (-0.1), indicating a weak negative correlation with observed data.

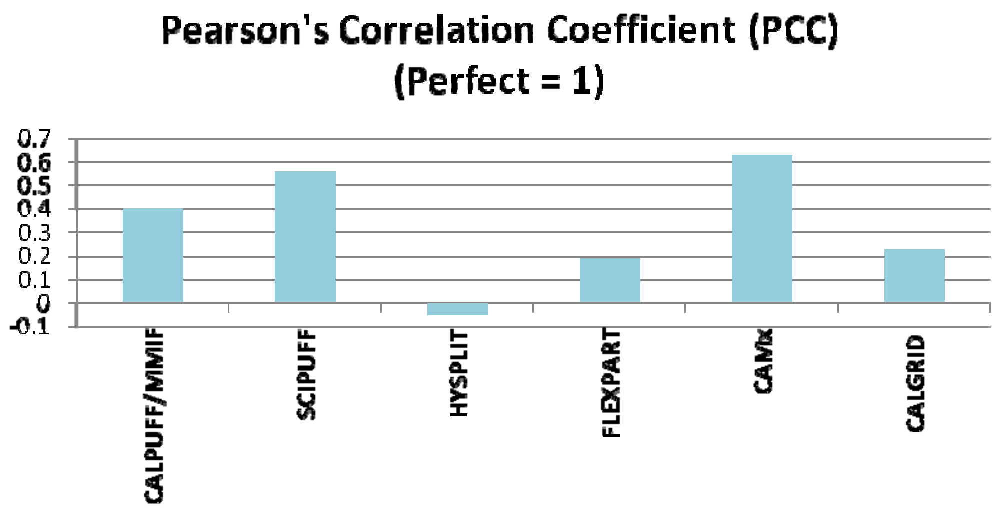

Figure C-26. Pearson's Correlation Coefficient (PCC) statistical performance metric for the six LRT models and CAPTEX Release 3.

Figure C-27 displays the FB parameter for the six LRT models. All six models exhibit a positive FB, which suggests an overestimation tendency. The best performing model with an FB value closest to zero are FLEXPART with a FB value of 0.68. CAMx (1.00), SCIPUFF (1.04) and CALPUFF (1.05) all have similar FB values are the second best performing group of models using the FB metric. CALGRID and HYSPLIT have the worst FB scores with values of 1.47 and 1.56 respectively.

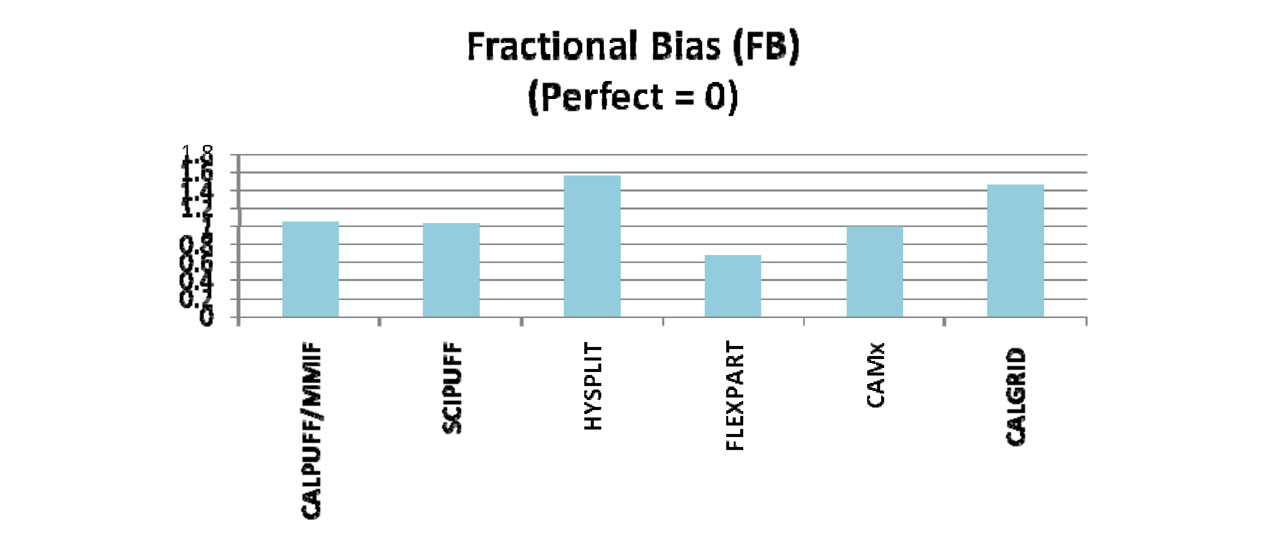

Figure C-27. Fractional Bias(FB) statistical performance metric for the six LRT models and CAPTEX Release 3.

The KS parameters for the six LRT models are shown in Figure C-28. HYSPLIT (31%) has the best KS parameter, which indicates the best match between the predicted and observed tracer concentration distributions, followed by CAMx (38%) and then SCIPUFF (43%). FLEXPART and CALGRID are essentially tied with the worst KS parameter with a value of 58%.

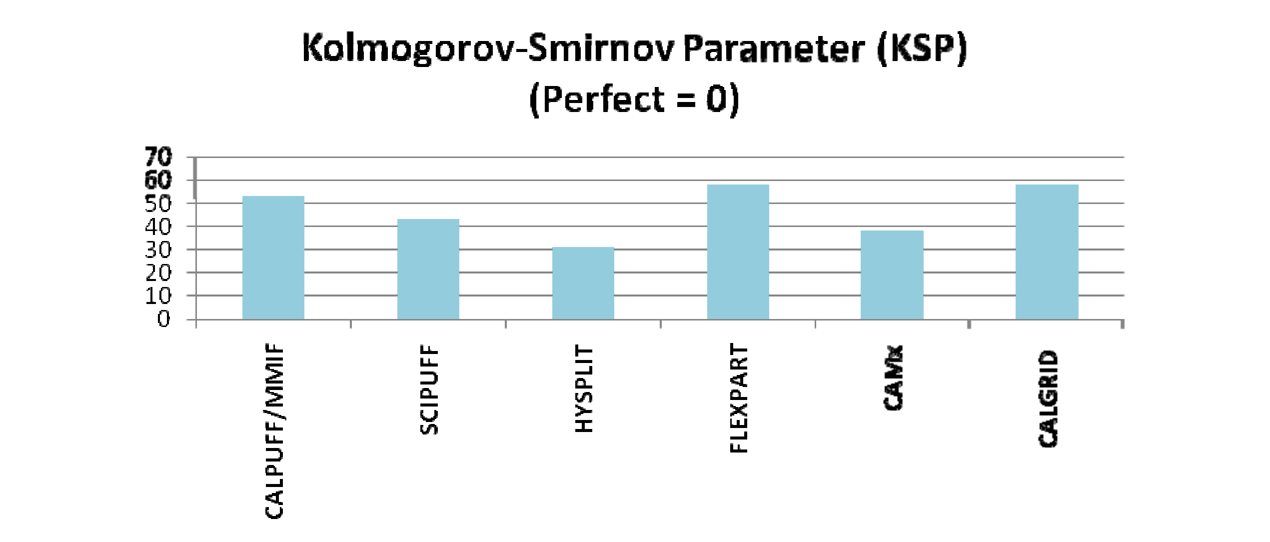

Figure C-28. Kolmogorov – Smirnov Parameter (KSP) statistical performance metrics for the six LRT models for CAPTEX Release 3.

The RANK statistical performance metric was proposed by Draxler (2001) as a single model performance metric that equally ranks the combination of performance metrics for correlation (PCC or R), bias (FB), spatial analysis (FMS) and unpaired distribution comparisons (KS). The RANK metrics ranges from 0.0 to 4.0 with a perfect model receiving a score of 4.0. Figure C-29 lists the RANK model performance statistics for the six LRT models. CAMx is the highest ranked model using the RANK metric with a value of 1.91. Note that CAMx scores high in all four areas of model performance (correlation, bias, spatial and cumulative distribution). The next best performing model according to the RANK metric is SCIPUFF with a score of 1.71. SCIPUFF scores relatively well across all of the four metrics, with slightly lower scores in cumulative distribution and correlation metrics compared to CAMx, contributing to its second rank. FLEXPART and CALPUFF are nearly even in terms of their performance with RANK values of 1.44 and 1.43 respectively. FLEXPART scores better than CALPUFF with the bias (FB) metric, whereas the reverse is true for the correlation (R^2) metric.

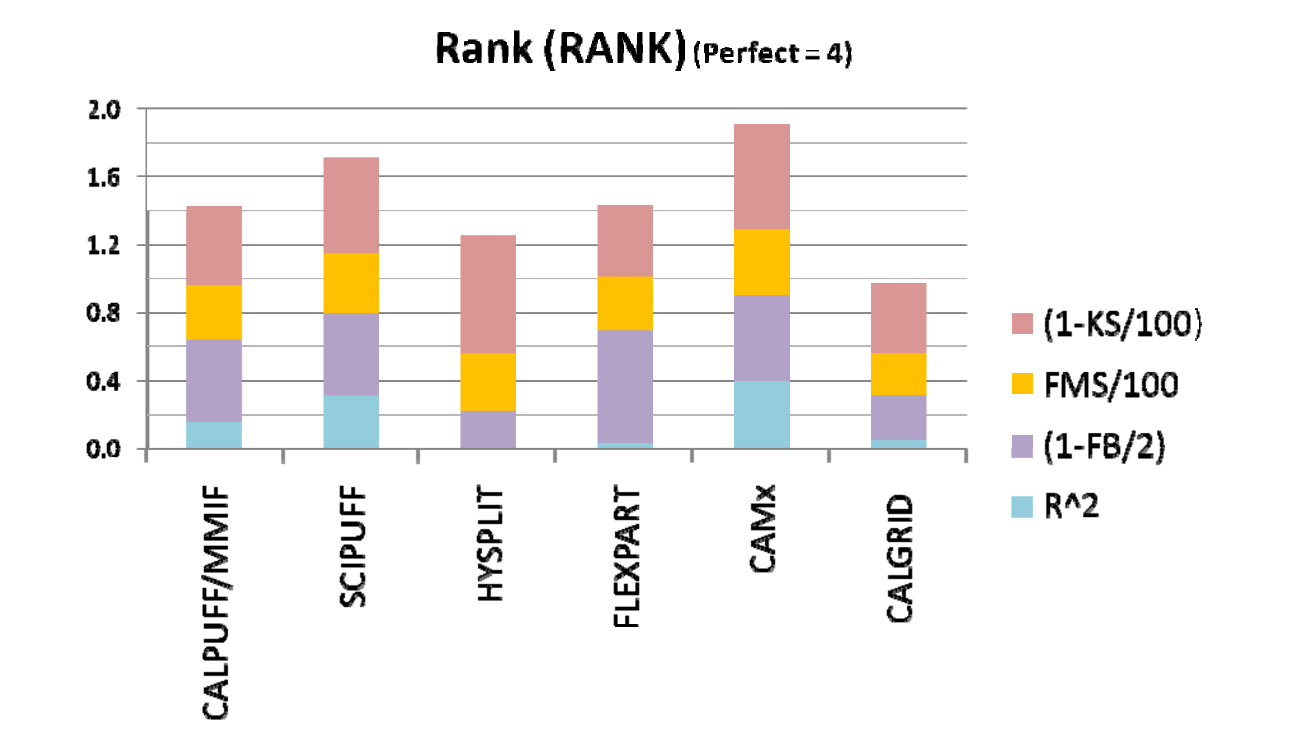

Figure C-29. RANK statistical performance metric for the six LRT models and CAPTEX Release 3.

C.4.2.1 SUMMARY OF LRT MODEL RANKINGS FOR CTEX3 USING STATISTICAL PERFORMANCE MEASURES

Table C-5 summarizes the rankings between the six LRT models for the 11 performance statistics analyzed. Depending on the statistical metric, three different models were ranked as the best performing model for a particular statistic with CAMx being ranked first more than the other models (46%) and FLEXPART ranked first second most (36%). CALGRID was consistently ranked the worst performing model being the poorest performing model for 6 of the 11 performance statistics.

In testing the efficacy of the RANK statistic for providing an overall ranking of model performance we the ranking of the six LRT models using the average rank of the 11 performance statistics versus the ranking from the RANK statistical metric (Table C-5). The average rank of model performance for the six LRT dispersion models and the CTEX3 experiment averaged across all 11 performance statistics and the comparison to the RANK rankings was as follows:

Ranking	Average of 11 Statistics	RANK
1.	CAMx	CAMx
2.	SCIPUFF	SCIPUFF
3.	FLEXPART	FLEXPART
4.	HYSPLIT	CALPUFF
5.	CALPUFF	HYSPLIT
6.	CALGRID	CALGRID

For the CTEX3 experiment, the average rankings across the 11 statistics is nearly identical to the rankings produced by the RANK integrated statistics that combines the four statistics for correlation (PCC), bias (FB), spatial (FMS) and cumulative distribution (KS) with only HYSPLIT and CALPUFF exchanging places as the 4th and 5th best performing models. CALPUFF performance was weighted down in the average statistic rankings due to lower scores in the FA2 and FA5 metrics compared to HYSPLIT. If not for this, the average rank across all 11 metrics would have been the same as Draxler's RANK score. Although this deviation did occur in the fourth and fifth ranked positions, the RANK statistic remains a valid performance statistic for indicating over all model performance of a LRT dispersion model. However, the analyst should use discretion in relying too heavily upon RANK score without consideration to which performance metrics are important measures for the particular evaluation goals. For example, if performance goals are not concerned with a model's ability to perform well in space and time, then reliance upon spatial statistics such as the FMS in the composite RANK value may not be appropriate. In the case of this evaluation, since space/time considerations are paramount for proper LRT model performance, the RANK metric is a valuable tool to rapidly assess model performance across a broad range of metrics being evaluated.

Table C-5. Summary of model ranking using the statistical performance metrics.

Statistic	1st	2nd	3rd	4th	5th	6th
FMS	CAMx	SCIPUFF	HYSPLIT	CALPUFF	FLEXPART	CALGRID
FAR	FLEXPART	CAMx	SCIPUFF	CALPUFF	HYSPLIT	CALGRID
POD	CAMx	FLEXPART	SCIPUFF	HYSPLIT	CALPUFF	CALGRID
TS	FLEXPART	CAMx	SCIPUFF	HYSPLIT	CALPUFF	CALGRID
FOEX	HYSPLIT	CAMx	SCIPUFF	CALPUFF	CALGRID	FLEXPART
FA2	CAMx	SCIPUFF	FLEXPART	HYSPLIT	CALGRID	CALPUFF
FA5	CAMx	SCIPUFF	FLEXPART	HYSPLIT	CALPUFF	CALGRID
NMSE	FLEXPART	CAMx	CALPUFF	SCIPUFF	CALGRID	HYSPLIT
PCC or R	CAMx	SCIPUFF	CALPUFF	CALGRID	FLEXPART	HYSPLIT
FB	FLEXPART	CAMx	SCIPUFF	CALPUFF	CALGRID	HYSPLIT
KS	HYSPLIT	CAMx	SCIPUFF	CALPUFF	FLEXPART	CALGRID
Avg. Ranking	CAMx	SCIPUFF	FLEXPART	HYSPLIT	CALPUFF	CALGRID
Avg. Score	1.55	2.72	3.0	4.0	4.27	5.55
RANK Ranking	CAMx	SCIPUFF	FLEXPART	CALPUFF	HYSPLIT	CALGRID
RANK	1.91	1.71	1.44	1.43	1.25	0.98

C.5 COMPARISON OF SIX LRT MODEL MODELING PERFORMANCE USING THE CAPTEX-5 EXPERIMENT

C.5.1 SPATIAL ANALYSIS OF MODEL PERFORMANCE

Figure C-30 displays the FMS spatial analysis performance metrics for the six LRT models and the CTEX5 tracer study field experiment. SCIPUFF (22.67%) and CAMx (22.66%) models are the two best performing models for the FMS statistic with nearly identical scores. They are followed by HYSPLIT (18.5%), CALPUFF (17.5%), FLEXPART (17.2), and CALGRID (16.1%).

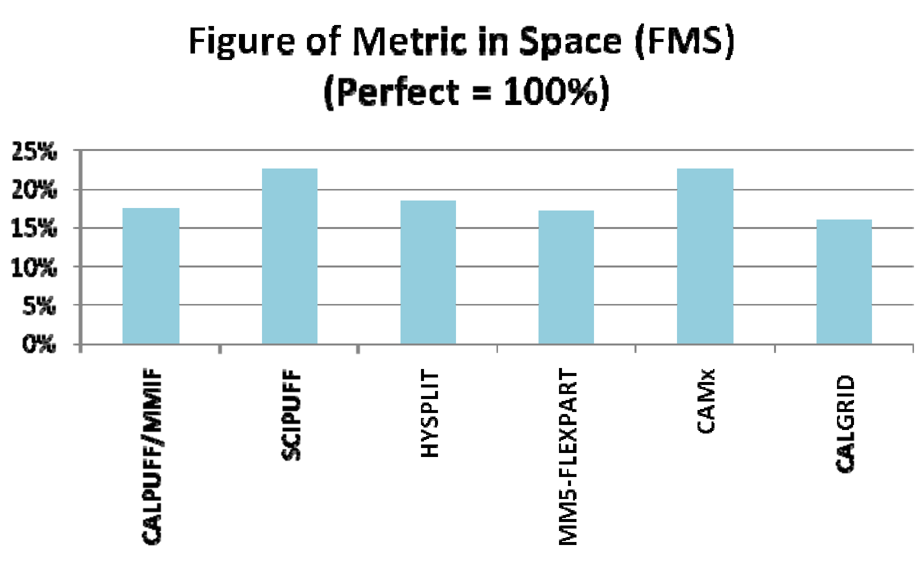

Figure C-30. Figure of Merit in Space (FMS) statistical performance metric for the six LRT models and CAPTEX Release 5.

Figure C-31 displays the FAR performance metrics. FLEXPART was the best (lowest) performing model using the FAR statistics with a score of 61.9%. The next two best performing models using the FAR metric were HYSPLIT (72.2%) and CAMx (75.6%). SCIPUFF, CALGRID, and CALPUFF had the worst (highest) FAR scores with values of 79.7%, 84.2%, and 87% respectively.

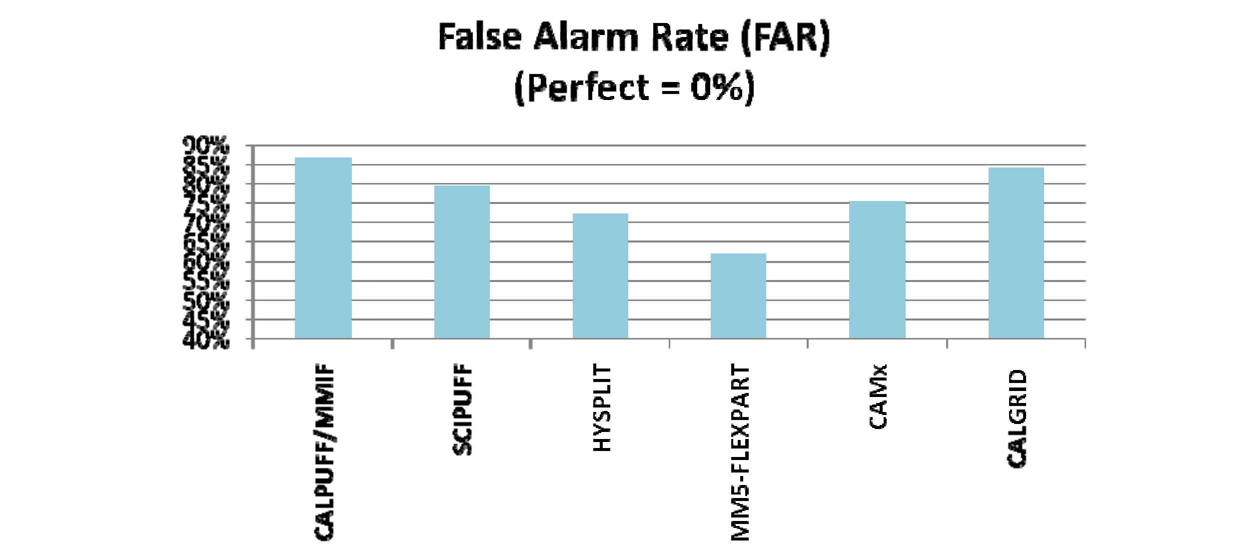

Figure C-31. False Alarm Rate (FAR) statistical performance metric for the six LRT models and CAPTEX Release 5.

Results for the Probability of Detection (POD) metric are presented in Figure C-32. SCIPUFF was the best performing model using the POD performance statistic with a value of 72.2%. CAMx was the second best performing model using POD followed by HYSPLIT, FLEXPART, CALPUFF and CALGRID.

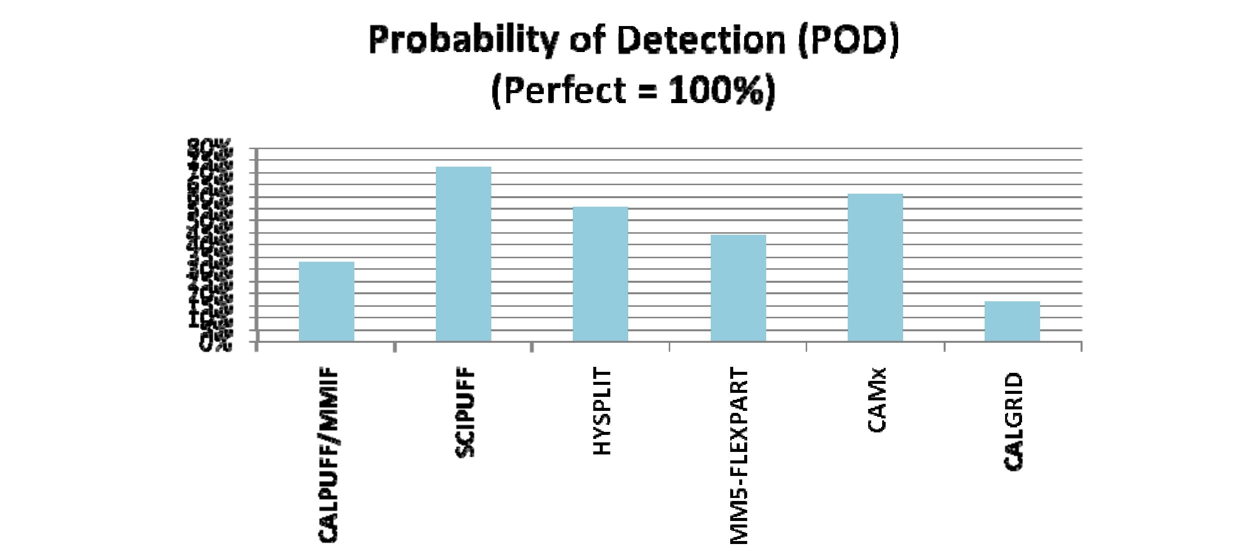

Figure C-32. Probability of Detection (POD) statistical performance metric for the six LRT models and CAPTEX Release 5.

Results for the TS metric are presented in Figure C-33. FLEXPART had the highest TS statistics with a score of 25.8%. HYSPLIT (22.7%), CAMx (21.2%), and SCIPUFF (18.8%) followed, and CALPUFF and CALGRID closed out with the worst (lowest) TS values of 10.3% and 8.8% respectively.

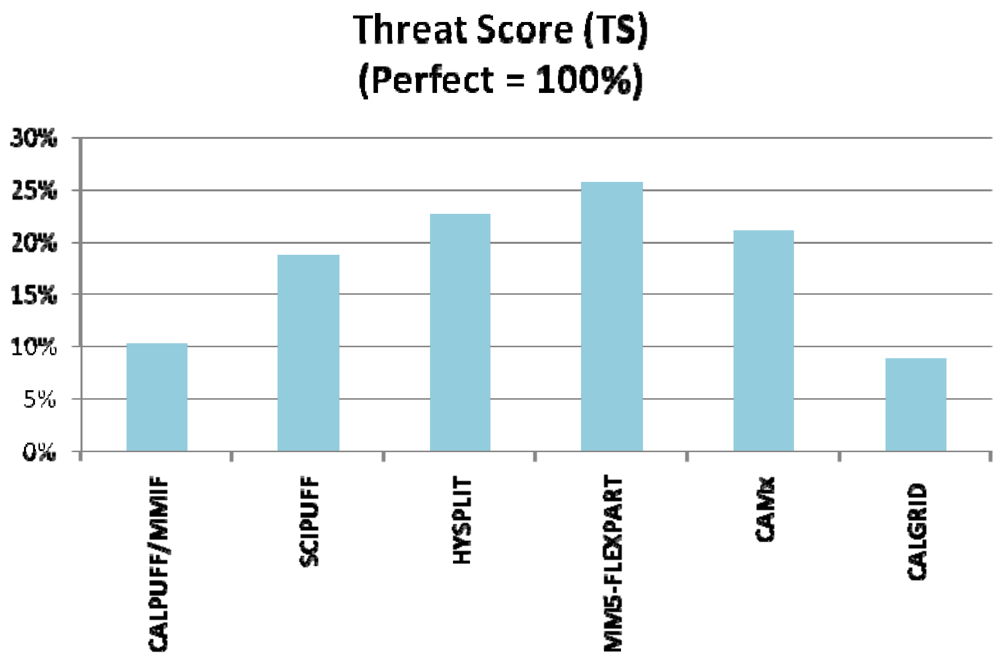

Figure C-33. Threat Score (TS) statistical performance metric for the six LRT models and CAPTEX Release 5.

Overall, the spatial performance for CTEX5 was relatively equal between FLEXPART and CAMx, with CAMx having the best performance for the FMS and POD statistics and FLEXPART having the best performance for the FAR and TS statistics. CALPUFF, SCIPUFF, and HYSPLIT were generally comparable in their spatial performance for CTEX5, with SCIPUFF showing marginally better scores in all four of the spatial metrics. CALGRID consistently exhibited the poorest performance across all four spatial metrics.

C.5.2 GLOBAL ANALYSIS OF MODEL PERFORMANCE

Figure C-34 displays the FOEX performance metrics for the six LRT models. CALPUFF had the best FOEX score (closest to zero) with a value of -2.6%. The second best performing model using the FOEX metric is CAMx (4.7%) followed by HYSPLIT (-9.2%) and CALGRID (-11.9%). SCIPUFF and FLEXPART had the poorest FOEX scores with values of 20.4% and -28.2% respectively.

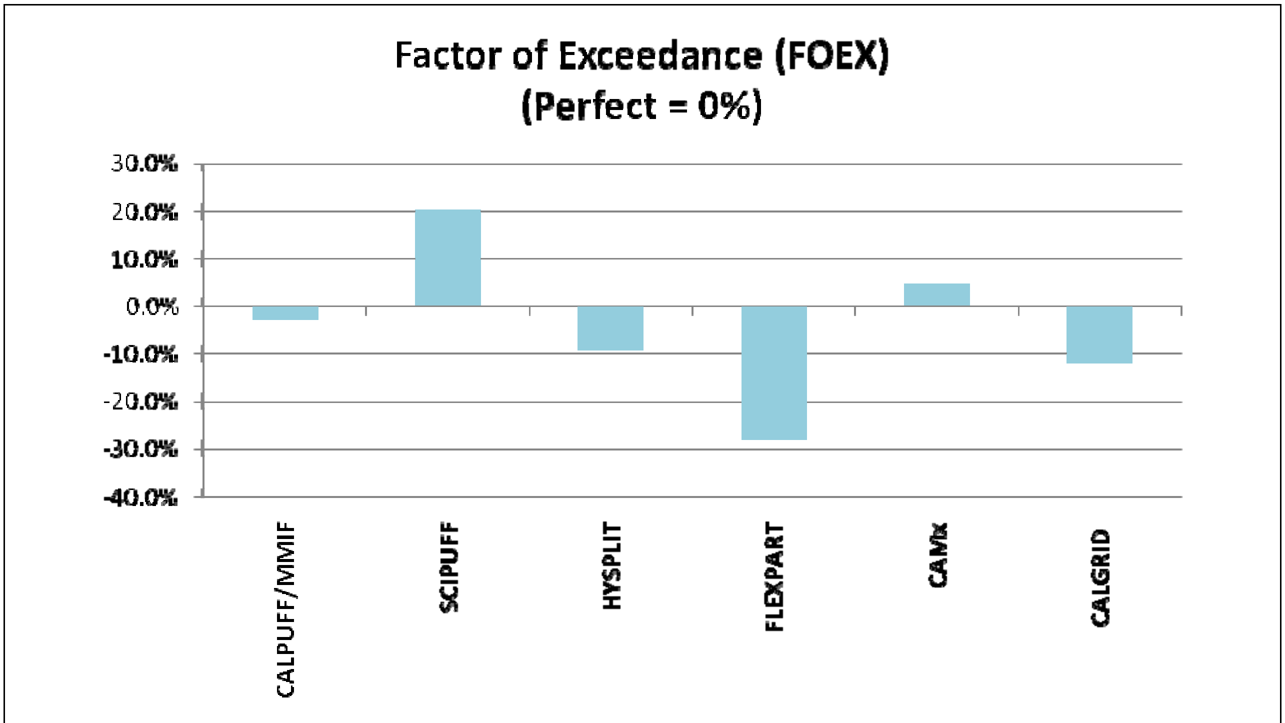

Figure C-34. Factor of Exceedance (FOEX) statistical performance metric for the six LRT models and CAPTEX Release 5.

The FA2 and FA5 scores are presented in Figure C-35. HYSPLIT has the best FAα scores with FA2 and FA5 values of 4.9% and 10.7%, respectively. CAMx and SCIPUFF have nearly identical FAα with values of 3.5% to 3.9% (FA2) and 9.3% to 9.4% (FA5). CALPUFF and FLEXPART follow with FA2/FA5 values of, respectively, 3.5%/7.9% and 2.3%/6.9%. CALGRID has the lowest FAα scores with FA2 and FA5 values of 0% and 0.9% respectively.

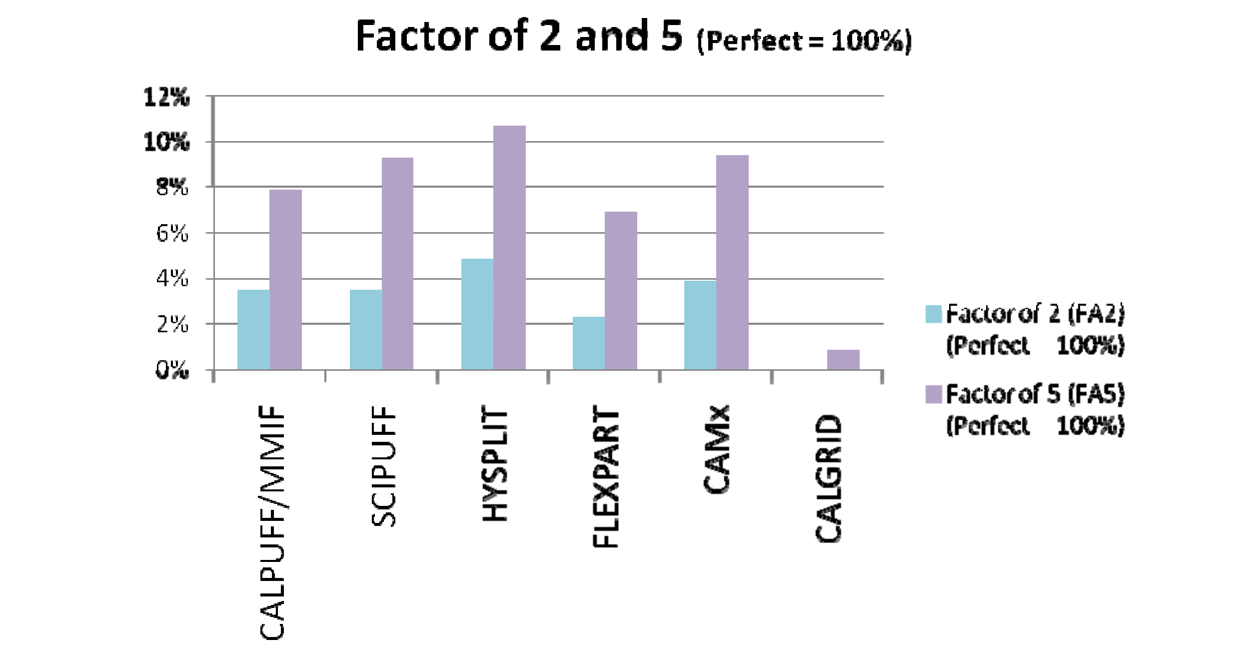

Figure C-35. Factor of 2 (FA2) and Factor of 5 (FA5) statistical performance metric for the six LRT models and CAPTEX Release 5.

The scores for the Normalized Mean Squared Error (NMSE) statistical metrics and the six LRT models are given in Figure C-36. CAMx is the best performing model using the NMSE metric with a score of 9.4 pg m^{-3} followed by SCIPUFF (14.8 pg m^{-3}). The middle tier of models are comprised of FLEXPART, HYSPLIT, and CALPUFF with values of 17.0, 17.2, and 19.5 pg m^{-3} respectively. CALGRID closes out with a NMSE value of 29.6 pg m^{-3}.

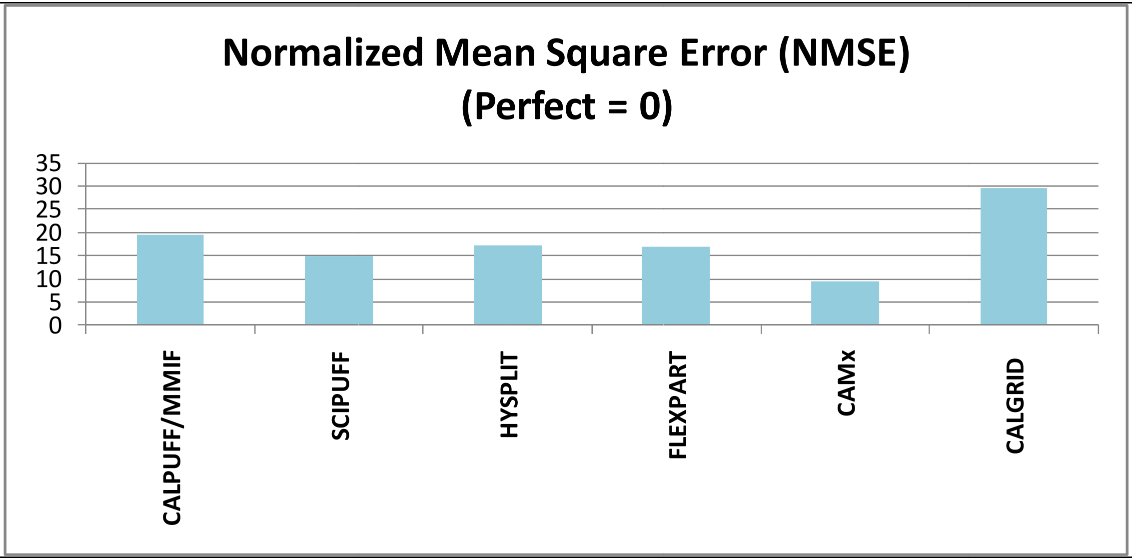

Figure C-36. Normalized Mean Square Error (NMSE) statistical performance metric for the six LRT models and CAPTEX Release 5. Values are expressed in pg m^{-3}.

The PCC values for the six LRT models are shown in Figure C-37. All models but CALGRID and CALPUFF have positive PCCs. The three best models according to the PCC statistical metric are HYSPLIT (0.60), CAMx (0.59) and SCIPUFF (0.56). FLEXPART has a PCC of 0.51. Both CALPUFF and CALGRID have negative PCC scores, indicating the modeled concentrations are anti-correlated with the observed data. CALGRID and CALPUFF have PCC values of -0.06 and -0.07, respectively.

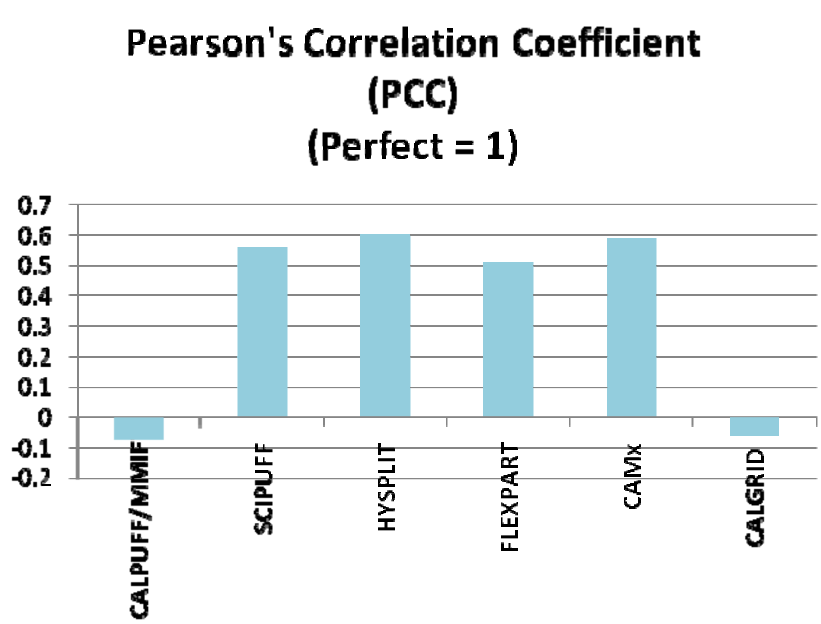

Figure C-37. Pearson's Correlation Coefficient (PCC) statistical performance metric for the six LRT models for CAPTEX Release 5.

Figure C-38 displays the FB parameter for the six LRT models and CTEX5. Four of the six models exhibit a positive FB, which suggests an overestimation tendency, whereas the other two have a negative FB. The best performing models with the FB parameter closest to zero are CAMx with a FB score of 0.49 indicating overestimation and CALPUFF with a FB value of -0.49 indicating underestimation. Next best is FLEXPART (-0.87) with an underestimation bias and SCIPUFF (0.89) with an overestimation bias followed by HYSPLIT (0.93) and CALPUFF (1.07).

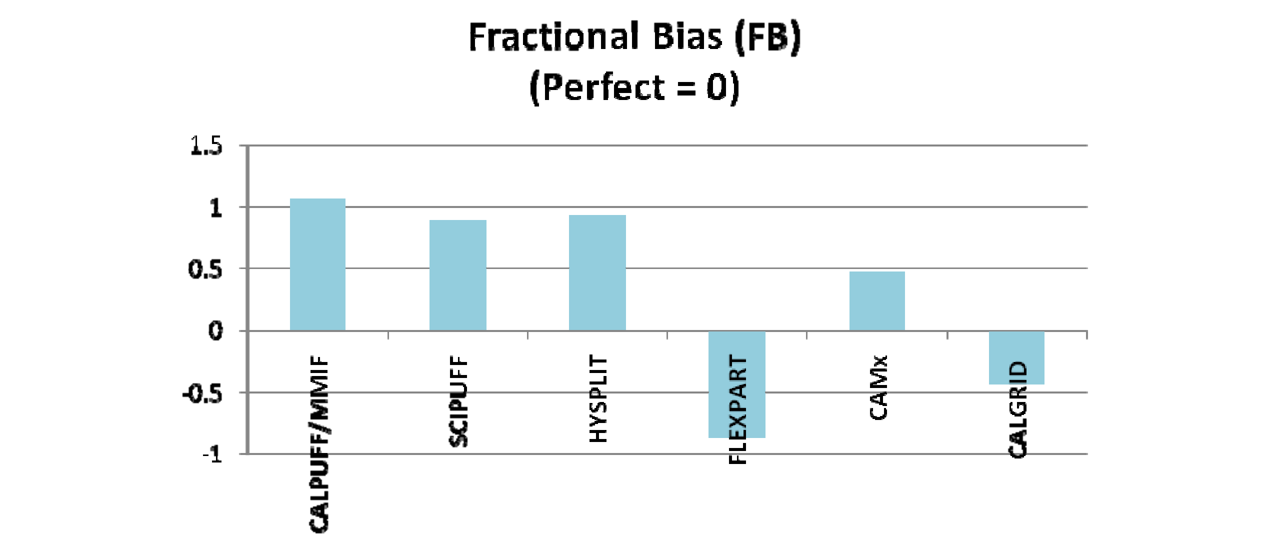

Figure C-38. Fractional Bias (FB) statistical performance metric for the six LRT models and CAPTEX Release 5.

The KS parameters for the six LRT models are shown in Figure C-39. HYSPLIT (28%) has the lowest KS parameter, which indicates the best match between the predicted and observed tracer concentration distributions according to the KS parameter, followed by CALPUFF (37%) and CALGRID (38%). CAMx follows with a score of 41% and FLEXPART and SCIPUFF close out with scores of 55% and 56% respectively.

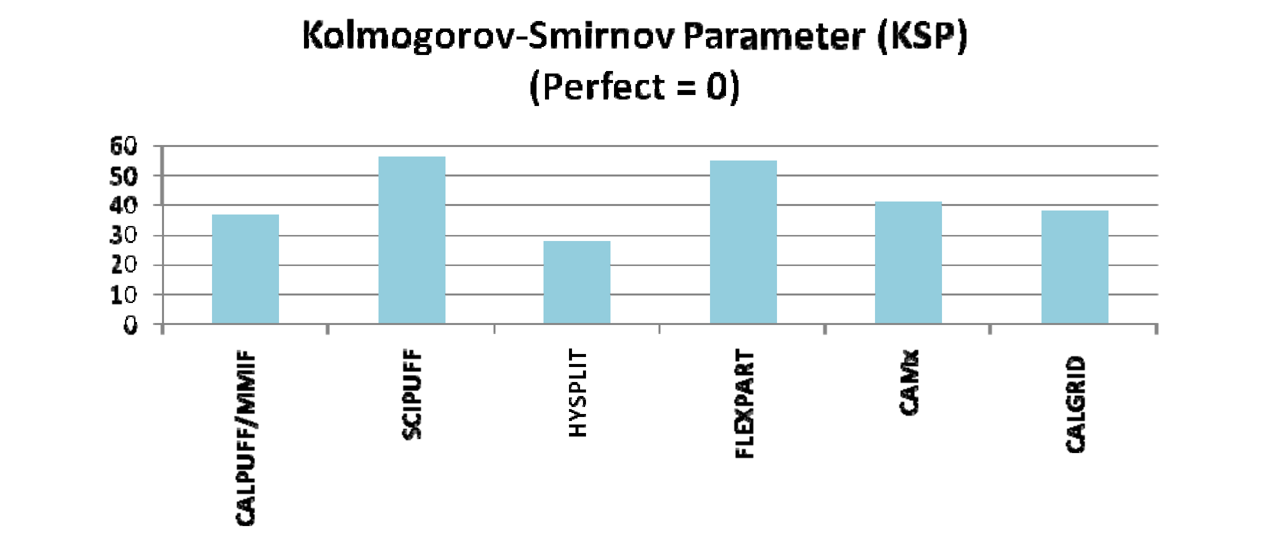

Figure C-39. Kolmogorov – Smirnov Parameter (KSP) statistical performance metrics for the six LRT models and CAPTEX Release 5.

Figure C-40 lists the RANK model performance statistics for the six LRT models. CAMx is the highest ranked model using the RANK metric with a value of 1.91 followed by HYSPLIT at 1.8. It is important to note, however, that both CAMx and HYSPLIT exhibit high scores in all four areas of model performance (correlation, bias, spatial and cumulative distribution). It is an important attribute of model performance to score high in all areas of model performance. The next best performing model according to the RANK metric is CALGRID with a score of 1.57, followed by SCIPUFF (1.53), FLEXPART (1.45), and finally CALPUFF (1.28). However, the CALGRID third best RANK metric comes at the expense of low spatial (FMS) and zero correlation (PCC or R2) performance skill.

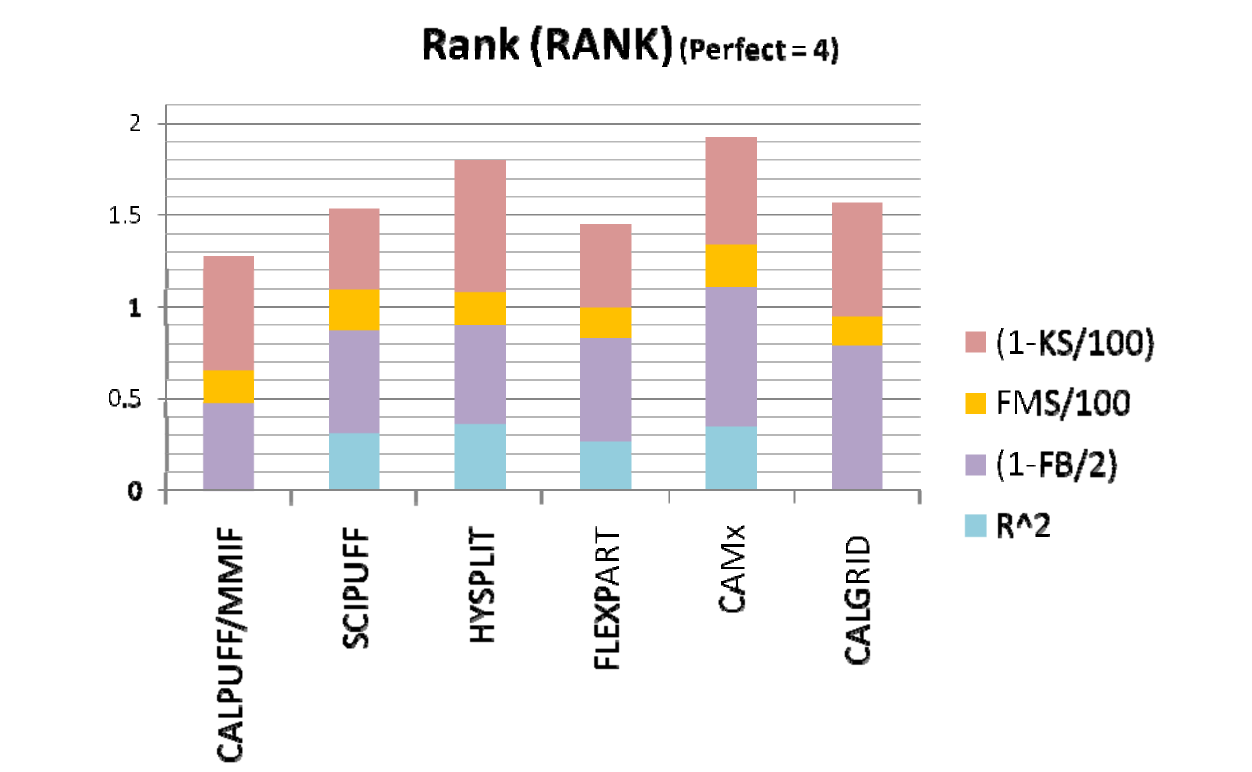

Figure C-40. RANK statistical performance metric for the six LRT models and CAPTEX Release 5.

C.5.2.1 SUMMARY OF SIX LRT MODEL RANKINGS FOR CTEX5 USING STATISTICAL PERFORMANCE MEASURES

Table C-6 summarizes the rankings of the six LRT models for the 11 performance statistics analyzed in CAPTEX Release 5 and compares the averaging ranking across the 11 statistics against the RANK metric. Depending on the statistical metric, five of the six models were ranked as the best performing model for a particular statistic. CALGRID was the only model not ranked first for any performance statistics, although it tied with CAMx for having the lowest (best) FB value (-0.49), but it was ranked behind CAMx (FB of +0.49) due to a desire for regulatory models to not have an underestimation bias. HYSPLIT was ranked the best performing model the most often scoring best in 4 of the 11 statistics (36% of the time). SCIPUFF, FLEXPART and CAMx all scored best with 2 of the 11 statistics (18%) with CALPUFF scoring best for just one statistical metric.

In testing the efficacy of the RANK statistic, overall rank across all eleven statistics was used to come up with an average modeled ranking to compare with the RANK statistic rankings. The average rank across all 11 performance statistics and the RANK rankings are as follows:

Ranking	**Average of 11 Statistics**	**RANK**
1.	CAMx	CAMx
2.	HYSPLIT	HYSPLIT
3.	SCIPUFF	CALGRID
4.	FLEXPART	SCIPUFF
5.	CALPUFF	FLEXPART
6.	CALGRID	CALPUFF

The results from CAPTEX Release 5 present an interesting case study on the use of the RANK metric to characterize overall model performance. As noted in Table C-6 and given above, the relative ranking of models using the average rankings across the 11 statistical metrics is considerably different than the RANK scores after the two highest ranked models. Both approaches rank CAMx as the best and HYSPLIT as the next best performing models for CTEX5, with rankings that are fairly close to each other. However, after that the two ranking techniques come to different conclusions regarding the ability of the models to simulate the observed tracer concentrations for the CTEX5 field experiment.

The most noticeable feature of the RANK metric for ranking models in CTEX5 is the third highest ranking model using RANK, CALGRID (1.57). CALGRID ranks as the worst or second worst performing model in 9 of the 11 performance statistics (82% of the time) and have an average ranking of 5.0, which means on average it is the 5th best performing model out of 6. In examining the contribution to the RANK metric for CALGRID, there is not a consistent contribution from all four broad categories to the composite score (Figure C-40). Recall from equation 2-12 in Section 2.4.3.2 that the RANK score is defined by the contribution of the four of the 11 statistics that represent measures of correlation/scatter (R2), bias (FB), spatial (FMS) and cumulative distribution:

$$RANK = \left|R^2\right| + \left(1 - \left|FB/2\right|\right) + FMS/100 + \left(1 - KS/100\right)$$

The majority of CALGRID's 1.57 RANK score comes from fractional bias and Kolmogorov-Smirnov parameter values. Recall from Figures C-36 and C-39 that the FOEX and FB metrics indicate that CALGRID consistently underestimates. The FB component to the composite score for CALGRID is one of the highest among the six models in this study, yet the underlying statistics indicate both marginal spatial skill and a degree of under-prediction (likely due to the spatial skill of the model).

The current form of the RANK score uses the absolute value of the fractional bias. This approach weights underestimation equally to overestimation. However, in a regulatory context, EPA is most concerned with models not being biased towards underestimation. When looking at all of the performance statistics, CALGRID is clearly one of the worst performing LRT models for CTEX5, and is arguably the worst performing model. Adaptation of RANK score for regulatory use will likely require refinement of the individual components to insure that this situation does not develop and to insure that the regulatory requirement of bias be accounted for when weighting the individual statistical measures to produce a composite score.

Table C-6. Summary of model rankings using the statistical performance metrics and comparison with the RANK metric.

Statistic	1st	2nd	3rd	4th	5th	6th
FMS	SCIPUFF	CAMx	HYSPLIT	CALPUFF	FLEXPART	CALGRID
FAR	FLEXPART	HYSPLIT	CAMx	SCIPUFF	CALGRID	CALPUFF
POD	SCIPUFF	CAMx	HYSPLIT	FLEXPART	CALPUFF	CALGRID
TS	FLEXPART	HYSPLIT	CAMx	SCIPUFF	CALPUFF	CALGRID
FOEX	CALPUFF	CAMx	HYSPLIT	CALGRID	SCIPUFF	FLEXPART
FA2	HYSPLIT	CAMx	CALPUFF	SCIPUFF	FLEXPART	CALGRID
FA5	HYSPLIT	CAMx	SCIPUFF	CALPUFF	FLEXPART	CALGRID
NMSE	CAMx	SCIPUFF	FLEXPART	HYSPLIT	CALPUFF	CALGRID
PCC or R	HYSPLIT	CAMx	SCIPUFF	FLEXPART	CALGRID	CALPUFF
FB	CAMx	CALGRID	FLEXPART	SCIPUFF	HYSPLIT	CALPUFF
KS	HYSPLIT	CALPUFF	CALGRID	CAMx	FLEXPART	SCIPUFF
Avg. Ranking	CAMx	HYSPLIT	SCIPUFF	FLEXPART	CALPUFF	CALGRID
Avg. Score	2.20	2.4	3.4	3.8	4.3	5.0
RANK Ranking	CAMx	HYSPLIT	CALGRID	SCIPUFF	FLEXPART	CALPUFF
RANK	1.91	1.80	1.57	1.53	1.45	1.28

C.5.3 SUMMARY AND CONCLUSIONS OF CAPTEX LRT MODEL EVALUATION

Following the ATMES-II evaluation paradigm described in Section 2.4.3.1 (spatial) and 2.4.3.3 (global), the performance of the six LRT dispersion models described in Section 2.2 have been evaluated for the Cross Appalachian Tracer Experiment (CAPTEX) Releases 3 and 5. Sensitivities of the INITD (particle/puff) configuration for HYSPLIT and Kz/advection solver combination for CAMx were examined for each CAPTEX release as well as in intercomparison of the model performance for the six models.

The model sensitivity results for HYSPLIT and CAMx are largely comparable to the conclusions from those of the ETEX experiment. For HYSPLIT, the puff-particle hybrid configurations appear to offer a distinct performance advantage over either HYSPLIT's pure particle or puff based formulations. For CAMx, the CMAQ Kz option typically performs the best, followed closely by TKE. The OB70 combination consistently performs the poorest for both CAPTEX releases. The evaluation of the use of the CAMx model's subgrid scale PiG module generally yields slightly degraded performance statistics over the NoPiG option.

United States Environmental Protection Agency	Office of Air Quality Planning and Standards Air Quality Assessment Division Research Triangle Park, NC	Publication No. EPA-454/R-12-003 May, 2012

NOx BART DETERMINATION COMMENTS

FOR

GREAT RIVER ENERGY (GRE) COAL CREEK STATION UNITS 1 AND 2

EXPERT REPORT

OF

DR. RANAJIT (RON) SAHU

ON BEHALF OF THE

NATIONAL PARKS CONSERVATION ASSOCIATION

OCTOBER 30, 2012

Professional Background

I have more than twenty-one years of experience in the fields of environmental, mechanical, and chemical engineering including: program and project management services; design and specification of pollution control equipment; soils and groundwater remediation; combustion engineering evaluations; energy studies; multimedia environmental regulatory compliance (involving statutes and regulations such as the Federal CAA and its Amendments, Clean Water Act, TSCA, RCRA, CERCLA, SARA, OSHA, NEPA as well as various related state statutes); transportation air quality impact analysis; multimedia compliance audits; multimedia permitting (including air quality NSR/PSD permitting, Title V permitting, NPDES permitting for industrial and storm water discharges, RCRA permitting, etc.), multimedia/multi-pathway human health risk assessments for toxics; air dispersion modeling; and regulatory strategy development and support including negotiation of consent agreements and orders.

I have more than nineteen years of project management experience and have successfully managed and executed numerous projects in this time period. This includes basic and applied research projects, design projects, regulatory compliance projects, permitting projects, energy studies, risk assessment projects, and projects involving the communication of environmental data and information to the public. Notably, I have successfully managed a complex soils and groundwater remediation project with a value of over $140 million involving soils characterization, development and implementation of the remediation strategy, regulatory and public interactions and other challenges.

I have provided consulting services to numerous private sector, public sector and public interest group clients. My major clients over the past seventeen years include various steel mills, petroleum refineries, cement companies, aerospace companies, power generation facilities, lawn and garden equipment manufacturers, spa manufacturers, chemical distribution facilities, and various entities in the public sector including EPA, the U.S. Dept. of Justice, various states, and various municipalities, among others. I have performed projects in more than 44 states, numerous local jurisdictions and internationally.

Specifically for cement plants, I have provided air quality consulting and permitting services for numerous cement plants in the US since roughly 1995. I have assisted various plant owners and operators as well as governmental agencies such as the EPA/DoJ in addressing compliance and non-compliance issues.

In addition to consulting, I have taught numerous courses in several Southern California universities including UCLA (air pollution), UC Riverside (air pollution, process hazard analysis), and Loyola Marymount University (air pollution, risk assessment, hazardous waste management) for the past seventeen years. In this time period I have also taught at Caltech, my alma mater, and at USC (air pollution) and Cal State Fullerton (transportation and air quality).

I have and continue to provide expert witness services in a number of environmental areas discussed above in both state and Federal courts, as well as before administrative bodies (please see Attachment A).

Additional details regarding my background and experience can be found in my resume provided in Attachment A which also includes a list of publications and presentations.

Introduction and Summary of Report

Recently, as part of the North Dakota Regional Haze State Implementation Plan (SIP), the North Dakota Department of Health (NDDH) has finalized its proposal for NOx Best Available Retrofit Technology (BART) for Coal Creek Station (CCS) Units 1 and 2. A history of this determination is provided in the document titled "Supplemental Evaluation of NOx BART Determination for Coal Creek Station Units 1 and 2, NDDH, September 2012" (hereafter "Supplemental Evaluation") available at http://www.ndhealth.gov/AQ/RegionalHaze/. As it had previously done, in its March 2010 SIP, the NDDH is proposing that the NOx BART for CCS Unit 1 and CCS Unit 2 be a limit of 0.17 lb/MMBtu (30 day rolling average basis), to be achieved at each unit based on combustion controls. These combustion controls include a technology called DryFining, which as discussed in the Supplemental Evaluation is employed at CCS Units 1 and 2, as well as the use of low NOx burners and over-fire air.

In determining that the BART limit should be 0.17 lb/MMBtu at each unit, the NDDH specifically rejected the use of the add-on NOx control technology called Selective Non-Catalytic Reduction (SNCR), suggested by the EPA. In this report, I will discuss why the NDDH's BART determinations are incorrect, and specifically, why its rationale and stated reasons for the rejection of SNCR is incorrect. In doing so, I will rely on the Supplemental Evaluation as well as other documents provided by Great River Energy (GRE), the owner of CCS and its consultants. All of the documents that I rely on in this regard are available at the aforementioned website. In addition, as I rely on other documents or data, I will provide appropriate citations via footnotes.

As the NDDH has done in its Supplemental Evaluation, my comments are also organized by topic, following the same sequence as provided in the Supplemental Evaluation.

Comments on Baseline NOxEmissions

For the reasons stated in the Supplemental Evaluation, the NDDH believes, per GRE, that the baseline NOx emissions of 5080 tons/yr for Unit 1 and 5086 tons/yr for Unit 2 are "reasonable." Briefly, NDDH states that

"Based on the information provided by GRE, a baseline emission rate based on 0.201 lb/106 Btu at each unit is appropriate. For purposes of determining the annual emissions, the last five years of data (2006 – 2010) were reviewed. Based on the average of the highest two years in the last five years, the baseline heat input was as follows:
Unit 1 = 5.0433×10^{13} Btu/hr
Unit 2 = 4.7965×10^{13} Btu/hr
The calculated baseline emissions are:
E (Unit 1) = (5.0433×10^{13} Btu/yr) (0.201 lb/106 Btu) ÷ (2000 lb/ton)
E (Unit 1) = 5,069 tons/yr
E (Unit 2) = (4.7965×10^{13} Btu/hr) (0.201 lb/106 Btu) ÷ (2000 lb/ton)
E (Unit 2) = 4,820 tons/yr
GRE established their baseline emissions at 5,080 tons per year for Unit 1 and 5,086 tons per year for Unit 2. GRE's estimate of baseline emissions appears to be reasonable."[1]

Thus, NDDH's (and GRE's) determination of the baseline at each unit rests on two numbers – the highest annual heat input in the baseline period (2006-2010) and the NOx rate of 0.201 lb/MMBtu. I will examine both. In order to do so, I use data provided by GRE for CCS to the EPA available at EPA's Acid Rain database (www.epa.gov/ampd). I have summarized this data, in monthly fashion in Attachment B.

As to heat input, it is clear from Attachment B that the highest annual heat input during the baseline period, using the same metric as used by NDDH (namely the "average of the highest two years in the last five years") shows that the heat inputs are significantly greater than that determined by the NDDH. They are as follows:

For Unit 1, 51,969,572 MMBtu/yr (instead of NDDH's 5.0433 x 10^13 or 50,433,000 MMBtu/yr)

For Unit 2, 50,882,663 MMBtu/yr (instead of NDDH's 47,965,000 MMBtu/yr)

[1] Supplemental Evaluation, p. 5.

Since the NDDH does not provide any backup calculations, I am not sure as to why they have lower numbers in this regard.

Turning to the NOx rate, the NDDH has accepted that the NOx emission rate at each unit should be 0.201 lb/MMBtu, which, according to GRE and the NDDH is the emission rate after installation of DryFining at Unit 1. As the NDDH explains, it is appropriate to consider Unit 1's NOx emissions since it includes the effects of DryFining but not the effects of a separate low NOx technology called LNC3+ which has now been installed at Unit 2. Thus, NDDH asked GRE that it determine the "with-DryFining" rate for Unit 1 for use at both Units.

Without getting into the merits of whether or not even the inclusion of DryFining in the baseline determination is appropriate, I will show that, even with the inclusion of DryFining, the selection of 0.201 lb/MMBtu is not supportable. Again, I turn to Attachment B, using the data for Unit 1.

First, I note that DryFining was installed at both units in late 2009 and was operational starting in 2010. This was publicly reported. For example, an article in Power Engineering noted that "The DryFining systems on both units at Coal Creek have been in continuous service since completing their 24-hour commercialization runs in December 2009."[2] Thus, I have reviewed the NOx data for the time period after 2010 and through the present (i.e., through September of 2012, the most recent data available) to determine the NOx rate. As the calculations in Attachment B show, the maximum monthly NOx rate for 2010-Sept 2012 is 0.2309 lb/MMBtu; further, the annual averages were 0.210, 0.204, and 0.208 for 2010, 2011, and 2012 year-to-date. Thus, the use of 0.201 lb/MMBtu to denote the highest baseline is inappropriate and not supportable.

In fact, using the correct heat inputs and a conservative rate of 0.208 lb/MMBtu which is the average of the annual averages listed above, I obtain the following baseline NOx emission rates:

For Unit 1, 51,969,572 MMBtu/yr x 0.208 lb/MMBtu/2000 lb/ton = 5404 tons/yr

For Unit 2, 50,882,663 MMBtu/yr x 0.208 lb/MMBtu/2000 lb/ton = 5292 tons/yr,

[2]Bullinger, C., et. al., An On-Site Process for Removing Moisture from Low-Rank Coal, Power Engineering, April 2010.Available at http://www.power-eng.com/articles/print/volume-114/issue-4/Features/an-on-site-process-for-removing-moisture-from-low-rank-coal.html. Exhibit 1a.

Of course the emissions would be even greater if I had used the maximum rate of 0.2309 lb/MMBtu.

In any case, the data do not support that implementation of DryFining would maintain a consistent NOx emission rate of 0.201 lb/MMBtu, as assumed by GRE and NDDH.

Thus, it is plain that both GRE's assumed baseline and NDDH's acceptance of GRE's baseline are incorrect. In each case, the baseline's used by GRE and NDDH significantly understate the actual appropriate baseline that should have been used in the analysis. For Unit 1, the baseline used (5080 tons/yr) is approximately 6% lower than the correct baseline of 5404 tons/yr. For Unit 2, the baseline used (5086 tons/yr) is approximately 4% lower.

The implication of using a lower baseline is that the benefits of using SNCR, as I will discuss later below are understated, leading to both lower visibility benefits and higher cost-effectiveness for SNCR. Since the NDDH has relied on both of these factors for rejecting SNCR, this error in the baseline calculation makes NDDH's rejection inappropriate, all other factors remaining the same.

However, as I discuss below, there are additional problems with NDDH's analysis.

Comments on SNCR Control Efficiency

As the NDDH summarizes,

"GRE estimated that the control efficiency of SNCR after the installation of LNC3+ will be 20%. EPA estimated that 25% control efficiency can be attained (77 FR 20919). GRE's estimate is based on a site-specific evaluation by URS.EPA's estimate is based on data from facilities other than Coal Creek Station included in the Control Cost Manual and information from Fuel Tech, Inc. and the Institute of Clean Air Companies (ICAC).

"As part of the revised BART analysis, GRE supplied an EPRI report titled 'Low-Baseline NOx Selective Non-Catalytic Reduction Demonstration'. The report documents the results of SNCR testing at Electric Energy's Joppa Unit 3."[3]

After brief discussion, the Supplemental Evaluation states that:

"The Department believes the URS estimate of 20% removal is credible and reasonable for the following reasons:
1) The EPRI report on low (≤88 ppm) uncontrolled NOx emission rates indicates substantially less than 25% removal. With LNC3+, the NOx emission rate at Coal Creek Station will be approximately 88 ppm.
2) The URS estimate was based on a site specific evaluation of Coal Creek Station. EPA's estimate was not.
3) The Control Cost Manual indicates SNCR will have a lower efficiency for boilers greater than 3,000 x 10^6 Btu/hr heat (CCS boilers are approximately 6,000 x 10^6 Btu/hr)."[4]

I have reviewed the SNCR analysis provided by URS. It is located in Appendix B of the "Coal Creek Station Units 1 and 2, Supplemental Best Available Retrofit Technology, Refined Analysis for NOx Emissions, November 2011; Updated April 5, 2012" provided by Barr Engineering on behalf of GRE to the NDDH. This document is also available on the aforementioned NDDH website.

First, URS's SNCR experience is quite limited. In fact, Appendix B lists all of URS's SNCR experience in a couple of tables. There are no projects for which URS did engineering work shown after 1998 (AES Warrior Run). Including any kind of work, such as feasibility studies, the latest project shown in 2002 (NRG, 5 stations, unspecified). Thus, EPA's observation in the FIP (at 121-124) that URS is not an SNCR vendor is correct and apt. While URS is a large engineering firm, SNCR experience is specialized and NDDH, faced with the aging experience list provided by URS,

[3] Supplemental Evaluation, p. 5.
[4] Supplemental Evaluation, p. 6.

should have conducted further due diligence as to current capabilities for SNCR. If it had done so, a good place to start would have been discussions with one of the leading vendors for SNCR in the US and worldwide, namely FuelTech. Not only would NDDH have obtained a better idea regarding SNCR efficiency using current implementation of SNCR technology, it would also have been able to obtain better cost and performance (i.e., ammonia slip) data, both of which are germane to a proper analysis of SNCR.

As I will show, in relying on URS information and the older Joppa Unit 3 report, NDDH has completely missed several recent advancements in SNCR. As a result, NDDH's rejection of SNCR is based on outdated, old, technical information.

Even though URS is not an SNCR vendor, it is well known, and even URS admits that SNCR performance is site-specific. In fact, in its SNCR memo, URS notes that "…SNCR performance is dependent upon factors that are specific to each source. These factors are; flue gas temperature, flue gas residence time at temperatures within the reaction temperature range, reagent distribution, uncontrolled NOx levels, mixing between the injected reagent and the flue gas, and the CO and O2 concentrations in the flue gas stream." I agree. However, having said so, none of these site-specific factors are evaluated by URS in its SNCR memo. In reality, this evaluation is often done by the SNCR vendor, such as FuelTech. Thus, NDDH's stated reason #2 above that URS's estimate of control efficiency was based on a site-specific evaluation is simply untrue. Further, given the site specific nature of this evaluation, NDDH's stated reason #1 (i.e., reliance on Joppa) is also irrelevant. I also note that the Joppa Unit 3 testing was conducted in November 2008[5] which predated several advancements in SNCR technology as I will discuss below. Of course, NDDH's stated reason #3 above is so weak that it deserves no comment; nonetheless, I note that the technology has evolved since that portion of the Cost Control Manual was written and the actual efficiency will be dependent on site specific factors as noted above.

Had NDDH (or even URS) conducted even the most cursory evaluation of the current state-of-the art SNCR, it would have found (and reported) that in order to obtain better mixing of the reagent (ammonia) and the exhaust gases, which has the effect of improving control efficiency and minimizing ammonia slip, FuelTech currently uses a technology called High Energy Reagent

[5] Low-Baseline NOx Selective Non-Catalytic Reduction Demonstration Joppa Unit 3, EPRI Report 1018665, March 2009, p. 3-1. Available at http://www.ndhealth.gov/AQ/RegionalHaze/.

Technology Injection or HERT. HERT is specifically designed for high energy, low momentum injectors to achieve low ammonia slip.[6] In fact, FuelTech describes "[R]ecent applications with low baseline and control levels at or below 0.1 lb/MMBtu…."[7] FuelTech acquired this technology around 2010 and it was well-known even prior. That the URS memo on SNCR, written well after this date (the Barr report was updated as recently as April 2012), makes no mention of HERT shows its irrelevance.

In view of this, it is my opinion that a proper evaluation of SNCR, including costs and ammonia slip, cannot be complete without a thorough evaluation of the NOx reduction that can be obtained using HERT, on a site-specific basis. This can only be done with further discussions directly with the technology vendor, Fuel Tech. Only GRE and/or NDDH can have this discussion since they are in a position to provide the site access and engineering details needed for this evaluation. Rejecting SNCR without this analysis (and including the results in the public docket) is premature and hasty.

It is my opinion that unless shown otherwise, based on the discussion above, a NOx rate of 0.1 lb/MMBtu using HERT should be assumed (along with DryFining and/or LNC3+) for SNCR, along with an ammonia slip of between 2-5 ppm. It should be GRE's burden to provide technical support as to why this level cannot be achieved.

Using the same baseline NOx levels that I have calculated above, and keeping the heat inputs constant as in the baseline period, the NOx <u>reductions</u> that SNCR/HERT would provide are as follows:

For Unit 1, 51,969,572 MMBtu/yr x (0.208– 0.10) lb/MMBtu/2000 lb/ton = 2806 tons/yr.

For Unit 2, 50,882,663 MMBtu/yr x (0.208– 0.10) lb/MMBtu/2000 lb/ton = 2748tons/yr.

Thus, all further analyses, including, critically, the cost-effectiveness and the visibility impacts analyses should be redone, using these reductions. Since the current analyses assume far smaller NOx reductions for each unit, for this reason alone, neither the visibility impacts analysis, nor the

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[6]SNCR – NOxOUT and HERT Processes, FuelTech. Available at http://www.ftek.com/en-US/products/apc/noxout/. Exhibit 1b.

[7] Dougherty, K., SNCR Operation Workshop, Reinhold NOx Roundtable Conference, February 2011. Available at http://www.ftek.com/media/en-US/ppts/Reinhold_2011_KD.pdf. Exhibit 1c.

cost-effectiveness analysis is correct. The visibility benefits as currently calculated are understated and the cost-effectiveness values calculated currently are over-stated.

In addition, the cost-effectiveness analysis presented by GRE and accepted by NDDH is additionally impaired by erroneous considerations of the capital cost of SNCR, which I discuss next.

Comments on Capital Cost of SNCR

In the Supplemental Evaluation, NDDH states the following:

"GRE has estimated the Installed Capital Cost (Total Capital Investment) for SNCR to be $12.18 million dollars for each unit. EPA has estimated that the capital cost to be $5,374,000 (76 FR 58620, Table 57). GRE's (URS) estimate is based on a site specific evaluation made by URS and URS software developed from actual projects. EPA's estimate uses GRE's estimate for direct capital cost and the remaining factors in the Control Cost Manual for SNCR (77 FR 58620). The major difference between the two cost estimates is a 1.6 retrofit factor used by GRE, but disallowed by EPA."[8] "With a retrofit factor of 1.0 (no increase for a retrofit), the IPM methodology predicts a cost that is about double EPA's estimated cost. With a retrofit factor of 1.6, the IPM estimates a cost that is about 5% higher than GRE's estimate. The GRE estimate using a 1.6 retrofit factor is within 30% of the IPM estimate with a retrofit factor of 1.0……[A]djusting the cost to 2011 dollars using the Consumer Price Index yields a cost range of $12 - $34 per kilowatt. GRE's estimate is approximately $20 per kilowatt (2011 dollars). EPA's estimate is approximately $9 per kilowatt (2009 dollars) or approximately $9.4 per kilowatt in the 2011 dollars."[9]

NDDH then summarizes as follows:

"Based upon its review and consideration, the Department believes GRE's capital cost estimate is credible and reasonable for the following reasons:
1) EPA's estimate is based on the Control Cost Manual which is out-of-date.
2) Cost estimates using the IPM and EPA's Fact Sheet for SNCR suggests GRE's estimate is accurate (±30%).
3) The GRE estimate is a site specific estimate as suggested by the BART Guidelines. EPA's estimate is not site specific."[10]

The gist of NDDH's argument regarding cost is that the URS estimate is based on a "site-specific" evaluation, that it relies on "software developed from actual projects" and must therefore be superior.

First, I reiterate URS's lack of experience with SNCR projects - with no stated projects in roughly 10 years. Second, I expose URS's lack of SNCR experience by showing that it is either unaware or did not choose to report on relevant recent developments such as HERT. Third, I have reviewed the URS SNCR memorandum in terms of how the capital cost estimate was developed and find no

[8] Supplemental Evaluation, p. 7.
[9] Supplemental Evaluation, p. 8.
[10] Supplemental Evaluation, p. 8.

support that it uses "site-specific" information. Perhaps NDDH believes that because URS staff may have visited the site, therefore the estimate is deemed "site-specific." If so, it is naïve.

Let us examine the estimate itself. For ease of reference, I have pasted below the entirety of URS's capital cost estimate (for 5 different cases) from its SNCR memorandum.

Table 3 – Material Costs

SNCR Material Costs			0.22 Inlet & 30% Reduction	0.20 Inlet & 25% Reduction	0.16 Inlet & 20% Reduction	0.15 Inlet & 20% Reduction	0.22 & 50% Reduction
Cost Basis Year			2011	2011	2011	2011	2011
SNCR Equipment Cost	$		$3,800,000	$3,700,000	$3,600,000	$3,600,000	$4,200,000
Installation Factor			1.30	1.30	1.30	1.30	1.30
Installed Equipment Cost	$		$4,970,000	$4,800,000	$4,700,000	$4,700,000	$5,500,000
Prime Contractor's Markup	$		$497,000	$480,000	$470,000	$470,000	$550,000
Total Installed Cost	$		$5,500,000	$5,300,000	$5,100,000	$5,100,000	$6,000,000
Retrofit Factor			1.6	1.6	1.6	1.6	1.6
Total Equipment Cost	$		$8,750,000	$8,500,000	$8,200,000	$8,200,000	$9,600,000
General Facilities	$		$440,000	$420,000	$410,000	$410,000	$480,000
Engineering Fees	$		$875,000	$850,000	$820,000	$820,000	$960,000
Process Contingencies	$		$503,000	$488,000	$472,000	$472,000	$553,000
Project Contingencies	$		$1,580,000	$1,540,000	$1,490,000	$1,490,000	$1,740,000
Total Plant Cost (TPC)	$		$12,145,000	$11,790,000	$11,420,000	$11,400,000	$13,350,000
Total Cash Expended (TCE)	$		$12,145,000	$11,790,000	$11,420,000	$11,400,000	$13,350,000
Allowance for Funds During Constru	$		0	0	0	0	0
Total Plant Investment (TPI)	$		$12,145,000	$11,790,000	$11,420,000	$11,400,000	$13,350,000
Preproduction Costs	$		$243,000	$236,000	$228,000	$227,000	$267,000
Inventory Capital	$		$167,000	$134,000	$100,000	$98,000	$260,000
Initial Catalyst and Chemicals	$		$0	$0	$0	$0	$0
Prepaid Royalties	$		$44,000	$42,000	$41,000	$41,000	$48,000
Total Capital Requirement (TCR)	$		$12,600,000	$12,200,000	$11,800,000	$11,800,000	$13,900,000
Market Demand Escalation	$		$0	$0	$0	$0	$0
Power Outage Penalty	$		$0	$0	$0	$0	$0
Land Cost	$		$0	$0	$0	$0	$0
TCR w/ Market Dem., Power Outage	$		$12,600,000	$12,200,000	$11,800,000	$11,800,000	$13,900,000
	$/kW		21.80	21.10	20.40	20.40	24.00
	Mills/KWh		0.40	0.38	0.37	0.37	0.44

Let us consider the "0.20 inlet & 25% Reduction" case, since it is the most relevant to the discussion based on the inlet value of 0.201 considered by NDDH.

First, there is simply no support or information for the basic assumption that the "SNCR Equipment Cost" is 3.7 million dollars. No vendor specifications or vendor quotes are provided. How this relates to any site-specific consideration is a mystery. NDDH should explain the basis of this fundamental cost line item.

Second, URS uses an "installation factor" of 1.3 on top of the 3.7 million dollars above, to arrive at an Installed Equipment Cost of 4.8 million dollars. The basis for the 1.3 or 30% factor and its scope is also a mystery since URS provides no support for this whatsoever.

Third, on top of the line items above, and neglecting the unsupported "Prime Contractor Markup," URS then adds on a multiplier of 1.6 for "Retrofit Factor." While it is expected that costs in a retrofit situation may be higher than a new construction, the choice of a retrofit factor should be based on site-specific details showing why costs would, in fact, be greater. But, here again, URS provides no support. In fact, the entire record contains not a shred of engineering support for this 1.6 retrofit factor. Yet, NDDH accepts it as fact. NDDH is mistaken. In fact, some of the most complex SCR projects (which involve far more equipment, ductwork rearrangements, fan upgrades, etc.) conducted by numerous coal plants in the last several years have retrofit factors that are far smaller. To use a blatantly high factor such as 1.6 with no support merely exposes and reinforces the idea that URS simply has little credibility with regards to SNCR. It is simply a transparent attempt to drive up the estimated cost, only to ensure rejection of the technology.

But the cost estimate is not done yet. Notwithstanding the inclusion of every conceivable contingency that should already be covered by the three items above, URS also added separate "Process Contingency" and "Project Contingency" line items – and these two alone are over 2 million dollars. Of course, URS does not explain why there should be any process contingency for an old technology such as SNCR or why one needs a substantial "project contingency" on top of an already inflated retrofit factor and installation factor.

That NDDH chose to accept this cost estimate (and chose to characterize it as being "site-specific") boggles the mind. In fact, rationally, a site-specific estimate would not have so many unspecific and unsupported factors and contingencies, since they would have been narrowed down relying on site-specific facts. That the estimate uses these unsupported factors and contingencies makes the estimate, by definition, not site specific.

The same sort of reliance on inappropriate and unsupported factors is also present in the most recent cost-estimates of SNCR provide by GRE. I have excerpted one of these below.

Great River Energy Coal Creek Station Technical Update 06/07/2012

BART Supplement - NOx Emission Control Cost Analysis

Table A-5: Unit 1 NOx Control - Selective Non-Catalytic Reduction SNCR Lignite Coal (Maintain Ash Sales)

CAPITAL COSTS		
Direct Capital Costs		
Purchased Equipment		3,700,000
Purchased Equipment Costs		
Instrumentation	10% of purchased equipment cost	370,000
Site Specific and Prime Contractor Markup	28% of purchased equipment cost	1,036,000
Freight	5% of purchased equipment cost	185,000
Purchased Equipment Total	43%	5,291,000
Purchased Equipment Total+ Retrofit Factor (A)		8,465,600
Indirect Installation		
General Facilities	See Notes & Assumptions 1 on pg. 1 of Table	420,000
Engineering & Home Office	See Notes & Assumptions 1 on pg. 1 of Table	850,000
Process Contingency	See Notes & Assumptions 1 on pg. 1 of Table	488,000
Total Indirect Installation Costs (B)	See Notes & Assumptions 1 on pg. 1 of Table	1,758,000
Project Contingeny (C)	See Notes & Assumptions 1 on pg. 1 of Table	1,540,000
Total Plant Cost (D)	A + B + C	11,763,600
Allowance for Funds During Construction (E)	0 for SNCR	0
Prepaid Royalties (F)	See Notes & Assumptionss 1 and 7 on pg. 1 of Table	42,000
Pre Production Costs (G)	See Notes & Assumptions 1 on pg. 1 of Table	236,000

Again, there is no support for the purchased equipment cost of 3.7 million at the beginning. Also, there is no support for the 10% instrumentation markup or the 28% "site-specific" markup and of course, the retrofit factor. As noted earlier, this estimate also contains the additional process and project contingencies.

Even with all of these "adjustments" the URS cost estimate is $21.1/kW. Let us compare this with typical SNCR costs, as provided by Fuel Tech, an actual vendor. In a recent SEC filing, Fuel Tech notes that "Fuel Tech's NOxOUT and HERT SNCR processes use non-hazardous urea as the reagent rather than ammonia. Both the NOxOUT and HERT processes on their own are capable of reducing NOx by up to 25% — 50% for utilities and by potentially significantly greater amounts for industrial units in many types of plants with capital costs ranging from $5 — $20/kW for utility boilers…."[11] This is instructive. URS's estimate is at or greater than the high range of Fuel Tech's estimate. In fact, given the size of the CCS units (i.e., over 600 MW), one would expect that they should have costs that are at the low-end of the $/kW cost range, given the economies of scale, not to mention the further economies afforded by sharing common equipment between the two units. In fact, EPA's estimate, which NDDH notes is $9.4/kW, is just about right, per Fuel Tech.

[11] http://www.faqs.org/sec-filings/100304/FUEL-TECH-INC_10-K/. Exhibit 1d.

Thus, the NDDH acceptance of these cost estimates has no basis. NDDH, in order to preserve its own credibility, should obtain a proper cost estimate from a vendor instead of relying on the GRE/Barr/URS "estimates" above.

Finally, NDDH's reason for setting aside the EPA estimate – namely that it is out of date would have had more credibility had it, in fact, reviewed GRE's cost basis for many items. Again, I have excerpted Table A-3 from GRE's most recent submittal to the NDDH. It is instructive to examine the "Data Sources" column in this table. In fact, many of the line items reference the very same EPA Control Cost Manual that NDDH deems out of date. Thus, NDDH's reasoning simply is flawed.

Great River Energy Coal Creek Station
BART Supplement - NOx Emission Control Cost Analysis
Table A-3: Summary of Utility, Chemical and Supply Costs

Technical Update 06/07/2012

Operating Unit: Unit 1 or 2 Study Year 2011

From Golder Report

Item	Unit Cost	Units	Reference Cost	Year	Data Source	Notes
Operating Labor	37.00	$/hr	25.86	2002	Stone & Webster 2002 Cost Estimate; confirmed by GRE	
Maintenance Labor	37.00	$/hr	26.25	2002	Stone & Webster 2002 Cost Estimate; confirmed by GRE	
Electricity	0.0604	$/kwh	0.049	2004	DOE Average Retail Price of Industrial Electricity, 2004	http://www.eia.doe.gov/emeu/aer/txt/ptb0810.html
Water	0.31	$/kgal	0.79	2002	Stone & Webster 2002 Cost Estimate; confirmed by GRE	
Cooling Water	0.32	$kgal	0.23	1999	EPA Air Pollution Control Cost Manual, 6th ed. Section 3.1 Ch 1	Ch 1 Carbon Adsorbers, 1999 $0.15 - $0.30 Avg of 22.5 and 7 yrs and 3% inflation
Compressed Air	0.37	$/kscf	0.25	1998	EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1	Example problem; Dried & Filtered, Ch 1.6 '98 cost adjusted for 3% inflation
Wastewater Disposal Neutralization	1.96	$/kgal	1.50	2002	EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 2 Chapter 2.5.5.5	Section 2 lists $1- $2/1000 gal. Cost adjusted for 3% inflation Sec 6 Ch 3 lists $1.30 - $2.15/1,000 gal
Wastewater Disposal Bio-Treat	4.96	$/kgal	3.80	2002	EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 5.2 Chapter 1	Ch 1 lists $1.00 - $6.00 for municipal treatment, $3.80 is average. Cost adjusted for 3% inflation
Solid Waste Disposal - No Impact	0.000	$/ton	0.00	2011	Assume no chang in GRE landfill cost for ash	Fly ash disposal of 0 net tons
Solid Waste Disposal - 30% Lost	5.438	$/ton	5.438	2011	Golder Fly Ash Management Evaluation - Nov. 2011	Cost per ton of $13.91/ ton for 234,500 tons less existing cost of $18.06/tons for 110,000 tons
Solid Waste Disposal - 100% Lost	7.396	$/ton	7.396	2011	Golder Fly Ash Management Evaluation - Nov. 2011	Cost per ton of $11.18/ ton for 525,000 tons less existing cost of $18.06/tons for 110,000 tons
Hazardous Waste Disposal	326.19	$/ton	250.00	2002	EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 2 Chapter 2.5.5.5	Section 2 lists $200 - $300/ton Used $250/ton. Cost adjusted for 3% inflation
Waste Transport	0.65	$/ton-mi	0.500	2002	EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 3	Example problem. Cost adjusted for 3% inflation
Ash Sales	12.300	$/ton	12.300	2011	Golder Fly Ash Management Evaluation - Nov. 2011	$/ton received for sale of ash; this amount is lost if ash cannot be sold
Ammonia Mitigation	5.610	$/ton	5.610	2011	Golder Fly Ash Management Evaluation - Nov. 2011	
Chemicals & Supplies						
Lime	90.00	$/ton	72.19	2005	GRE per Diane Stockdill 12/6/05 email	Cost adjusted for 3% inflation
Caustic	364	$/ton	305.21	2005	GRE per Diane Stockdill 12/6/05 email	Cost adjusted for 3% inflation
Urea	500	$/ton	500	2011	URS SNCR Report - November 2011	
Oxygen	17.91	kscf	15.00	2005	Get cost from Air Prod Website	Cost adjusted for 3% inflation
EPA Urea	179.1	$/ton				
Ammonia	1	$/lb	0.92	2005	GRE per Diane Stockdill	Cost adjusted for 3% inflation
Other						
Sales Tax	0	%			GRE per Diane Stockdill 12/6/05 email	
Interest Rate	5.50%	%			GRE per Diane Stockdill 12/6/05 email	Estimated prime rate plus 3%

Please note, for units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal

Future Operating Scenario for BART Cost Analysis

Operating Information	Unit 1	Unit 2	Units	Data Source	Notes
Annual Op. Hrs	8,409.6	8,409.6	Hours	July 2010 to October 2011 Coal Creek Emission Data	
Utilization Rate	100.0%	100.0%		GRE per Diane Stockdill 12/6/05 email	
Equipment Life	20	20	yrs		Engineering Estimate
Coal Ash	11.70	11.70	wt % ash	2010 Coal Creek Emission Inventory	
Coal Sulfur	0.64	0.64	% Coal Sulfur Content	July 2010 to October 2011 Coal Creek Emission Data	
Coal Heating Value	6,373	6,373	Btu/lb of coal	July 2010 to October 2011 Coal Creek Emission Data	
Design Capacity	6,015	6,022	MMBtu/hr		
ID Fan Flow Rates	Assumes coal drying with DryFining™				
Standardized Flow Rate	866293.7	866293.7	scfm @ 32º F		
Temperature	330.0	330.0	Deg F	GRE per G. Riveland 4/5/06 email	
Moisture Content	13.3%	13.3%		GRE per G. Riveland 4/5/06 email	
Actual Flow Rate	2,234,300	2,234,300	acfm	GRE per G. Riveland 4/5/06 email	
Standardized Flow Rate	1,391,000	1,391,000	scfm @ 330º F	GRE per G. Riveland 4/5/06 email	
Dry Std Flow Rate	1,205,997	1,205,997	dscfm @ 330º F		
NOx Pollutant Data					
Max Emis (lb/hr)	1,208.1	1,209.5		Calculated using baseline emission rate and design capacities	
Max Emis (tpy)	5,079.9	5,085.8		Calculated	
Baseline Emiss (lb/MMBtu)	0.201	0.201		Unit 1 average prior to LNC3+ installation	

I also note that the IPM cost modeling that GRE did and that NDDH references also contains numerous non-site-specific assumptions. For example, the IPM models as calculated by GRE show that the SNCR cost is highly sensitive to retrofit factor assumption. For example, in the IPM runs presented by GRE, the base cost for SNCR ("BMS") is 2.995 million with retrofit factor (RF)=1, 3.894 million with RF=1.3, and 4.788 million with RF=1.6. Yet, again, there is little or no justification for selection of the RF of 1.6 other than a footnote (FN5) to Table A-5 which states that "Retrofit factor of 60% used by URS based on site visit to Coal Creek Station…" Without documentation, it is not clear how URS determined the RF just by visiting or walking around the site.

Based on the above, I can only conclude that GRE's SNCR cost estimate is inflated. A reasonable capital cost would likely be at the low end of the $5-20/kW range. Given the inherent efficiency associated with installing two of these and therefore sharing in a substantial portion of the fixed costs, a reasonable capital cost may be in the $9/kW or even lower range.

Comments on Lost Ash Sales

Finally, NDDH and GRE provide extensive discussion on the likelihood of lost ash sales as a result of ammonia slip. And, as a result, the cost estimate is further inflated to account for both lost ash sales and ash disposal.

It is my opinion that this is entirely premature. As I have noted above, current SNCR/HERT technology is designed precisely to minimize ammonia slip. Thus, it is not reasonable to presume that ammonia slip will be high and therefore the costs of lost ash sales/ash disposal will be real.

Although there are several technologies that are being used to mitigate ammonia from fly-ash currently (including the one by Headwaters, that has been discussed in the record), I believe that a discussion of these options is also pre-mature, given that the underlying problem simply may not exist using SNCR/HERT.

Even though GRE's analysis considers a range of lost ash sales, NDDH provides no basis for its assumption that "…GRE expects a minimum of 30% lost ash sales and possibly 100% lost ash sales…"[12] The Golder report merely contains a sensitivity analysis of what the costs might be if there were various levels of lost ash sales. It does not contain any basis for what the actual lost ash sales may be. Nor can it, given that the cause of the ash contamination would be ammonia slip, a factor that is not within Golder's technical scope. Even Golder's report states that "Definitive information is not available for the levels of ammonia that could be present in the fly ash at CCS due to SNCR ammonia slip…" as the NDDH notes.[13]

It is also curious that GRE and Golder did not examine a case of 15% loss of ash sales, given GRE's own experience at the East Lake Station in Ohio. As the Supplemental Evaluation states, "GRE has reported that theEast Lake Station in Ohio must treat or blend 85% of their ash to make itmarketable because of ammonia contamination. Fifteen percent of the ash hashighly variable ammonia concentrations due to SNCR upset or plant load swings.This 15% of the ash is unmarketable because of the high ash ammonia content."[14]

[12] Supplemental Evaluation, p. 10.
[13] Supplemental Evaluation, p. 11.
[14] Supplemental Evaluation, p. 10.

In summary, on this issue, I reiterate that inclusion of any costs for loss of ash sales and/or ash disposal is premature without a careful examination of the low-ammonia slip SNCR advancements as represented by HERT.

Conclusion

As I have discussed in this report, NDDH's proposal that the NOx BART for the CCS Units 1 and 2 be set without SNCR and at a level of 0.17 lb/MMBtu is not supported. NDDH has accepted, without examination or independent verification, GRE's flawed technical analysis. The baseline NOx levels are wrong and lower than they should be. The SNCR NOx reduction capability assumed is outdated and under-predicts what is achievable. Together, as I have shown, the NOx reduction that should be expected is much greater at each unit. That means that the visibility benefit when SNCR is used, as currently relied upon, is understated and would be much greater than assumed.[15] Thus, NDDH's rejection of SNCR due to low visibility benefits is unsupported.

In addition, as I have shown, SNCR capital costs have been over-estimated. Thus, the cost-effectiveness of SNCR (whether total or incremental) are overestimated as well. Again, rejection of SNCR on cost ground is therefore not supported.

Finally, the issue of loss of fly ash sales or ash disposal, is, at this stage, completely speculative.

Based on the above, it is my opinion that the NDDH evaluation does not constitute a thorough, technically competent evaluation of SNCR, as it is being implemented today, relying on vendors and consultants who have the requisite expertise.

[15] I also note that the visibility modeling uses a CALPUFF option to use puff splitting, which is unusual – and this is likely further to reduce visibility benefits. Protocol for BART-Related Visibility Impairment Modeling Analyses in North Dakota (Final), November, 2005, North Dakota Department of Health. Table 3-5.

ATTACHMENT A – RESUME

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CONSULTANT, ENVIRONMENTAL AND ENERGY ISSUES

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EXPERIENCE SUMMARY

Dr. Sahu has over twenty one years of experience in the fields of environmental, mechanical, and chemical engineering including: program and project management services; design and specification of pollution control equipment; soils and groundwater remediation; combustion engineering evaluations; energy studies; multimedia environmental regulatory compliance (involving statutes and regulations such as the Federal CAA and its Amendments, Clean Water Act, TSCA, RCRA, CERCLA, SARA, OSHA, NEPA as well as various related state statutes); transportation air quality impact analysis; multimedia compliance audits; multimedia permitting (including air quality NSR/PSD permitting, Title V permitting, NPDES permitting for industrial and storm water discharges, RCRA permitting, etc.), multimedia/multi-pathway human health risk assessments for toxics; air dispersion modeling; and regulatory strategy development and support including negotiation of consent agreements and orders.

He has over nineteen years of project management experience and has successfully managed and executed numerous projects in this time period. This includes basic and applied research projects, design projects, regulatory compliance projects, permitting projects, energy studies, risk assessment projects, and projects involving the communication of environmental data and information to the public. Notably, he has successfully managed a complex soils and groundwater remediation project with a value of over $140 million involving soils characterization, development and implementation of the remediation strategy, regulatory and public interactions and other challenges.

He has provided consulting services to numerous private sector, public sector and public interest group clients. His major clients over the past seventeen years include various steel mills, petroleum refineries, cement companies, aerospace companies, power generation facilities, lawn and garden equipment manufacturers, spa manufacturers, chemical distribution facilities, and various entities in the public sector including EPA, the US Dept. of Justice, California DTSC, various municipalities, etc.). Dr. Sahu has performed projects in over 44 states, numerous local jurisdictions and internationally.

Dr. Sahu's experience includes various projects in relation to industrial waste water as well as storm water pollution compliance include obtaining appropriate permits (such as point source NPDES permits) as well development of plans, assessment of remediation technologies, development of monitoring reports, and regulatory interactions.

In addition to consulting, Dr. Sahu has taught numerous courses in several Southern California universities including UCLA (air pollution), UC Riverside (air pollution, process hazard analysis), and Loyola Marymount University (air pollution, risk assessment, hazardous waste management) for the past seventeen years. In this time period he has also taught at Caltech, his alma mater and at USC (air pollution) and Cal State Fullerton (transportation and air quality).

Dr. Sahu has and continues to provide expert witness services in a number of environmental areas discussed above in both state and Federal courts as well as before administrative bodies (please see Annex A).

EXPERIENCE RECORD

2000-present **Independent Consultant.** Providing a variety of private sector (industrial companies, land development companies, law firms, etc.) public sector (such as the US Department of Justice) and public interest group clients with project management, air quality consulting, waste remediation and management consulting, as well as regulatory and engineering support consulting services.

1995-2000 Parsons ES, **Associate, Senior Project Manager and Department Manager for** Air Quality/Geosciences/Hazardous Waste Groups, Pasadena. Responsible for the management of a group of approximately 24 air quality and environmental professionals, 15 geoscience, and 10 hazardous waste professionals providing full-service consulting, project management, regulatory compliance and A/E design assistance in all areas.

Parsons ES, **Manager for Air Source Testing Services**. Responsible for the management of 8 individuals in the area of air source testing and air regulatory permitting projects located in Bakersfield, California.

1992-1995 Engineering-Science, Inc. **Principal Engineer and Senior Project Manager** in the air quality department. Responsibilities included multimedia regulatory compliance and permitting (including hazardous and nuclear materials), air pollution engineering (emissions from stationary and mobile sources, control of criteria and air toxics, dispersion modeling, risk assessment, visibility analysis, odor analysis), supervisory functions and project management.

1990-1992 Engineering-Science, Inc. **Principal Engineer and Project Manager** in the air quality department. Responsibilities included permitting, tracking regulatory issues, technical analysis, and supervisory functions on numerous air, water, and hazardous waste projects. Responsibilities also include client and agency interfacing, project cost and schedule control, and reporting to internal and external upper management regarding project status.

1989-1990 Kinetics Technology International, Corp. **Development Engineer.** Involved in thermal engineering R&D and project work related to low-NOx ceramic radiant burners, fired heater NOx reduction, SCR design, and fired heater retrofitting.

1988-1989 Heat Transfer Research, Inc. **Research Engineer**. Involved in the design of fired heaters, heat exchangers, air coolers, and other non-fired equipment. Also did research in the area of heat exchanger tube vibrations.

EDUCATION

1984-1988 Ph.D., Mechanical Engineering, California Institute of Technology (Caltech), Pasadena, CA.

1984 M. S., Mechanical Engineering, Caltech, Pasadena, CA.

1978-1983 B. Tech (Honors), Mechanical Engineering, Indian Institute of Technology (IIT) Kharagpur, India

TEACHING EXPERIENCE

Caltech

"Thermodynamics," Teaching Assistant, California Institute of Technology, 1983, 1987.

"Air Pollution Control," Teaching Assistant, California Institute of Technology, 1985.

"Caltech Secondary and High School Saturday Program," - taught various mathematics (algebra through calculus) and science (physics and chemistry) courses to high school students, 1983-1989.

"Heat Transfer," - taught this course in the Fall and Winter terms of 1994-1995 in the Division of Engineering and Applied Science.

“Thermodynamics and Heat Transfer,” Fall and Winter Terms of 1996-1997.

U.C. Riverside, Extension

"Toxic and Hazardous Air Contaminants," University of California Extension Program, Riverside, California. Various years since 1992.

"Prevention and Management of Accidental Air Emissions," University of California Extension Program, Riverside, California. Various years since 1992.

"Air Pollution Control Systems and Strategies," University of California Extension Program, Riverside, California, Summer 1992-93, Summer 1993-1994.

"Air Pollution Calculations," University of California Extension Program, Riverside, California, Fall 1993-94, Winter 1993-94, Fall 1994-95.

"Process Safety Management," University of California Extension Program, Riverside, California. Various years since 1992-2010.

"Process Safety Management," University of California Extension Program, Riverside, California, at SCAQMD, Spring 1993-94.

"Advanced Hazard Analysis - A Special Course for LEPCs," University of California Extension Program, Riverside, California, taught at San Diego, California, Spring 1993-1994.

"Advanced Hazardous Waste Management" University of California Extension Program, Riverside, California. 2005.

LoyolaMarymountUniversity

"Fundamentals of Air Pollution - Regulations, Controls and Engineering," LoyolaMarymountUniversity, Dept. of Civil Engineering. Various years since 1993.

"Air Pollution Control," LoyolaMarymountUniversity, Dept. of Civil Engineering, Fall 1994.

"Environmental Risk Assessment," LoyolaMarymountUniversity, Dept. of Civil Engineering. Various years since 1998.

"Hazardous Waste Remediation" LoyolaMarymountUniversity, Dept. of Civil Engineering. Various years since 2006.

University of Southern California

"Air Pollution Controls," University of Southern California, Dept. of Civil Engineering, Fall 1993, Fall 1994.

"Air Pollution Fundamentals," University of Southern California, Dept. of Civil Engineering, Winter 1994.

University of California, Los Angeles

"Air Pollution Fundamentals," University of California, Los Angeles, Dept. of Civil and Environmental Engineering, Spring 1994, Spring 1999, Spring 2000, Spring 2003, Spring 2006, Spring 2007, Spring 2008, Spring 2009.

International Programs

"Environmental Planning and Management," 5 week program for visiting Chinese delegation, 1994.

"Environmental Planning and Management," 1 day program for visiting Russian delegation, 1995.

"Air Pollution Planning and Management," IEP, UCR, Spring 1996.

"Environmental Issues and Air Pollution," IEP, UCR, October 1996.

PROFESSIONAL AFFILIATIONS AND HONORS

President of India Gold Medal, IIT Kharagpur, India, 1983.

Member of the Alternatives Assessment Committee of the Grand Canyon Visibility Transport Commission, established by the Clean Air Act Amendments of 1990, 1992-present.

American Society of Mechanical Engineers: Los Angeles Section Executive Committee, Heat Transfer Division, and Fuels and Combustion Technology Division, 1987-present.

Air and Waste Management Association, West Coast Section, 1989-present.

PROFESSIONAL CERTIFICATIONS

EIT, California (# XE088305), 1993.

REA I, California (#07438), 2000.

Certified Permitting Professional, South Coast AQMD (#C8320), since 1993.

QEP, Institute of Professional Environmental Practice, since 2000.

CEM, State of Nevada (#EM-1699). Expiration 10/07/2011.

PUBLICATIONS (PARTIAL LIST)

"Physical Properties and Oxidation Rates of Chars from Bituminous Coals," with Y.A. Levendis, R.C. Flagan and G.R. Gavalas, *Fuel*, **67**, 275-283 (1988).

"Char Combustion: Measurement and Analysis of Particle Temperature Histories," with R.C. Flagan, G.R. Gavalas and P.S. Northrop, *Comb. Sci. Tech.***60**, 215-230 (1988).

"On the Combustion of Bituminous Coal Chars," PhD Thesis, California Institute of Technology (1988).

"Optical Pyrometry: A Powerful Tool for Coal Combustion Diagnostics," *J. Coal Quality*, **8**, 17-22 (1989).

"Post-Ignition Transients in the Combustion of Single Char Particles," with Y.A. Levendis, R.C.Flagan and G.R. Gavalas, *Fuel*, **68**, 849-855 (1989).

"A Model for Single Particle Combustion of Bituminous Coal Char." Proc. ASME National Heat Transfer Conference, Philadelphia, **HTD-Vol. 106**, 505-513 (1989).

"Discrete Simulation of Cenospheric Coal-Char Combustion," with R.C. Flagan and G.R.Gavalas, *Combust. Flame*, **77**, 337-346 (1989).

"Particle Measurements in Coal Combustion," with R.C. Flagan, in "**Combustion Measurements**" (ed. N. Chigier), Hemisphere Publishing Corp. (1991).

"Cross Linking in Pore Structures and Its Effect on Reactivity," with G.R. Gavalas in preparation.

"Natural Frequencies and Mode Shapes of Straight Tubes," Proprietary Report for Heat Transfer Research Institute, Alhambra, CA (1990).

"Optimal Tube Layouts for Kamui SL-Series Exchangers," with K. Ishihara, Proprietary Report for Kamui Company Limited, Tokyo, Japan (1990).

"HTRI Process Heater Conceptual Design," Proprietary Report for Heat Transfer Research Institute, Alhambra, CA (1990).

"Asymptotic Theory of Transonic Wind Tunnel Wall Interference," with N.D. Malmuth and others, Arnold Engineering Development Center, Air Force Systems Command, USAF (1990).

"Gas Radiation in a Fired Heater Convection Section," Proprietary Report for Heat Transfer Research Institute, College Station, TX (1990).

"Heat Transfer and Pressure Drop in NTIW Heat Exchangers," Proprietary Report for Heat Transfer Research Institute, College Station, TX (1991).

"NOx Control and Thermal Design," Thermal Engineering Tech Briefs, (1994).

“From Puchase of Landmark Environmental Insurance to Remediation: Case Study in Henderson, Nevada,” with Robin E. Bain and Jill Quillin, presented at the AQMA Annual Meeting, Florida, 2001.

“The Jones Act Contribution to Global Warming, Acid Rain and Toxic Air Contaminants,” with Charles W. Botsford, presented at the AQMA Annual Meeting, Florida, 2001.

PRESENTATIONS (PARTIAL LIST)

"Pore Structure and Combustion Kinetics - Interpretation of Single Particle Temperature-Time Histories," with P.S. Northrop, R.C. Flagan and G.R. Gavalas, presented at the AIChE Annual Meeting, New York (1987).

"Measurement of Temperature-Time Histories of Burning Single Coal Char Particles," with R.C. Flagan, presented at the American Flame Research Committee Fall International Symposium, Pittsburgh, (1988).

"Physical Characterization of a Cenospheric Coal Char Burned at High Temperatures," with R.C. Flagan and G.R. Gavalas, presented at the Fall Meeting of the Western States Section of the Combustion Institute, Laguna Beach, California (1988).

"Control of Nitrogen Oxide Emissions in Gas Fired Heaters - The Retrofit Experience," with G. P. Croce and R. Patel, presented at the International Conference on Environmental Control of Combustion Processes (Jointly sponsored by the American Flame Research Committee and the Japan Flame Research Committee), Honolulu, Hawaii (1991).

"Air Toxics - Past, Present and the Future," presented at the Joint AIChE/AAEE Breakfast Meeting at the AIChE 1991 Annual Meeting, Los Angeles, California, November 17-22 (1991).

"Air Toxics Emissions and Risk Impacts from Automobiles Using Reformulated Gasolines," presented at the Third Annual Current Issues in Air Toxics Conference, Sacramento, California, November 9-10 (1992).

"Air Toxics from Mobile Sources," presented at the Environmental Health Sciences (ESE) Seminar Series, UCLA, Los Angeles, California, November 12, (1992).

"Kilns, Ovens, and Dryers - Present and Future," presented at the Gas Company Air Quality Permit Assistance Seminar, Industry Hills Sheraton, California, November 20, (1992).

"The Design and Implementation of Vehicle Scrapping Programs," presented at the 86th Annual Meeting of the Air and Waste Management Association, Denver, Colorado, June 12, 1993.

"Air Quality Planning and Control in Beijing, China," presented at the 87th Annual Meeting of the Air and Waste Management Association, Cincinnati, Ohio, June 19-24, 1994.

Annex A

Expert Litigation Support

1. Matters for which Dr. Sahu has have provided <u>depositions and affidavits/expert reports</u> include:

(a) Deposition on behalf of Rocky Mountain Steel Mills, Inc. located in Pueblo, Colorado – dealing with the manufacture of steel in mini-mills including methods of air pollution control and BACT in steel mini-mills and opacity issues at this steel mini-mill

(b) Affidavit for Rocky Mountain Steel Mills, Inc. located in Pueblo Colorado – dealing with the technical uncertainties associated with night-time opacity measurements in general and at this steel mini-mill.

(c) Expert reports and depositions (2/28/2002 and 3/1/2002; 12/2/2003 and 12/3/2003; 5/24/2004) on behalf of the US Department of Justice in connection with the Ohio Edison NSR Cases. *United States, et al. v. Ohio Edison Co., et al.,* C2-99-1181 (S.D. Ohio).

(d) Expert reports and depositions (5/23/2002 and 5/24/2002) on behalf of the US Department of Justice in connection with the Illinois Power NSR Case. *United States v. Illinois Power Co., et al.,* 99-833-MJR (S.D. Ill.).

(e) Expert reports and depositions (11/25/2002 and 11/26/2002) on behalf of the US Department of Justice in connection with the Duke Power NSR Case. *United States, et al. v. Duke Energy Corp.,* 1:00-CV-1262 (M.D.N.C.).

(f) Expert reports and depositions (10/6/2004 and 10/7/2004; 7/10/2006) on behalf of the US Department of Justice in connection with the American Electric Power NSR Cases. *United States, et al. v. American Electric Power Service Corp., et al.*, C2-99-1182, C2-99-1250 (S.D. Ohio).

(g) Affidavit (March 2005) on behalf of the Minnesota Center for Environmental Advocacy and others in the matter of the Application of Heron Lake BioEnergy LLC to construct and operate an ethanol production facility – submitted to the Minnesota Pollution Control Agency.

(h) Expert reports and depositions (10/31/2005 and 11/1/2005) on behalf of the US Department of Justice in connection with the East Kentucky Power Cooperative NSR Case. *United States v. East Kentucky Power Cooperative, Inc*., 5:04-cv-00034-KSF (E.D. KY).

(i) Deposition (10/20/2005) on behalf of the US Department of Justice in connection with the Cinergy NSR Case. *United States, et* al. *v. Cinergy Corp., et al.*, IP 99-1693-C-M/S (S.D. Ind.).

(j) Affidavits and deposition on behalf of Basic Management Inc. (BMI) Companies in connection with the BMI vs. USA remediation cost recovery Case.

(k) Expert report on behalf of Penn Future and others in the Cambria Coke plant permit challenge in Pennsylvania.

(l) Expert report on behalf of the Appalachian Center for the Economy and the Environment and others in the Western Greenbrier permit challenge in West Virginia.

(m) Expert report, deposition (via telephone on January 26, 2007) on behalf of various Montana petitioners (Citizens Awareness Network (CAN), Women's Voices for the Earth (WVE) and the Clark Fork Coalition (CFC)) in the Thompson River Cogeneration LLC Permit No. 3175-04 challenge.

(n) Expert report and deposition (2/2/07) on behalf of the Texas Clean Air Cities Coalition at the Texas State Office of Administrative Hearings (SOAH) in the matter of the permit challenges to TXU Project Apollo's eight new proposed PRB-fired PC boilers located at seven TX sites.

(o) Expert testimony (July 2007) on behalf of the Izaak Walton League of America and others in connection with the acquisition of power by Xcel Energy from the proposed Gascoyne Power Plant – at the State of Minnesota, Office of Administrative Hearings for the Minnesota PUC (MPUC No. E002/CN-06-1518; OAH No. 12-2500-17857-2).

(p) Affidavit (July 2007) Comments on the Big Cajun I Draft Permit on behalf of the Sierra Club – submitted to the Louisiana DEQ.

(q) Expert reports and deposition (12/13/2007) on behalf of Commonwealth of Pennsylvania – Dept. of Environmental Protection, State of Connecticut, State of New York, and State of New Jersey (Plaintiffs) in connection with the Allegheny Energy NSR Case. *Plaintiffs v. Allegheny Energy Inc., et al.,* 2:05cv0885 (W.D. Pennsylvania).

(r) Expert reports and pre-filed testimony before the Utah Air Quality Board on behalf of Sierra Club in the Sevier Power Plant permit challenge.

(s) Expert reports and deposition (October 2007) on behalf of MTD Products Inc., in connection with General Power Products, LLC v MTD Products Inc., 1:06 CVA 0143 (S.D. Ohio, Western Division)

(t) Experts report and deposition (June 2008) on behalf of Sierra Club and others in the matter of permit challenges (Title V: 28.0801-29 and PSD: 28.0803-PSD) for the Big Stone II unit, proposed to be located near Milbank, South Dakota.

(u) Expert reports, affidavit, and deposition (August 15, 2008) on behalf of Earthjustice in the matter of air permit challenge (CT-4631) for the Basin Electric Dry Fork station, under construction near Gillette, Wyoming before the Environmental Quality Council of the State of Wyoming.

(v) Affidavits (May 2010/June 2010 in the Office of Administrative Hearings))/Declaration and Expert Report (November 2009 in the Office of Administrative Hearings) on behalf of NRDC and the Southern Environmental Law Center in the matter of the air permit challenge for Duke Cliffside Unit 6. Office of Administrative Hearing Matters 08 EHR 0771, 0835 and 0836 and 09 HER 3102, 3174, and 3176 (consolidated).

(w) Declaration (August 2008), Expert Report (January 2009), and Declaration (May 2009) on behalf of Southern Alliance for Clean Energy et al., v Duke Energy Carolinas, LLC. in the matter of the air permit challenge for Duke Cliffside Unit 6. *Southern Alliance for Clean Energy et al., v. Duke Energy Carolinas, LLC*, Case No. 1:08-cv-00318-LHT-DLH (Western District of North Carolina, Asheville Division).

(x) Dominion Wise County MACT Declaration (August 2008)

(y) Expert Report on behalf of Sierra Club for the Green Energy Resource Recovery Project, MACT Analysis (June 13, 2008).

(z) Expert Report on behalf of Sierra Club and the Environmental Integrity Project in the matter of the air permit challenge for NRG Limestone's proposed Unit 3 in Texas (February 2009).

(aa) Expert Report and deposition on behalf of MTD Products, Inc., in the matter of Alice Holmes and Vernon Holmes v. Home Depot USA, Inc., et al. (June 2009, July 2009).

(bb) Expert Report on behalf of Sierra Club and the Southern Environmental Law Center in the matter of the air permit challenge for Santee Cooper's proposed Pee Dee plant in South Carolina (August 2009).

(cc) Statements (May 2008 and September 2009) on behalf of the Minnesota Center for Environmental Advocacy to the Minnesota Pollution Control Agency in the matter of the Minnesota Haze State Implementation Plans.

(dd) Expert Report (August 2009) and Deposition (October 2009) on behalf of Environmental Defense, in the matter of permit challenges to the proposed Las Brisas coal fired power plant project at the Texas State Office of Administrative Hearings (SOAH).

(ee) Deposition (October 2009) on behalf of Environmental Defense and others, in the matter of challenges to the proposed Coleto Creek coal fired power plant project at the Texas State Office of Administrative Hearings (SOAH). (October 2009).

(ff) Expert Report, Rebuttal Report (September 2009) and Deposition (October 2009) on behalf of the Sierra Club, in the matter of challenges to the proposed Medicine Bow Fuel and Power IGL plant in Cheyenne, Wyoming.

(gg) Expert Report (December 2009), Rebuttal reports (May 2010 and June 2010) and depositions (June 2010) on behalf of the US Department of Justice in connection with the Alabama Power Company NSR Case. *United States v. Alabama Power Company*, CV-01-HS-152-S (Northern District of Alabama, Southern Division).

(hh) Prefiled testimony (October 2009) and Deposition (December 2009) on behalf of Environmental Defense and others, in the matter of challenges to the proposed White Stallion Energy Center coal fired power plant project at the Texas State Office of Administrative Hearings (SOAH).

(ii) Deposition (October 2009) on behalf of Environmental Defense and others, in the matter of challenges to the proposed Tenaska coal fired power plant project at the Texas State Office of Administrative Hearings (SOAH). (April 2010).

(jj) Written Direct Testimony (July 2010) and Written Rebuttal Testimony (August 2010) on behalf of the State of New Mexico Environment Department in the matter of Proposed Regulation 20.2.350 NMAC – *Greenhouse Gas Cap and Trade Provisions*, No. EIB 10-04 (R), to the State of New Mexico, Environmental Improvement Board.

(kk) Expert report (August 2010) and Rebuttal Expert Report (October 2010) on behalf of the US Department of Justice in connection with the Louisiana Generating NSR Case. *United States v. Louisiana Generating, LLC,* 09-CV100-RET-CN (Middle District of Louisiana).

(ll) Declaration (August 2010), Reply Declaration (November 2010), Expert Report (April 2011), Supplemental and Rebuttal Expert Report (July 2011) on behalf of the US EPA and US Department of Justice in the matter of DTE Energy Company and Detroit Edison Company (Monroe Unit 2). *United States of America v. DTE Energy Company and Detroit Edison Company*, Civil Action No. 2:10-cv-13101-BAF-RSW (US District Court for the Eastern District of Michigan).

(mm) Expert Report and Deposition (August 2010) as well as Affidavit (September 2010) on behalf of Kentucky Waterways Alliance, Sierra Club, and Valley Watch in the matter of challenges to the NPDES permit issued for the Trimble County power plant by the Kentucky Energy and Environment Cabinet to Louisville Gas and Electric, File No. DOW-41106-047.

(nn) Expert Report (August 2010), Rebuttal Expert Report (September 2010), Supplemental Expert Report (September 2011), and Declaration (November 2011) on behalf of Wild Earth Guardians in the matter of opacity exceedances and monitor downtime at the Public Service Company of Colorado (Xcel)'s Cherokee power plant. No. 09-cv-1862 (D. Colo.).

(oo) Written Direct Expert Testimony (August 2010) and Affidavit (February 2012) on behalf of Fall-Line Alliance for a Clean Environment and others in the matter of the PSD Air Permit for Plant Washington issued by Georgia DNR at the Office of State Administrative Hearing, State of Georgia (OSAH-BNR-AQ-1031707-98-WALKER).

(pp) Deposition (August 2010) on behalf of Environmental Defense, in the matter of the remanded permit challenge to the proposed Las Brisas coal fired power plant project at the Texas State Office of Administrative Hearings (SOAH).

(qq) Expert Report, Supplemental/Rebuttal Expert Report, and Declarations (October 2010) on behalf of New Mexico Environment Department (Plaintiff-Intervenor), Grand Canyon Trust and Sierra Club (Plaintiffs) in the matter of Public Service Company of New Mexico (PNM)'s Mercury Report for the San Juan Generating Station, CIVIL NO. 1:02-CV-0552 BB/ATC (ACE). US DistrictCourtfortheDistrict of New Mexico.

(rr) CommentReport (October 2010) ontheDraftPermitIssuedbythe Kansas DHE toSunflower Electric forHolcombUnit 2. Preparedonbehalf of the Sierra Club and Earthjustice.

(ss) ExpertReport (October 2010) and RebuttalExpertReport (November 2010) (BART DeterminationsforPSCoHayden and CSU Martin Drake units) tothe Colorado Air QualityCommissiononbehalf of Coalition of EnvironmentalOrganizations.

(tt) ExpertReport (November 2010) (BART DeterminationsforTriState Craig Units, CSU Nixon Unit, and PRPA RawhideUnit) tothe Colorado Air QualityCommissiononbehalf of Coalition of EnvironmentalOrganizations.

(uu) Declaration (November 2010) on behalf of the Sierra Club in connection with the Martin Lake Station Units 1, 2, and 3. *Sierra Club v. Energy Future Holdings Corporation and Luminant Generation Company LLC*, Case No. 5:10-cv-00156-DF-CMC (US District Court for the Eastern District of Texas, Texarkana Division).

(vv) Comment Report (December 2010) on the Pennsylvania Department of Environmental Protection (PADEP)'s Proposal to grant Plan Approval for the Wellington Green Energy Resource Recovery Facility on behalf of the Chesapeake Bay Foundation, Group Against Smog and Pollution (GASP), National Park Conservation Association (NPCA), and the Sierra Club.

(ww) Written Expert Testimony (January 2011) and Declaration (February 2011) to the Georgia Office of State Administrative Hearings (OSAH) in the matter of Minor Source HAPs status for the proposed Longleaf Energy Associates power plant (OSAH-BNR-AQ-1115157-60-HOWELLS) on behalf of the Friends of the Chattahoochee and the Sierra Club).

(xx) Declaration (February 2011) in the matter of the Draft Title V Permit for RRI Energy MidAtlantic Power Holdings LLC Shawville Generating Station (Pennsylvania), ID No. 17-00001 on behalf of the Sierra Club.

(yy) ExpertReport (March 2011), RebuttalExpertReport (Jue 2011) on behalf of the United States in *United States of America v. Cemex, Inc.*, Civil Action No. 09-cv-00019-MSK-MEH (US District Court for the District of Colorado).

(zz) Declaration (April 2011) in the matter of the Lower Colorado River Authority (LCRA)'s Fayette (Sam Seymour) Power Plant on behalf of the Texas Campaign for the Environment. *Texas Campaign for the Environment v. Lower Colorado River Authority,* Civil Action No. 4:11-cv-00791 (US District Court for the Southern District of Texas, Houston Division).

(aaa) Declaration (June 2011) on behalf of the Plaintiffs MYTAPN in the matter of Microsoft-Yes, Toxic Air Pollution-No (MYTAPN) v. State of Washington, Department of Ecology and Microsoft Corporation Columbia Data Center to the Pollution Control Hearings Board, State of Washington, Matter No. PCHB No. 10-162.

(bbb) Expert Report (June 2011) on behalf of the New Hampshire Sierra Club at the State of New Hampshire Public Utilities Commission, Docket No. 10-261 – the 2010 Least Cost Integrated Resource Plan (LCIRP) submitted by the Public Service Company of New Hampshire (re. Merrimack Station Units 1 and 2).

(ccc) Declaration (August 2011) in the matter of the Sandy Creek Energy Associates L.P. Sandy Creek Power Plant on behalf of Sierra Club and Public Citizen. *Sierra Club, Inc. and Public Citizen, Inc. v. Sandy Creek Energy Associates, L.P.,* Civil Action No. A-08-CA-648-LY (US District Court for the Western District of Texas, Austin Division).

(ddd) Expert Report (October 2011) on behalf of the Defendants in the matter of *John Quiles and Jeanette Quiles et al. v. Bradford-White Corporation, MTD Products, Inc., Kohler Co., et al.,* Case No. 3:10-cv-747 (TJM/DEP) (US District Court for the Northern District of New York).

(eee) Declaration (February 2012) and Second Declaration (February 2012) in the matter of *Washington Environmental Council and Sierra Club Washington State Chapter v. Washington State Department of Ecology and Western States Petroleum Association,* Case No. 11-417-MJP (US District Court for the Western District of Washington).

(fff) Expert Report (March 2012) in the matter of *Environment Texas Citizen Lobby, Inc and Sierra Club v. ExxonMobil Corporation et al.,* Civil Action No. 4:10-cv-4969 (US District Court for the Southern District of Texas, Houston Division).

(ggg) Declaration (March 2012) in the matter of *Center for Biological Diversity, et al. v. United States Environmental Protection Agency,* Case No. 11-1101 (consolidated with 11-1285, 11-1328 and 11-1336) (US Court of Appeals for the District of Columbia Circuit).

(hhh) Declaration (March 2012) in the matter of *Sierra Club v. The Kansas Department of Health and Environment*, Case No. 11-105,493-AS (Holcomb power plan) (Supreme Court of the State of Kansas).

(iii) Declaration (March 2012) in the matter of the Las Brisas Energy Center *Environmental Defense Fund et al., v. Texas Commission on Environmental Quality,* Cause No. D-1-GN-11-001364 (District Court of Travis County, Texas, 261st Judicial District).

(jjj) Expert Report (April 2012) in the matter of the Portland Power plant *State of New Jersey and State of Connecticut (Intervenor-Plaintiff) v. RRI Energy MidAtlantic Power Holdings et al.,* Civil Action No. 07-CV-5298 (JKG) (US District Court for the Eastern District of Pennsylvania).

2. Occasions where Dr. Sahu has provided <u>Written or Oral testimony before Congress</u>:

(kkk) In July 2012, provided expert written and oral testimony to the House Subcommittee on Energy and the Environment, Committee on Science, Space, and Technology at a Hearing entitled "Hitting the Ethanol Blend Wall – Examining the Science on E15."

3. Occasions where Dr. Sahu has provided oral testimony <u>at trial or in similar proceedings</u> include the following:

(lll) In February, 2002, provided expert witness testimony on emissions data on behalf of Rocky Mountain Steel Mills, Inc. in Denver District Court.

(mmm) In February 2003, provided expert witness testimony on regulatory framework and emissions calculation methodology issues on behalf of the US Department of Justice in the Ohio Edison NSR Case in the US District Court for the Southern District of Ohio.

(nnn) In June 2003, provided expert witness testimony on regulatory framework, emissions calculation methodology, and emissions calculations on behalf of the US Department of Justice in the Illinois Power NSR Case in the US District Court for the Southern District of Illinois.

(ooo) In August 2006, provided expert witness testimony regarding power plant emissions and BACT issues on a permit challenge (Western Greenbrier) on behalf of the Appalachian Center for the Economy and the Environment in West Virginia.

(ppp) In May 2007, provided expert witness testimony regarding power plant emissions and BACT issues on a permit challenge (Thompson River Cogeneration) on behalf of various Montana petitioners (Citizens Awareness Network (CAN), Women's Voices for the Earth (WVE) and the Clark Fork Coalition (CFC)) before the Montana Board of Environmental Review.

(qqq) In October 2007, provided expert witness testimony regarding power plant emissions and BACT issues on a permit challenge (Sevier Power Plant) on behalf of the Sierra Club before the Utah Air Quality Board.

(rrr) In August 2008, provided expert witness testimony regarding power plant emissions and BACT issues on a permit challenge (Big Stone Unit II) on behalf of the Sierra Club and Clean Water before the South Dakota Board of Minerals and the Environment.

(sss) In February 2009, provided expert witness testimony regarding power plant emissions and BACT issues on a permit challenge (Santee Cooper Pee Dee units) on behalf of the Sierra Club and the Southern Environmental Law Center before the South Carolina Board of Health and Environmental Control.

(ttt) In February 2009, provided expert witness testimony regarding power plant emissions, BACT issues and MACT issues on a permit challenge (NRG Limestone Unit 3) on behalf of the Sierra Club and the Environmental Integrity Project before the Texas State Office of Administrative Hearings (SOAH) Administrative Law Judges.

(uuu) In November 2009, provided expert witness testimony regarding power plant emissions, BACT issues and MACT issues on a permit challenge (Las Brisas Energy Center) on behalf of the Environmental Defense Fund before the Texas State Office of Administrative Hearings (SOAH) Administrative Law Judges.

(vvv) In February 2010, provided expert witness testimony regarding power plant emissions, BACT issues and MACT issues on a permit challenge (White Stallion Energy Center) on behalf of the Environmental Defense Fund before the Texas State Office of Administrative Hearings (SOAH) Administrative Law Judges.

(www) In September 2010 provided oral trial testimony on behalf of Commonwealth of Pennsylvania – Dept. of Environmental Protection, State of Connecticut, State of New York, State of Maryland, and State of New Jersey (Plaintiffs) in connection with the Allegheny Energy NSR Case in US District Court in the Western District of Pennsylvania. *Plaintiffs v. Allegheny Energy Inc., et al.,* 2:05cv0885 (W.D. Pennsylvania).

(xxx) Oral Direct and Rebuttal Expert Testimony (September 2010) on behalf of Fall-Line Alliance for a Clean Environment and others in the matter of the PSD Air Permit for Plant Washington issued by Georgia DNR at the Office of State Administrative Hearing, State of Georgia (OSAH-BNR-AQ-1031707-98-WALKER).

(yyy) Oral Testimony (September 2010) on behalf of the State of New Mexico Environment Department in the matter of Proposed Regulation 20.2.350 NMAC – *Greenhouse Gas Cap and Trade Provisions,* No. EIB 10-04 (R), to the State of New Mexico, Environmental Improvement Board.

(zzz) Oral Testimony (October 2010) regarding mercury and total PM/PM10 emissions and other issues on a remanded permit challenge (Las Brisas Energy Center) on behalf of the Environmental Defense Fund before the Texas State Office of Administrative Hearings (SOAH) Administrative Law Judges.

(aaaa) Oral Testimony (November 2010) regarding BART for PSCo Hayden, CSU Martin Drake units before the Colorado Air Quality Commission on behalf of the Coalition of Environmental Organizations.

(bbbb) Oral Testimony (December 2010) regarding BART for TriState Craig Units, CSU Nixon Unit, and PRPA RawhideUnit) before the Colorado Air Quality Commission on behalf of the Coalition of Environmental Organizations.

(cccc) Deposition (December 2010) on behalf of the US Department of Justice in connection with the Louisiana Generating NSR Case. *United States v. Louisiana Generating, LLC*, 09-CV100-RET-CN (Middle District of Louisiana).

(dddd) Deposition (February 2011 and January 2012) on behalf of Wild Earth Guardians in the matter of opacity exceedances and monitor downtime at the Public Service Company of Colorado (Xcel)'s Cherokee power plant. No. 09-cv-1862 (D. Colo.).

(eeee) Oral Expert Testimony (February 2011) to the Georgia Office of State Administrative Hearings (OSAH) in the matter of Minor Source HAPs status for the proposed Longleaf Energy Associates power plant (OSAH-BNR-AQ-1115157-60-HOWELLS) on behalf of the Friends of the Chattahoochee and the Sierra Club).

(ffff) Deposition (August 2011) on behalf of the United States in *United States of America v. Cemex, Inc.*, Civil Action No. 09-cv-00019-MSK-MEH (US District Court for the District of Colorado).

(gggg) Deposition (July 2011) and Oral Testimony at Hearing (February 2012) on behalf of the Plaintiffs MYTAPN in the matter of Microsoft-Yes, Toxic Air Pollution-No (MYTAPN) v. State of Washington, Department of Ecology and Microsoft Corporation Columbia Data Center to the Pollution Control Hearings Board, State of Washington, Matter No. PCHB No. 10-162.

(hhhh) Oral Testimony at Hearing (April 2012) on behalf of the New Hampshire Sierra Club at the State of New Hampshire Public Utilities Commission, Docket No. 10-261 – the 2010 Least Cost Integrated Resource Plan (LCIRP) submitted by the Public Service Company of New Hampshire (re. Merrimack Station Units 1 and 2).

(iiii) Oral Testimony at Hearing (March 2012) on behalf of the US Department of Justice in connection with the Louisiana Generating NSR Case. *United States v. Louisiana Generating, LLC*, 09-CV100-RET-CN (Middle District of Louisiana).

ATTACHMENT B – HEAT INPUT AND NOX DATA FOR COAL CREEK UNITS 1 AND 2

Attachment B - EPA AMPD Heat Input and NOx Data for Baseline Analysis for Coal Creek Unit 1						
Year	**Mo**	**Heat Input (HI) (MMBtu/mo or MMBtu/yr)**			**NOx Rate (lb/MMBtu)**	
		Monthly	**24-Month Annual Average**	**Highest Annual During 2006-2010**	**Monthly Average**	**Highest During 2010-today (post-DryFining)**
2002	1	4464270			0.193	
2002	2	3326511			0.225	
2002	3	4179657			0.205	
2002	4	719068			0.207	
2002	5	3982244			0.217	
2002	6	4155036			0.216	
2002	7	4206698			0.225	
2002	8	4574418			0.211	
2002	9	4149499			0.201	
2002	10	4270719			0.204	
2002	11	4284372			0.197	
2002	12	4322165			0.217	
2003	1	4486900			0.209	
2003	2	3946579			0.210	
2003	3	4573131			0.197	
2003	4	3794806			0.195	
2003	5	4100413			0.207	
2003	6	4320176			0.195	
2003	7	4341810			0.196	
2003	8	4532202			0.184	
2003	9	4165673			0.230	
2003	10	4212368			0.220	
2003	11	4323100			0.204	
2003	12	4496129	48963971		0.203	
2004	1	4469619	48966646		0.205	
2004	2	4322403	49464591		0.211	
2004	3	4067515	49408520		0.194	
2004	4	4296112	51197042		0.213	
2004	5	3751856	51081848		0.198	
2004	6	4405496	51207079		0.214	
2004	7	4345373	51276416		0.239	
2004	8	4488812	51233614		0.228	
2004	9	4105967	51211848		0.220	
2004	10	4373739	51263358		0.231	
2004	11	4423512	51332928		0.210	
2004	12	4377372	51360531		0.236	
2005	1	4621627	51427894		0.219	
2005	2	4090630	51499920		0.229	
2005	3	2605983	50516346		0.222	
2005	4	781045	49009466		0.263	
2005	5	4602051	49260284		0.225	
2005	6	4576433	49388413		0.230	
2005	7	4643255	49539135		0.232	
2005	8	4611940	49579005		0.253	
2005	9	4294650	49643493		0.243	
2005	10	4430688	49752653		0.248	
2005	11	4130868	49656537		0.234	

2005	12	4671234	49744090		0.224	
2006	1	4541147	49779853		0.215	
2006	2	4099086	49668195		0.215	
2006	3	4536894	49902885		0.214	
2006	4	4280142	49894900		0.243	
2006	5	3653718	49845831		0.231	
2006	6	4365008	49825587		0.243	
2006	7	4513004	49909402		0.244	
2006	8	4558891	49944441		0.237	
2006	9	4259186	50021051		0.256	
2006	10	3673392	49670878		0.251	
2006	11	3995258	49456751		0.242	
2006	12	4393228	49464679		0.256	
2007	1	4335117	49321424		0.247	
2007	2	4097086	49324652		0.240	
2007	3	4366244	50204783		0.245	
2007	4	4310624	51969572		0.258	
2007	5	3869574	51603333		0.242	
2007	6	3821947	51226091		0.252	
2007	7	4258605	51033765		0.247	
2007	8	4254326	50854958		0.260	
2007	9	4091902	50753584		0.264	
2007	10	4112952	50594716		0.247	
2007	11	4150611	50604588		0.245	
2007	12	4327634	50432788		0.236	
2008	1	4323041	50323735		0.230	
2008	2	4048267	50298325		0.220	
2008	3	1935511	48997634		0.270	
2008	4		46857563	**51969572**		
2008	5	1651968	45856688		0.241	
2008	6	3631117	45489742		0.259	
2008	7	4631214	45548848		0.251	
2008	8	4640699	45589752		0.253	
2008	9	4316004	45618160		0.262	
2008	10	4254615	45908772		0.272	
2008	11	4201076	46011681		0.274	
2008	12	4412971	46021552		0.259	
2009	1	4375926	46041956		0.254	
2009	2	3941802	45964314		0.238	
2009	3	4441212	46001798		0.247	
2009	4	3934701	45813837		0.247	
2009	5	3337700	45547900		0.241	
2009	6	4164687	45719270		0.241	
2009	7	4249076	45714505		0.259	
2009	8	4282616	45728650		0.215	
2009	9	4012503	45688951		0.283	
2009	10	4376416	45820683		0.250	
2009	11	4205423	45848089		0.214	
2009	12	4303353	45835949		0.234	
2010	1	4176804	45762831		0.219	
2010	2	3654508	45565951		0.229	
2010	3	3854291	46525342		0.231	
2010	4	4065868	48558276		0.213	**0.2309**
2010	5	4147040	49805811		0.206	
2010	6	4161443	50070975		0.210	
2010	7	4256831	49883783		0.195	

2010	8	4314145	49720506		0.220	
2010	9	4183844	49654426		0.207	
2010	10	4031522	49542880		0.191	
2010	11	4224691	49554687		0.200	
2010	12	4338824	49517613		0.213	
2011	1	4129466	49394383		0.215	
2011	2	3732587	49289776		0.175	
2011	3	4296951	49217646		0.192	
2011	4	115164	47307877		0.209	
2011	5	2314976	46796515		0.197	
2011	6	4159462	46793903		0.193	
2011	7	4379237	46858983		0.187	
2011	8	3651923	46543636		0.219	
2011	9	3827880	46451325		0.224	
2011	10	4290947	46408590		0.213	
2011	11	3818103	46214930		0.223	
2011	12	4298107	46212306		0.212	
2012	1	4343841	46295825		0.216	
2012	2	3895175	46416159		0.216	
2012	3	4052971	46515498		0.215	
2012	4	3781096	46373112		0.202	
2012	5	3480564	46039874		0.214	
2012	6	4174518	46046411		0.190	
2012	7	4297435	46066713		0.205	
2012	8	4254578	46036929		0.205	
2012	9	3898064	45894039		0.220	

Attachment B - EPA AMPD Heat Input for Baseline Analysis for Coal Creek Unit 2				
Year	Mo	Heat Input (HI) (MMBtu/mo or MMBtu/yr)		
		Monthly	24-Month Annual Average	Highest Annual During 2006-2010
2002	1	4292197		
2002	2	3839316		
2002	3	4279425		
2002	4	4162710		
2002	5	4170502		
2002	6	4358812		
2002	7	4358586		
2002	8	4465966		
2002	9	4315958		
2002	10	4309787		
2002	11	4121860		
2002	12	3935104		
2003	1	4290000		
2003	2	3887160		
2003	3	3917393		
2003	4	4238714		
2003	5	4481915		
2003	6	4345891		
2003	7	4540368		
2003	8	4290911		
2003	9	3759772		
2003	10	4379375		
2003	11	4192832		
2003	12	4314070	50624311	
2004	1	4148838	50552631	
2004	2	3792948	50529447	
2004	3	2601340	49690404	
2004	4	1401729	48309914	
2004	5	4335527	48392427	
2004	6	4306482	48366262	
2004	7	4225108	48299523	
2004	8	4474040	48303560	
2004	9	4289832	48290497	
2004	10	4199503	48235355	
2004	11	4022327	48185589	
2004	12	4130827	48283450	
2005	1	4106929	48191915	
2005	2	3745135	48120902	
2005	3	3797668	48061040	
2005	4	4229320	48056343	
2005	5	4432786	48031778	
2005	6	3938127	47827896	
2005	7	4499492	47807458	
2005	8	4500871	47912438	
2005	9	4297317	48181210	
2005	10	4178552	48080799	
2005	11	4261642	48115204	
2005	12	4357732	48137035	

2006	1	4470800	48298016	**50882663**
2006	2	4096516	48449800	
2006	3	4427633	49362947	
2006	4	4241901	50783033	
2006	5	3395335	50312936	
2006	6	4323148	50321270	
2006	7	4508597	50463014	
2006	8	4511499	50481744	
2006	9	4220954	50447305	
2006	10	4270823	50482965	
2006	11	4224807	50584205	
2006	12	4344801	50691191	
2007	1	4329014	50802234	
2007	2	3905993	50882663	
2007	3	2148333	50057996	
2007	4	813	47943742	
2007	5	3780604	47617651	
2007	6	3955089	47626133	
2007	7	4044598	47398685	
2007	8	4325998	47311249	
2007	9	4105985	47215583	
2007	10	4290895	47271755	
2007	11	3853577	47067722	
2007	12	4417281	47097497	
2008	1	4409743	47066968	
2008	2	3132683	46585051	
2008	3	3444494	46093482	
2008	4	4279154	46112108	
2008	5	4313695	46571288	
2008	6	4096004	46457716	
2008	7	4115729	46261282	
2008	8	3801912	45906489	
2008	9	3873420	45732722	
2008	10	4132484	45663552	
2008	11	3846005	45474152	
2008	12	4264961	45434232	
2009	1	3957628	45248538	
2009	2	3445043	45018063	
2009	3	4468554	46178174	
2009	4	4307660	48331597	
2009	5	2499387	47690989	
2009	6	4312304	47869596	
2009	7	4310950	48002773	
2009	8	4242354	47960951	
2009	9	3861104	47838510	
2009	10	4186485	47786305	
2009	11	4256954	47987994	
2009	12	4372159	47965432	
2010	1	4389399	47955260	
2010	2	3688688	48233263	
2010	3	2656644	47839338	
2010	4		45699761	
2010	5	1894458	44490143	
2010	6	4233347	44558814	
2010	7	4346022	44673961	
2010	8	4303542	44924776	

2010	9	3943718	44959925	
2010	10	4301024	45044195	
2010	11	4119017	45180700	
2010	12	4122700	45109570	
2011	1	4147317	45204415	
2011	2	3898084	45430935	
2011	3	4073670	45233494	
2011	4	4133614	45146471	
2011	5	2564449	45179002	
2011	6	4149968	45097834	
2011	7	4229275	45056996	
2011	8	3886660	44879150	
2011	9	4013298	44955247	
2011	10	4170188	44947098	
2011	11	3396424	44516833	
2011	12	4279677	44470592	
2012	1	4291199	44421492	
2012	2	3840214	44497255	
2012	3	4000055	45168961	
2012	4	4012157	47175040	
2012	5	2886147	47670884	
2012	6	3831982	47470202	
2012	7	4322708	47458545	
2012	8	3962649	47288098	
2012	9	4088734	47360606	

Power Engineering

An On-Site Process for Removing Moisture from Low-Rank Coal

04/01/2010

By Charles Bullinger, P.E. and Mark Ness, P.E., Great River Energy; Nenad Sarunac, Lehigh University; and James C. Kennedy, WorleyParsons

Lower-than-design heating value of delivered coal can result in higher fuel flow rate, higher flue gas flow rate, higher station service power, lower plant efficiency and higher mill and coal pipe/burner operations and maintenance costs, plus a host of lesser effects.

Commissioned in 1979 and 1981, Coal Creek Station near Underwood, N.D. includes two 600 MWg mine-mouth, lignite-fired natural circulation units with tangentially-fired, dual-furnace boilers with eight pulverizers each. Both units were installed with wet scrubbers as original equipment. Great River Energy, an electric cooperative owned by 28 members and serving 1.7 million customers in Minnesota and Wisconsin, owns and operates Coal Creek, as well as nine other power plants with a total output of more than 2,500 MW. Fuel for Coal Creek is provided by North American Coal Corp.'s Falkirk Mine near the plant.

Coal Creek's design performance was based on an original fuel heating value specification of 6,800 Btu/lb. However, the heating value of the fuel being delivered to the plant has only been about 6,100 to 6,200 Btu/lb. The major effect of this 10 percent shortfall in heating value has been reduced boiler thermal efficiency, lost pulverizer selection flexibility, increased volumetric flue gas flow and increased station service power requirements. The reduced heating value is caused by increased moisture and ash in the coal. At Coal Creek, the plant design fuel had a moisture content of about 36.6 percent and an ash content of 6.2 percent. The delivered fuel is around 38 percent moisture and 10.9 percent ash.

During the 1990's, the plant's engineering staff began investigating options for meeting future emission regulations. Conventional techniques involved changing fuels and/or adding environmental control equipment. But these approaches often result in cutting emissions at the expense of increases in unit heat rate and operating and maintenance costs. Higher heat rate results in higher required fuel heat input, higher CO_2 emissions, higher flow rate of flue gas leaving the boiler and lower net plant capacity resulting from higher station service power requirements or equipment capacity limitations. Further, the increased flue gas flow rate leads to larger-sized environmental control equipment, plus higher equipment cost and station service power. As many of these same factors would be fundamentally improved by restoring the performance lost to the reduced fuel HHV situation, Coal Creek's plant staff elected to pursue a different course of action.

Developing DryFining

Given the potential dual benefits of recovering lost performance and reducing emissions, a decision was made in 1997 to address the low heating value problem at its root cause. With the ongoing assistance of Lehigh University's Energy Research Center and the Electric Power Research Institute (EPRI), an approach was selected using waste heat sources available in the plant to dry the incoming fuel stream using a fluid bed dryer prior to bunkering. This program, termed the Lignite Fuel Enhancement System, led to the development of Great River Energy's patented and trademarked "DryFining" process. Development was executed in three stages: a feasibility stage, a prototyping stage (Phase One) and a scale up stage (Phase Two).

The feasibility stage consisted of a "proof of concept" demonstration. A two-ton-per-hour fluid bed pilot plant was built in the Coal Creek Station coal yard with the support of the Lignite Energy Council and North Dakota Industrial Commission. Testing confirmed the dryer would dry fuel as required. Further, taking advantage of the inherent characteristic of bed fluidization to naturally segregate free material by density, it also selectively removed heavier ash components, most notably iron sulfide (pyrite). This segregation of sulfur-bearing minerals offered Great River Energy the potential benefit of removing a significant proportion of sulfur from the fuel stream prior to its entering the boiler. This benefit subsequently was confirmed in Phase Two. A similar segregation of mercury-bearing minerals also was noted. As a scrubbed facility and faced with substantial capital expenditures to meet pending stringent sulfur and mercury emissions targets, this segregation benefit offered Great River Energy an attractive alternative for emissions compliance.

Phase One drew on the pilot plant testing program to confirm the drying process. At the heart of this process was a nominal 75 ton/hr fully instrumented, low-temperature, prototype fluidized bed dryer (FBD) developed by a team of industry participants led by Great River Energy. As part of this developmental process, Great River Energy obtained funding from the U.S. Department of Energy (DOE) as a participant in the first round of DOE's Clean Coal Power Initiative (CCPI) in 2003. The Coal Creek CCPI project was administered by DOE's Office of Fossil Energy and managed by the National Energy Technology Laboratory (NETL). The prototype was integrated into Unit 2 at Coal Creek Station by effectively converting pulverizer 26 to 100 percent dried fuel. It operated almost continuously over a range of conditions from 2006 to summer 2009. During this period, the prototype FBD has processed more than 650,000 tons of coal at throughputs as high as 105 tons/hr. The prototype confirmed the capability of the full-scale dryer to reduce fuel moisture to the levels desired. Just as significantly for Great River Energy, the prototype confirmed the segregation effects observed during pilot testing translated to the full-scale device. The target performance parameters and results from the prototype testing program are summarized in Table 1.

TABLE 1 PROTOTYPE PERFORMANCE

Parameter	Prototype Feed In	Prototype Feed Out	Change
Prototype Feed Rate (tons/hr)	75		
Moisture	37.06%	28.98%	21.8%
HHV (BTU/Lb)	6,299	7,026	727
Sulfur Reduction due to segregation		-27.7%	
Mercury Reduction due to segregation		-31.3%	

The total expected reduction in sulfur and mercury emissions for the fully configured commercial coal drying system at Coal Creek Station will equal the combination of the outright reduction in fuel flow into the plant as a result of improved efficiency coupled with the sulfur removed in the reject stream that results from the segregation process. This flow of high-density, high-ash material from the bottom of the dryer was sampled and returned to the fuel stream on the prototype system to reduce the prototype cost. On the full-scale commercial system it is discharged to the ash system. This stream is analogous to the material that should be removed through the pyrite reject process at the pulverizers but at a much higher removal rate. This is because the fuel's residence time in the dryers is much longer (measured in minutes) compared to the fuel residence time in the pulverizers (measured in seconds). This results in much more complete material segregation. As a large proportion of the sulfur in Coal Creek's coal is pyritic in form and readily segregates, the sulfur content of the reject stream is significantly higher compared to the product stream.

Commercial Application

Following successful completion of Phase One and prototype evaluation, Great River Energy and the DOE agreed to proceed with the Phase Two full-scale demonstration of the drying system on Unit 2 at Coal Creek in 2006.

The prototype's promising results led the Board of Great River Energy to direct that the DryFining system be installed on both Coal Creek units. To a large extent, this decision was driven by the prospects of large offsets in capital expenditures for additions to the flue gas de-sulfurization systems, for mercury control and for NO_X emissions curtailment. DryFining proved to be the most economical solution for achieving long-term environmental compliance. It offered an opportunity to combine environmental improvement, heat rate improvement, operational improvement and expense reduction in one package. Rather than increasing the plant's O&M budget to achieve the environmental improvements, the plant estimated more than $30 million a year in expense reductions from fuel, auxiliary power and consumables.

Design throughput of the full-scale system is 3.75 million tons/year of coal, sufficient to meet 100 percent of Unit 2's needs. Four full-scale dryers, similar in design to the prototype, provide the necessary throughput with conservative redundancy. In accordance with the Board's directive, four additional coal dryers were installed on Unit 1 concurrent with the Unit 2 installation. Modification and commissioning of both units was completed in late 2009.

The performance parameters noted in Table 1 focus only on the prototype. The full-size scale-up will result in systemic improvements in the area of fuel handling, mill operation, combustion, maintenance practices, auxiliary equipment performance and emissions. For example, by reducing the overall fuel flow to the boilers by 13 to14 percent, at least one less pulverizer will have to be in operation to reach full load. This restores the flexibility to schedule pulverizer maintenance outages without risk of limiting unit output. Further, a high proportion of Coal Creek's combustion air flow is used as primary air to operate the pulverizers at required coal throughputs. This proportion will be substantially reduced with dryer fuel. As a result, internal pulverizer erosion, coal conduit erosion, coal conduit air flow distribution differential and fuel flow distribution differential all will be reduced. Also, increased secondary air flow will add flexibility for combustion and over fire air tuning.

From Great River Energy's perspective, the greatest benefits accrue from emission reductions. The slip stream testing of the prototype's rejects flow confirmed that a high proportion of pyritic sulfur can be removed in this manner. As this sulfur form composes nearly 30 percent of the overall sulfur content of Coal Creek's fuel, expectations are that the sulfur reduction associated with the drying process will approach this value. The reduction in sulfur associated with the reduced fuel flow into the plant (due to improvement in boiler efficiency) strongly suggests that overall SO_2 reduction in the flue gas exiting the boiler will be 40 percent. Similarly, examination of the rejects stream also indicated it was enriched in mercury. This had been noted during the initial pilot stage. Based on the mercury concentrations noted in the reject stream analysis, about 40 percent of the incoming mercury is projected to be removed prior to combustion.

Because it was a single device demonstrator, no formal systematic evaluation of NO_X emissions was made during the prototype test program. However, plant continuous emissions monitoring system (CEMS) output shows a sustained reduction in NO_X during the test period, as had been suspected. The post-modification testing scheduled for spring 2010 will specifically examine and quantify NO_X emissions for the full-scale application. Projections from the CEMS data lead Great River Energy to believe a 20 percent reduction in NO_X will result from the full-scale modification.

Like other utilities, Great River Energy is sensitive to CO_2 emissions concerns. The reduction in CO_2 mass emissions is proportional to the improvement in unit efficiency. For the prototype coal drying system operating at target moisture reduction of 8.5 percent points, this reduction, based purely on direct thermal efficiency improvement, projects to approximately 2 percent. However, due to the unique method of heat integration associated with the full-scale process, a reduction closer to 4 percent is expected. Evaluations completed for other locations parallel this projection. Clearly, knowledge of heat source integration options, along with precise and well-defined coal characteristics, is fundamental to optimizing DryFining for specific facilities.

The DryFining systems on both units at Coal Creek have been in continuous service since completing their 24-hour commercialization runs in December 2009. Post-installation performance testing will be completed in spring 2010. Initial results have been promising.

Authors: James Kennedy is a senior technical consultant for WorleyParsons' Select Specialist business line, providing support in the area of boilers, fuels and combustion. He has 38 years of industry experience including 32 years involved with commissioning, servicing and maintaining large coal-fired boilers for an OEM. He has a BSME from the University of Michigan and is a member of ASME.

Charles Bullinger has held various positions at Coal Creek Station since 1977, having led the engineering group there for 15 years. He organized and led a team that developed DryFining and is the primary contact and project manager for the DOE Round 1 Clean Coal Power Initiative. Presently assisting WorleyParsons in the commercialization and licensing of DryFining, Charles is a registered professional engineer in North Dakota and Minnesota.

Mark Ness is principal engineer at Great River Energy's Coal Creek Station, having held engineering positions there since 1983. Prior to that he was a steam turbine field engineer for Brown Boveri and was a graduate of the U.S. Navy Nuclear Power Program. He received his BSME from NDSU and is a registered professional engineer in North Dakota.

Dr. Nenad Sarunac is a principal research engineer and associate director of the Energy Research Center at Lehigh University in the areas of process analysis, diagnostics and optimization at Lehigh's Energy Research Center. His areas of work include enhancing quality of high-moisture fuels, recovery and utilization of waste heat, heat integration, performance monitoring and improvement, power, combustion and sootblowing optimization, and application of artificial intelligence in the power industry. He has received his Bachelor's degree in Mechanical Engineering, from University of Zagreb, a Master's degree in Electrical Engineering from the University of Zagreb, and his Ph.D. in Mechanical Engineering from Lehigh University.

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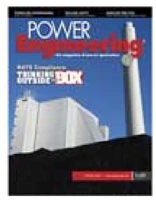

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  - Rich Reagent Injection (RRI)
  - ULTRA™
  - ULTRA-5™
  - NO_xOUT CASCADE®
  - NO_xOUT SCR®
  - Static Mixers
  - Ammonia Injection Grid (AIG)
  - GSG™ Graduated Straightening Grid
  - SCR Catalyst Management Services
  - Flue Gas Conditioning
  - Urea Reagent
  - **FUEL CHEM**
  - Overview
  - TIFI® Targeted In-Furnace Injection
  -
    - TIFI MG™
    - TIFI Hybrid™
    - TIFI XP™
    - TIFI MP™
    - TIFI Flux™
    - TIFI BlueCat™
    - TCI® Targeted Corrosion Inhibition™
  - Fireshield®
  - **Aftermarket Parts and Services**

- **Contact Us**
- Services
  - **Modeling**
  - Overview
  - Computational Fluid Dynamics (CFD)
  - Experimental Modeling
  - Virtual Vantage®
  - **Combustion Testing**
  - Coal Flow
  - Air Flow
  - **SCR Services**
  - Overview
- Solutions
  - **Boiler Operations**
  - Overview
  - Fuel Flexibility
  - Slag Control
  - **Air Pollution Control**
  - Overview
  - NO_x
  - SO_3
  - SO_2
  - $PM_{2.5}$
  - **US Regulations**
  - Overview
  - **Current Air Regulatory Drivers**
  - Clean Air Act
  - Cross-State Air Pollution Rule (CSAPR)
  - Clean Air Visibility Rule (CAVR)
  - Industrial Boiler (MACT)
  - **Past Regulatory Drivers**
  - Clean Air Transport Rule (CATR)
  - Clean Air Interstate Rule (CAIR)
  - NO_x SIP Call
  - Ozone Transport Commission
- News
  - Press Releases
  - Earnings Releases
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- Library
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Company Reports

- Annual Reports
- Form 10-K & Form 10-Q
- Proxy Materials
- SEC Filings

Upcoming Events

November 6, 2012 @ 9:00AM ET
Fuel Tech Reports 3Q12 Results

November 14-15, 2012
Power Experts Conference
Marriott Downtown
Atlanta, GA

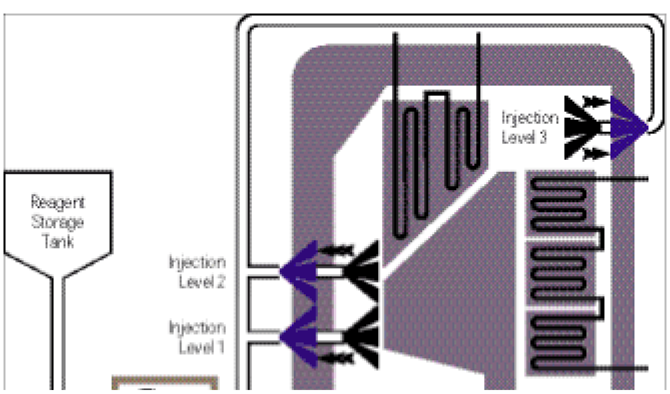
December 11-13, 2012
POWER-GEN International
Orange County Convention Center
Orlando, FL

More

Home > Products > SNCR Systems - NO_xOUT® and HERT™

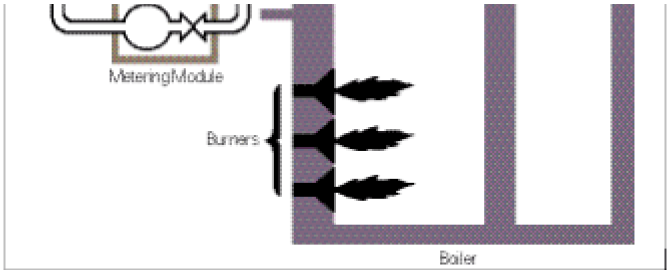
SNCR Systems - NO_xOUT® and HERT™

- Urea-based Selective Non-Catalytic Reduction (SNCR)
- 25% - 50% NO_x Reduction
- Over 520 Installations Worldwide



NO_xOUT® SNCR Process

The NOxOUT® SNCR Process is a urea-based Selective Non-Catalytic Reduction (SNCR) process for reduction of oxides of nitrogen (NO_x) from stationary combustion sources. The process requires precisely engineered injection of stabilized urea liquor into



combustion flue gas temperatures as high as 2500° F. Fuel Tech customizes the design and injection strategy for each application since most NO_x reduction occurs in a temperature range between 1650° F - 2100° F. As shown in the diagram, the injection is typically multi-level and controlled automatically to adjust urea injection in response to boiler load changes and changing furnace conditions.

HERT™ High Energy Reagent Technology™ SNCR System

The HERT™ System uses a high energy injection strategy to inject urea into the furnace. Depending on the specifics of each application, the injection can be through the over-fire air or by using a dedicated air stream provided by a small, separate blower skid. The HERT™ systems have met NO_x reductions guarantees on commercial installations while minimizing ammonia slip with this patented injection process.

The SNCR systems provided by Fuel Tech may include NO_xOUT® injectors along with HERT™ System Injection technology, using the same urea storage, handling and control components. Fuel Tech's SNCR applications rely heavily on the use of Computational Fluid Dynamics (CFD) models and Chemical Kinetics Modeling and their resulting visualization utilizing proprietary software. Our NO_xOUT SNCR technology is sufficiently flexible to apply to a variety of commercial and process combustion units, as detailed below.

NOxOUT® Process Injection	SNCR Technology	HERT™ High Energy Reagent Technology Injections
• High momentum injectors	• CFD/CKM Modeling	• High energy, low momentum injectors
• Maximize performance	• Reliable equipment	• Maximize performance with minimal ammonia slip
• Adjustable for NOx reduction downstream of injection point	• On-site optimization	• Localized NO_x reduction

Fuels

- Coal
- Lignite
- Oil
- Gas
- Municipal Solid Waste
  - Sludge
  - Wood
  - Biomass
  - Refinery/CO Gas

Process Combustion Units

- Cement Kilns
- Glass Furnaces
- Ethylene Furnaces
  - Calciners
  - Coke Ovens
  - Lime Kilns

Commercial Combustion Units

- Tangentially-Fired Utility Boilers
- Cyclone-Fired Utility Boilers
- Wall-Fired Utility Boilers (wet & dry)
- Refinery Crude Heaters and CO Boilers
- Sludge Combustors
- Industrial Power Boilers
- Municipal Waste

Combustors
- Incinerators
- Circulating Fluidized Bed Boilers
- Stoker-Fired Boilers Burning Wood and Coal
- Package Boilers

From a compliance standpoint, the NO_xOUT® process has been used to satisfy Best Available Control Technology (BACT) requirements for Municipal Solid Waste combustors, coal-fired Independent Power Producer (IPP) units, and fluidized bed boilers. The SNCR process has been used to comply with Reasonably Available Control Technology (RACT) requirements in ozone non-attainment areas and Administrative Compliance Orders in specific locales.

A primary feature of the NO_xOUT® and HERT™ processes is the ease of combination with other NO_x reduction technologies. Combinations that have been retrofit with the NO_xOUT® process are low NO_x burners, over-fire air, combustion tempering, neural network controls, and gas reburn. Fuel Tech's patented ASCR™ Advanced SCR process combines a variety of technologies to provide up to 80+% NO_x reductions at a fraction of the cost of conventional SCR systems.

Related Documents

SNCR - NOxOUT® and HERT™ Systems Brochure

ASCR™ Brochure

The design and operation of an Advanced NO_x Control System on 636TPD MWC at Lee County WTE Facility
Presented at NAWTEC 2009

Demonstration of NO_x Emissions Below 0.15lb/MBtu in a Cyclone Boiler Using In-Furnace NO_x Control

NOx Control Technologies: Focus SNCR
Presented at the Western Coal Council, Burning PRB Coal Seminar, 2001

First Installation of Selective Non-Catalytic NO_x Reduction Process on Utility Boilers in Korea
Presented at the U.S. EPA/DOE/EPRI Mega Symposium, 2001

FUEL TECH, INC. - FORM 10-K - March 4, 2010

Attached files

File	Filename
EX-32 - EX-32 - FUEL TECH, INC.	y83029exv32.htm
EX-31.1 - EX-31.1 - FUEL TECH, INC.	y83029exv31w1.htm
EX-23.1 - EX-23.1 - FUEL TECH, INC.	y83029exv23w1.htm
EX-31.2 - EX-31.2 - FUEL TECH, INC.	y83029exv31w2.htm
EX-10.16 - EX-10.16 - FUEL TECH, INC.	y83029exv10w16.htm
EX-10.15 - EX-10.15 - FUEL TECH, INC.	y83029exv10w15.htm
EX-10.14 - EX-10.14 - FUEL TECH, INC.	y83029exv10w14.htm
EX-10.10 - EX-10.10 - FUEL TECH, INC.	y83029exv10w10.htm
EX-10.17 - EX-10.17 - FUEL TECH, INC.	y83029exv10w17.htm

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SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-K

(Mark One)

þ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 [NO FEE REQUIRED]**

For the fiscal year ended: December 31, 2009

OR

o **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 [NO FEE REQUIRED]**

For the transition period from __________ to __________

Commission File No. 001-33059

Fuel Tech, Inc.

(Exact name of registrant as specified in its charter)

Delaware	20-5657551
(State or other jurisdiction of incorporation of organization)	(I.R.S. Employer Identification Number)

Fuel Tech, Inc.
27601 Bella Vista Parkway
Warrenville, IL 60555-1617
630-845-4500
(Address and telephone number of principal executive offices)

Securities registered pursuant to Section 12(b) of the Act:

Common Stock $0.01 par value per share	**The NASDAQ Stock Market, Inc**
(Title of Class)	**(Name of Exchange on Which Registered)**

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Yes o No þ

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.

Yes o No þ

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. o

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes þ No o

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted to Rule 405 of Regulation S-T (§229.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes o No þ

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, non-accelerated filer or a smaller reporting company (as defined in rule 12b-2 under the Securities Exchange Act of 1934).

Large accelerated filer o	**Accelerated filer þ**	**Non-accelerated filer o**	**Smaller reporting company o**
		(Do not check if a smaller reporting company)	

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes o No þ

The aggregate market value of the voting stock held by non-affiliates of the registrant based on the average bid and asked prices of June 30, 2009 was $174,532,000. The aggregate market value of the voting stock held by non-affiliates of the registrant based on the average bid and asked prices of February 10, 2009 was $111,084,000.

Indicate number of shares outstanding of each of the registered classes of Common Stock at March 1, 2010: 24,211,967 shares of Common Stock, $0.01 par value.

Documents incorporated by reference:

Certain portions of the Proxy Statement for the annual meeting of stockholders to be held in 2010 are incorporated by reference in Parts II, III, and IV hereof.

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TABLE OF DEFINED TERMS

Term	Definition
ABC	American Bailey Corporation
AIG	Ammonia Injection Grid
ASCR™	A trademark used to describe Fuel Tech's combination of SNCR and SCR
CAAA	Clean Air Act Amendments of 1990
CAIR	Clean Air Interstate Rule
CASCADE™	A trademark used to describe Fuel Tech's combination of SNCR and SCR
CAVR	Clean Air Visibility Rule
CFD	Computational Fluid Dynamics
Common Shares	Shares of the Common Stock of Fuel Tech
Common Stock	Common Stock of Fuel Tech
EPA	The U.S. Environmental Protection Agency
FGC	Flue Gas Conditioning
FUEL CHEM®	A trademark used to describe Fuel Tech's fuel and flue gas treatment processes, including its TIFI® Targeted In-Furnace Injection™ technology to control slagging, fouling, corrosion and a variety of sulfur trioxide-related issues
GSG™	Graduated Straightening Grid
HERT™ High Energy Reagent Technology™	A trademark used to describe a Fuel Tech SNCR process
Loan Notes	Nil-coupon, non-redeemable convertible unsecured loan notes of Fuel Tech
NOx	Oxides of nitrogen
NOxOUT®	A trademark used to describe Fuel Tech's SNCR process for the reduction of NOx.
NOxOUT-SCR®	A trademark used to describe Fuel Tech's direct injection of urea as a catalyst reagent.
SCR	Selective Catalytic Reduction
SIP Call	State Implementation Plan Regulation
SNCR	Selective Non-Catalytic Reduction
TCI® Targeted Corrosion Inhibition™	A FUEL CHEM program designed for high-temperature slag and corrosion control, principally in waste-to-energy boilers
TIFI® Targeted In-Furnace Injection™	A proprietary technology that enables the precise injection of a chemical reagent into a boiler or furnace as part of a FUEL CHEM program
ULTRA™	A trademark used to describe Fuel Tech's process for generating ammonia for use as SCR reagent

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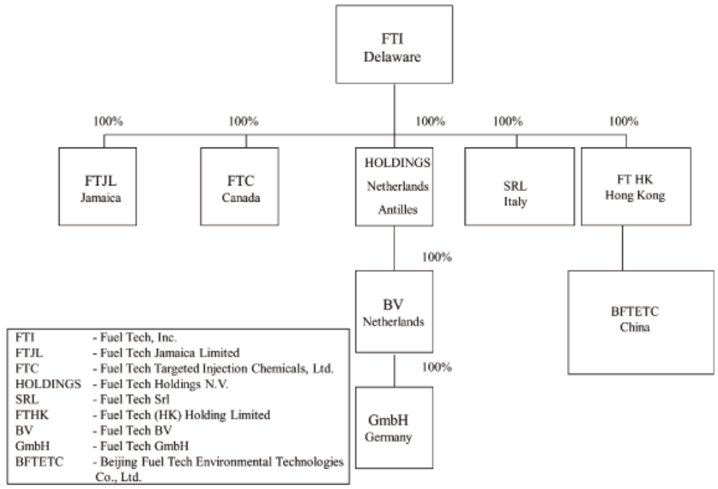
Fuel Tech, Inc. and Subsidiaries
December 31, 2009



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PART I

Forward-Looking Statements

This Annual Report on Form 10-K contains "forward-looking statements," as defined in Section 21E of the Securities Exchange Act of 1934, as amended, are made pursuant to the safe harbor provisions of the Private Securities Litigation Reform Act of 1995 and reflect our current expectations regarding our future growth, results of operations, cash flows, performance and business prospects, and opportunities, as well as assumptions made by, and information currently available to, our management. We have tried to identify forward-looking statements by using words such as "anticipate," "believe," "plan," "expect," "intend," "will," and similar expressions, but these words are not the exclusive means of identifying forward-looking statements. These statements are based on information currently available to us and are subject to various risks, uncertainties, and other factors, including, but not limited to, those discussed herein under the caption "Risk Factors" that could cause our actual growth, results of operations, financial condition, cash flows, performance and business prospects and opportunities to differ materially from those expressed in, or implied by, these statements. Except as expressly required by the federal securities laws, we undertake no obligation to update such factors or to publicly announce the results of any of the forward-looking statements contained herein to reflect future events, developments, or changed circumstances or for any other reason. Investors are cautioned that all forward-looking statements involve risks and uncertainties, including those detailed in Fuel Tech's filings with the Securities and Exchange Commission. See "Risk Factors" in Item 1A.

ITEM 1 - BUSINESS

As used in this Annual Report on Form 10-K, the terms "we," "us," "our," "the Company," and "Fuel Tech" refer to Fuel Tech, Inc. and our wholly-owned subsidiaries.

Fuel Tech

Fuel Tech, Inc. (Fuel Tech) is a fully integrated company that uses a suite of advanced technologies to provide boiler optimization, efficiency improvement and air pollution reduction and control solutions to utility and industrial customers worldwide. Originally incorporated in 1987 under the laws of the Netherlands Antilles as Fuel-Tech N.V., Fuel Tech became domesticated in the United States on September 30, 2006, and continues as a Delaware corporation with its corporate headquarters at 27601 Bella Vista Parkway, Warrenville, Illinois, 60555-1617. Fuel Tech maintains an Internet website at www.ftek.com. Our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and any amendments to those reports filed or furnished pursuant to Section 13(a) of the Securities Exchange Act of 1934 are made available through our website as soon as reasonably practical after we electronically file or furnish the reports to the Securities and Exchange Commission. Also available on the Corporation's website are the Company's Corporate Governance Guidelines and Code of Ethics and Business Conduct, as well as the charters of the audit, compensation and nominating committees of the Board of Directors. All of these documents are available in print without charge to stockholders who request them. Information on our website is not incorporated into this report.

Fuel Tech's special focus is the worldwide marketing of its nitrogen oxide (NOx) reduction and FUEL CHEM® processes. The Air Pollution Control (APC) technology segment reduces NOx emissions in flue gas from boilers, incinerators, furnaces and other stationary combustion sources by utilizing combustion optimization techniques and Low NOx and Ultra Low NOx Burners; NOxOUT® and HERT™ High Energy Reagent Technology™ SNCR systems; systems that incorporate CASCADE™, ULTRA™ and NOxOUT-SCR® processes; and Ammonia Injection Grid (AIG) and the Graduated Straightening Grid (GSG™). The FUEL CHEM technology segment improves the efficiency, reliability and environmental status of combustion units by controlling slagging, fouling and corrosion, as well as the formation of sulfur trioxide, ammonium bisulfate, particulate matter (PM2.5), carbon dioxide, NOx and unburned carbon in fly ash through the addition of chemicals into the fuel or via TIFI® Targeted In-Furnace Injection™ programs. Fuel Tech has other technologies, both commercially available and in the development stage, all of which are related to APC and FUEL CHEM processes or are similar in their technological base. Fuel Tech's business is materially dependent on the continued existence and enforcement of worldwide air quality regulations.

American Bailey Corporation

Douglas G. Bailey, Chairman and Director of Fuel Tech, and Ralph E. Bailey, Director and Chairman Emeritus of Fuel Tech, are stockholders of American Bailey Corporation (ABC), which is a related party. Please refer to Note 10 to the consolidated financial statements in this document for information about transactions between Fuel Tech and ABC. Additionally, see the more detailed information relating to this subject under the caption "Certain Relationships and Related Transactions" in Fuel Tech's Proxy Statement, to be distributed in connection with Fuel Tech's 2010 Annual Meeting of Stockholders, which information is incorporated by reference.

Air Pollution Control

Regulations and Markets

The U.S. air pollution control market is currently the primary driver in Fuel Tech's NOx reduction technology segment. This market is dependent on air pollution regulations and their continued enforcement. These regulations are based on the Clean Air Act Amendments of 1990 (the "CAAA"), which require reductions in NOx emissions on varying timetables with respect to

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various sources of emissions. Under the State Implementation Plan (SIP) Call, a regulation promulgated under the Amendments (discussed further below), over 1,000 utility and large industrial boilers in 19 states were required to achieve NOx reduction targets by May 31, 2004.

In 1994, governors of 11 Northeastern states, known collectively as the Ozone Transport Region, signed a Memorandum of Understanding requiring utilities to reduce their NOx emissions by 55% to 65% from 1990 levels by May 1999. In 1998, the Environmental Protection Agency (EPA) announced more stringent regulations. The Ozone Transport SIP Call regulation, designed to mitigate the effects of wind-aided ozone transported from the Midwestern and Southeastern U.S. into the Northeastern non-attainment areas, required, following the litigation described below, 19 states to make even deeper aggregate reductions of 85% from 1990 levels by May 31, 2004. Over 1,000 utility and large industrial boilers are affected by these mandates. Additionally, most other states with non-attainment areas were also required to meet ambient air quality standards for ozone by 2007.

Although the SIP Call was the subject of litigation, an appellate court of the D.C. Circuit upheld the validity of this regulation. This court's ruling was later affirmed by the U.S. Supreme Court.

In February 2001, the U.S. Supreme Court, in a unanimous decision, upheld EPA's authority to revise the National Ambient Air Quality Standard (NAAQS) for ozone to 0.080 parts per million averaged through an eight-hour period from the current 0.120 parts per million for a one-hour period. This more stringent standard provided clarity and impetus for air pollution control efforts well beyond the then current ozone attainment requirement of 2007. In keeping with this trend, the Supreme Court, only days later, denied industry's attempt to stay the SIP Call, effectively exhausting all means of appeal. The ozone NAAQS is currently 0.075 parts per million averaged over an eight-hour period, and EPA is proposing to reduce the Standard to 0.06 or 0.07 parts per million for the most severe non-attainment areas by 2013.

On December 23, 2003, the EPA proposed a new regulation affecting the SIP Call states by specifying more expansive NOx reduction. This rule, under the name Clean Air Interstate Rule (CAIR), was issued by the EPA on March 10, 2005. Commencing in 2009, CAIR specifies that additional annual NOx reduction requirements be extended to most SIP-affected units in 28 eastern states, while permitting a cap and trade format similar to the SIP Call. The Company expects an additional 1,300 electric generating units using coal and other fuels to be affected by this rule. In an action related to CAIR, on June 15, 2005, the EPA issued the Clean Air Visibility Rule (CAVR), which is a nationwide initiative to improve federally preserved areas through reduction of NOx and other pollutants. CAVR expands the NOx reduction market to Western states unaffected by CAIR or the SIP Call. Compliance begins in 2013 and CAVR will potentially affect an additional 230 western coal-fired electric-generating units. In addition, CAVR, along with the EPA rule for revised eight-hour ozone attainment, have the potential to impact thousands of boilers and industrial units in multiple industries nationwide for units burning coal and other fuels starting in 2013.

On July 11, 2008, the U.S. District Court of Appeals for the District of Columbia Circuit vacated the CAIR regulations under the CAAA under the premise that the EPA exceeded its authority when the rule was created in 2005. The court found "more than several fatal flaws in the rule" but neither took issue with the concept that NOx emissions are to be controlled nor over the limits and thresholds established by CAIR. In vacating the rule in its entirety, the court remanded to EPA to promulgate a rule consistent with the court's opinion. On September 24, 2008, the EPA filed a petition for the case to be reviewed by the full Court of Appeals, not just the three judge panel that issued the vacatur ruling in July 2008. On October 22, 2008, the EPA was granted a 15-day period to present a basis as to why the court should reconsider its decision. On December 23, 2008, the D.C. Circuit granted the EPA's petition only to the extent that it remanded the case without vacatur for EPA to conduct further proceedings consistent with the court's prior opinion. In summary, the court stated that "...allowing CAIR to remain in effect until it is replaced by a rule consistent with our opinion would at least temporarily preserve the environmental values covered by CAIR." The court did not impose a particular schedule by which the EPA must alter CAIR, however a revised rule is expected to be published by the EPA in 2010 and taking effect in 2011. CAIR requires the affected states to be in year-round NOx emission compliance beginning January 1, 2009. While we cannot predict the ultimate outcome of a revised CAIR or new multi-pollutant legislation under consideration by Congress, any unfavorable outcome could have a material adverse effect on our business, results of operations, cash flows, and financial position. However, the primary driver of CAIR, the Federal Clean Air Act, including the associated National Ambient Air Quality Standards, is in effect and states must comply with this law.

Fuel Tech also sells NOx control systems outside the United States, specifically in Europe and in the People's Republic of China (China). NOxOUT systems have long been sold in the traditional markets of Western Europe, but interest is growing in newer markets like Eastern Europe as well as Israel for complete NOx reduction programs on both new and existing boilers. Under EU Directives, certain waste incinerators and cement plants must come into compliance with specified NOx reduction targets by the end of 2009, while certain power plants must be in compliance by 2016.

China also represents attractive opportunities for Fuel Tech as the government has set pollution control and energy conservation and efficiency improvements as top priorities. Fuel Tech has viable technologies to help achieve these objectives. China has taken initial steps to reduce NOx emissions on new electric utility units (principally Low NOx Burners), and on-going research and demonstration projects are generating cost performance data for use in tightening standards in the near future, both for new and retrofit units. China's dominant reliance on coal as an energy resource is not expected to change in the foreseeable future. Clean air has been and will continue to be a pressing issue, especially with China's robust economic growth, expected growth in power production (4%-5% average annual increase through 2020), and an increasingly expanded role in international events and organizations. China hosted the 2008 Beijing Summer Olympics and will host the 2010 Shanghai World Expo and the Asian Games in Guangdong. China plans to address in a significant way the pollution control for the existing fleet of fossil plants in the Twelfth Five-Year Plan that takes effect in 2011.

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The "*Fossil-Fired Power Plant's NOx Emission Prevention and Control Policy*" (the "Policy") issued by the Ministry of Environmental Protection on January 27, 2010 set the directions for future choices of technologies in flue gas NOx emission control. It is expected that detailed regulations which will implement the Policy will be announced later by appropriate government agencies. The Policy applies to all coal-fired power plants and co-generation units where the focus is placed on 200 MW or larger, as well as the units in the designated "Focus Regions" (areas around Beijing, Shanghai, and Guangdong). By the Policy, all new, rebuilt or plants that have undergone expansion should consider Low-NOx Combustion Technologies (such as Low-NOx Burners and Over-Fire Air systems) as the priority choice. On operating units, if the NOx emission levels still do not meet the emission standard, then the unit should install flue gas de-NOx technology. Major flue gas de-NOx technologies called out in the Policy include Selective Catalytic Reduction (SCR), Selective Non-Catalytic Reduction (SNCR), and Combined SCR-SNCR systems. For systems which require ammonia as a reducing agent for SCR, SNCR-SCR and SNCR, there are special policy guidelines depending on the unit location. For all units within the special Focus Regions, the preferred reducing agent is urea.

Fuel Tech has established a significant market position in NOx control resulting from the initial national demonstration projects utilizing CASCADE technology at Jiangsu Kanshan (two new 600 megawatt units), NOxOUT Selective Non-Catalytic Reduction (SNCR) technology at Jiangyin Ligang (four new 600 megawatt units) and Inner Mongolia (two new 600 megawatt units), and ULTRA technology on two retrofit projects in Beijing. These projects have established Fuel Tech NOx control technologies as being acceptable to use in reducing NOx emissions and have resulted in additional contracts in China. With the variety for future choices of technologies for NOx emission control that are in the Twelfth Five-Year Plan which begins in January 1, 2011, we believe the China market holds significant opportunities for Fuel Tech.

The key market dynamic for this product line is the continued use of coal as the principal fuel source for global electricity production. Coal accounts for approximately 50% of all U.S. electricity generation. Coal's share of global electricity generation is forecast to be approximately 45% by 2030. Major coal consumers include China, the United States and India.

Products

Fuel Tech's NOx reduction technologies are installed worldwide on over 550 combustion units, including utility, industrial and municipal solid waste applications. Products include customized NOx control systems and patented urea-to-ammonia conversion technology, which can provide safe reagent for use in Selective Catalytic Reduction (SCR) systems.

- Low NOx Burners and Ultra Low NOx Burners are available for coal-, oil-, and gas-fired industrial and utility units. Each system application is specifically designed to maximize NOx reduction. Computational Fluid Dynamics combustion modeling is used to validate the design prior to fabrication of equipment. NOx reductions can range from 40%-60% depending on the fuel type. Over-Fire Air systems stage combustion for enhanced NOx reduction. Additional NOx reductions, beyond Low NOx Burners, of 35%-50%, are possible on different boiler configurations on a range of fuel types. Combined overall reductions range from 50-70%, with overall capital costs range from $10 — $20/kW and levelized total costs ranging from $300 — $1,500/ton of NOx removed, depending on the scope.

- Fuel Tech's NOxOUT and HERT SNCR processes use non-hazardous urea as the reagent rather than ammonia. Both the NOxOUT and HERT processes on their own are capable of reducing NOx by up to 25% — 50% for utilities and by potentially significantly greater amounts for industrial units in many types of plants with capital costs ranging from $5 — $20/kW for utility boilers and with total annualized operating costs ranging from $1,000 — $2,000/ton of NOx removed.

- Fuel Tech's Advanced Selective Catalytic Reduction (ASCRTM) systems include LNB, OFA, and SNCR components, along with a downsized SCR catalyst, Ammonia Injection Grid (AIG), and Graduated Straightening Grid (GSGTM) systems to provide up to 90% NOx reduction at significantly lower capital and operating costs than conventional SCR systems while providing greater operational flexibility to plant operators. The capital costs for ASCR systems can range from $30 — $150/kW depending on boiler size and configuration, which is significantly less than that of conventional SCRs, which can cost $300/kW or more, while operating costs are competitive with those experienced by SCR systems. The CASCADETM and NOxOUT-SCR® processes are basic types of ASCR systems which use just SNCR and SCR catalyst components. The CASCADE systems can achieve 60-70% NOx reduction, with capital costs being a portion of the ASCR values defined above. Fuel Tech's NOxOUT-SCR process utilizes urea as the SCR catalyst reagent to achieve NOx reductions of up to 85% from smaller stationary combustion sources with capital and operating costs competitive with equivalently sized, standard SCR systems.

- Fuel Tech's ULTRATM process is designed to convert urea to ammonia safely and economically for use as a reagent in the SCR process for NOx reduction. Recent local objections in the ammonia permitting process have raised concerns regarding the safety of ammonia shipment and storage in quantities sufficient to supply SCR. In addition, the Department of Homeland Security has characterized anhydrous ammonia as a Toxic Inhalation Hazard (TIH) commodity. This is contributing to new restrictions by rail carriers on the movement of anhydrous ammonia and to an escalation in associated rail transport and insurance rates. Overseas, new coal-fired power plants incorporating SCR systems are expected to be constructed at a rapid rate in China, and Fuel Tech's ULTRA process is believed to be a market leader for the safe conversion of urea to ammonia just prior to injection into the flue gas duct, which is particularly important near densely populated cities, major waterways, harbors or islands, or where the transport of anhydrous or aqueous ammonia is a safety concern.

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- Under an exclusive licensing agreement with FGC Corporation, Fuel Tech sells flue gas conditioning systems incorporating FGC Corporation technology for utility applications in all geographies outside the United States and Canada. Flue gas conditioning systems improve the efficiency of particulate collectors, including electrostatic precipitators (ESPs) and fabric filters. These conditioning systems represent a far lower capital cost approach to improving ash particulate capture versus the alternative of installing larger ESPs or fabric filter technology to meet opacity levels.

- Fuel Tech now provides process design optimization, performance testing and improvement, and catalyst selection services for SCR systems on coal-fired boilers. In addition, other related services, including start-ups, maintenance support and general consulting services for SCR systems, as well as ammonia injection grid design and tuning, to help optimize catalyst performance and catalyst management services to help optimize catalyst life, are now offered to customers around the world. Fuel Tech also specializes in both physical experimental models, which involve construction of scale models through which fluids are tested, and computational fluid dynamics models, which simulate fluid flow by generating a virtual replication of real-world geometry and operating inputs. Fuel Tech designs flow corrective devices, such as turning vanes, ash screens, static mixers and our patent pending Graduated Straightening Grid GSGTM. Fuel Tech's models help clients optimize performance in flow critical equipment, such as selective catalytic reactors in SCR systems, where the effectiveness and longevity of catalysts are of utmost concern. The Company's modeling capabilities are also applied to other power plant systems where proper flow distribution and mixing are important for performance, such as flue gas desulphurization scrubbers, electrostatic precipitators, air heaters, exhaust stacks and carbon injection systems for mercury removal.

Sales of the NOx reduction technologies were $34.7 million, $44.4 million and $47.8 million for the years ended December 31, 2009, 2008 and 2007, respectively.

NOx Reduction Competition

Competition with Fuel Tech's NOx reduction suite of products may be expected from companies supplying urea SNCR systems, combustion modification products, SCR systems and ammonia SNCR systems. In addition, Fuel Tech experiences competition in the urea-to-ammonia conversion market.

Combustion modifications, including Low NOx Burners and Over-Fire Air systems, can be fitted to most types of boilers with cost and effectiveness varying with specific boilers. Combustion modifications may yield up to 20% — 60% NOx reduction economically with capital costs ranging from $10 — $20/kW and levelized total costs ranging from $300 — $1,500/ton of NOx removed. The modifications are designed to reduce the formation of NOx and are typically the first NOx reduction efforts employed. Such companies as Alstom, Foster Wheeler Corporation, The Babcock & Wilcox Company, Combustion Components Associates, Inc., Siemens, and Babcock Power, Inc. are active competitors in the Low-NOx burner business. On January 5, 2009, Fuel Tech acquired substantially all of the assets of Advanced Combustion Technology, Inc., a company that had been engaged in the Low NOx Burner business.

Once NOx is formed, then the SCR process is an effective and proven method of control for removal of NOx up to 90%. SCR systems have a high capital cost of $300+/kW on retrofit coal applications. Such companies as Alstom, The Babcock & Wilcox Company, Hitachi, Foster Wheeler Corporation, Peerless Manufacturing Company, and Babcock Power, Inc., are active SCR system providers, or providers of the catalyst itself.

The use of ammonia as the reagent for the SNCR process can reduce NOx by 30% — 70% on incinerators, but has limited applicability in the utility industry. Ammonia system capital costs range from $5 - $20/kW, with annualized operating costs ranging from $1,000 — $3,000/ton of NOx removed. These systems require the use of either anhydrous or aqueous ammonia, both of which are hazardous substances.

Combustion Components Associates, Inc. is a licensed implementer of our NOxOUT SNCR systems, and thus, may compete with us in the market for such technology.

In addition to or in lieu of using the foregoing processes, certain customers may elect to close or de-rate plants, purchase electricity from third-party sources, switch from higher to lower NOx-emitting fuels or purchase NOx emission allowances.

Lastly, with respect to urea-to-ammonia conversion technologies, a competitive approach to Fuel Tech's controlled urea decomposition system is available from Wahlco, Inc., which manufactures a system that hydrolyzes urea under high temperature and pressure.

APC BACKLOG

Consolidated APC backlog at December 31, 2009 was $22.0 million versus backlog at December 31, 2008 of approximately $9.0 million. Substantially all of the backlog as of December 31, 2009 should be recognized as revenue in fiscal 2010, although the timing of such revenue recognition in 2010 is subject to the timing of the expenses incurred on existing projects.

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FUEL CHEM

Product and Markets

The FUEL CHEM technology segment revolves around the unique application of specialty chemicals to improve the efficiency, reliability and environmental status of plants operating in the electric utility, industrial, pulp and paper, waste-to-energy, university and district heating markets. FUEL CHEM programs are currently in place on over 95 combustion units, treating a wide variety of solid and liquid fuels, including coal, heavy oil, biomass and municipal waste.

Central to the FUEL CHEM approach is the introduction of chemical reagents, such as magnesium hydroxide, to combustion units via in-body fuel application (pre-combustion) or via direct injection (post-combustion) utilizing Fuel Tech's proprietary TIFI technology. By attacking performance-hindering problems, such as slagging, fouling and corrosion, as well as the formation of sulfur trioxide (SO3), ammonium bisulfate (ABS), particulate matter (PM2.5), carbon dioxide (CO2), NOx and unburned carbon in fly ash, the Company's programs offer numerous operational, financial and environmental benefits to owners of boilers, furnaces and other combustion units.

The key market dynamic for this product line is the continued use of coal as the principal fuel source for global electricity production. Coal accounts for approximately 50% of all U.S. electricity generation. Coal's share of global electricity generation is forecast to be approximately 45% by 2030. Major coal consumers include the United States, China and India.

The principal markets for this product line are electric power plants burning coals with slag-forming constituents such as sodium, iron and high levels of sulfur. Sodium is typically found in the Powder River Basin (PRB) coals of Wyoming and Montana. Iron is typically found in coals produced in the Illinois Basin (IB) region. High sulfur content is typical of IB coals and certain Appalachian coals. High sulfur content can give rise to unacceptable levels of SO3 formation in plants with SCR systems and flue gas desulphurization units (scrubbers).

The combination of slagging coals and SO3-related issues, such as "blue plume" formation, air pre-heater fouling and corrosion, SCR fouling and the proclivity to suppress certain mercury removal processes, represents attractive market potential for Fuel Tech.

Internationally, market opportunities exist in Europe and in the Asia-Pacific region, particularly China and India, where high-slagging coals are fueling a large and growing fleet of power plants. To address the Chinese market, where particular emphasis is being placed on energy efficiency, Fuel Tech extended its exclusive teaming agreement with ITOCHU Hong Kong Ltd., a subsidiary of ITOCHU Corporation, through February 28, 2010. The exclusivity portion of this agreement expired on this date while the relationship with Itochu continues and is undergoing certain modifications to better address the Chinese FUEL CHEM market. Working with Itochu, the first FUEL CHEM demonstration program in China was announced in January 2008, a second demonstration program was announced in October 2008 and a third in May 2009. In addition, Fuel Tech was awarded its first FUEL CHEM demonstration program in India in January 2008. TIFI initiatives aimed at energy efficiency improvements resulted from maintaining better cleanliness on heat transfer equipment in particularly coal, oil, municipal solids waste, and biomass fired combustion facilities. FUEL CHEM benefits are characterized by generating more power and steam using the same fuel, capability of burning more lower grade fuels, reduction of environmental toxic release, reduction of operation and maintenance cost, safe and more stable operations, as well as in reduced CO2 emissions, which potentially can be monetized under provisions of the Kyoto Protocol.

A potentially large fuel treatment market exists in Mexico, where high-sulfur, low-grade fuel oil containing vanadium and nickel is the primary source for electricity production. The presence of these metallic constituents promotes slag build-up, and the fuel properties can result in acid gas and particulate emissions in local combustion units. Fuel Tech has successfully treated such units with its TIFI technology. To capitalize on this market opportunity, the Company signed a five-year license implementation agreement with Energy Marine Services, S.A. de C.V. (EMS), a private Mexican corporation, to implement our TIFI program for utility and end user customers in Mexico. In 2009, our TIFI program has been in continuous use on three boilers at CFE's power plant. In addition, EMS's partner company was awarded a project to install TIFI equipment on three boilers at a different power plant also owned by CFE. Our TIFI program on all three boilers is expected to be operational in 2010. CFE is Mexico's largest state power company with greater than 50 GW of installed capacity.

Sales of the FUEL CHEM products were $36.7 million, $36.7 million and $32.5 million for the years ended December 31, 2009, 2008 and 2007, respectively.

Competition

Competition for Fuel Tech's FUEL CHEM product line includes chemicals sold by specialty chemical and combustion engineering companies, such as GE Infrastructure, Ashland Inc., and Environmental Energy Services, Inc. No substantive competition currently exists for Fuel Tech's TIFI technology, which is designed primarily for slag control and SO3 abatement, but there can be no assurance that such lack of substantive competition will continue.

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INTELLECTUAL PROPERTY

The majority of Fuel Tech's products are protected by U.S. and non-U.S. patents. Fuel Tech owns 77 granted patents worldwide and has 10 patent applications pending in the United States and 45 pending in non-U.S. jurisdictions. These patents and applications cover some 31 inventions, 19 associated with the NOx reduction business, seven associated with the FUEL CHEM business and five associated with non-commercialized technologies. Our patents have expiration dates ranging from February 17, 2010 to February 16, 2026. The average remaining duration of our patents is approximately six and one-half years. Graduated Straightening Grid (GSG™) technology was added into Fuel Tech's inventions in 2008 through the acquisition of substantially all of the assets of FlowTack. GSG improves flow distribution and direction to potentially improve SCR and CASCADE performance, and minimize flow-related erosion, dust accumulation and heat transfer problems. These inventions represent significant enhancements of the application and performance of the technologies. As a result of the 2009 acquisition of substantially all of the assets of Advanced Combustion Technology, Inc., Fuel Tech added patented HERT SNCR technology and patent pending Ultra Low NOx Burner replacement system technology. Further, Fuel Tech believes that the protection provided by the numerous claims in the above referenced patents or patent applications is substantial, and affords Fuel Tech a significant competitive advantage in its business. Accordingly, any significant reduction in the protection afforded by these patents or any significant development in competing technologies could have a material adverse effect on Fuel Tech's business.

EMPLOYEES

At December 31, 2009, Fuel Tech had 168 employees, 141 in North America, 18 in China and 9 in Europe. Fuel Tech enjoys good relations with its employees and is not a party to any labor management agreement.

ACQUISITION

On January 5, 2009, Fuel Tech consummated its acquisition of substantially all of the assets of Advanced Combustion Technology, Inc. (ACT) pursuant to that certain Asset Purchase Agreement, dated December 5, 2008, among the Company, ACT, Peter D. Marx, Robert W. Pickering and Charles E. Trippel. Prior to closing, ACT, headquartered in Hooksett, New Hampshire, was a leading provider of nitrogen oxide (NOx) control systems, including Low NOx Burners and Over-Fire Air systems. The business formerly operated by ACT is part of the Company's Air Pollution Control reporting segment. In connection with the closing, Fuel Tech paid approximately $23,000 in cash to ACT. In addition, ACT may receive certain performance-based contingent payments in the future.

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ITEM 1A - RISK FACTORS

Investors in Fuel Tech should be mindful of the following risk factors relative to Fuel Tech's business.

(i) Lack of Diversification

Fuel Tech has two broad technology segments that provide advanced engineering solutions to meet the pollution control, efficiency improvement, and operational optimization needs of energy-related facilities worldwide. They are as follows:

- The Air Pollution Control technology segment includes technologies to reduce NOx emissions in flue gas from boilers, incinerators, furnaces and other stationary combustion sources. These include Low- and Ultra-Low NOx Burners (LNB and ULNB), Over-Fire Air (OFA) systems, NOxOUT® and HERTTM Selective Non-Catalytic Reduction (SNCR) systems, and Advanced Selective Catalytic Reduction (ASCRTM) systems. The ASCR system includes ULNB, OFA, and SNCR components, along with a downsized SCR catalyst, ammonia injection grid (AIG), and Graduated Straightening Grid GSGTM systems to provide high NOx reductions at significantly lower capital and operating costs than conventional SCR systems. The CASCADETM and NOxOUT-SCR® processes are basic types of ASCR systems, using just SNCR and SCR catalyst components. ULTRA™ technology creates ammonia at a plant site using safe urea for use with any SCR application. Flue gas conditioning systems are chemical injection systems offered in markets outside the U.S. and Canada to enhance electrostatic precipitator and fabric filter performance in controlling particulate emissions.

- The FUEL CHEM® technology segment, which uses chemical processes in combination with advanced CFD and CKM boiler modeling, for the control of slagging, fouling, corrosion, opacity and other sulfur trioxide-related issues in furnaces and boilers through the addition of chemicals into the furnace using TIFI® Targeted In-Furnace Injection™ technology.

An adverse development in Fuel Tech's advanced engineering solution business as a result of competition, technological change, government regulation, or any other factor could have a significantly greater impact than if Fuel Tech maintained more diverse operations.

(ii) Competition

Competition in the Air Pollution Control market will come from competitors utilizing their own NOx reduction processes, including SNCR systems, Low NOx Burners, Over-Fire Air systems, flue gas recirculation, ammonia SNCR, SCR and, with respect to particular uses of urea not infringing Fuel Tech's patents, urea (see Item 1 "Intellectual Property"). Competition will also come from business practices such as the purchase rather than the generation of electricity, fuel switching, closure or de-rating of units, and sale or trade of pollution credits and emission allowances. Utilization by customers of such processes or business practices or combinations thereof may adversely affect Fuel Tech's pricing and participation in the NOx control market if customers elect to comply with regulations by methods other than the purchase of Fuel Tech's suite of Air Pollution Control products. See Item 1 "*Products*" and "*NOx Reduction Competition*" in the *Air Pollution Control* segment overview.

Competition in the FUEL CHEM markets includes chemicals sold by specialty chemical and combustion engineering companies, such as GE Infrastructure, Ashland Inc. and Environmental Energy Services, Inc. As noted previously, no significant competition currently exists for Fuel Tech's patented TIFI technology, which is designed primarily for slag control and SO3 abatement. However, there can be no assurance that such lack of significant competition will continue.

(iii) Dependence on and Change in Air Pollution Control Regulations and Enforcement

Fuel Tech's business is significantly impacted by and dependent upon the regulatory environment surrounding the electricity generation market. Our business will be adversely impacted to the extent that regulations are repealed or amended to significantly reduce the level of required NOx reduction, or to the extent that regulatory authorities delay or otherwise minimize enforcement of existing laws. Additionally, long-term changes in environmental regulation that threaten or preclude the use of coal or other fossil fuels as a primary fuel source for electricity production, based on the theory that gases emitted therefrom impact climate change through a greenhouse effect, and result in the reduction or closure of a significant number of fossil fuel-fired power plants, may adversely affect the Company's business, financial condition and results of operations. See Item 1 above under the caption "*Regulations and Markets*" in the *Air Pollution Control* segment overview.

(iv) Protection of Patents and Proprietary Rights

Fuel Tech holds licenses to or owns a number of patents for our products and processes. In addition, we also have numerous patents pending. There can be no assurance that pending patent applications will be granted or that outstanding patents will not be challenged or circumvented by competitors. Certain critical technology relating to our products is protected by trade secret laws and by confidentiality and licensing agreements. There can be no assurance that such protection will prove adequate or that we will have adequate remedies against contractual counterparties for disclosure of our trade secrets or violations of Fuel Tech's intellectual property rights. See Item 1 "Intellectual Property."

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(v) Foreign Operations

In 2007, we expanded our operations into China by establishing a wholly-owned subsidiary in Beijing. The Asia-Pacific region, particularly China and India, offers significant market opportunities for Fuel Tech as these nations look to establish regulatory policies for improving their environment and utilizing fossil fuels, especially coal, efficiently and effectively. The future business opportunities in these markets are dependent on the continued implementation of regulatory policies that will benefit our technologies, the acceptance of Fuel Tech's engineering solutions in such markets, and the ability of potential customers to utilize Fuel Tech's technologies on a cost-effective basis.

(vi) Product Pricing and Operating Results

The onset of significant competition for either of the technology segments might have an adverse impact on product pricing and a resulting adverse impact on realized gross margins and operating profitability.

(vii) Raw Material Supply and Pricing

The FUEL CHEM Technology segment is dependent upon a supply of magnesium hydroxide. Any adverse change in the availability of this chemical will likely have an adverse impact on ongoing operation of our FUEL CHEM programs. On March 4, 2009, we entered into a Restated Product Supply Agreement ("PSA") with Martin Marietta Magnesia Specialties, LLC (MMMS) in order to assure the continuance of a stable supply from MMMS of magnesium hydroxide products for our requirements in the United States and Canada until December 31, 2013, the date of the expiration of the PSA. Magnesium hydroxide products are a significant component of the FUEL CHEM programs. Pursuant to the PSA, MMMS supplies us with magnesium hydroxide products manufactured pursuant to our specifications and we have agreed to purchase from MMMS, and MMMS has agreed to supply, 100% of our requirements for such magnesium hydroxide products for our customers who purchase such products for delivery in the United States and Canada. There can be no assurance that Fuel Tech will be able to obtain a stable source of magnesium hydroxide in markets outside the United States.

(viii) Customer Access to Capital Funds

Uncertainty about current economic conditions in the United States and globally poses risk that Fuel Tech's customers may postpone spending for capital improvement projects in response to tighter credit markets, negative financial news and/or decline in demand for electricity generated by combustion units, all of which could have a material negative effect on demand for the Fuel Tech's products and services.

(ix) Customer Concentration

A small number of customers have historically accounted for a material portion of Fuel Tech's revenues (see note 12 – Business Segment, Geographic and Quarterly Financial Data). There can be no assurance that Fuel Tech's current customers will continue to place orders, that orders by existing customers will continue at the levels of previous periods, or that Fuel Tech will be able to obtain orders from new customers. The loss of one or more of our customers could have a material adverse effect on our sales and operating results.

(x) Domestic Credit Facility

Fuel Tech is party to a $25 million revolving credit agreement with JPMorgan Chase Bank, N.A. As of December 31, 2009, there were no outstanding borrowings on this facility and Fuel Tech was in compliance with all debt covenants contained in the agreement. Nevertheless, in the event of any default on the part of Fuel Tech under this agreement, the lender is entitled to accelerate payment of any amounts outstanding and may, under certain circumstances, cancel the facility. If the Company were unable to obtain a waiver for a breach of covenant and the lender accelerated the payment of any outstanding amounts, such acceleration may cause the Company's cash position to significantly deteriorate or, if cash on hand were insufficient to satisfy the payment due, may require the Company to obtain alternate financing. See "Liquidity and Sources of Capital" under Item 7 "Management's Discussion and Analysis of Financial Condition and Results of Operations."

ITEM 1B - UNRESOLVED STAFF COMMENTS

None

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ITEM 2 - PROPERTIES

Fuel Tech and its subsidiaries operate from leased office facilities in Stamford, Connecticut; Durham, North Carolina; Gallarate, Italy and Beijing, China. Fuel Tech does not segregate any of its leased facilities by operating business segment. The terms of the three material agreements are as follows:

- The Stamford, Connecticut building lease term, for approximately 6,000 square feet, runs from February 1, 2010 to January 31, 2020. The facility houses certain administrative functions such as Investor Relations and certain APC sales functions. This lease replaces the prior facility lease for a separate location in Stamford which expired on January 31, 2010, which Fuel Tech did not renew. .

- The Beijing, China building lease term, for approximately 4,000 square feet, runs from September 1, 2009 to August 31, 2010. This facility serves as the operating headquarters for our Beijing Fuel Tech operation. Fuel Tech has the option to extend the lease term at a market rate to be agreed upon between Fuel Tech and the lessor.

- The Durham, North Carolina building lease term, for approximately 16,000 square feet, runs from November 1, 2005 to April 30, 2014. This facility houses the former Tackticks and FlowTack operations. Fuel Tech has no option to extend the lease.

In addition to the above, on November 30, 2007, Fuel Tech purchased an office building in Warrenville, Illinois, which has served as our corporate headquarters since June 23, 2008. This facility, with approximately 40,000 square feet of office space, was purchased for approximately $6,000,000 and subsequently built out and furnished for an additional cost of approximately $5,500,000. This facility will meet our growth requirements for the foreseeable future. Our prior headquarters, an 18,000 square foot location in Batavia, Illinois, was under an operating lease until May 31, 2009. We did not renew this lease.

ITEM 3 - LEGAL PROCEEDINGS

We are from time to time involved in litigation incidental to our business. We are not currently involved in any litigation in which we believe an adverse outcome would have a material effect on our business, financial conditions, results of operations, or prospects.

ITEM 4 - SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

During the fourth quarter of 2009, no matters were submitted to a vote of security holders.

PART II

ITEM 5 - MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASE OF EQUITY SECURITIES

Market

Fuel Tech's Common Shares have been traded since September 1993 on The NASDAQ Stock Market, Inc. The trading symbol is FTEK.

Prices

The table below sets forth the high and low sales prices during each calendar quarter since January 2008.

2009	High	Low
Fourth Quarter	$12.65	$7.51
Third Quarter	12.55	7.90
Second Quarter	14.15	9.28
First Quarter	12.23	7.01

2008	High	Low
Fourth Quarter	$18.95	$ 6.05
Third Quarter	24.76	14.52
Second Quarter	27.16	17.55
First Quarter	22.94	14.15

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Dividends

Fuel Tech has never paid cash dividends on its common stock and has no current plan to do so in the foreseeable future. The declaration and payment of dividends on the Common Stock are subject to the discretion of the Company's Board of Directors. The decision of the Board of Directors to pay future dividends will depend on general business conditions, the effect of a dividend payment on our financial condition, and other factors the Board of Directors may consider relevant. The current policy of the Company's Board of Directors is to reinvest earnings in operations to promote future growth.

Share Repurchase Program

Fuel Tech purchased no equity securities during the quarter and year ended December 31, 2009.

Holders

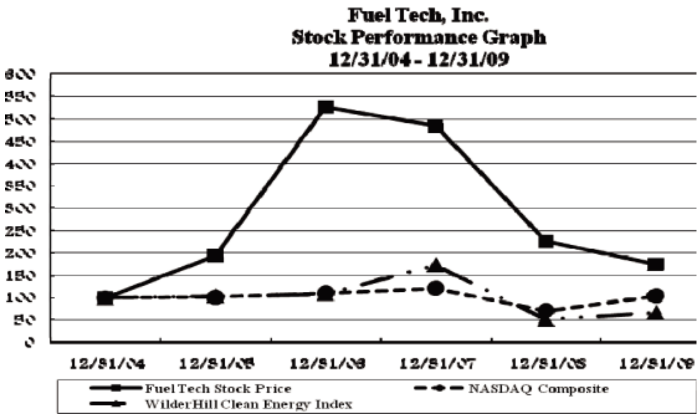
Based on information from the Company's Transfer Agent and from banks and brokers, the Company estimates that, as of February 22, 2010, there were approximately 19,800 beneficial holders and 254 registered stockholders of Fuel Tech's Common Shares.

Transfer Agent

The Transfer Agent and Registrar for the Common Shares is BNY Mellon Shareowner Services, 480 Washington Boulevard, Jersey City, New Jersey 07310-1900.

Performance Graph

The following line graph compares (i) Fuel Tech's total return to stockholders per share of Common Stock for the five years ended December 31, 2009 to that of (ii) the NASDAQ Composite index, and (iii) the WilderHill Clean Energy Index for the period December 31, 2004 through December 31, 2009.



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ITEM 6 - SELECTED FINANCIAL DATA

Selected financial data are presented below as of the end of and for each of the fiscal years in the five-year period ended December 31, 2009. The selected financial data should be read in conjunction with the audited consolidated financial statements as of and for the year ended December 31, 2009, and "Management's Discussion and Analysis of Financial Condition and Results of Operations" included elsewhere in this report and the schedules thereto. As a result of the acquisitions of substantially all of the assets of ACT in the first quarter of 2009, and Tackticks, LLC and FlowTack, LLC in the fourth quarter of 2008, the Company's condensed consolidated results for the periods presented are not directly comparable. See Note 13 for pro forma results from business acquisitions.

CONSOLIDATED STATEMENT of OPERATIONS DATA

	For the years ended December 31				
	2009	2008	2007	2006	2005
(in thousands of dollars, except for share and per- share data)					
Revenues	$ 71,397	$ 81,074	$ 80,297	$ 75,115	$ 52,928
Cost of sales	42,444	44,345	42,471	38,429	27,118
Selling, general and administrative and other costs and expenses	32,034	30,502	27,087	25,953	18,655
Operating (loss) income	(3,081)	6,227	10,739	10,733	7,155
Net (loss) income	(2,306)	3,360	7,243	6,826	7,588
Basic (loss) income per Common Share	$ (0.10)	$ 0.14	$ 0.33	$ 0.32	$ 0.38
Diluted (loss) income per Common Share	$ (0.10)	$ 0.14	$ 0.29	$ 0.28	$ 0.33
Weighted-average basic shares outstanding	24,148,000	23,608,000	22,280,000	21,491,000	20,043,000
Weighted-average diluted shares outstanding	24,148,000	24,590,000	24,720,000	24,187,000	23,066,000

CONSOLIDATED BALANCE SHEET DATA

	December 31				
	2009	2008	2007	2006	2005
(in thousands of dollars)					
Working capital	$ 30,578	$ 43,956	$ 45,143	$ 38,715	$ 19,590
Total assets	92,262	88,631	87,214	65,660	44,075
Long-term obligations	2,196	1,389	1,255	500	448
Total liabilities	14,040	15,056	23,975	18,005	14,939
Stockholders' equity (1)	78,222	73,575	63,239	47,655	29,136

Notes:

(1) Stockholders' equity includes principal amount of nil coupon non-redeemable perpetual loan notes. See Note 6 to the consolidated financial statements.

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ITEM 7 - MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Background

Fuel Tech, Inc. ("Fuel Tech") has two broad technology segments that provide advanced engineering solutions to meet the pollution control, efficiency improvement and operational optimization needs of energy-related facilities worldwide. They are as follows:

Air Pollution Control Technologies

The Air Pollution Control technology segment includes technologies to reduce NOx emissions in flue gas from boilers, incinerators, furnaces and other stationary combustion sources. These include Low- and Ultra-Low NOx Burners (LNB and ULNB), Over-Fire Air (OFA) systems, NOxOUT® and HERTTM Selective Non-Catalytic Reduction (SNCR) systems, and Advanced Selective Catalytic Reduction (ASCRTM) systems. The ASCR system includes ULNB, OFA, and SNCR components, along with a downsized SCR catalyst, Ammonia Injection Grid (AIG), and Graduated Straightening Grid (GSGTM) systems to provide high NOx reductions at significantly lower capital and operating costs than conventional SCR systems. The CASCADETM and NOxOUT-SCR® processes are basic types of ASCR systems, using just SNCR and SCR catalyst components. ULTRA™ technology creates ammonia at a plant site using safe urea for use with any SCR application. Flue gas conditioning systems are chemical injection systems offered in markets outside the U.S. and Canada to enhance electrostatic precipitator and fabric filter performance in controlling particulate emissions. Fuel Tech distributes its products through its direct sales force, licensees and agents.

FUEL CHEM Technologies

The FUEL CHEM® technology segment, which uses chemical processes in combination with advanced CFD and CKM boiler modeling, for the control of slagging, fouling, corrosion, opacity and other sulfur trioxide-related issues in furnaces and boilers through the addition of chemicals into the furnace using TIFI® Targeted In-Furnace Injection™ technology. Fuel Tech sells its FUEL CHEM program through its direct sales force and agents to industrial and utility power-generation facilities. At December 31, 2009, FUEL CHEM programs were installed on over 90 combustion units around the world, treating a wide variety of solid and liquid fuels, including coal, heavy oil, biomass and municipal waste. The FUEL CHEM program improves the efficiency, reliability and environmental status of plants operating in the electric utility, industrial, pulp and paper, waste-to-energy, university and district heating markets and offers numerous operational, financial and environmental benefits to owners of boilers, furnaces and other combustion units.

The key market dynamic for both technology segments is the continued use of fossil fuels, especially coal, as the principal fuel source for global electricity production. Coal accounts for approximately 50% of all U.S. electricity generation. Coal's share of global electricity generation is forecast to be approximately 45% by 2030. Major coal consumers include China, the United States and India.

Critical Accounting Policies and Estimates

The consolidated financial statements are prepared in accordance with accounting principles generally accepted in the United States of America, which require us to make estimates and assumptions. We believe that of our accounting policies (see Note 1 to the consolidated financial statements), the following involve a higher degree of judgment and complexity and are deemed critical. We routinely discuss our critical accounting policies with the Company's Audit Committee.

Revenue Recognition

Revenues from the sales of chemical products are recorded when title transfers, either at the point of shipment or at the point of destination, depending on the contract with the customer.

Fuel Tech uses the percentage of completion method of accounting for equipment construction and license contracts that are sold within the Air Pollution Control technology segment. Under the percentage of completion method, revenues are recognized as work is performed based on the relationship between actual construction costs incurred and total estimated costs at completion. Revisions in completion estimates and contract values in the period in which the facts giving rise to the revisions become known can influence the timing of when revenues are recognized under the percentage of completion method of accounting. Provisions are made for estimated losses on uncompleted contracts in the period in which such losses are determined. As of December 31, 2009, Fuel Tech had one construction contract in progress that was identified as a loss contract in the amount of $166. As of December 31, 2008, Fuel Tech had no construction contracts in progress that were identified as loss contracts.

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Fuel Tech's APC contracts are typically six to twelve months in length. A typical contract will have three or four critical operational measurements that, when achieved, serve as the basis for us to invoice the customer via progress billings. At a minimum, these measurements will include the generation of engineering drawings, the shipment of equipment and the completion of a system performance test.

As part of most of its contractual APC project agreements, Fuel Tech will agree to customer-specific acceptance criteria that relate to the operational performance of the system that is being sold. These criteria are determined based on mathematical modeling that is performed by Fuel Tech personnel, which is based on operational inputs that are provided by the customer. The customer will warrant that these operational inputs are accurate as they are specified in the binding contractual agreement. Further, the customer is solely responsible for the accuracy of the operating condition information; all performance guarantees and equipment warranties granted by us are void if the operating condition information is inaccurate or is not met.

Accounts receivable includes unbilled receivables, representing revenues recognized in excess of billings on uncompleted contracts under the percentage of completion method of accounting. At December 31, 2009 and December 31, 2008, unbilled receivables were approximately $7,814 and $5,552, respectively. Billings in excess of costs and estimated earnings on uncompleted contracts were $316 and $1,223, at December 31, 2009 and December 31, 2008, respectively. Such amounts are included in other accrued liabilities on the consolidated balance sheet.

Fuel Tech has installed over 550 units with APC technology and has never failed to meet a performance guarantee when the customer has provided the required operating conditions for the project. As part of the project implementation process, we perform system start-up and optimization services that effectively serve as a test of actual project performance. We believe that this test, combined with the accuracy of the modeling that is performed, enables revenue to be recognized prior to the receipt of formal customer acceptance.

Allowance for Doubtful Accounts

In order to control and monitor the credit risk associated with our customer base, we review the credit worthiness of customers on a recurring basis. Factors influencing the level of scrutiny include the level of business the customer has with Fuel Tech, the customer's payment history and the customer's financial stability. Representatives of our management team review all past due accounts on a weekly basis to assess collectibility. At the end of each reporting period, the allowance for doubtful accounts balance is reviewed relative to management's collectibility assessment and is adjusted if deemed necessary. Our historical credit loss has been insignificant.

Assessment of Potential Impairments of Goodwill and Intangible Assets

Goodwill and indefinite-lived intangible assets are no longer amortized, but rather are reviewed annually (in the fourth quarter) or more frequently if indicators arise, for impairment. The Company does not have any indefinite-lived intangible assets other than goodwill. Such indicators include a decline in expected cash flows, a significant adverse change in legal factors or in the business climate, unanticipated competition, or slower growth rates, among others.

Goodwill is allocated among and evaluated for impairment at the reporting unit level, which is defined as an operating segment or one level below an operating segment. Fuel Tech has two reporting units which are reported in the FUEL CHEM segment and the APC Technology segment. As of December 31, 2009 and 2008, goodwill allocated to the FUEL CHEM Technology segment was $1,723 and 1,723, respectively, while goodwill allocated to the APC Technology segment was $19,328 and $3,435, respectively. The $15,893 increase in goodwill in the APC Technology segment is due to the acquisition of substantially all of the assets of Advanced Combustion Technology, Inc. on January 5, 2009.

The evaluation of impairment involves comparing the current fair value of the business to the carrying value. Fuel Tech uses a discounted cash flow (DCF) model to determine the current fair value of its two reporting units as this methodology was deemed to best quantify the present values of the Company's expected future cash flows and yield a fair value that should be in line with the aggregate market value placed on the Company via the current stock price multiplied by the outstanding common shares. A number of significant assumptions and estimates are involved in the application of the DCF model to forecast operating cash flows, including markets and market share, sales volumes and prices, costs to produce and working capital changes. Events outside the Company's control, specifically market conditions that impact revenue growth assumptions, could significantly impact the fair value calculated. These assumptions are, however, somewhat insensitive to these external events in all but the most egregious situations due to the relatively conservative nature upon which such future growth assumptions were developed. Management considers historical experience and all available information at the time the fair values of its reporting units are estimated. However, actual fair values that could be realized in an actual transaction may differ from those used to evaluate the impairment of goodwill.

The application of our DCF model in estimating the fair value of each reporting segment is based on the 'income' approach to business valuation. In using this approach for each reportable segment, we forecast segment revenues and expenses out to perpetuity and then discount the resulting cash flows back using an appropriate discount rate. The forecast considers, among other items, the current and expected business environment, expected changes in the fixed and variable cost structure as the business grows and a revenue growth rate that we feel is both achievable and sustainable. The discount rate used is composed of a number of identifiable risk factors, including equity risk and small company premiums, that when added together, results in a total return that a prudent investor would demand for an investment in our company.

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In the event the estimated fair value of a reporting unit per the DCF model is less than the carrying value, additional analysis would be required. The additional analysis would compare the carrying amount of the reporting unit's goodwill with the implied fair value of that goodwill, which may involve the use of valuation experts. The implied fair value of goodwill is the excess of the fair value of the reporting unit over the fair values assigned to all of the assets and liabilities of that unit as if the reporting unit was acquired in a business combination and the fair value of the reporting unit represented the purchase price. If the carrying value of goodwill exceeds its implied fair value, an impairment loss equal to such excess would be recognized, which could significantly and adversely impact reported results of operations and stockholders' equity.

Based upon the nature of the goodwill recorded on the balance sheets as of December 31, 2009 and 2008, the Company believes that, in order for an impairment to occur, a series of material prolonged negative economic events would have to occur. These events would most likely be seen in economic indicators such as suppressed consolidated revenues or Common Stock price, reduced cash flows or declining APC order backlog. Management does not believe that as pertains to Fuel Tech's business that certain negative economic events related to the global economic downturn are likely to be prolonged.

Impairment of Long-Lived Assets and Amortizable Intangible Assets

Long-lived assets, including property, plant and equipment (PP&E) and intangible assets, are reviewed for impairment when events and circumstances indicate that the carrying amount of the assets (asset groups) may not be recoverable. An impairment loss is recognized when estimated future undiscounted cash flows expected to result from the use of the asset (asset group) and its eventual disposition are less than the carrying amount. When quoted market prices are not available, various valuation techniques, including the discounted value of estimated future cash flows, are utilized. This process involves examining the operating condition of individual assets and estimating a fair value based upon its current condition, relevant market factors and remaining estimated operational life compared to remaining depreciable life. However, due to the nature of our PP&E, which is comprised mainly of assets related to our headquarters building and equipment deployed at customer locations for our FUEL CHEM programs, and the shorter-term duration over which FUEL CHEM equipment is depreciated, the likelihood of impairment is low. The discontinuation of a FUEL CHEM program at a customer site would most likely result in the re-deployment of all or most of the effected assets to another customer location rather than an impairment.

Valuation Allowance for Deferred Income Taxes

Deferred tax assets represent deductible temporary differences and net operating loss and tax credit carryforwards. A valuation allowance is recognized if it is more likely than not that some portion of the deferred tax asset will not be realized. At the end of each reporting period, Fuel Tech reviews the realizability of the deferred tax assets. As part of this review, we consider if there are taxable temporary differences that could generate taxable income in the future, if there is the ability to carry back the net operating losses or credits, if there is a projection of future taxable income, and if there are any tax planning strategies that can be readily implemented.

Stock-Based Compensation

Fuel Tech recognizes compensation expense for employee equity awards ratably over the requisite service period of the award. We utilize the Black-Scholes option-pricing model to estimate the fair value of awards. Determining the fair value of stock options using the Black-Scholes model requires judgment, including estimates for (1) risk-free interest rate – an estimate based on the yield of zero–coupon treasury securities with a maturity equal to the expected life of the option; (2) expected volatility – an estimate based on the historical volatility of Fuel Tech's Common Stock for a period equal to the expected life of the option; and (3) expected life of the option – an estimate based on historical experience including the effect of employee terminations. If any of these assumptions differ significantly from actual, stock-based compensation expense could be impacted.

Recently Adopted Accounting Standards

In June 2009, the Financial Accounting Standards Board (FASB) issued authoritative guidance establishing two levels of U.S. generally accepted accounting principles (GAAP) — authoritative and non-authoritative — and making the Accounting Standards Codification (ASC) the source of authoritative, non-governmental GAAP, except for rules and interpretive releases of the Securities and Exchange Commission. This guidance, which was incorporated into Accounting Standards Codification Topic 105, "Generally Accepted Accounting Principles," was effective for financial statements issued for interim and annual periods ending after September 15, 2009. The adoption changed certain disclosure references to U.S. GAAP, but did not have any other effect on the Company's consolidated financial statements.

In June 2009, the FASB issued revised authoritative guidance related to variable interest entities (VIE), which requires entities to perform a qualitative analysis to determine whether a variable interest gives the entity a controlling financial interest in a VIE. The guidance also requires an ongoing reassessment of variable interests and eliminates the quantitative approach previously required for determining whether an entity is the primary beneficiary. This guidance, which was incorporated into ASC Topic 810, "Consolidation," will be effective as of the beginning of an entity's first annual reporting period that begins after November 15, 2009 (January 1, 2010 for the Company). The implementation of this standard did not have a material effect on the Company's consolidated financial statements.

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In May 2009, the FASB issued authoritative guidance establishing general standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued. This guidance, which was incorporated into ASC Topic 855, "Subsequent Events," was effective for interim or annual financial periods ending after June 15, 2009, and the adoption did not have any impact on the Company's consolidated financial statements. We have evaluated subsequent events through March 4, 2010, the date this report on Form 10-K was filed with the U.S. Securities and Exchange Commission. We made no significant changes to our consolidated financial statements as a result of our subsequent events evaluation.

In April 2009, the FASB issued updated guidance related to business combinations, which is included in the Codification in ASC 805-20, "Business Combinations — Identifiable Assets, Liabilities and Any Non-controlling Interest." ASC 805-20 amends the provisions in ASC 805 for the initial recognition and measurement, subsequent measurement and accounting, and disclosures for assets and liabilities arising from contingencies in business combinations. ASC 805-20 is effective for contingent assets or contingent liabilities acquired in business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008. See Note 2 for a discussion of the adoption impact.

2009 versus 2008

Revenues for the years ended December 31, 2009 and 2008 were $71,397 and $81,074, respectively. The year-over-year decrease of $9,677, or 12%, was driven by reduced orders in the APC technology segment.

Revenues for the APC technology segment were $34,721 for the year ended December 31, 2009, a decrease of $9,672, or 22%, versus fiscal 2008. The global financial crisis coupled with domestic regulatory uncertainty regarding the eventual timing of the implementation of the Clean Air Interstate Rule (CAIR) contributed to an across-the-board slowdown of capital project orders for pollution control equipment from our customer base which had a negative effect on segment revenues and the APC order backlog. While revenues are down from the prior year, this segment remains uniquely positioned to capitalize on the next phase of increasingly stringent U.S. and Chinese air quality standards, specifically on NOx control. Interest in Fuel Tech's suite of pollution control technologies, on both a new and retrofit basis, remains strong, both domestically and abroad, and 2009 quotation and order activity was substantially in excess of that experienced in 2008. During 2009, Fuel Tech announced new APC contracts valued at approximately $37,800.

Revenues for the FUEL CHEM technology segment for the year ended December 31, 2009 were $36,676, substantially on par with the record revenues reported for the year ended December 31, 2008 of $36,681. This segment's ability to generate revenues comparable to prior year levels demonstrates the continued market acceptance of Fuel Tech's patented TIFI Targeted In-Furnace Injection technology, particularly on coal-fired units, which represent the largest market opportunity for the technology.

During 2009, Fuel Tech added 10 new units to its customer base, four of which were coal-fired units. The addition of these customer units, which historically average approximately $1,000 in annual revenues once converted to commercial status, and increased project demonstration activity helped mitigate the decrease in demand for electricity, largely related to the economic recession, that has dictated that certain Fuel Tech customers shut down or scale back some boiler operations. This, in turn, has resulted in some FUEL CHEM programs being operated at reduced levels or, in some cases, being temporarily turned off. Historically, most demonstrations convert into commercial accounts.

During a FUEL CHEM demonstration period, the Company will typically absorb all of the direct costs (e.g., chemicals, on-site personnel, equipment depreciation and demonstration-related travel expenses) and indirect costs of operating the demonstration and will offset these costs with partial billings to the customer. While each demonstration is unique, a typical demonstration will operate for 90 days and the Company will accumulate future billing amounts that will usually be invoiced to the customer only if the FUEL CHEM program converts to commercial status. These amounts may range from less than $100 to over $1,000 depending on the quantity of chemical fed, the agreed-upon cost sharing arrangement and the length of the demonstration program.

During the demonstration period, the aggregate cost of all FUEL CHEM demonstration programs will have a dilutive effect on the segment gross margin percentage as the related revenues earned will approximate the costs incurred and result in nominal gross margin dollars being recorded. In certain situations, the Company agrees to fully fund a demonstration program due to the strategic importance of its success and conversion to commercial status. In these cases, the specific program's recognized revenues will be zero and the gross margin dollar contribution will be negative by the amount of the program's cost, thus even further diluting the segment's gross margin percentage.

Cost of sales for the year ended December 31, 2009 and 2008 was $42,444 and $44,345, respectively. Cost of sales as a percentage of revenues for the years ended December 31, 2009 and 2008 was 59% and 54%, respectively. Cost of sales as a percentage of revenue for the APC technology segment increased to 62% in 2009 from 55% in 2008. The increase is attributed to the mix of lower margin project business, including one large contract with a significant amount of lower margin installation work and the pass through of approximately $2.2 million in catalyst sales at a nominal mark-up percentage. Cost of sales as a percentage of revenue for the FUEL CHEM technology segment increased to 57% in 2009 from 55% in 2008 primarily due to increased chemical manufacturing costs.

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Selling, general and administrative expenses for the years ended December 31, 2009 and 2008 were $31,492 and $28,402, respectively. The increase of $3,090, or 11%, is attributed to the following:

– Personnel and other expenses related to the acquisitions of substantially all of the assets of Tackticks LLC, FlowTack LLC, and ACT contributed additional incremental expenses of $2,292 for fiscal 2009.

– The implementation of a new sales commission program for both the APC and FUEL CHEM technology segments resulted in an increase of $793 in commission expense.

– The Company also incurred year-over-year increases in depreciation expense of $395 driven by the acceleration of leasehold improvement amortization expense related to the termination of the current Stamford office lease, legal fees of $250 due to international contracts and acquisition-related activities, and accounting and auditing fees of $109 primarily related to acquisition-related activities.

– Partially offsetting these amounts were a $781 one-time gain from the revaluation of the contingent liability related to the ACT acquisition.

Research and development expenses were $542 and $2,100 for the years ended December 31, 2009 and 2008, respectively. The decline in expenditures is due to the Company moderating its near-term R&D expenditures in the wake of the global financial crisis. However, Fuel Tech maintained its focused approach in the pursuit of commercial applications for its technologies outside of its traditional markets, and in the development and analysis of new technologies that could represent incremental market opportunities domestically and abroad.

Interest income for the year ended December 31, 2009 decreased by $709 to $32 versus 2008 predominantly due to reductions in cash balances on hand as a result of the cash outlay for the acquisitions of substantially all of the assets of Tackticks, LLC and FlowTack, LLC, and ACT coupled with a decrease in the average return in the Company's interest-bearing accounts in which the cash is invested. Interest expense of $120 was recorded in 2009 primarily due to the debt incurred to start-up activities at Fuel Tech's office in Beijing, China. Finally, the modest change in other income / (expense) is due to the impact of foreign exchange rates as it relates to balances denominated in foreign currencies and is translation, not transaction, in nature.

For the year end December 31, 2009, Fuel Tech recorded an income tax benefit of $1,104 on the Company's pre-tax loss of ($3,410). For the year ended December 31, 2008, Fuel Tech recorded income tax expense of $3,247 on pre-tax income of $6,607.

2008 versus 2007

Revenues for the years ended December 31, 2008 and 2007 were $81,074 and $80,297, respectively. The year-over-year increase of $777, or 1%, was driven by a 13% increase in revenues from the FUEL CHEM technology segment that were largely offset by a modest revenue decline in the APC technology segment.

Revenues for the APC technology segment were $44,393 for the year ended December 31, 2008, a decrease of $3,357, or 7%, versus 2007. The global financial crisis and the vacatur of the Clean Air Interstate Rule (CAIR) in July 2008 (subsequently remanded in December 2008) had a negative effect on segment revenues and APC order backlog. This segment is well positioned to capitalize on CAIR — the next phase of increasingly stringent U.S. air quality standards — which is effective January 1, 2009, and the Clean Air Visibility Rule (CAVR), which is effective January 1, 2013. Thousands of utility and industrial boilers will be impacted by these regulations and Fuel Tech's technologies will serve as an important element in enabling utility and industrial boiler unit owners to attain compliance. During 2008, Fuel Tech announced new contracts valued at approximately $21,000.

Revenues for the FUEL CHEM technology segment were $36,681 for the year ended December 31, 2008, an increase of $4,134, or 13%, versus 2007. This segment's growth is indicative of the continued market acceptance of Fuel Tech's patented TIFI Targeted In-Furnace Injection technology, particularly on coal-fired units, which represent the largest market opportunity for the technology, both domestically and abroad. During 2008, Fuel Tech added 15 new units to its customer base, 13 of which were coal-fired units, the largest annual total in the Company's history. As these units were added in 2008 they generated incremental revenues verses 2007 and were the primary reason for the year-over-year increase in segment revenues. Historically, most demonstrations convert into commercial accounts.

During a FUEL CHEM demonstration period, the Company will typically absorb all of the direct costs (e.g., chemicals, on-site personnel, equipment depreciation and demonstration-related travel expenses) and indirect costs of operating the demonstration and will offset these costs with partial billings to the customer. While each demonstration is unique, a typical demonstration will operate for 90 days and the Company will accumulate future billing amounts that will usually be invoiced to the customer only if the FUEL CHEM program converts to commercial status. These amounts may range from less than $100 to over $1,000 depending on the quantity of chemical injection, the agreed-upon cost sharing arrangement and the length of the demonstration program.

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During the demonstration period, the aggregate cost of all FUEL CHEM demonstration programs will have a dilutive effect on the segment gross margin percentage as the related revenues earned will approximate the costs incurred and result in nominal gross margin dollars being recorded. In certain situations, the Company agrees to fully fund a demonstration program due to the strategic importance of its success and conversion to commercial status. In these cases, the specific program's recognized revenues will be zero and the gross margin dollar contribution will be negative by the amount of the program's cost, thus even further diluting the segment's gross margin percentage.

Cost of sales for the years ended December 31, 2008 and 2007 was $44,345 and $42,471, respectively. Cost of sales as a percentage of revenues for the years ended December 31, 2008 and 2007 was 54% and 53%, respectively. The 2008 cost of sales percentage for the APC technology segment increased to 55% from 54% in 2007. The increase is attributable to the mix of project business. The cost of sales percentage for the FUEL CHEM technology segment increased from 51% in 2007 to 55% in 2008 due to incremental costs associated with demonstration programs and other related start-up activities related to the record number of new incremental units noted above, especially for the demonstrations in India and China. During 2008, the Company invested $888 and $300, primarily in engineering labor and chemicals, for FUEL CHEM demonstration programs in India and China, respectively. In addition, the aggregate 2008 FUEL CHEM demonstration expenses for new units in the U.S. was approximately $930. These demonstration programs resulted in a 2008 cost of sales percentage increase of 5.9% versus 2007.

Selling, general and administrative expenses for the years ended December 31, 2008 and 2007 were $28,402 and $24,950, respectively. The $3,452 increase over 2007 is principally attributable to the following:

- Fuel Tech recorded $5,815 in stock compensation expense in 2008 in accordance with ASC 718, as discussed in Note 7 to the consolidated financial statements. This amount represented a $1,024 increase over 2007, attributable to stock option awards to Directors and certain Fuel Tech employees in 2008 and the on-going expense recognition related to stock options awarded in prior years.

- Fuel Tech invested approximately $2,000 in personnel and other costs, including expenses associated with the start-up of the Company's Beijing, China office, in the areas of Engineering, Sales, Marketing and Administration to ensure the Company's financial and operational infrastructure are able to accommodate anticipated future growth.

- Partially offsetting this unfavorable variance was a reduction in annual incentive expenses of $1,500 as the minimum income threshold for the year ended December 31, 2008 was not met and, thus, no 2008 bonus payments were made under the Company's incentive plan.

- The Company also incurred incremental year-over-year expense increases in the following areas: consulting services increased $486 driven by expertise required in certain foreign countries for initial market penetration and domestic financial advisory services; acquisition-related expenses of $390, insurance expense increased $210 due to general inflation, the addition of new policies, increased coverage on certain policies and an increase in insurable assets; recruiting fees increased $316 due to the costs associated with adding one new member to our Board of Directors and the hiring of a new Chief Financial Officer; and non-income taxes increased $199 due primarily to a foreign business tax increase and additional real estate taxes on the Company's new headquarters facility.

Research and development expenses were $2,100 and $2,137 for the years ended December 31, 2008 and 2007, respectively. Fuel Tech has established a more focused approach in the pursuit of commercial applications for its technologies outside of its traditional markets, and in the development and analysis of new technologies that could represent incremental market opportunities.

Interest income for the year ended December 31, 2008 decreased by $893 versus 2007 due to decreases in the interest rates paid by institutions with whom the Company's investments were located. Further, Fuel Tech recorded interest expense of $135 in 2008 related specifically to a short-term credit facility that was used to support the start-up of Fuel Tech's office in Beijing, China. Finally, the change in other income (expense) is due largely to the impact of foreign exchange rates related to balances denominated in foreign currencies.

For the year ended December 31, 2008, Fuel Tech recorded tax expense of $3,247. For the year ended December 31, 2007, Fuel Tech recorded tax expense of $5,187 that predominantly represented deferred tax expense related to taxable income recognized in 2007.

Liquidity and Sources of Capital

At December 31, 2009, Fuel Tech had cash and cash equivalents of $20,965 and working capital of $30,578 versus cash and cash equivalents of $28,149 and working capital of $43,956 at December 31, 2008. Operating activities provided $13,527 of cash for the year ended December 31, 2009, primarily due to a decrease in accounts receivable of $5,488 due to the timing of customer receipts, and the add back of non-cash items including stock compensation expense of $6,001, depreciation expense of $3,796 and amortization expense of $1,312 and a decrease in prepaid expenses of $3,293. Partially offsetting these items were a net loss due to unfavorable business operations of $2,390, a decrease in accounts payable of $2,372 due to the timing of vendor invoices and related payments, and a decrease in income tax provision of $1,492.

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Operating activities provided $8,047 of cash for the year ended December 31, 2008, primarily due to the favorable operating results of the business segments and that resulted in net income of $3,360, a decrease in accounts receivable of $8,491 due to the timing of customer receipts, and the add back of non-cash items including stock compensation expense of $5,815, depreciation expense of $2,810 and amortization expense of $184. Partially offsetting these items were a decrease in accounts payable of $5,436 due to the timing of vendor invoices and related payments, an increase in prepaid expense of $3,509, and a decrease in accrued and other non-current liabilities of $3,720.

Investing activities used cash of $22,389 for the year ended December 31, 2009. This amount was comprised of three items: the acquisition of substantially all of the assets of ACT required a total funding of $20,185; capital expenditures of $2,004, primarily to support and enhance the operations of the FUEL CHEM technology segment; and an increase in restricted cash of $200 to support the transfer of pre-existing stand-by letters of credit and bank guaranties from Wachovia to JPM Chase. Other than the outfitting of the new corporate headquarters building in 2008, the Company has historically incurred a nominal amount of maintenance capital expenditures.

The Company generated cash from financing activities for the year ended December 31, 2009 of $1,596, primarily from the excess tax benefits realized of $605 from stock options exercised during the year and from additional borrowings of $737 to support the growth of the Beijing office.

On June 30, 2009, Fuel Tech entered into a $25,000 revolving credit facility (the "Facility") with JPMorgan Chase Bank, N.A (JPM Chase). The Facility has a term of two years through June 30, 2011, is unsecured, bears interest at a rate of LIBOR plus a spread range of 250 basis points to 300 basis points, as determined under a formula related to the Company's leverage ratio, and has the Company's Italian subsidiary, Fuel Tech S.r.l., as a guarantor. Fuel Tech can use this Facility for cash advances and standby letters of credit. As of December 31, 2009, there were no outstanding borrowings on this Facility. The Company's prior facility with Wachovia Bank, N.A. was terminated on June 30, 2009.

At its inception, the Facility contained several debt covenants with which the Company must comply on a quarterly or annual basis, including: an annual capital expenditure limit of $10,000 and a minimum net income for the quarterly period ended September 30, 2009 of $750. For subsequent periods, the Facility covenants included a maximum funded debt to EBITDA ratio of 2.0:1.0 for the quarterly period ended December 31, 2009 and a maximum funded debt to EBITDA ratio of 1.5:1.0 for all succeeding quarterly periods until the facility expires. Maximum funded debt is defined as all borrowed funds, outstanding standby letters of credit and bank guarantees. EBITDA includes after tax earnings with add backs for interest expense, income taxes, and depreciation and amortization expenses. In addition, the Company must maintain a minimum tangible net worth of $42,000, adjusted upward for 50% of net income generated and 100% of all capital issuances.

At December 31, 2009, the Company was in compliance with all loan covenants on the Facility, including a year-to-date capital expenditure amount of $2,004, an actual quarterly net income of $232 and a tangible net worth amount of $50,422, which was above the required amount of $47,477 by $2,945. Due to the Company's quarterly net loss of ($698) for the three-month period ended September 30, 2009, however, the Company was in breach of its minimum quarterly net income covenant of $750. The Company amended the Facility to obtained a waiver of this covenant breach from JPM Chase for the quarterly period ended September 30, 2009 and revised certain financial covenants as follows: for the three-month period ended December 31, 2009 the Company shall achieve a Minimum Net Income of ($2,000), and for the three-month period ended March 31, 2010 the Company's Leverage Ratio shall not exceed 2.75:1.0. The purchase price for allowable acquisitions made during any fiscal year was also lowered to $5,000 in the aggregate if the Leverage Ratio is greater than 2.75:1.0. No other Facility covenants were modified for any other period. The Company's spread matrix for fees paid on items such as standby letters of credit was adjusted upward to include additional tiers tied to the quarterly calculated Leverage Ratio.

Beijing Fuel Tech Environmental Technologies Company, Ltd. (Beijing Fuel Tech), a wholly-owned subsidiary of Fuel Tech, has a revolving credit facility (the "China Facility") agreement with JPM Chase for RMB 35 million (approximately $5,000), which expires on June 30, 2010. The facility is unsecured, bears interest at a rate of 120% of the People's Bank of China (PBOC) Base Rate and does not contain any material debt covenants. Beijing Fuel Tech can use this facility for cash advances and bank guarantees. As of December 31, 2009, Beijing Fuel Tech has borrowings outstanding in the amount $2,925.

At December 31, 2009, the Company had outstanding standby letters of credit and bank guarantees, predominantly to customers, totaling approximately $5,823 in connection with contracts in process. Fuel Tech is committed to reimbursing the issuing bank for any payments made by the bank under these instruments. At December 31, 2009, there were no cash borrowings under the revolving credit facility and approximately $19,177 was available. Management has met with the Company's lending institutions and, during the course of those meetings, was not made aware of any information indicating that they will not be able to perform their obligations for any letters of credit or guarantees issued, nor be unable to supply funds to Fuel Tech if the Company chooses to borrow funds under its two revolving credit facilities.

In the event of default on either the JPM Chase domestic facility or the JPM Chase China facility, the cross default feature in each allows the lending bank to accelerate the payments of any amounts outstanding and may, under certain circumstances, allow the bank to cancel the facility. If the Company were unable to obtain a waiver for a breach of covenant and the bank accelerated the payment of any outstanding amounts, such acceleration may cause the Company's cash position to deteriorate or, if cash on hand were insufficient to satisfy the payment due, may require the Company to obtain alternate financing to satisfy the accelerated payment.

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Interest payments in the amount of $120, $135 and $24 were made during the years ended December 31, 2009, 2008 and 2007, respectively.

In the opinion of management, Fuel Tech's expected near-term revenue growth will be driven by the timing of penetration of the coal-fired utility marketplace via utilization of its TIFI technology, by utility and industrial entities' adherence to the NOx reduction requirements of the various domestic environmental regulations, and by the expansion of both business segments in non-U.S. geographies. Fuel Tech expects its liquidity requirements to be met by the operating results generated from these activities.

Contractual Obligations and Commitments

In its normal course of business, Fuel Tech enters into agreements that obligate Fuel Tech to make future payments. The operating lease obligations noted below are primarily related to supporting the operations of the business.

There are no purchase obligations in the table below

	Payments due by period in thousands of dollars				
Contractual Cash Obligations	**Total**	**Less than 1 year**	**1-3 years**	**3-5 years**	**More than 5 years**
Short-Term Debt Obligations	$2,925	$2,925	$ —	$ —	$ —
Estimated interest payments on long-term debt obligations*	170	170	—	—	—
Operating Lease Obligations	3,955	623	1,075	807	1,450
Total	$7,050	$3,718	$1,075	$807	$1,450

* Long-term debt obligations consist solely of borrowings under the Company's Chinese revolving credit facility which bears interest at a rate of 120% of the People's Bank of China (PBOC) Base Rate, or 5.8%, at December 31, 2009.

Interest payments in the amount of $120, $135 and $24 were made during the years ended December 31, 2009, 2008 and 2007, respectively.

Fuel Tech, in the normal course of business, uses bank performance guarantees and letters of credit in support of construction contracts with customers as follows:

- in support of the warranty period defined in the contract; or
- in support of the system performance criteria that are defined in the contract.

In addition, Fuel Tech uses letters of credit as security for other obligations as needed in the normal course of business. As of December 31, 2009, Fuel Tech had outstanding bank performance guarantees and letters of credit as noted in the table below:

	Commitment expiration by period in thousands of dollars				
Commercial Commitments	**Total**	**Less than 1 year**	**2-3 years**	**4-5 years**	**Thereafter**
Standby letters of credit and bank guarantees	$5,622	$4,819	$165	$638	$ —

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The following table summarizes Fuel Tech's ASC 740 obligations as of December 31, 2009. Please refer to Note 4 to the consolidated financial statements in this document for a description of our ASC 740 obligations.

	Commitment expiration by period in thousands of dollars				
Commercial Commitments	Total	Less than 1 year	2-3 years	4-5 years	Thereafter
ASC 740 Obligations	$724	$ —	$ —	$ —	$ 724

Off-Balance-Sheet Transactions

There were no off-balance-sheet transactions during the two-year period ended Decmeber 31, 2009.

Subsequent Events

The Company evaluated its December 31, 2009 consolidated financial statements for subsequent events through March 3, 2010, the date the consolidated financial statements were available to be issued. The Company is not aware of any subsequent events which would require recognition in the consolidated financial statements.

ITEM 7A - QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Fuel Tech's earnings and cash flow are subject to fluctuations due to changes in foreign currency exchange rates. We do not enter into foreign currency forward contracts or into foreign currency option contracts to manage this risk due to the immaterial nature of the transactions involved.

Fuel Tech is also exposed to changes in interest rates primarily due to its long-term debt arrangement (refer to Note 9 to the consolidated financial statements). A hypothetical 100 basis point adverse move in interest rates along the entire interest rate yield curve would not have a materially adverse effect on interest expense during the upcoming year ended December 31, 2010.

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ITEM 8 — FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Report of Independent Registered Public Accounting Firm on Internal Control Over Financial Reporting

The Board of Directors and Stockholders
Fuel Tech, Inc.

We have audited Fuel Tech, Inc (a Delaware corporation) and Subsidiaries' (the "Company") internal control over financial reporting as of December 31, 2009 based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included the accompanying Management's Report on Internal Control Over Financial Reporting appearing under Item 9A. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, Fuel Tech and Subsidiaries maintained, in all material respects, effective internal control over financial reporting as of December 31, 2009, based on criteria established in *Internal Control – Integrated Framework* issued by COSO.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of the Company as of December 31, 2009 and 2008 and the related consolidated statements of operations, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2009, and our report dated March 4, 2010 expressed an unqualified opinion on those financial statements.

/s/ GRANT THORNTON LLP

Chicago, Illinois
March 4, 2010

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Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders
Fuel Tech, Inc.

We have audited the accompanying consolidated balance sheets of Fuel Tech, Inc. (a Delaware corporation) and Subsidiaries (the "Company") as of December 31, 2009 and 2008, and the related consolidated statements of operations, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2009. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Fuel Tech, Inc. and Subsidiaries as of December 31, 2009 and 2008 and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2009, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 to the consolidated financial statements, the Company adopted new accounting guidance on January 1, 2009 related to the accounting for business combination.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Company's internal control over financial reporting as of December 31, 2009, based on the criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) and our report dated March 4, 2010 expressed an unqualified opinion on the effective operation of internal control over financial reporting.

/s/ GRANT THORNTON LLP

Chicago, Illinois
March 4, 2010

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Fuel Tech, Inc.
Consolidated Balance Sheets
(in thousands of dollars, except share and per-share data)

December 31	2009	2008 As Adjusted, See Note 2
ASSETS		
Current assets:		
Restricted cash	$ 200	$ —
Cash and cash equivalents	20,965	28,149
Accounts receivable, net of allowance for doubtful accounts of $70 and $80, respectively	17,877	23,365
Inventories	450	1,014
Deferred income taxes	636	767
Prepaid expenses and other current assets	2,294	4,328
Total current assets	42,422	57,623
Property and equipment, net of accumulated depreciation of $14,562 and $12,588, respectively	15,549	17,515
Goodwill	21,051	5,158
Other intangible assets, net of accumulated amortization of $2,817 and $1,504, respectively	6,749	2,543
Deferred income taxes	4,183	2,560
Other assets	2,308	3,232
Total assets	$ 92,262	$ 88,631
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Short-term debt	$ 2,925	$ 2,188
Accounts payable	5,824	8,196
Accrued liabilities:		
Employee compensation	671	510
Other accrued liabilities	2,424	2,773
Total current liabilities	11,844	13,667
Other liabilities	2,196	1,389
Total liabilities	14,040	15,056
Stockholders' equity:		
Common stock, $.01 par value, 40,000,000 shares authorized, 24,211,967 and 24,110,967 shares issued, respectively	242	241
Additional paid-in capital	125,458	118,588
Accumulated deficit	(47,828)	(45,522)
Accumulated other comprehensive income	269	187
Nil coupon perpetual loan notes	81	81
Total stockholders' equity	78,222	73,575
Total liabilities and stockholders' equity	$ 92,262	$ 88,631

See notes to consolidated financial statements.

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Fuel Tech, Inc.
Consolidated Statements of Operations
(in thousands of dollars, except share and per-share data)

For the years ended December 31	2009	2008 As Adjusted, See Note 2	2007
Revenues	$ 71,397	$ 81,074	$ 80,297
Costs and expenses:			
Cost of sales	42,444	44,345	42,471
Selling, general and administrative	32,273	28,402	24,950
Gain on revaluation of ACT liability	(781)	—	—
Research and development	542	2,100	2,137
	74,478	74,847	69,558
Operating (loss) income	(3,081)	6,227	10,739
Interest expense	(120)	(135)	(24)
Interest income	32	741	1,634
Other (expense) / income	(241)	(226)	81
(Loss) Income before taxes	(3,410)	6,607	12,430
Income tax benefit / (expense)	1,104	(3,247)	(5,187)
Net (loss) income	$ (2,306)	$ 3,360	$ 7,243
Net (loss) income per Common Share:			
Basic	$ (0.10)	$ 0.14	$ 0.33
Diluted	$ (0.10)	$ 0.14	$ 0.29
Weighted-average number of Common Shares outstanding:			
Basic	24,148,000	23,608,000	22,280,000
Diluted	24,148,000	24,590,000	24,720,000

See notes to consolidated financial statements.

SNCR Operation Workshop

February 7, 2011

NO_x Roundtable Conference

Birmingham, AL

Kevin Dougherty - Fuel Tech

Fuel Tech Overview

- FUEL CHEM® Technology
  - Boiler Efficiency and Availability Improvements
  - Slag and Corrosion Reduction
  - Controls SO_3 Emissions and Addresses Related Issues
- Innovative Approaches to Enable Clean Efficient Energy
  - Capital Projects for Multi-Pollutant Control
  - NO_XOUT® Products including SNCR, CASCADE, RRI, ULTRA
  - Flue Gas Conditioning Systems for Particulate Control – Outside US and Canada
  - Sorbent Injection for SO_2 Control
- Flow Modeling and SCR Catalyst Management Services
  - Computational Flow Dynamics and Physical Flow Modeling for Power Plant Systems
  - SCR System Optimization and Catalyst Management Services
- Technology solutions based on Advanced Engineering Computer Visualization and Modeling
- Strong Balance Sheet (Stock Symbol: NASDAQ – FTEK)

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Recent Developments

- **Full Spectrum of Multi-Pollutant Control Options to Minimize Capital Investment and Maximize Performance**
- **Mercury**
  - TIFI through SO_3 Mitigation Improves Hg Capture
  - NO_xOUT Cascade provides 90+% Hg Oxidation with a single layer of SCR Catalyst
- **Particulate**
  - Flue Gas Conditioning Injection Systems for ESP Performance Enhancements
  - Markets Outside the US and Canada where Coal Ash is more difficult for ESP collection
  - Sonic Horns for Economizer and Backend Issues
- **SO_2 - Sorbent Injection Systems Low Capital Option (30-40% Reduction)**
- **SO_3 - TIFI controls backend issues**
- **Large Particle Ash - TIFI reduces Popcorn Ash Cleaning**

FUEL TECH
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Fuel Tech's Global Presence

Office Locations: Warrenville, IL; Stamford, CT; Durham, NC; Milan, Italy; Beijing, China

Countries where Fuel Tech does business: USA, Belgium, Canada, China, Columbia, Czech Republic, Denmark, Dominican Republic, Ecuador, France, Germany, India, Italy, Jamaica, Mexico, Poland, Portugal, Puerto Rico, Romania, South Korea, Spain, Taiwan, Turkey, United Kingdom, Venezuela

FUEL TECH
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Our Locations


Stamford, CT

Durham, NC

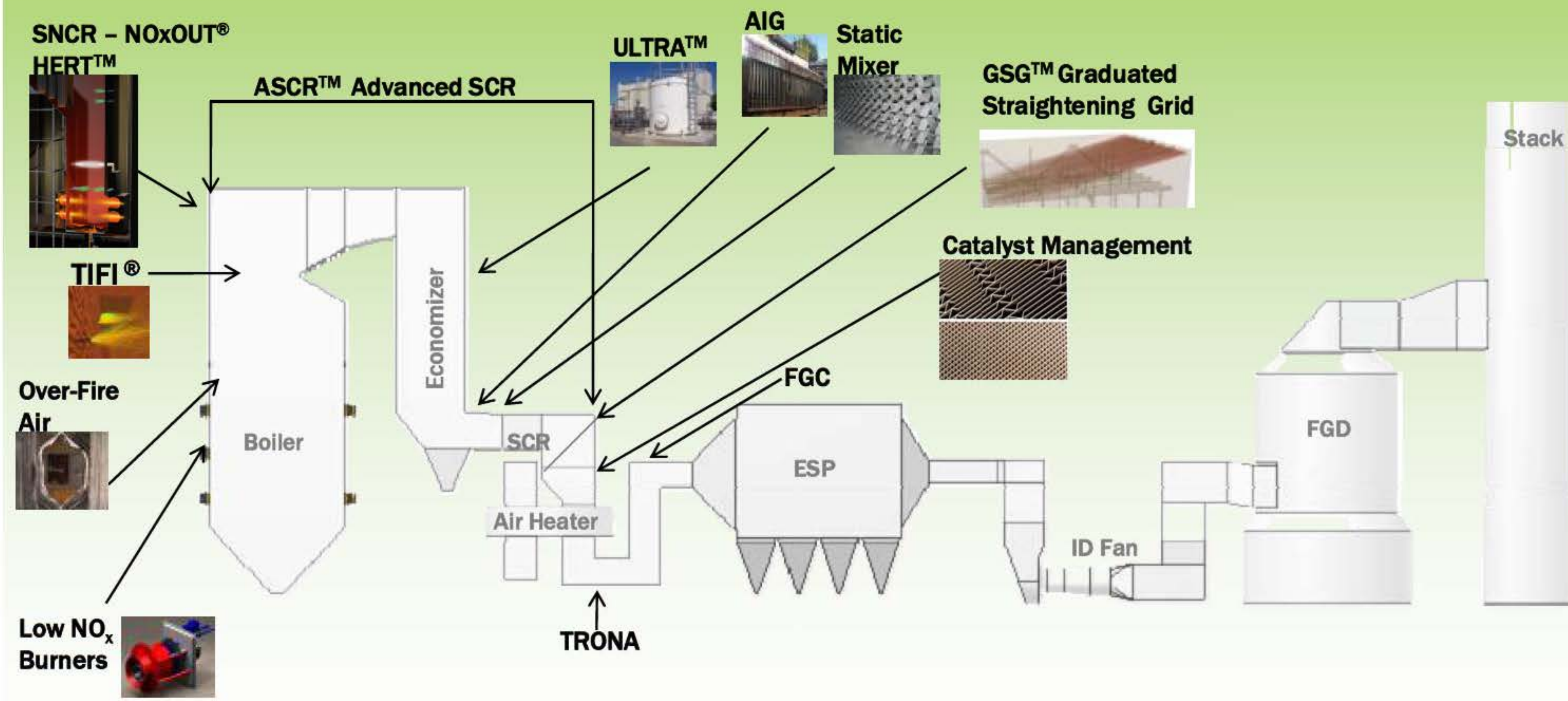


Milan, Italy


Warrenville, IL


Beijing, China

Typical Power Plant



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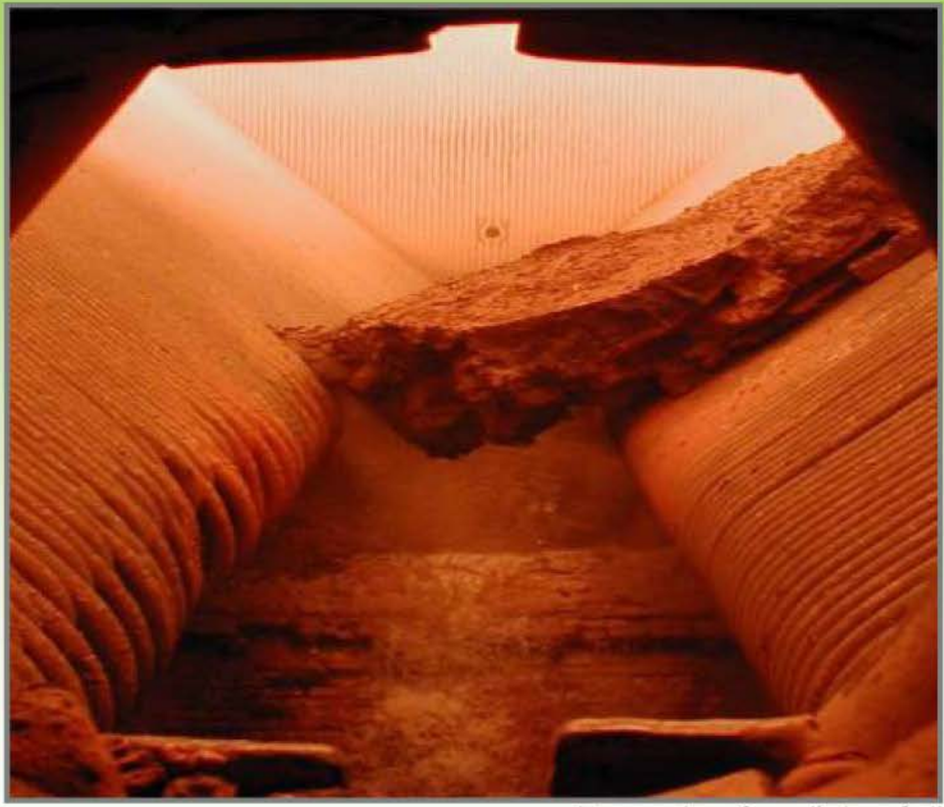
FUEL CHEM®

- Multiple Solutions
- Operating Program
- Overview

FUEL CHEM® Program

- Slag – the iron, sodium and other minerals in coal that do not burn
- Above the ash fusion temperature these minerals melt and adhere to steam pipes and boiler walls
- More economical coals can have higher slagging properties
- Traditional removal methods
  - During Operations:
    - Air / water cannons
    - Thermal shocking
  - Shotguns
  - During Outages (6-10 days):
    - Dynamite
    - Mechanical Removal with Scrapers / Chisels / Etc.


Example of a clinker fall

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FUEL CHEM® Program Benefits

- Efficiency
  - Recovery of Derated MW
  - Heat Rate Improvement for Steam Production
  - Reduced Fan Power Requirements
  - Reduced Sootblowing
  - Reduced Operating O_2 Level
  - Reduced CO in Furnace and at the Stack
  - Increased Fuel Flexibility

- Availability and Reliability
  - Reduced Forced Outage Time
  - Reduced Derates
  - Increased Capacity and Boiler Availability
  - Reduced Outage Cleaning Times
  - Reduced Exit Gas Temperatures

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FUEL CHEM® Program Benefits

- **Environmental**
  - CO_2 Reduction
  - SO_3 Reduction
  - Opacity Improvement
  - Promotes Mercury Capture
  - Reduced Large Particle Ash (LPA)
- **Safety**
  - Reduced Maintenance Operations
- **Maintenance**
  - Reduced Corrosion in Economizer, Air Heater, Ductwork, and Stack
  - Reduced Clinker Grinder Maintenance
  - Tube Life Extension
    - Reduced Sootblowing
    - Reduced Slag Damage
  - Reduced Cleaning Expenses
    - Less Explosives
    - Lower Water Consumption

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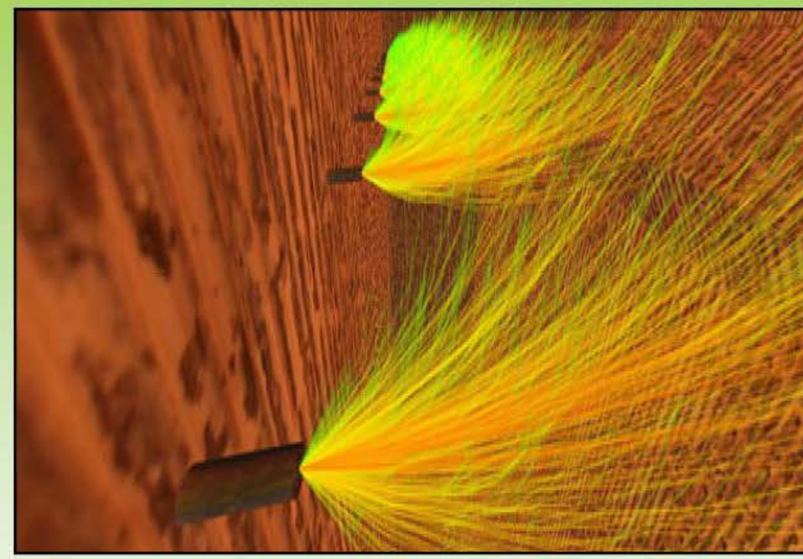
TIFI® Targeted In-Furnace Injection™ Program

TIFI® Targeted In-Furnace Injection™ Technology

- Improves Fuel Flexibility
- Reduces Slagging and Fouling
  - Providing Greater Boiler Efficiency
- SO_3 Plume & Opacity Control
- Heat Rate Improvement



TIFI® Injector on boiler wall

Fuel Types

Coal	Alternative Fuels	Residual Fuels
• PRB • ILB • Lignite • CAPP	• Biomass • Pet Coke • Hog Fuels • WTE Fuels	• No. 6 Fuel • Waste Oil • Bunker C • Liquid Waste Fuels • Black Liquor

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Technologies to enable clean efficient energy™

TIFI ® Technology Overview

TIFI MG™
- Utilizes magnesium hydroxide slurry
- Sprayed into the combustion unit at locations defined by computer modeling.
- TIFI MG solution reacts with slag as it is forming and penetrate existing deposits.

TIFI XP™
- Builds upon TIFI technology
- Designed to provide users both slag control and fuel flexibility.
- Allows users to burn less-expensive, yet higher-slagging coals such as ILB

TIFI MP™
- Furnace chemical injection program
- Uses two reagents for the reduction of SO_2

TIFI Flux™
- Specifically designed for cyclone boilers
- Focused on burning PRB and other low iron coals

TIFI BlueCat™
- Copper based product
- Used to lower carbon monoxide (CO) and unburned coal (LOI)
- Can be used in combination with TIFI MP to provide SO_2 trim control

TIFI Hybrid™
- Designed for oil-fired boilers
- Uses a combination of TIFI MG combined with in-fuel injection

TCI™
- Designed principally for boilers in the waste-to-energy (WTE) industry
- Inhibits corrosion and slag build-up

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Air Pollution Control Technologies

APC Technology Overview

Combustion

LNB

- 40-60% NO_x Reduction
- Industrial & utility applications
- Upgrades to existing burners available

OFA

- 35-70% NO_x Reduction over Low NO_x burners
- Unique port design enhances mixing to limit impact on combustion efficiency

Post-Combustion

SNCR

- 20-50% NO_x Reduction
- Urea-based maximized performance with minimal ammonia slip

ASCR

- 80+% NO_x Reduction
- 30-70% Less capital then traditional SCR

ULTRA

- Proprietary urea conversion process to generate ammonia for SCR systems
- Safer than ammonia
- Compatible with a wide range of urea sources

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NOx Regulations

- Clean Air Interstate Rule
  - 0.15 lb/MMBtu for 2009
  - 0.12 lb/MMBtu by 2015
- Transport Rule (final by mid-2011 for 2012 compliance)
- Transport Rule 2 (final by 2012 for 2014 compliance)
- Carper/Alexander Legislation (2011?)
- Boiler MACT and CISWI Rule
  - MACT Sources < 250MMBtu
  - Final Rule by February 2012 – 3 years to implement
- Other State Options and Rules

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Reducing NOx Emissions

- Fuel Switching
- Combustion Tuning
- Combustion Controls
  - Low-NOx Burners
  - Over-Fired Air
- Post-Combustion Controls
  - Selective Non-Catalytic Reduction
    - Fuel-Rich Reducing Environment
    - Fuel-Lean Oxidizing Environment
  - Selective Catalytic Reduction

Reducing NOx Emissions

- How to Capture the Strengths?
- How do we expand the Limits?
- Are there Synergies?

- Customized Solutions:
  - Emission Requirements
  - Existing NOx Controls
  - Total Site Emissions: GHG, CO, etc.
- A Complete Site Perspective

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A Complete Site Perspective

- Coal Specifications
- Combustion Systems: Burners & OFA
- Furnace Slag / Fouling
- Heat Rate and Furnace Efficiency
- Unit Capacity Factor
- Excess O2 / LOI
- Post-Combustion NOx Control
- SO2 and SO3

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NOx Reduction Strategies

- Cost Effective Total NOx Reduction
  - Starts with Combustion
  - Capitalize on Synergies of Combining Technologies
  - Get Guaranteed Performance on each Technology

- Fuel Tech Advanced SCR (ASCR)
  - LNB/OFA
  - SNCR
  - Reduced SO_3 Levels
  - ASCR catalyst will provide Hg Oxidation
  - Reduced On-going Catalyst Replacement Costs
  - NOx Reduction at Low Boiler Load and Low SCR Temperature
  - 80-85% Combined NOx Reduction

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NOx Reduction Technologies

Post-Combustion Options without Full Scale SCR

- **SNCR - NO_xOUT® and HERT Systems**
  - **\$5-20/kW Capital Cost including Installation**
  - **25-50% Reduction**
- **SNCR/RRI**
  - **\$7-22/kW and 40-60% Reduction**
- **ASCR™ Advanced SCR Systems**
  - **\$30-75/kW and 65-85% Reduction**

Full Scale SCR Technology

- **Up to \$300+/kW with *85-90% Reduction***
- **Fuel Tech Option for Safe Urea Reagent Supply – ULTRA™ (\$2-3M Capital)**

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NOx Reduction Technologies – Summary

- Low Capital Cost NOx Reduction Solutions
- Guaranteed NOx Reduction Process Performance and Compliance Assurance
- Complete Plant/Process Integration & Seamless Control
- Minimal Maintenance Requirements & Proven System Reliability
- Full Line of NOx Control Solutions
- More Than 25 Years Serving Owners of Power and Steam Generating Facilities

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APC Installed Experience

- Advanced Combustion Systems
  - Over 100 Units to Date for Low NOx Burners, OFA, and Combustion Optimization from 20 MW to 1200 MW
- NOxOUT® and HERT™ SNCR Systems
  - Over 600 Units to Date, With > 100 Utility Units
  - All Combustion and Fuel Types
- NOxOUT ULTRA® Systems
  - Over 24 Units to Date, 5 to 1,250 PPH of SCR Reagent Feed Systems
- SCR Design and Modeling Services
  - Over 55,000 MW's of SCR Design, 20,000 MW's of AIG Tuning
  - Modeling Solutions for Scrubbers, ESPs, FF, Dry Sorbent, HXs, Etc.

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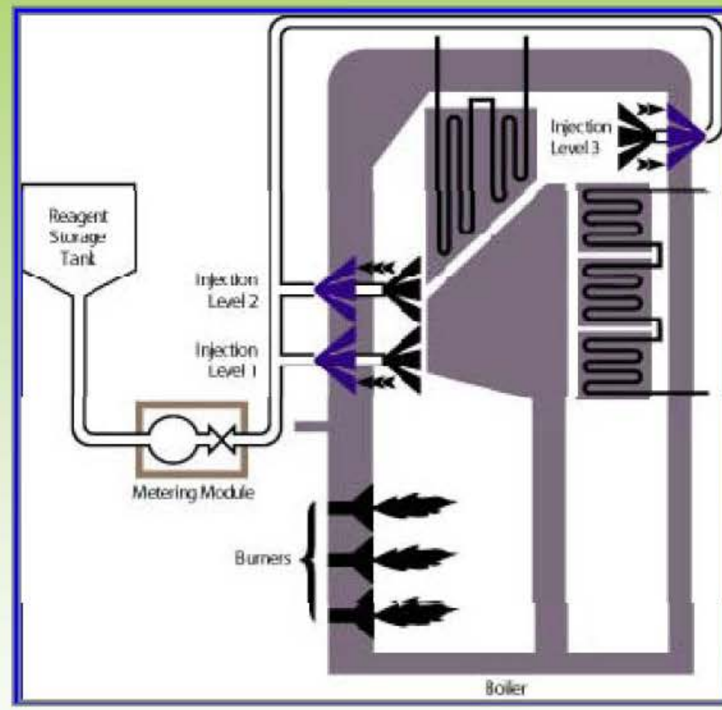
Selective Non-Catalytic Reduction (SNCR)

SNCR Technology Overview: NOxOUT® and HERT™ Systems

- In-furnace, Post-combustion NO_x Control
- Injection of Urea in Upper Furnace
- Process Reaction Temperature Range: 1600°F to 2200°F
- NO_x Reduction Range
  - Utility Boilers: 25 to 50%
  - Industrial Boilers: 30 to 70%



Selective Non-Catalytic Reduction

SNCR Process Chemical Reactions

(1) $4NO + 2CO(NH2)_2 + O_2 \Rightarrow 4N_2 + 4H_2O + 2CO_2$

(2) $2NO_2 + 2CO(NH2)_2 + O_2 \Rightarrow 3N_2 + 4H_2O + 2CO_2$

Nitrogen Oxides + Urea + Oxygen ⇨ Nitrogen + Water Vapor + Carbon Dioxide

Typically 95% of NOx is associated with Eq 1

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SNCR Technology Overview

- In-furnace, Post-combustion Control
  - Injection of Aqueous Urea Droplets
  - 25 – 70% NOx Reduction
  - Many Injection Options:
    - Compressed Air
    - Mechanical
    - Multiple Nozzle Lances – Water Cooled
  - Package Boilers to Utility Boilers
  - Option for Aqueous or Anhydrous Ammonia

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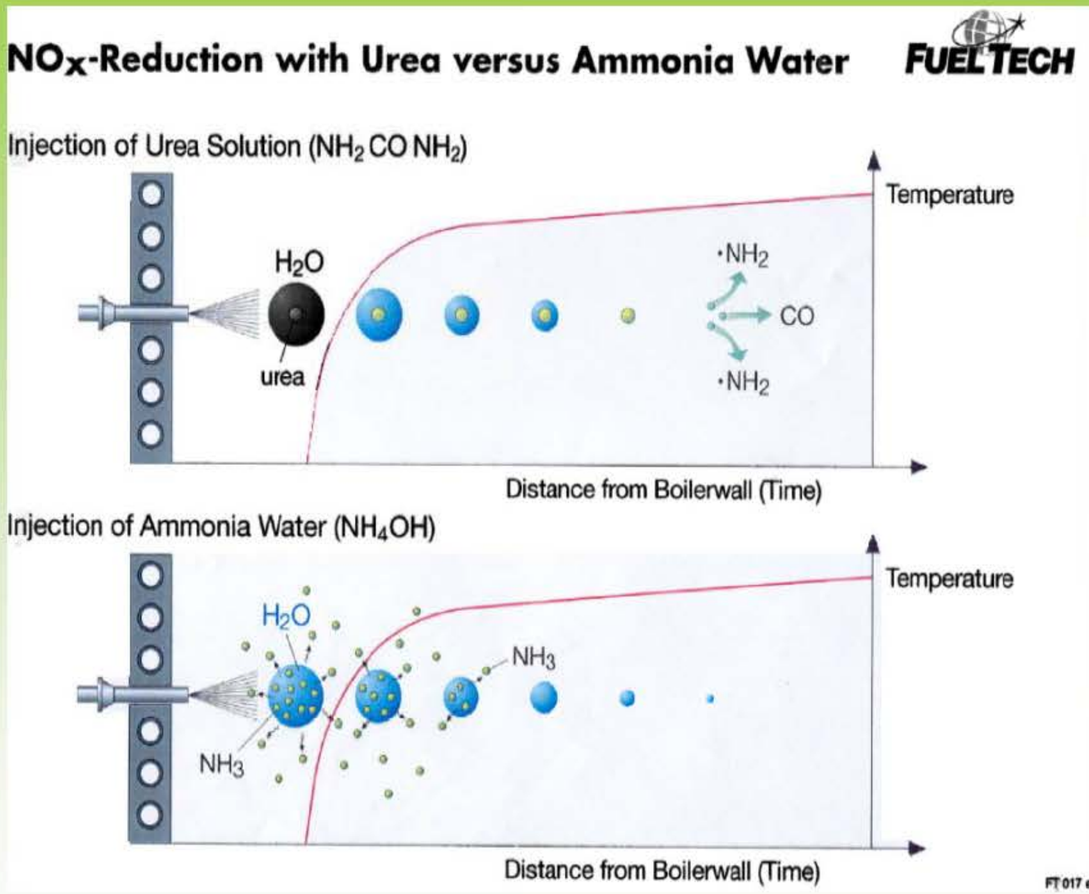
Advantages of Fuel Tech's SNCR System

- Guaranteed Proven NOx Reduction
  - 15 – 35% Utility
  - 20 – 70% Industrial/Incineration
  - Repeatable
  - Controlled NH3 Slip
- Low Capital Cost
- Fast Implementation
- Turn On/Off As Needed
- Compatible with Other APC Technologies
  - LNB/OFA
  - ASCR or SCR
  - ESP's and Fabric Filters

Urea vs. Ammonia for SNCR



Urea droplets formed by FTI injectors are characterized in test facilities using laser Doppler techniques.

SNCR Boiler and Fuel Experience

Utility Boilers
- T-fired
- Wet Bottom
- Wall Fired
- Cyclone
- Tower

Industrial
- Circulating Fluidized Bed
- Bubbling Fluidized Bed
- Stoker, Grate Fired
- Incinerators
- Industrial

Coal
- Bituminous
- Sub-bituminous
- Lignite

Other Fuels
- Oil – #2 and #6
- Natural Gas
- Refinery Gases (High CO)
- Municipal Solid Waste
- Tire Derived Fuel
- Wood
- Sludge

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SNCR Systems – Industry Experience

- Electric Utilities
- Wood-fired IPPs / CoGen
- TDF Plants
- Pulp & Paper
  - Grate-fired
  - Sludge Combustors
  - Recovery Boilers
  - Wellons Boilers
  - Cyclones

- Refinery Process Furnaces
- CO Boilers
- Petrochemical Industry
- CoGeneration Boilers
- Municipal Solid Waste
- Process Units
- Cement Kilns

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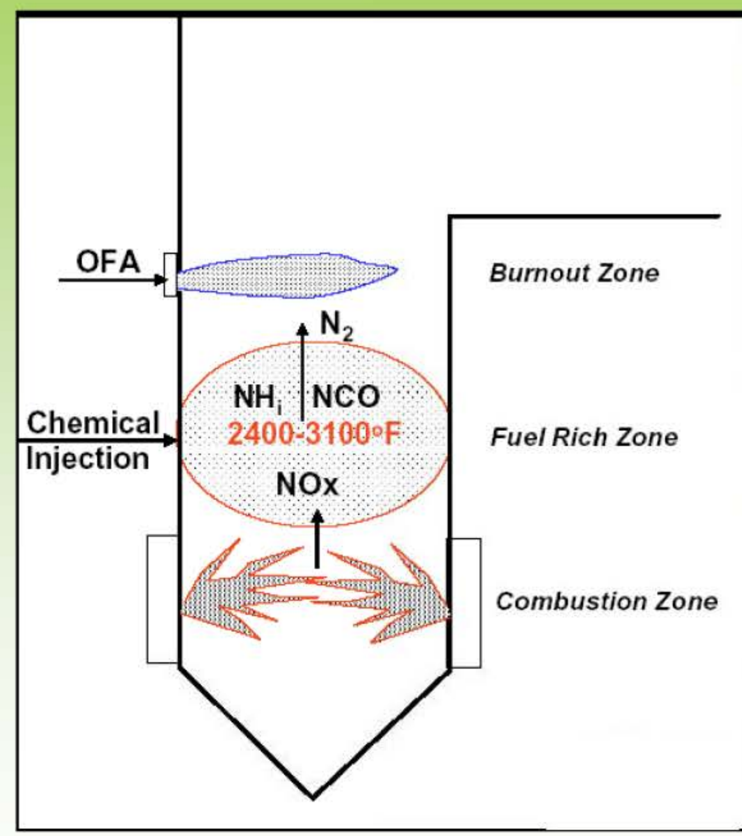
Rich Reagent Injection (RRI) Technology Overview

- 40 to 60% NO_x Reduction Combined with SNCR on Cyclone Boilers
- NO_x Reduction in 30% Range with RRI Only
- Non-catalytic Reduction of NO_x via Urea Injection in Sub-stoichiometric Conditions (SR: 0.85 to 0.95)
- No Reagent Slip Due to High Residence Time and Reagent Oxidation in the Burnout Zone
- Process Reaction Temperature Range: 2600°F to 3100°F
- Technology Licensed from REI



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SNCR PROCESS DESIGN AND MODELING

SNCR Critical Process Parameters

- Effective Temperature Window for Chemical Release and Reaction – 1600°F to 2200°F, Depending on Application
- Temperature too High ⇨ NH2 Oxidation to NOx, Temperature too Low ⇨ Ammonia Slip
- Flue Gas Velocity and Residence Time Considerations
- Background Gas Composition – NOx, CO, O_2, and Sulfur Content of the Fuel

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Controlling Risks SNCR:

- Carefully Target the Injection Zone
  - CFD Modeling
  - Field Assessments / Demonstrations
- Understand the Chemistry
  - Urea and ammonia Mechanisms
  - Ammonium Bisulfate Formation
- Refer to Experience Database
  - More Than 500 Applications
  - More Than 100 Utility Furnaces

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SNCR Process Design

Computational Fluid Dynamics (CFD)

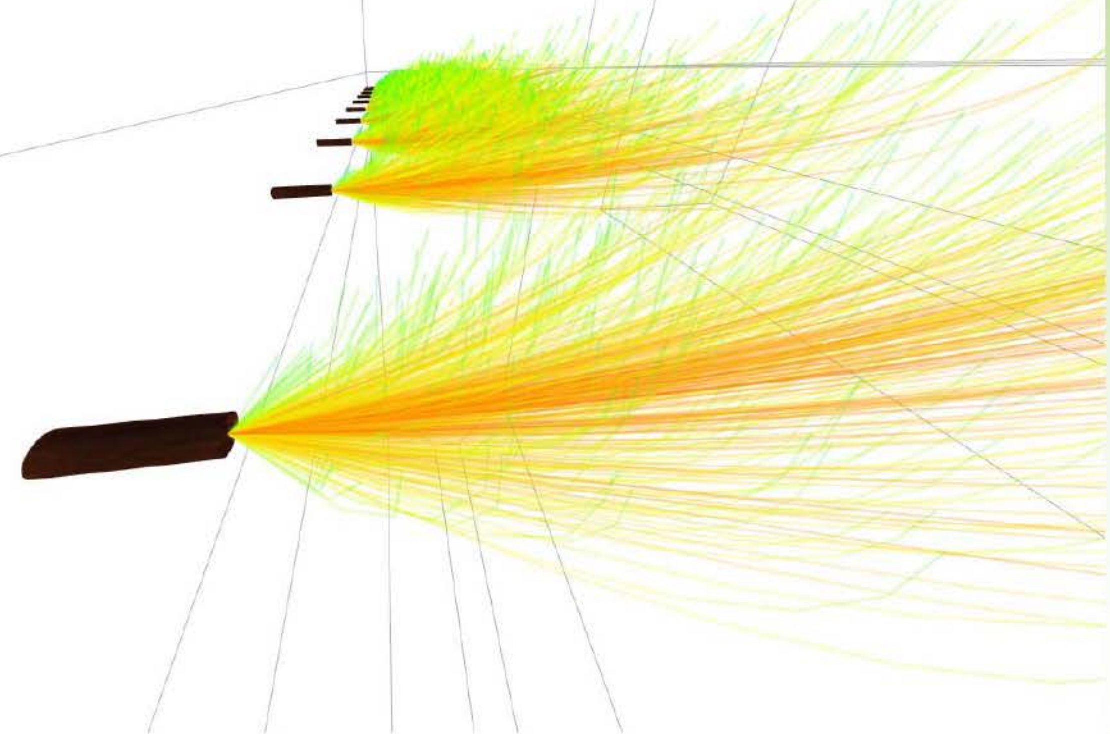
Used to Define Effective Boundaries of Critical Process Parameters, Test Effectiveness of Distribution Strategies, Identify/Locate/Define Gas Species Concentrations – Physical Unit Data (Drawings, etc.) and Field Testing as Input

Chemical Kinetic Model (CKM)

Used to Calculate Each Specific Time/Temperature Reduction Reaction – Overlay the SNCR Process on the CFD

SNCR Process Application

- Computational Fluid Dynamics
- Chemical Kinetics Model
- Injection Model



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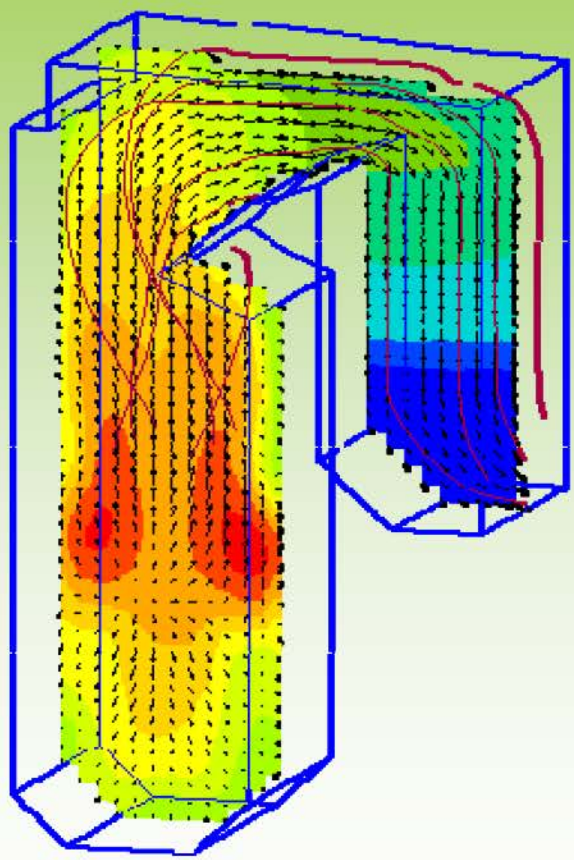
SNCR Process Modeling Steps



Step 1: Define the Unit Geometry

Step 2: Block Out Obstructed Cells and Faces

Step 3: Define Mass and Heat Sources

Step 4: Solve for Flue Gas Temperatures and Velocities

<u>Step 5</u>: Generate Temperature Versus Residence Time Data for CKM

Step 6: Identify Temperature Limits for Effective NOxOUT Performance

Step 7: Select Injector Locations and Spray Characteristics

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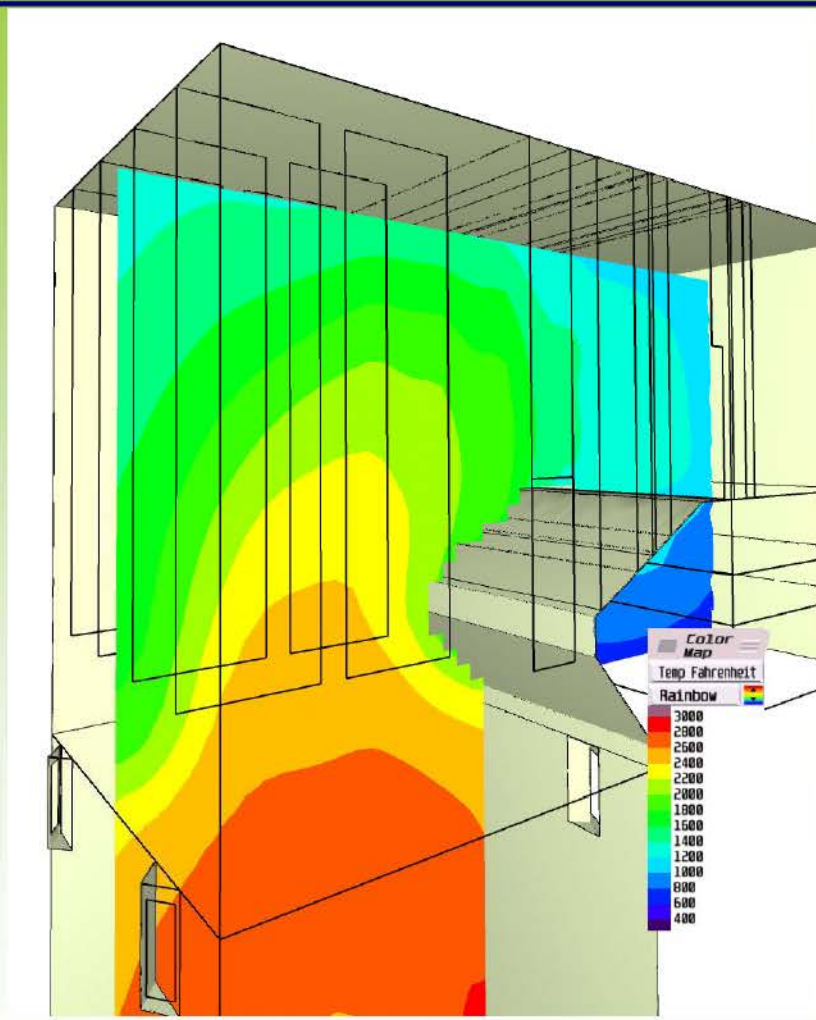
Baseline Testing (HVT) for CFD/CKM



- High Velocity Thermocouple Suction Pyrometer and Portable Gas Analyzer Used to Gather Temperature and Flue Gas Composition
- Develop Grid of Measurements Based on Actual Operating Conditions
- Build CFD Model Using Data Gathered from Field
- Overlay SNCR Process on CFD to Determine Reagent Distribution and Performance

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Temperature and Species Mapping

- Three (3) Boiler Loads
  - Full, Mid, and Low Load Depending on NOx Removal Requirements
- Typical One (1) Week Service
  - One (1) Field Engineer, Two (2) Technicians
- Fuel Tech to Provide All Equipment Including High Velocity Thermocouple (HVT), Cooling Water Pumps, Hoses, and Analyzers
- Scope By Others
  - Maintain Steady State Boiler Conditions for 4 – 6 Hours per Load
  - DCS Data during Testing
  - Water and Electrical Hook-ups
  - Observation Doors or Ports for HVT Testing
  - Fuel and Operational Data, Boiler Drawings

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SNCR Baseline Testing - HVT

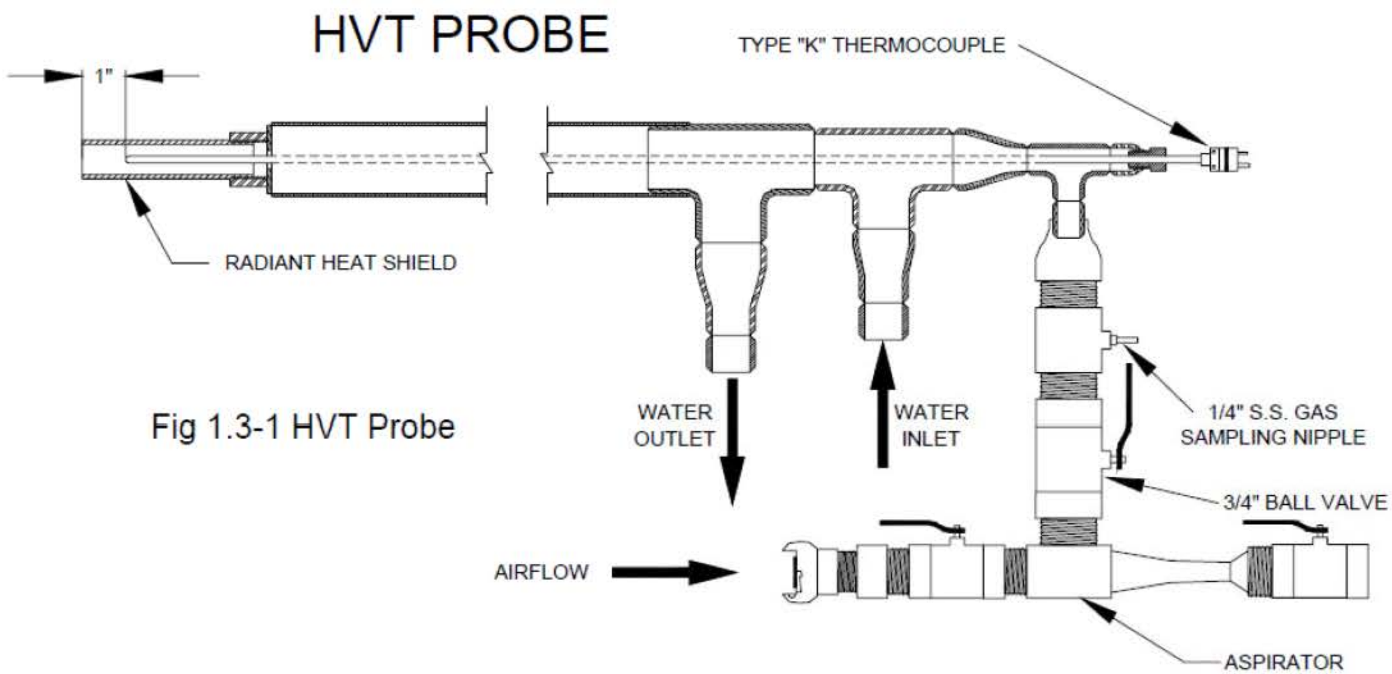

Fig 1.3-1 HVT Probe

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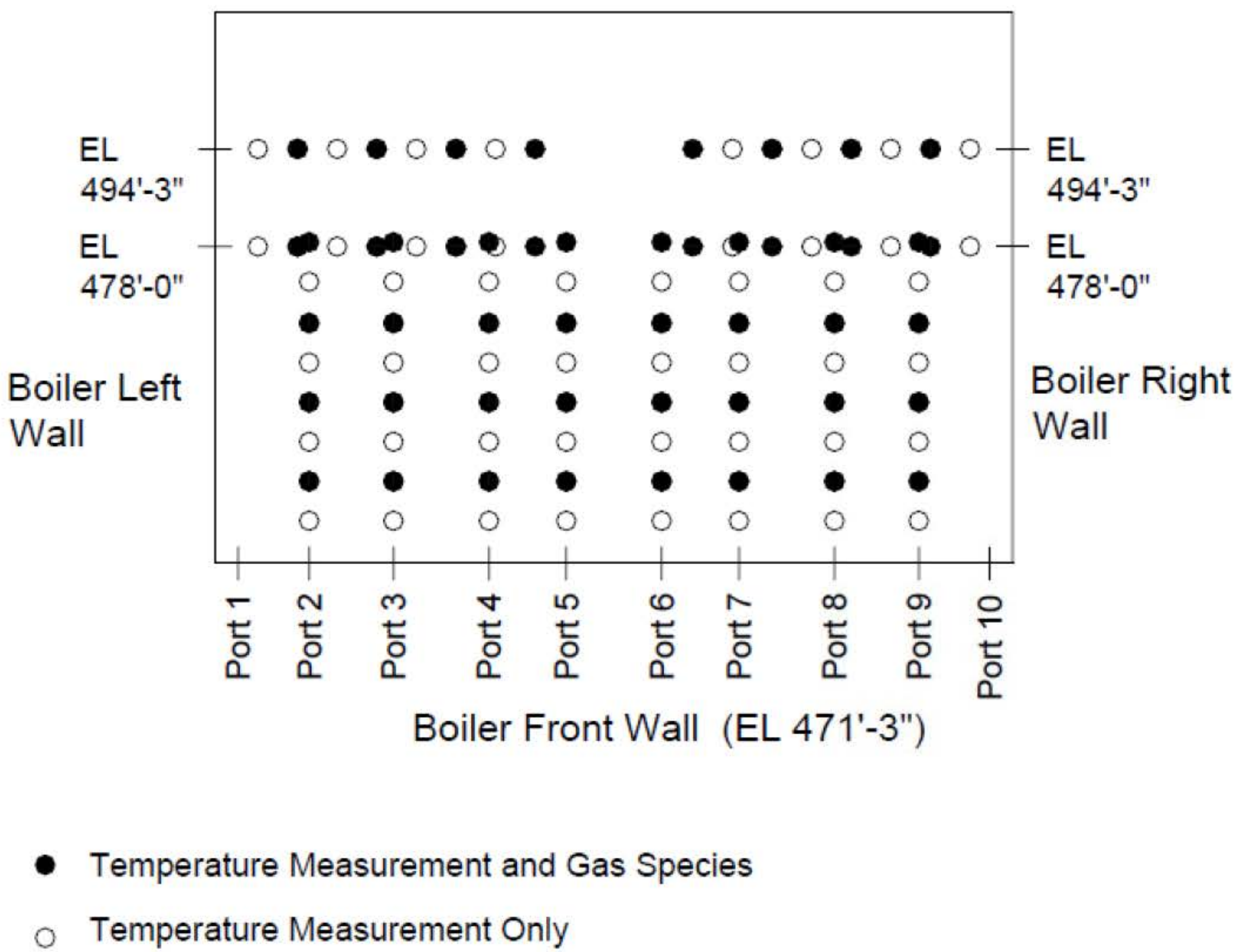
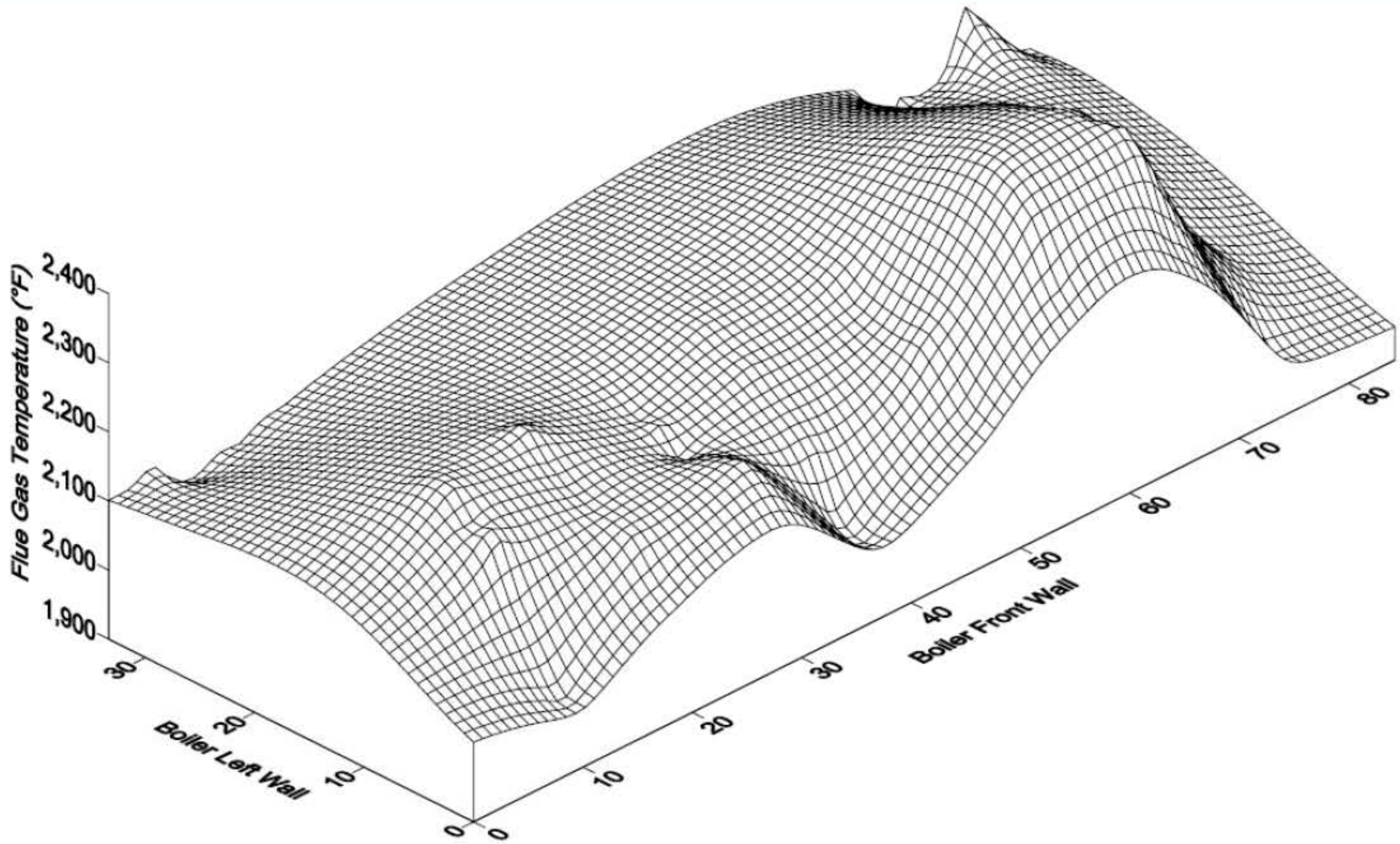
SNCR Baseline Testing - HVT



SNCR Baseline Testing - HVT

	Start Time:	12:42		Finish:		12:58
Eastern Port (forward of RH Pend Platen) Elevation 506'-3"						
Depth	Temp.	%Oxygen		CO (ppm)	NO (ppm)	NO (corr)
2'	2,003°F					
4'	2,105°F	0.0	0.0	49,910	114	98
6'	2,136°F					
8'	2,173°F	0.3	0.7	22,095	122	107
10'	2,181°F					
12'	2,187°F	2.1	2.6	5,648	94	91
14'	2,154°F					
16'	2,184°F	6.8	7.4	239	72	93
18'	2,222°F	6.1	6.9	72	73	91
Average	*2,149°F*	*3.29*		*15,593*	*95*	*96*
Low	*2,003°F*	*0.00*		*72*	*72*	*91*
High	*2,222°F*	*7.40*		*49,910*	*122*	*107*

HVT Testing – Temperature (°F)



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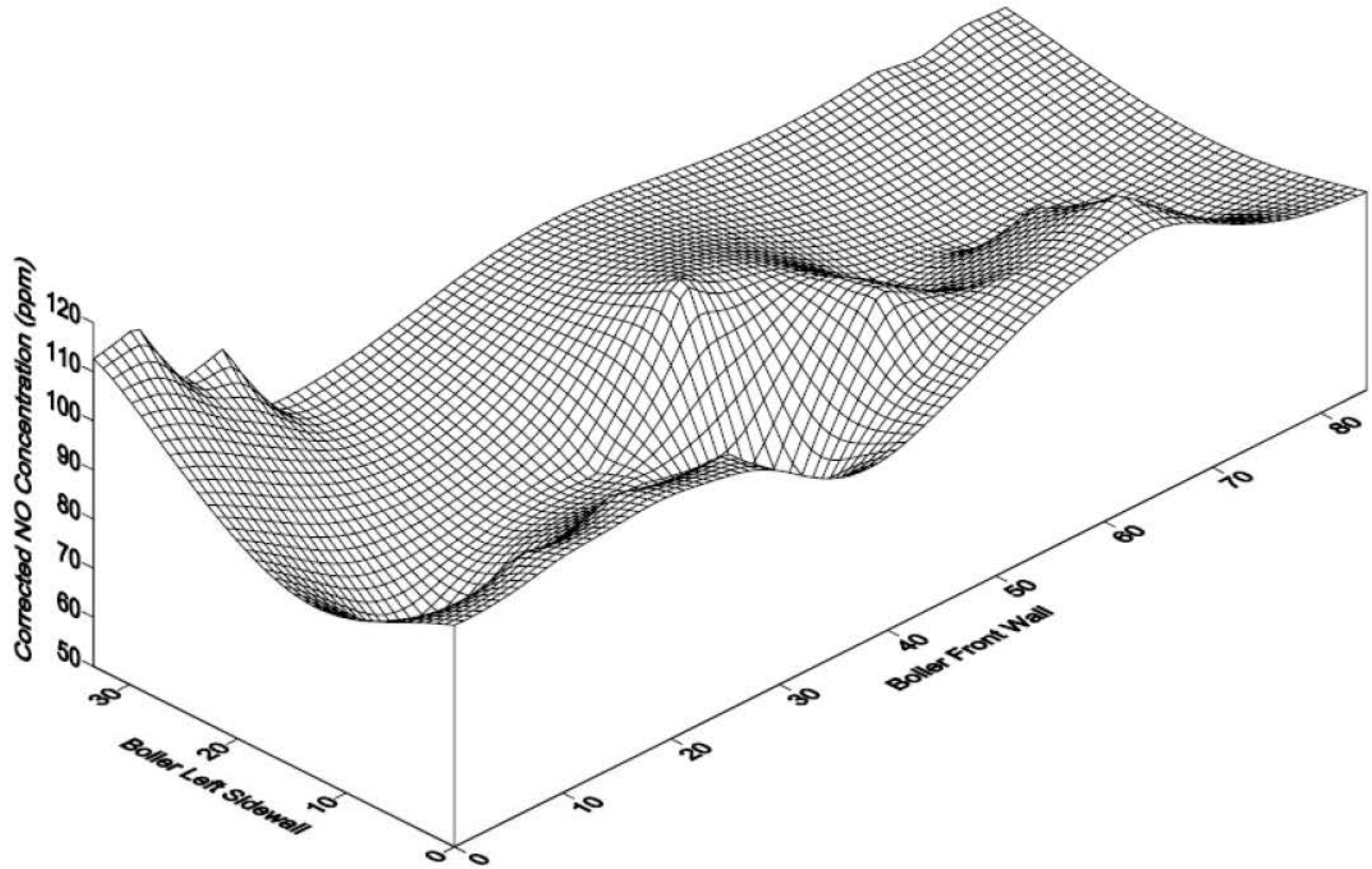
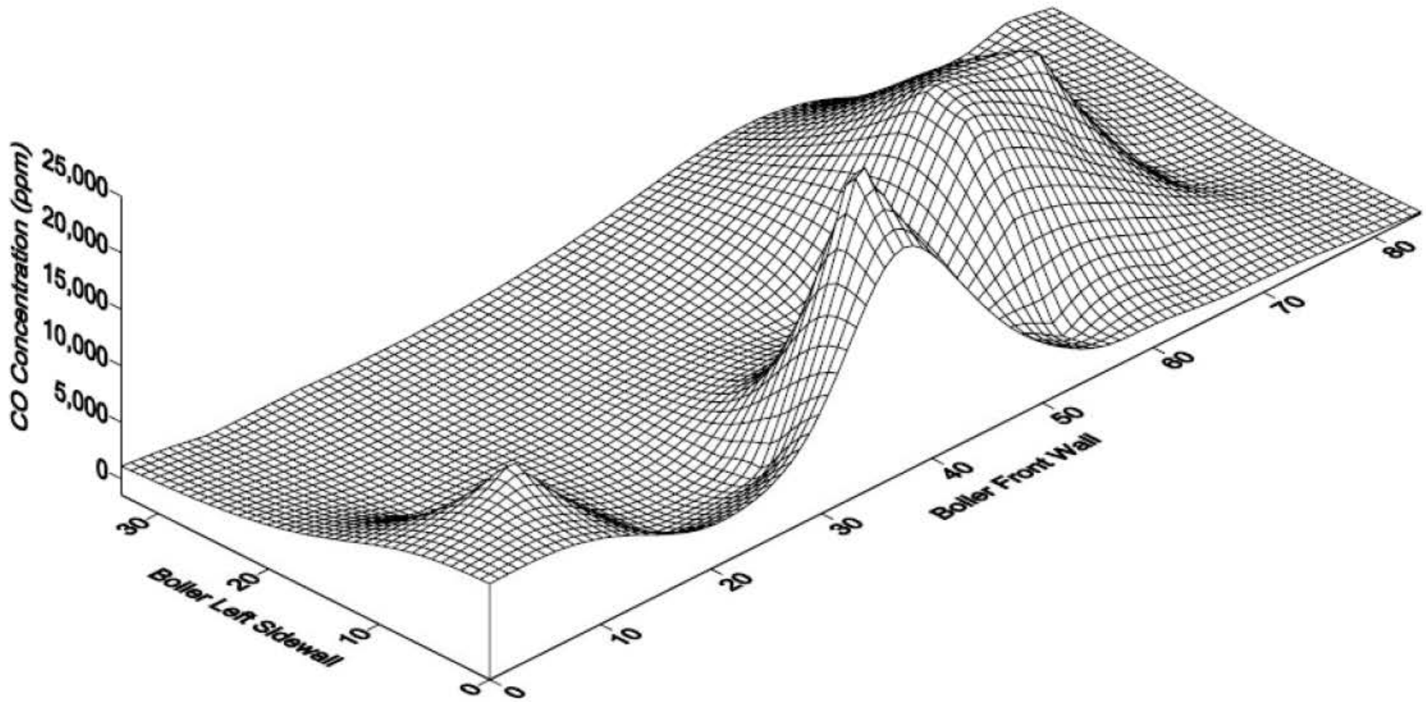
HVT Testing – NOx Concentration (ppm)



HVT Testing – CO Concentration (ppm)



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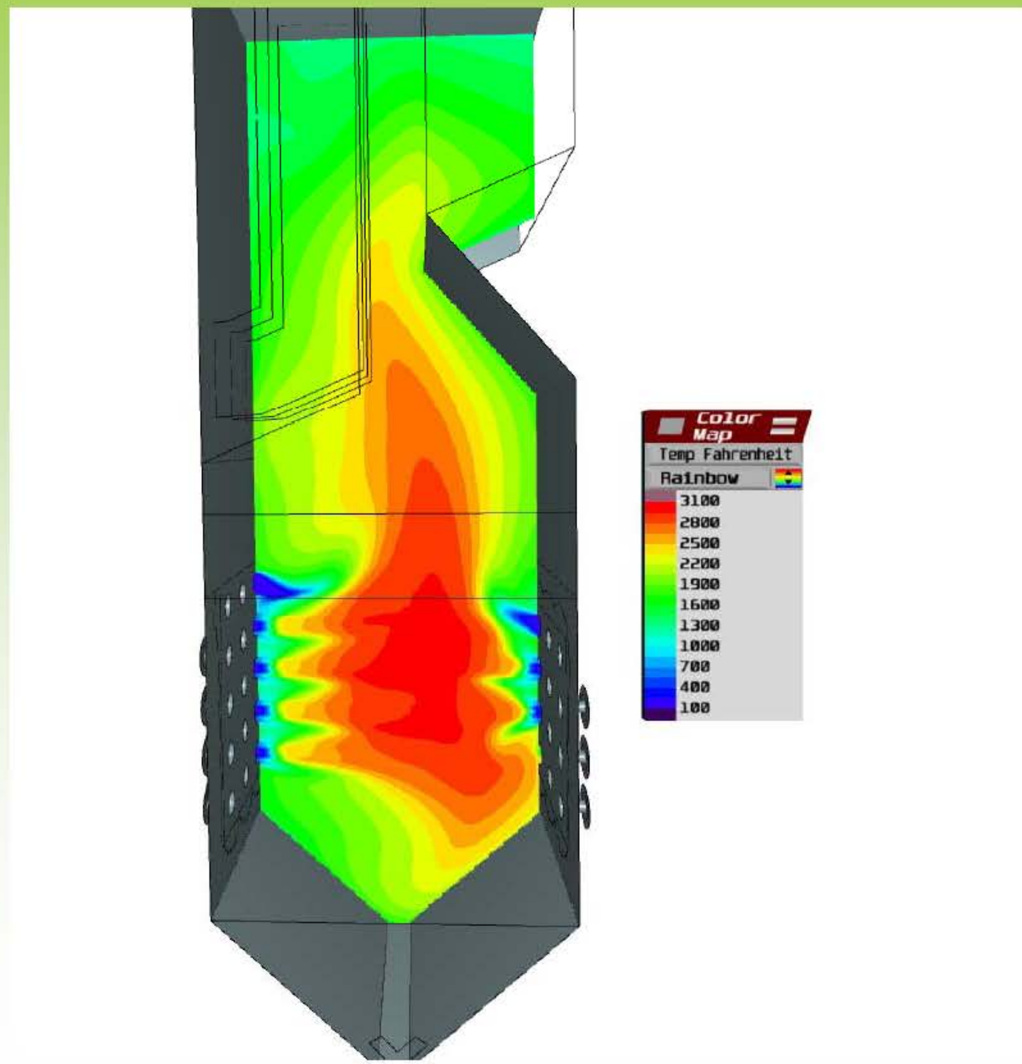
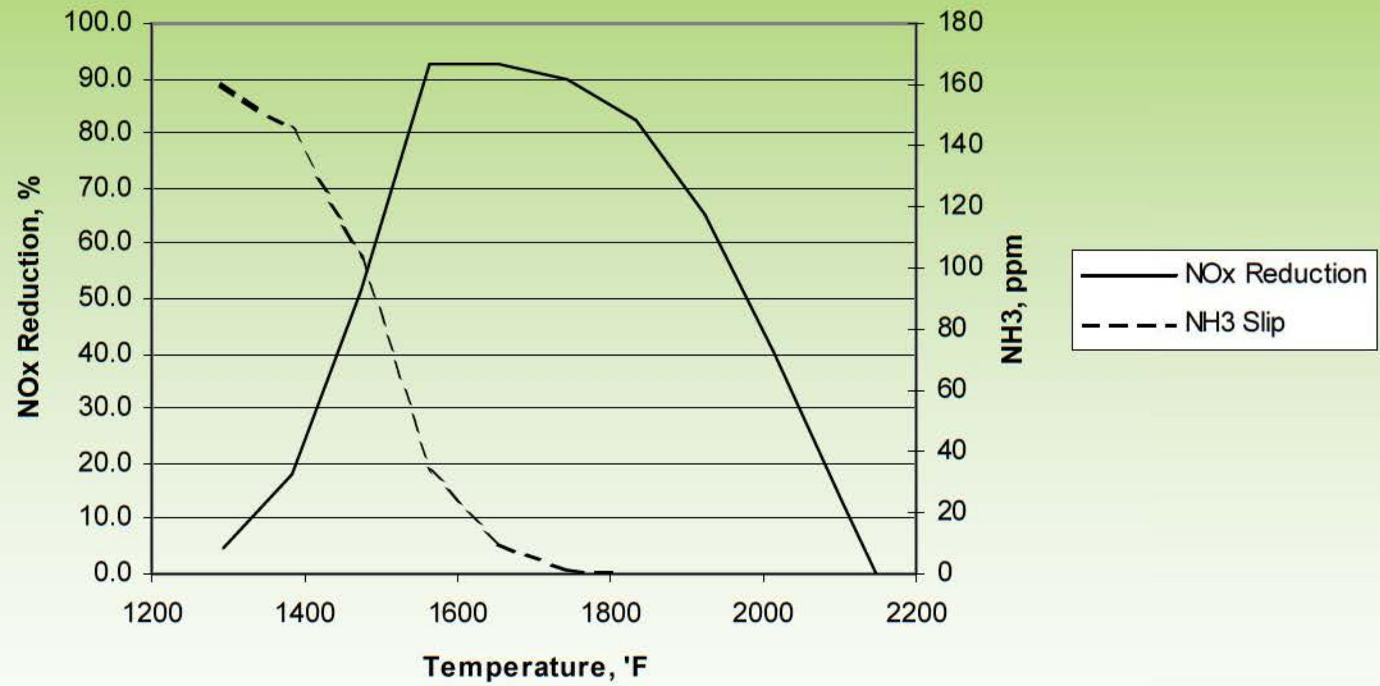
Baseline Furnace Model

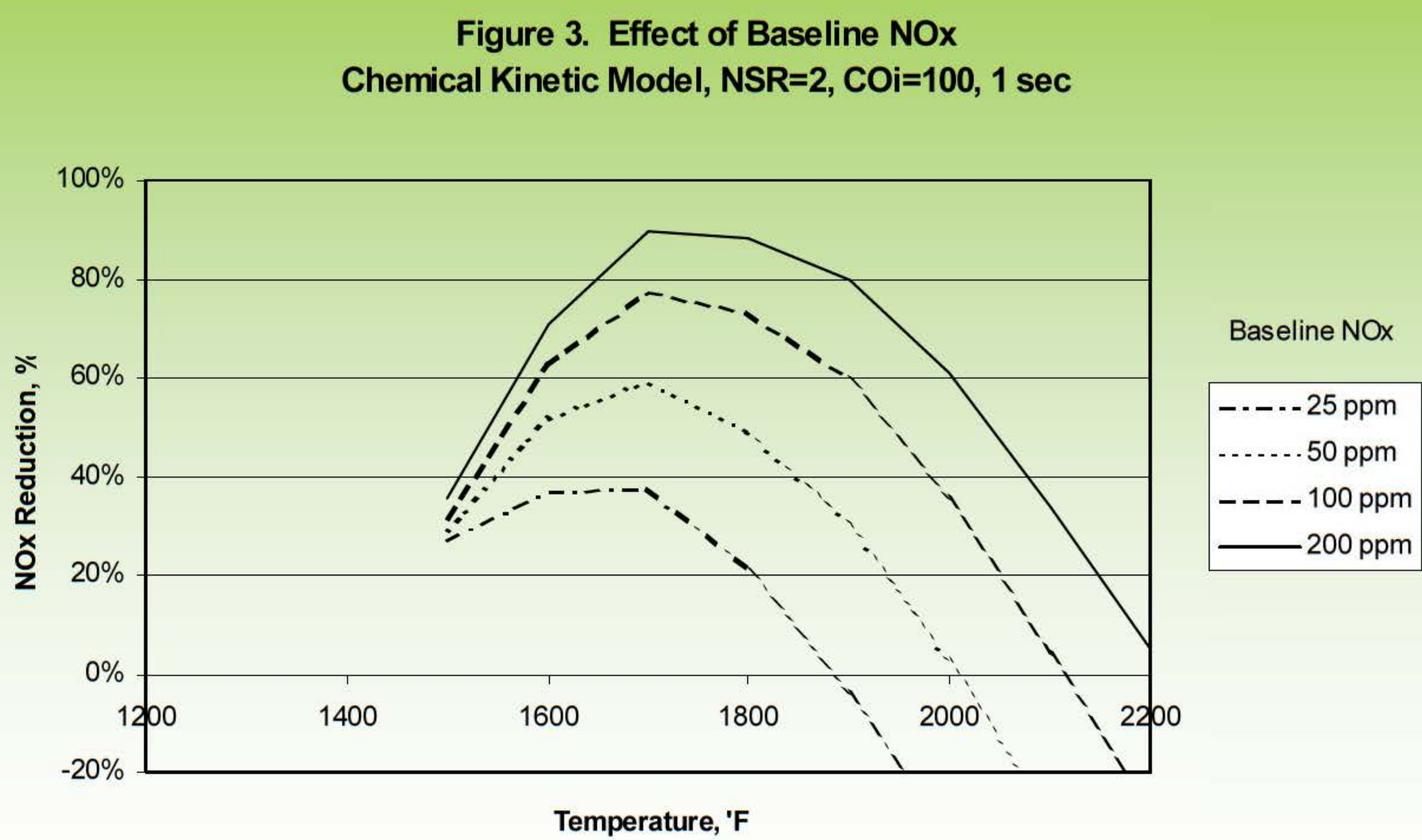


SNCR Design – Temperature Window

Figure 1. SNCR Temperature Window
Chemical Kinetic Model, NOxi=200 ppm, COi=100 ppm, NSR=2, 1 sec.

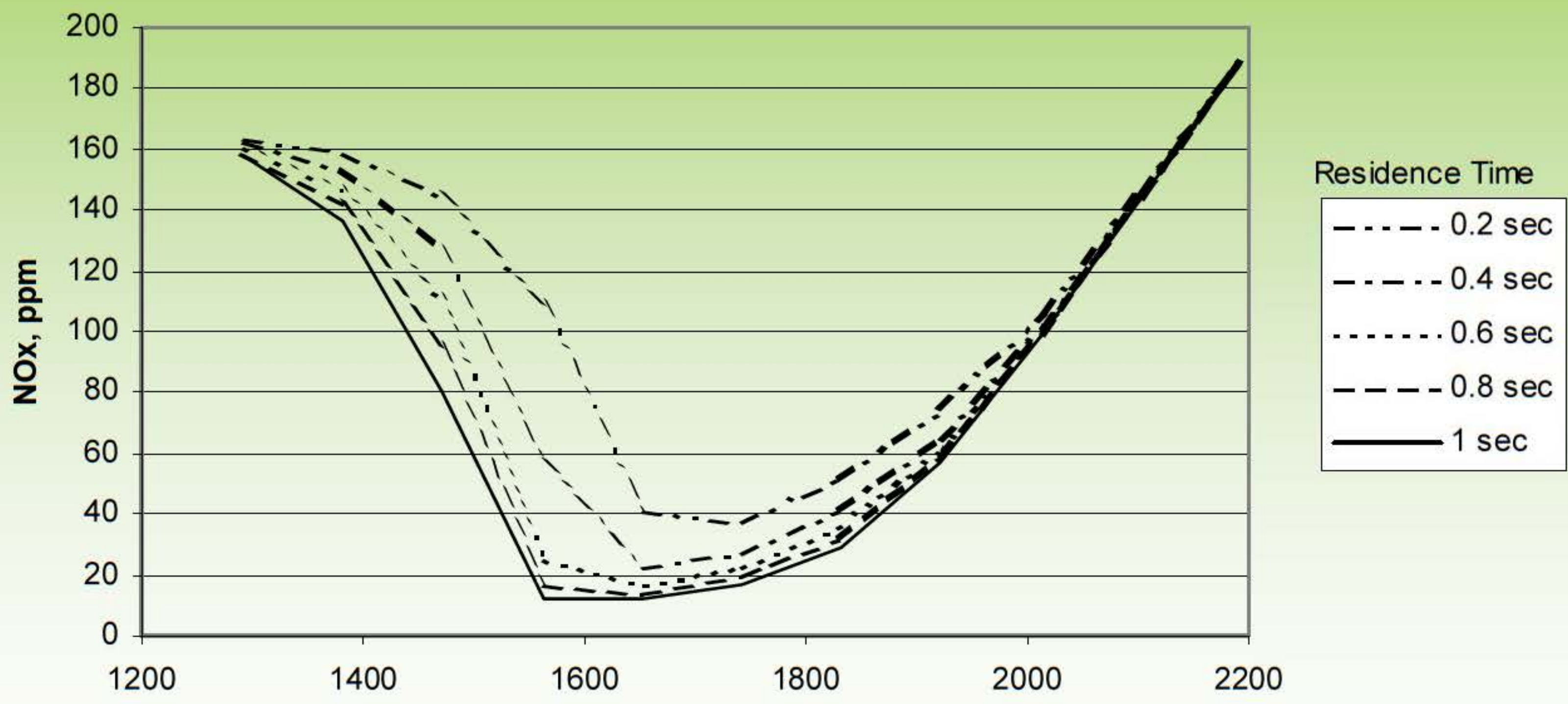


SNCR Design – Baseline NOx



SNCR Design – Residence Time

Figure 2. Effect of Residence Time
Chemical Kinetic Model, NSR=2, COi=100 ppm, NOxi=200 ppm



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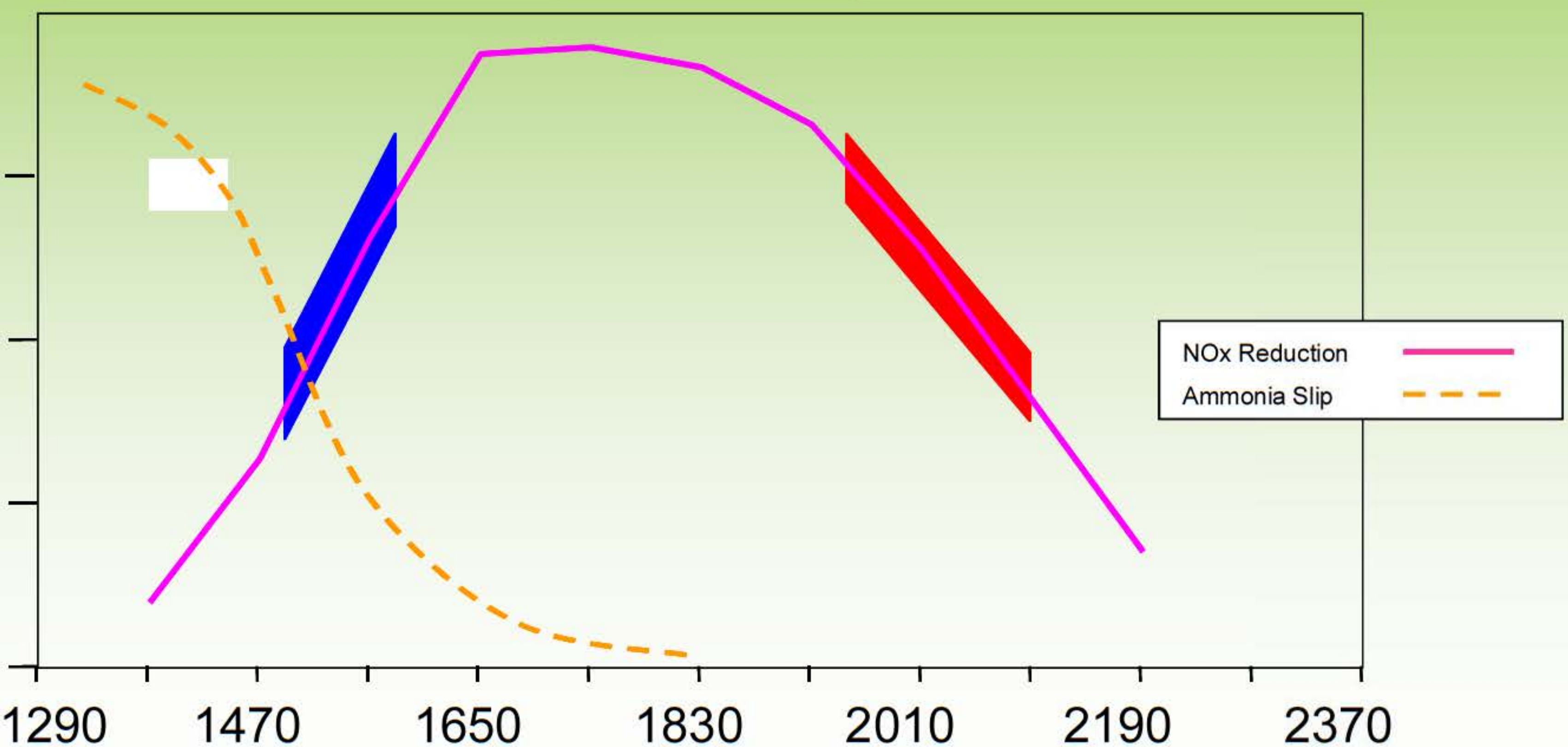
"Right Side of Slope" Injection

Low Temperature Issues
- Slow Droplet Evaporation
- Slow Kinetics
- Low OH Concentration
- Ammonia Slip Increase

High Temperature Issues
- Rapid Droplet Evaporation
- Fast Kinetics
- Increased OH Concentration
- Urea Oxidation to NOx



Influence of CO on SNCR Process

1) $NH_3 + OH \Rightarrow NH_2 + H_2O$ and $HNCO + OH \Rightarrow NCO + H_2O$

   Note: Reaction rates increase with temperature, which explains low ammonia slip for high temperature applications. Clearly, OH is needed for this step.

2) $NH_2 + NO \Rightarrow NNH + OH \Rightarrow N_2 + H_2O$

   $NCO + NO \Rightarrow N_2O + CO \Rightarrow N_2 + CO_2$

   Note: NH2 and NCO are NOx reducing species – these reactions take place if working within the appropriate temperature window.

Influence of CO on SNCR Process

3) $NH_2 + OH \Rightarrow NH + H_2O$

$NH + OH \Rightarrow HNO + H$

$HNO + OH \Rightarrow NO + H_2O$ (*NOx Formation*)

$NCO + OH \Rightarrow NO + CO + H$ (*NOx Formation*)

Note: If the operating temperature is high, these reactions will occur rather than the desirable NOx reducing reactions. In this case, the OH works against us… CO Enters into the picture –

4) $CO + O_2 + H_2O \Rightarrow CO_2 + 2OH$

Note: The higher the CO concentration, the higher the OH generated. The elevated OH concentration generates increased levels of NH2 and NCO (Equation 1), even at low temperatures.

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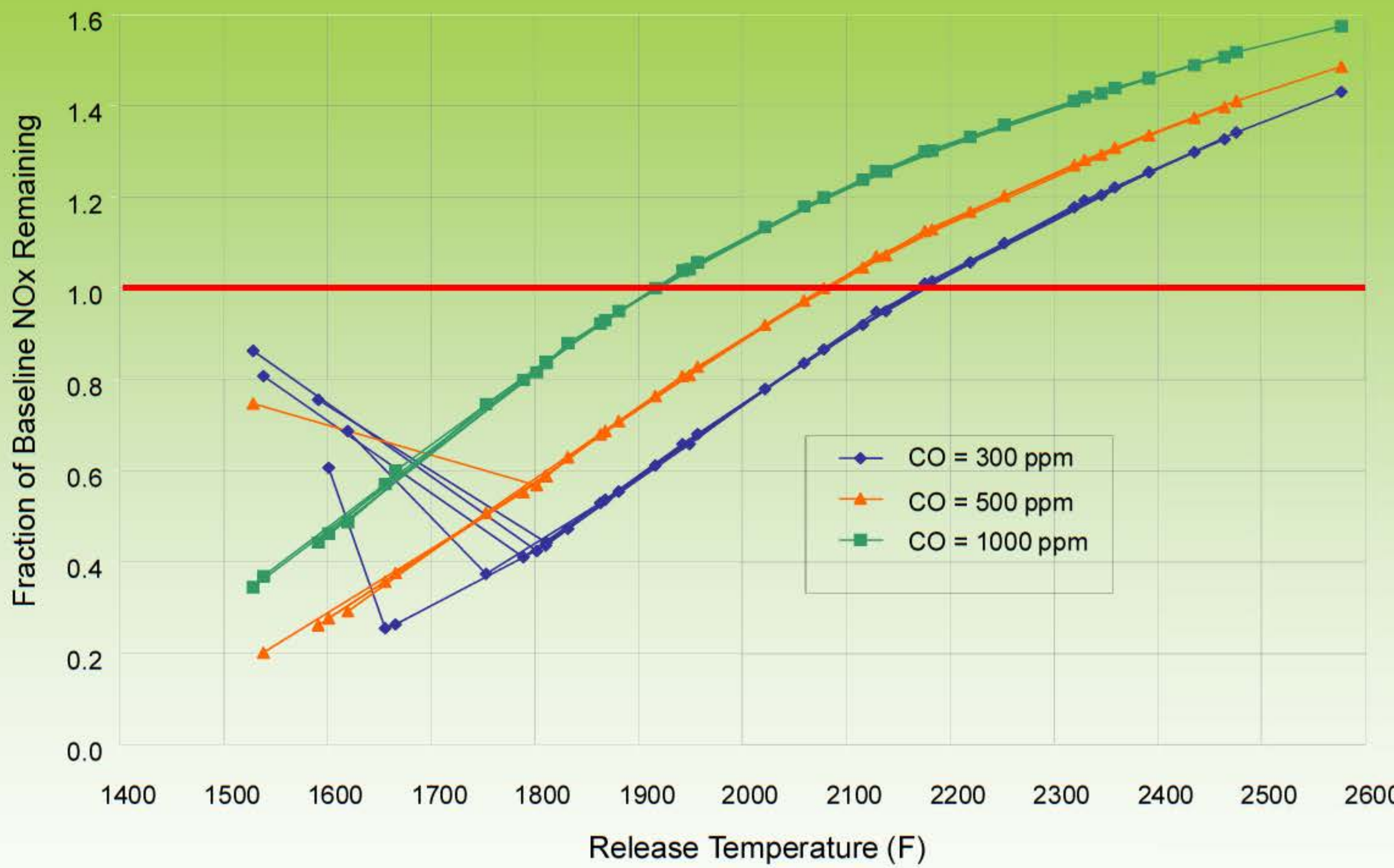
Influence of CO on SNCR Process



Note: Higher CO Levels Increase the Rates of NH2 Formation and NH3 Oxidation to NO; Effective NOx Reduction Window for Process is Shifted to a Lower Temperature.

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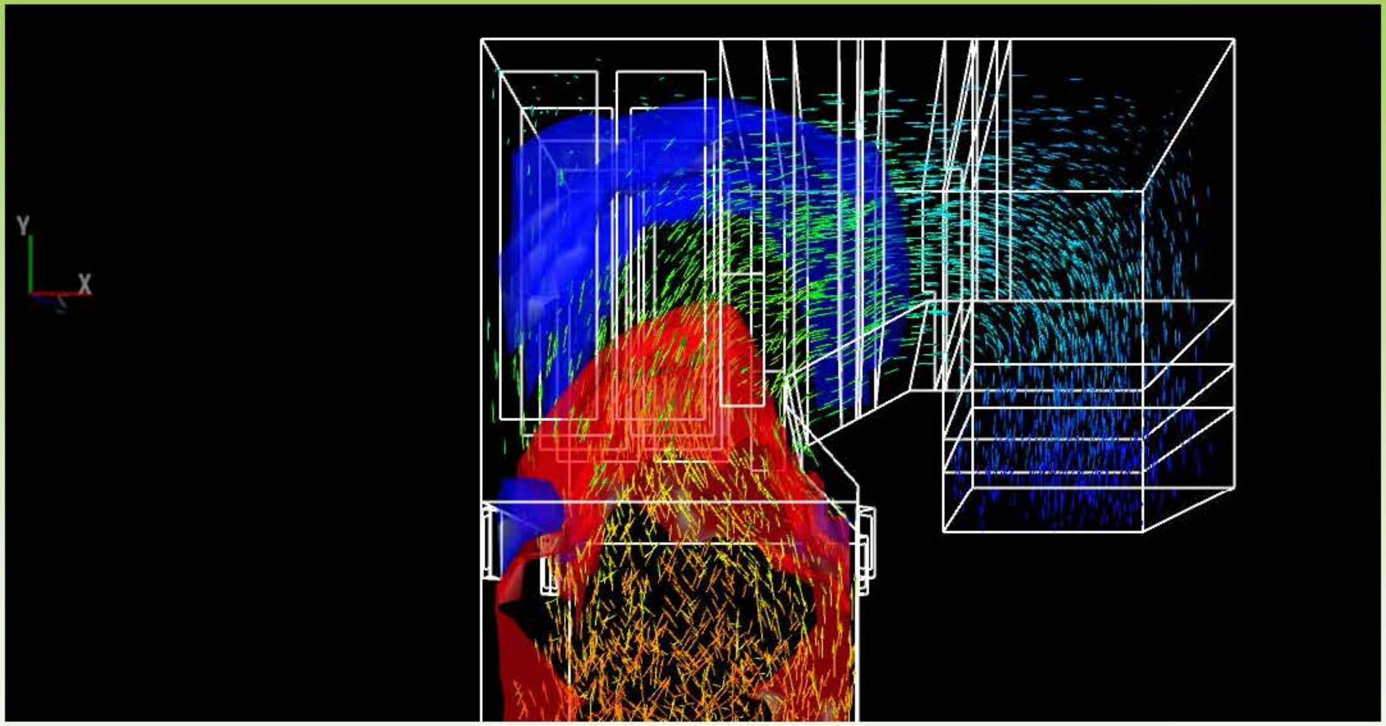
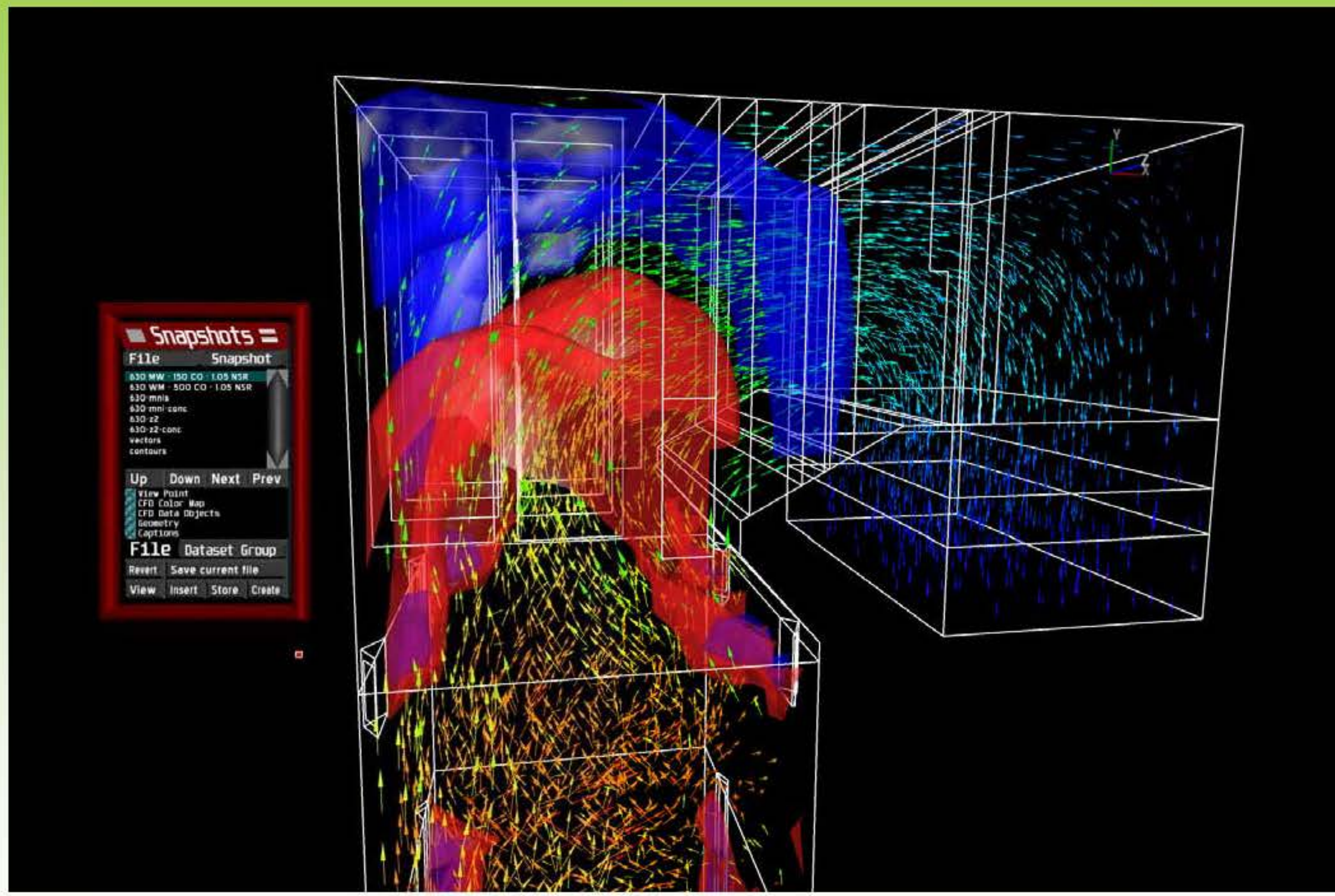
SNCR Effective Temperature Window



2200°F 1600°F

Temperature Window – 150 ppm CO



1950°F 1750°F

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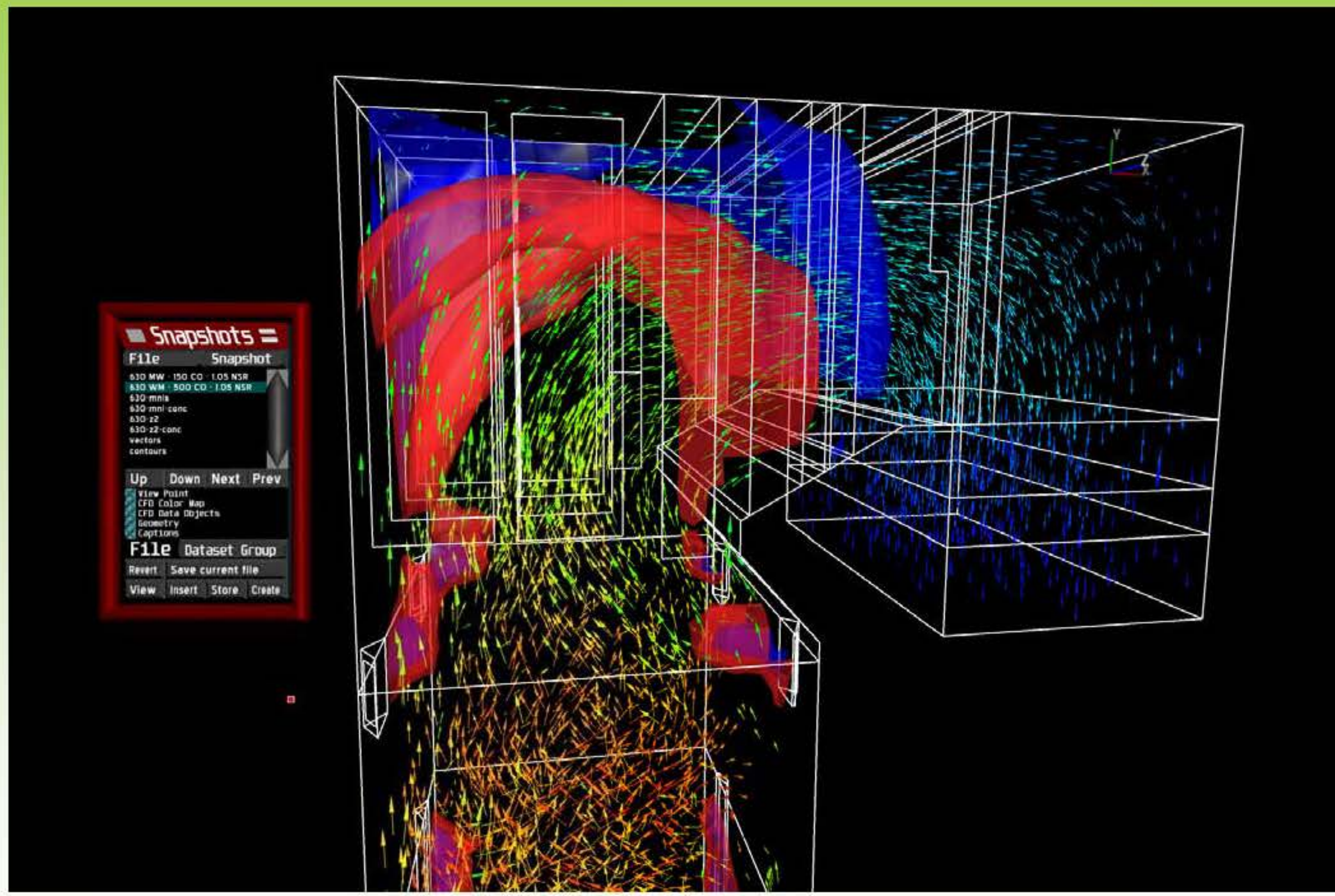
Temperature Window – 500 ppm CO



1750°F 1450°F

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SNCR INJECTION SYSTEMS

SNCR Injection Strategies

- NOxOUT® Technology
  - Air Atomized Urea Injection
  - Larger Droplet Size for Hot and/or Large Boilers and Furnaces
- High Energy Reagent Technology (HERT)
  - Mechanically Atomized Urea Injection through OFA Ports (High Momentum Injectors) and Additional Levels of Injectors in Upper Furnace (Low Momentum Injectors)
  - Recent Applications with Low Baseline Applications and Control Levels at or Below 0.100 lb/MMBtu
- Multiple Nozzle Lances (MNLs)
  - Air Atomized, Fine Mist
  - Convection Pass Injection
- Combined Injection Strategy for Significant NOx Reduction with NH3 Low Slip Control

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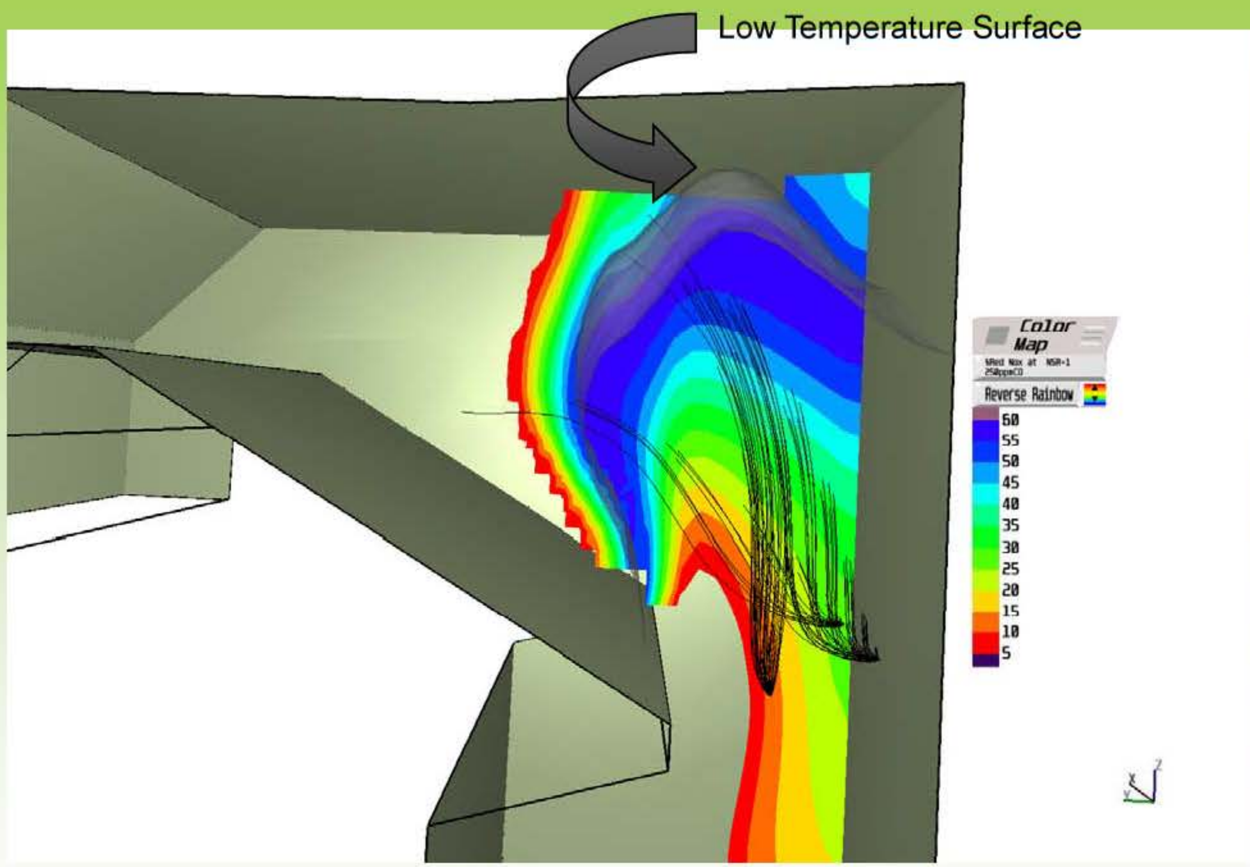
Injection Strategy for SNCR Process



In this figure, the CKM results are overlaid on the ammonia slip limit surface from the previous slide. The colored bands illustrate that NOx reduction is very limited near the plane formed by the bullnose while NOx reduction approaching 60% can be achieved near the low temperature limit.

SNCR Injection Options

- HERT
  - Lower ammonia slip
  - Higher allowable injection rates
  - Higher NOx reduction performance and higher chemical usage
- NOxOUT
  - More flexibility to control reaction zone
  - Lower chemical usage
  - Ammonia slip can be used with ASCR

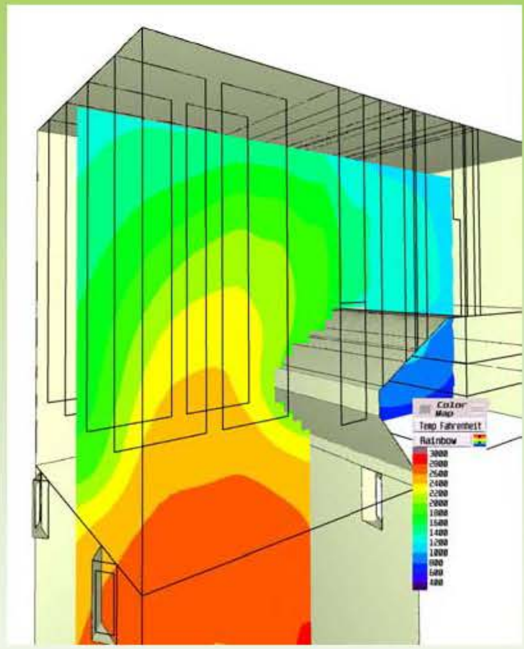
HERT™ Injection Dynamics

- Air Jet penetrates the flue gas flow
- Small urea droplets
- Air and flue gas (NOx) mix
- Droplets heat up and evaporate
- Urea and NO_x Mix
- Urea decomposes to N_2 and H_2O
- Urea reacts with NO

SNCR PERFORMANCE

SNCR NOx Reduction Performance

- **Gathering of Data and Information**
  - Operational Data
  - Drawings
- **Temperature and Species Mapping**
  - Upper Furnace Temperatures, NOx, CO, and O2
- **Computational Fluid Dynamics (CFD) and Chemical Kinetics Modeling (CKM)**
  - Boiler Model for Performance and Injector Placement
- **Demonstration System Option**
  - 2 to 3 Week Test System
  - Fuel Tech Personnel for Setup, Operation, and Teardown



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HERT Performance

- High reductions from low NOx baseline conditions
- Outlet NOx below 0.1 lb/MMBtu
- Low ammonia slip
- Experience on Range of boiler sizes and types
- Over 40 Combined Commercial and Demonstration Systems

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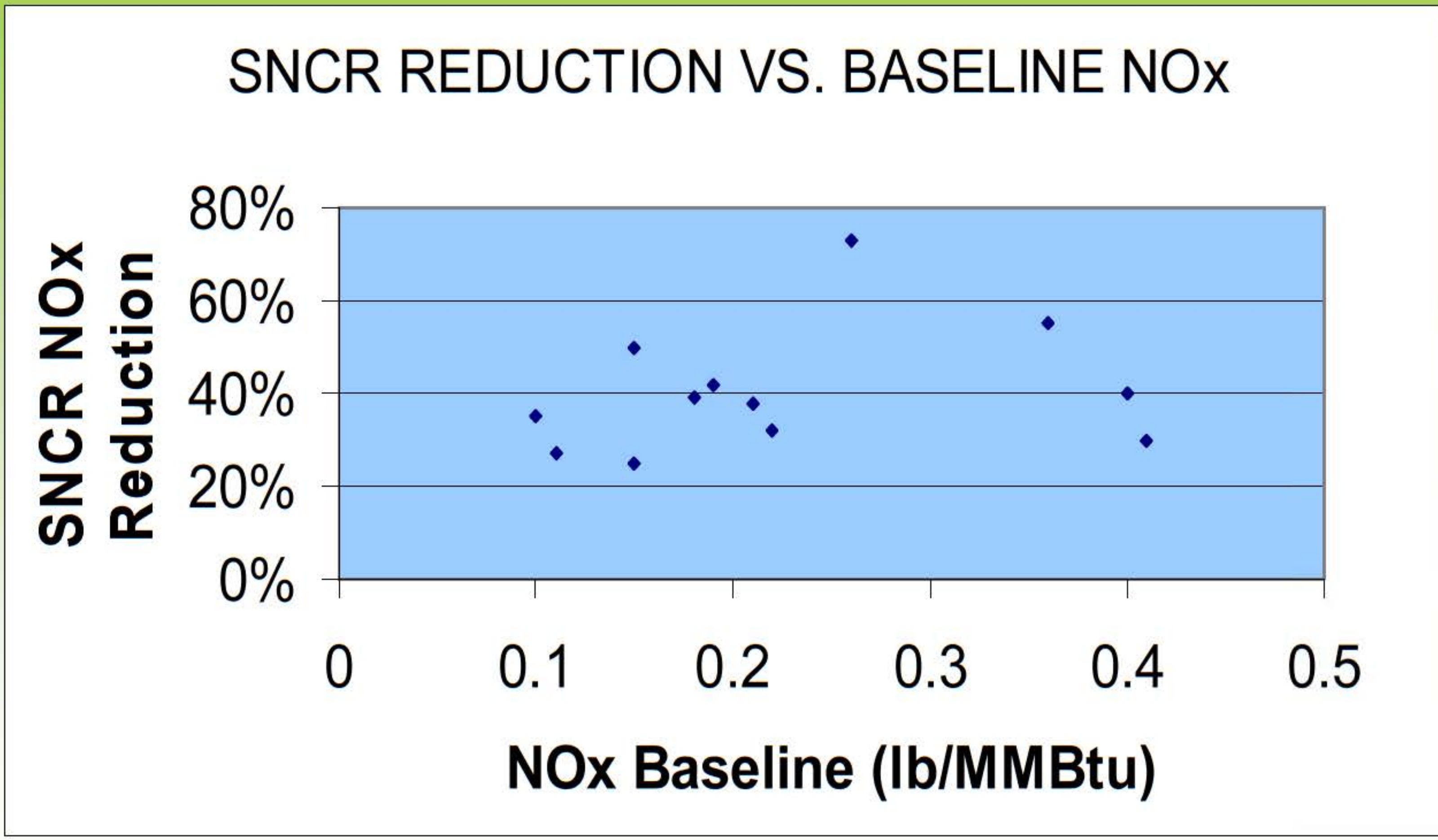
HERT Performance



HERT Performance Summary

Partial List of Commercial and Demo (D) Systems

MW	BASELINE NOx	% REDUCTION	OUTLET NOx
45	0.18	39%	0.11
60	0.19	42%	0.11
100	0.21	38%	0.13
120	0.22	32%	0.15
180	0.40	40%	0.24
200	0.15	25%	0.11
200	0.15	50%	0.08
275 D	0.11	27%	0.08
275 D	0.10	35%	0.07
350 D	0.36	55%	0.16
425 D	0.26	73%	0.07
600 D	0.41	30%	0.29

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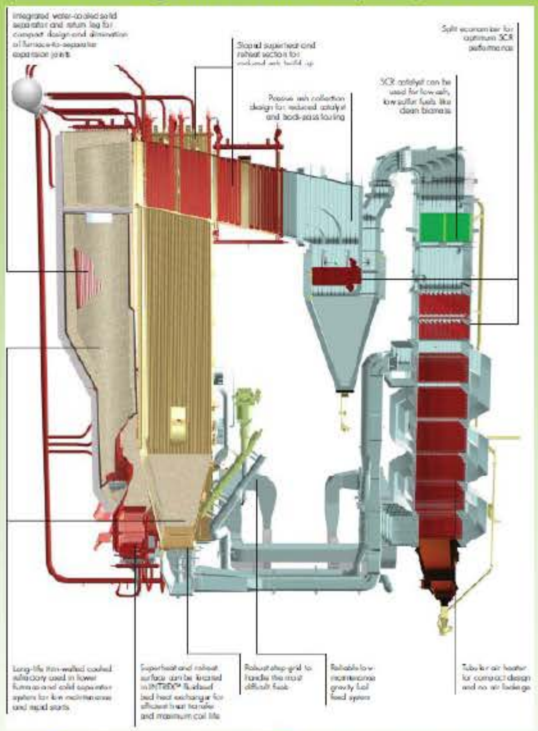
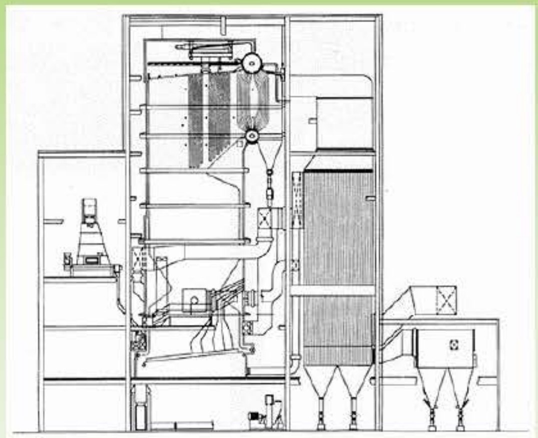
Biomass-fired Applications – Boiler Options

Circulating Fluidized Bed (CFB) Boilers



Drawing courtesy of Foster Wheeler

Grate-fired Stoker Boilers



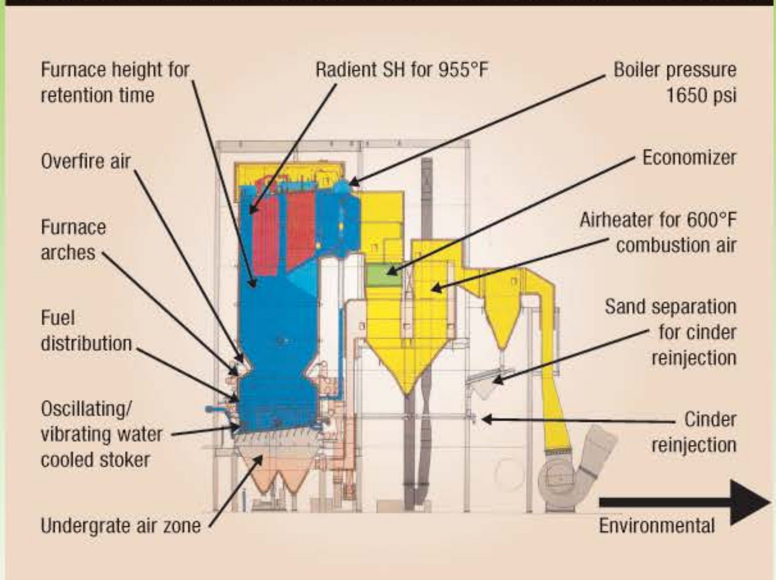
Drawing courtesy of McBurney

Bubbling Fluidized Bed (BFB) Boilers

Drawing courtesy of B&W

SNCR for Grate-fired Stoker

Figure 1 TYPICAL MODERN BIOMASS STOKER BOILER SYSTEM



Drawing Courtesy of Babcock & Wilcox

Stoker Boiler Example

- 50 MW Design
- Uncontrolled NOx: 0.25 lb/MMBtu
- Flue Gas Temp @ SH Entrance: 1850°F to 1950°F
- Upper Furnace CO: 400 ppm
- SNCR Performance: 40-50%
- NH3 Slip: 20 ppm
- Comments
  - Working with boiler OEMs to modify designs to provide more favorable upper furnace conditions for SNCR – reducing temperature and increasing residence time

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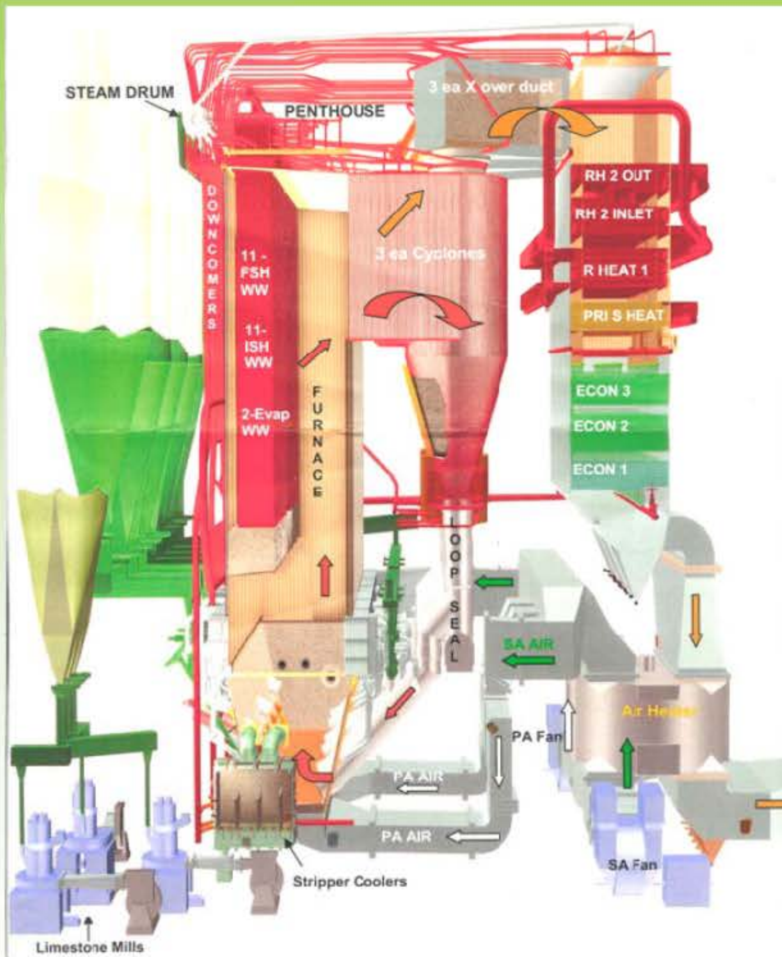
SNCR for Circulating Fluidized Bed (Utility)



CFB Boiler Example

- 2 × 325 MW Boilers
- Uncontrolled NOx: 0.150 lb/MMBtu
- Flue Gas Temp @ Cyclone Entrance: 1575°F to 1650°F
- Upper Furnace CO: < 100 ppm
- SNCR Performance: 40-60%
- NH_3 Slip: 20 ppm
- Comments
  - Eight (8) SNCR Injectors per Cyclone, Three Cyclones
  - NOx Controlled to 0.085 lb/MMBtu
  - Aqueous NH_3 Used

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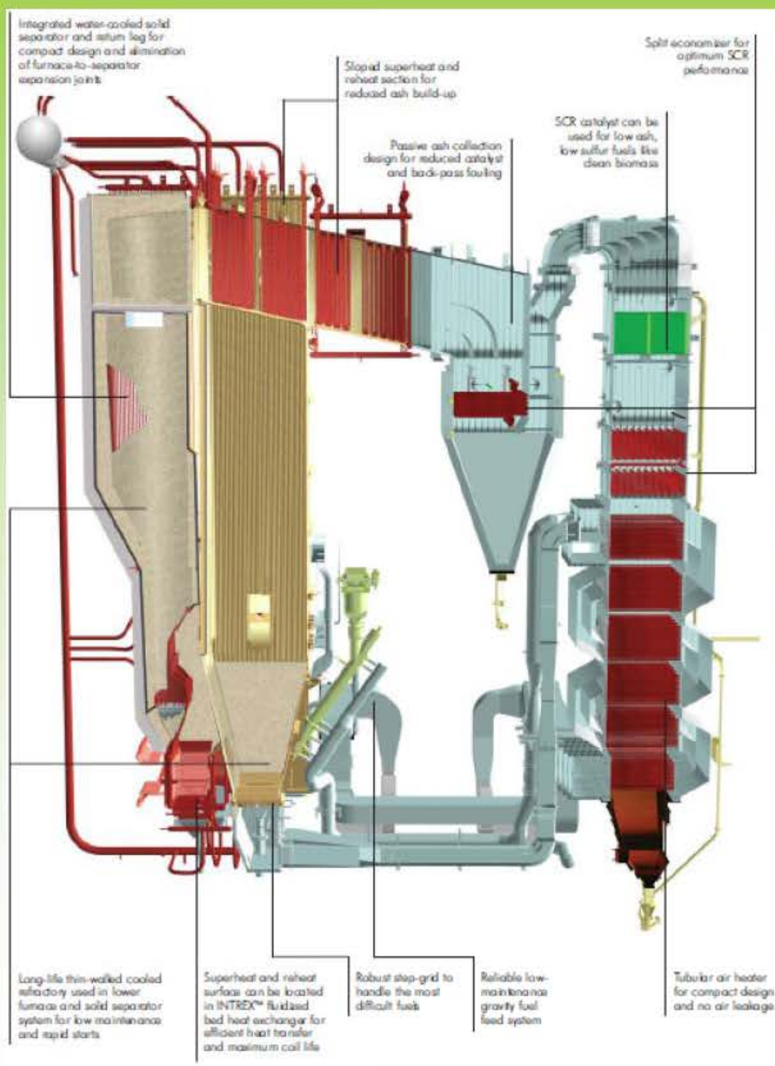
SNCR for Circulating Fluidized Bed (Industrial)



CFB Boiler Example

- 50 MW Design
- Uncontrolled NOx: 0.18 lb/MMBtu to 0.20 lb/MMBtu
- Flue Gas Temp @ Cyclone Entrance: 1600°F to 1650°F
- Upper Furnace CO: < 200 ppm
- SNCR Performance: 50% to 70%
- NH3 Slip: 20 ppm
- Comments
  - NOx Controlled to 0.075 lb/MMBtu
  - Urea and Aqueous NH3 Options, Low Temperature and Long Residence Time Favors Both

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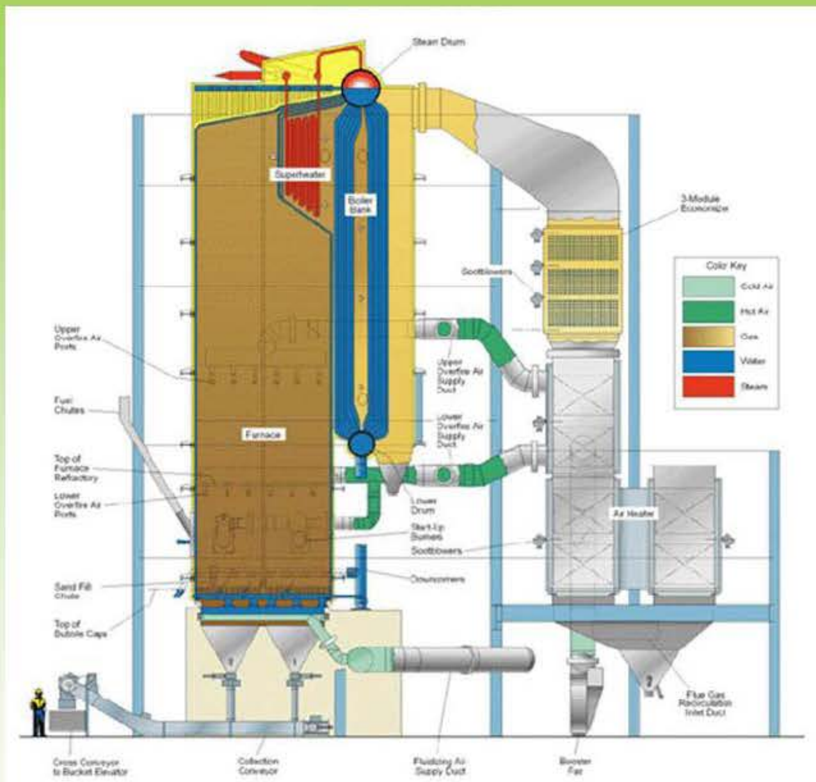
SNCR for Bubbling Fluidized Bed

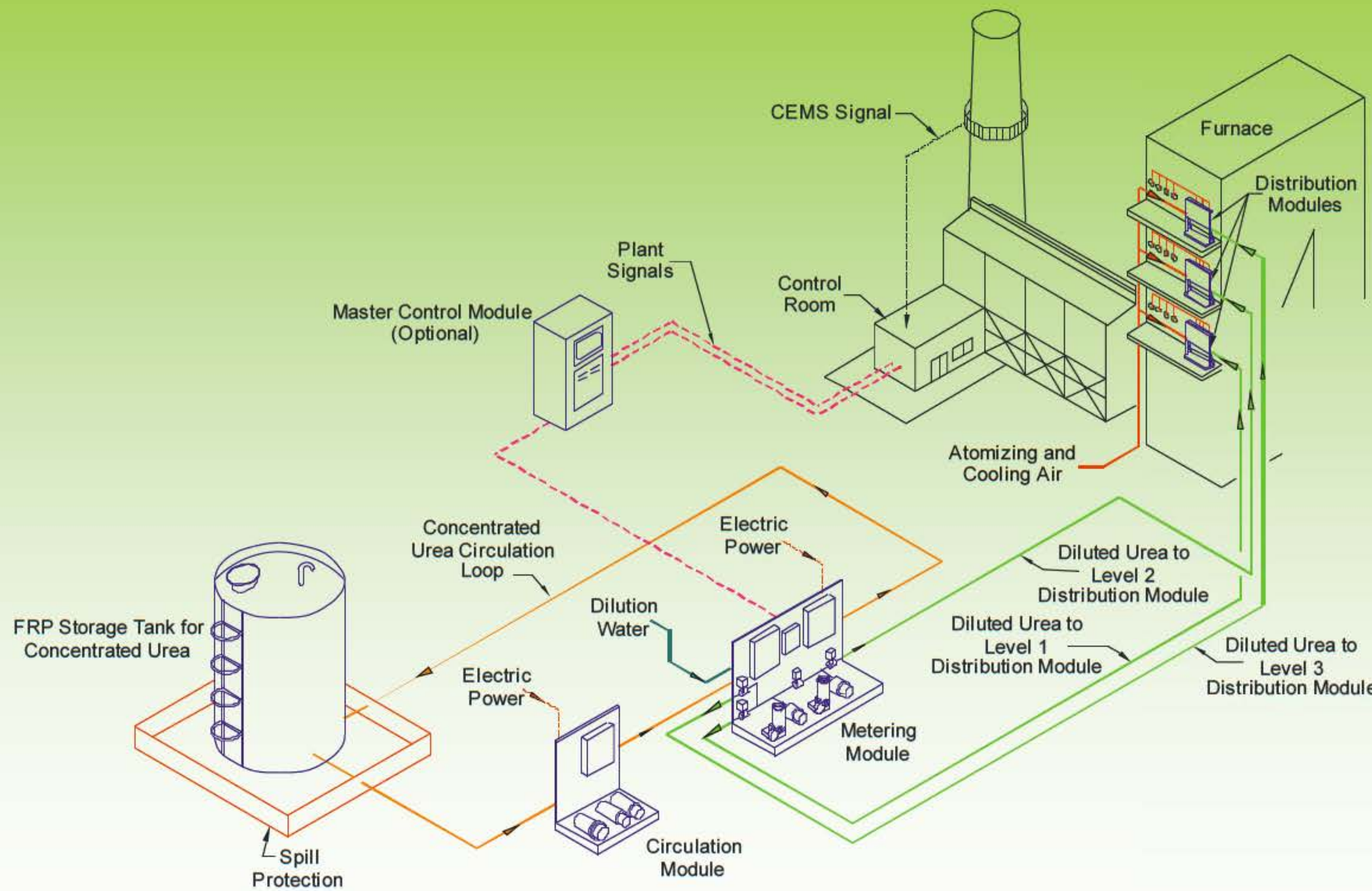


BFB Boiler Example

- 50 MW Design
- Uncontrolled NOx: 0.18 lb/MMBtu to 0.20 lb/MMBtu
- Flue Gas Temp @ Cyclone Entrance: 1600°F to 1650°F
- Upper Furnace CO: < 200 ppm
- SNCR Performance: 50% to 75%
- NH3 Slip: 20 ppm
- Comments
  - Controlled NOx = 0.075 lb/MMBtu
  - Urea and Aqueous NH3 Options, Low Temperature and Long Residence Time Favors Both

SNCR EQUIPMENT LAYOUT AND COMPONENTS

NOxOUT® SNCR Process Schematic



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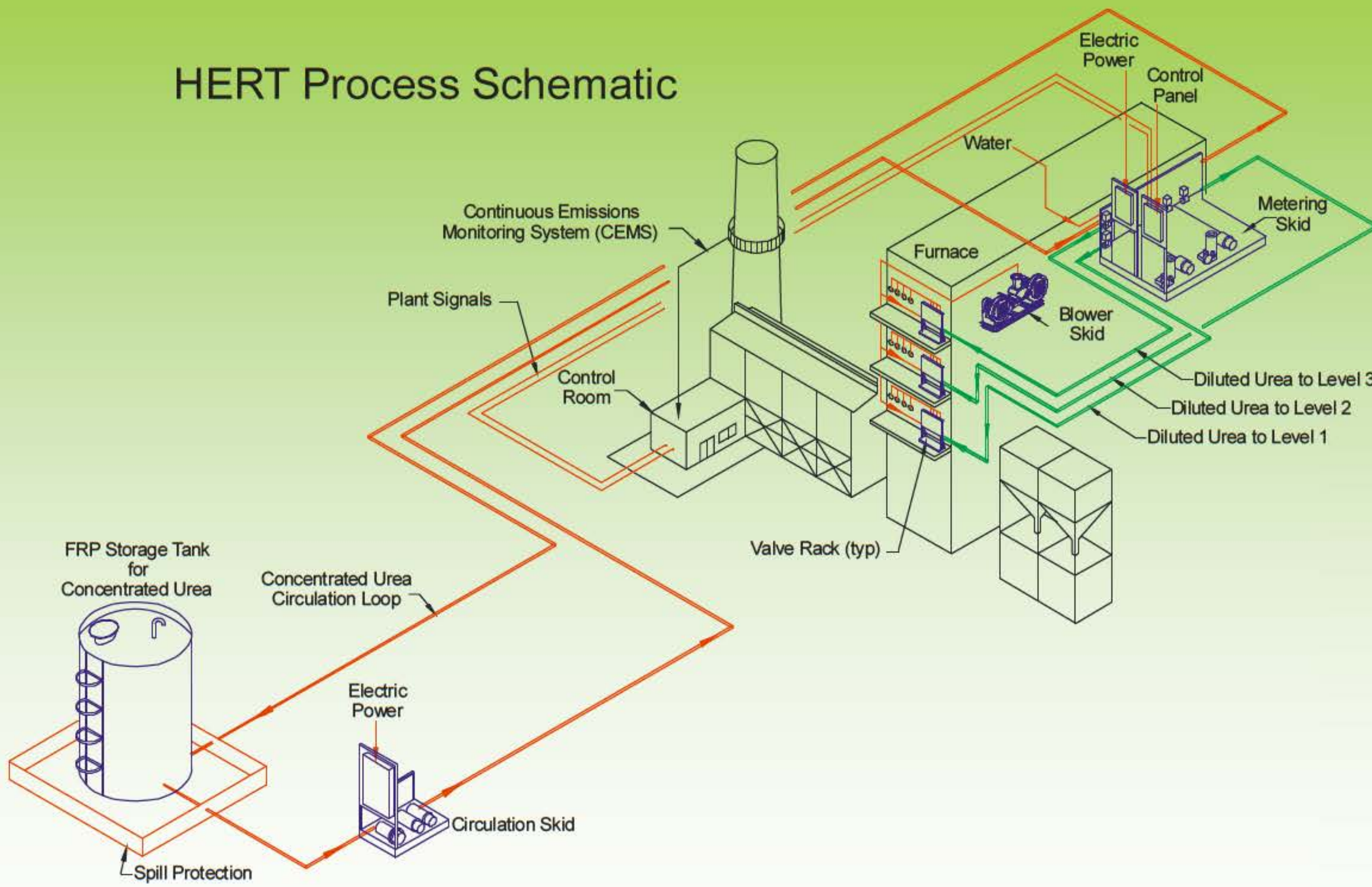
HERT™ SNCR Process Schematic



Note: A key difference between HERT and NOxOUT SNCR is the use of small, mechanically atomized droplets that are guided to the high NOx regions using high momentum injectors installed in OFA ports and low momentum injectors in upper level ports where blower air guides the diluted urea.

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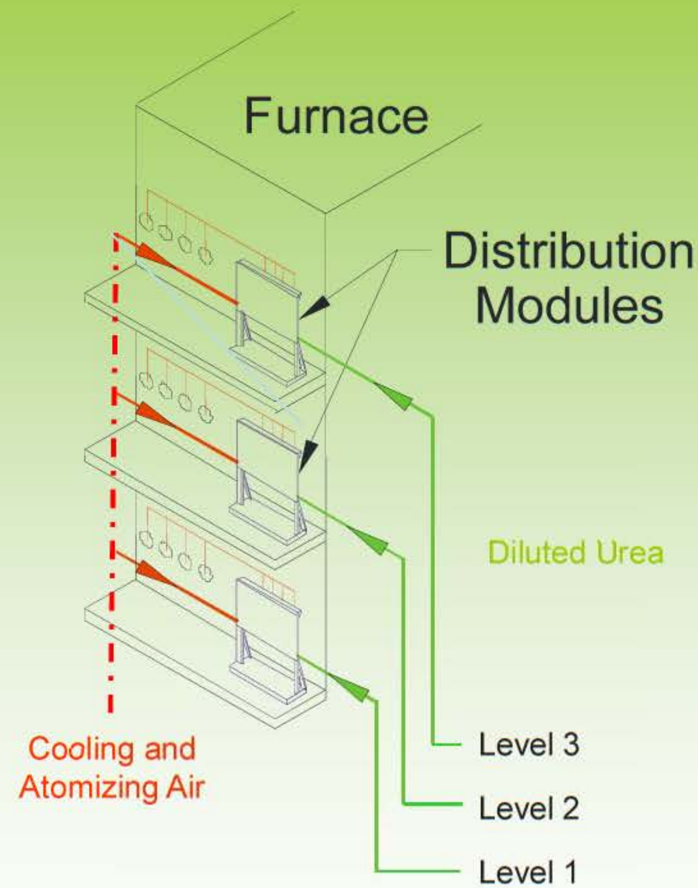
SNCR Distribution Modules & NOxOUT Injectors



Notes

1) Number of levels is determined by the furnace geometry and the desired load range for SNCR operation.
2) The location of injectors is generally dictated by access and physical obstructions – CFD/CKM model determines preferred locations.
3) Compressed air and diluted urea is sent from the Metering Module to the Distribution Modules, where the air pressure and urea flow rate to each injector are controlled.

Urea Tanks

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Urea Tank

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NOxOUT Reagent Storage

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Circulation Modules

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HERT Circulation Skid

Metering Module

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HERT System Solenoid Rack

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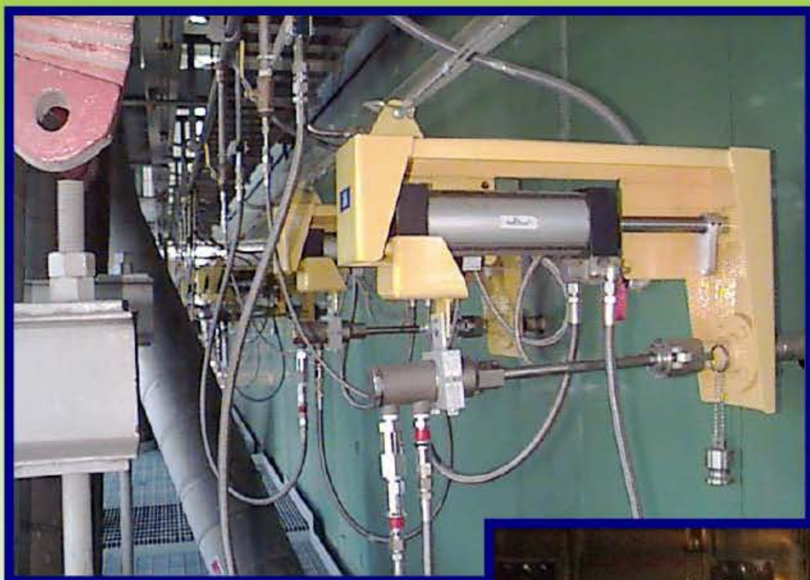
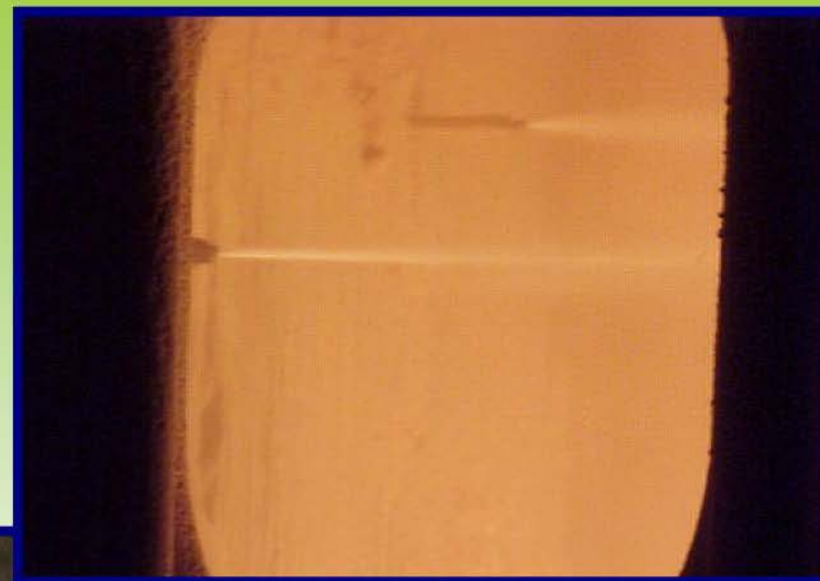
NOxOUT Injection





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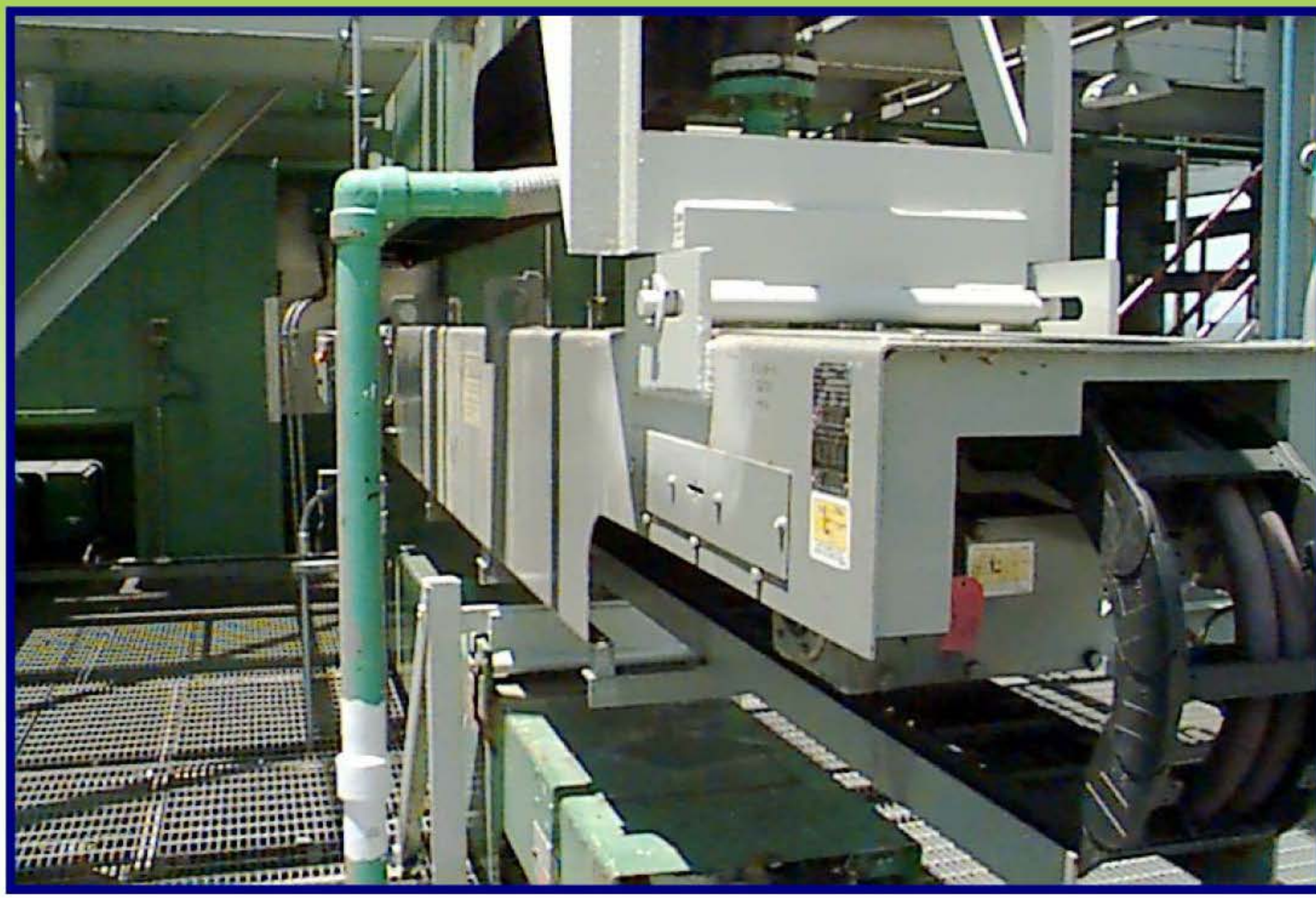
Multiple Nozzle Lances



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HERT INJECTOR

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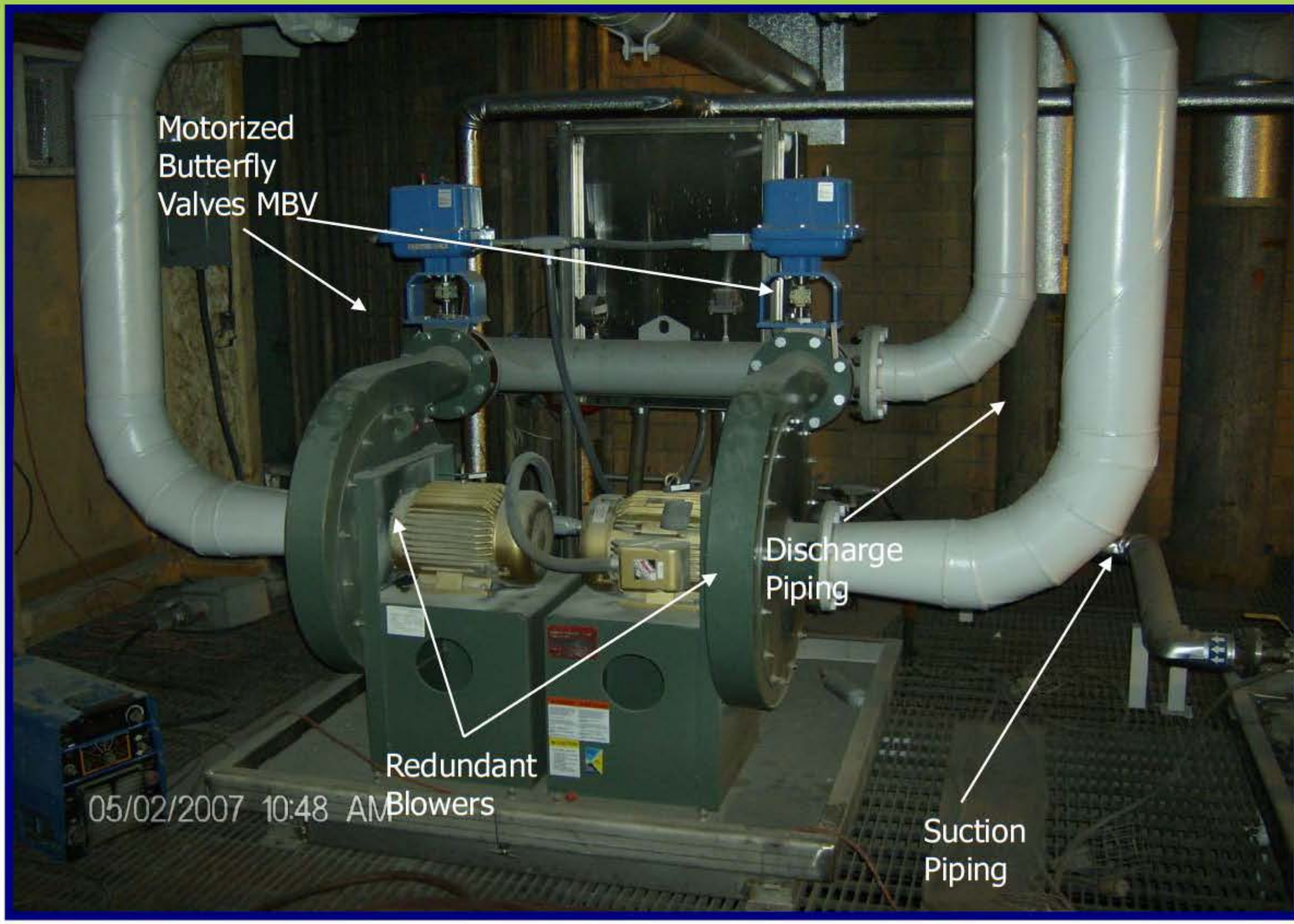
Blower Skid



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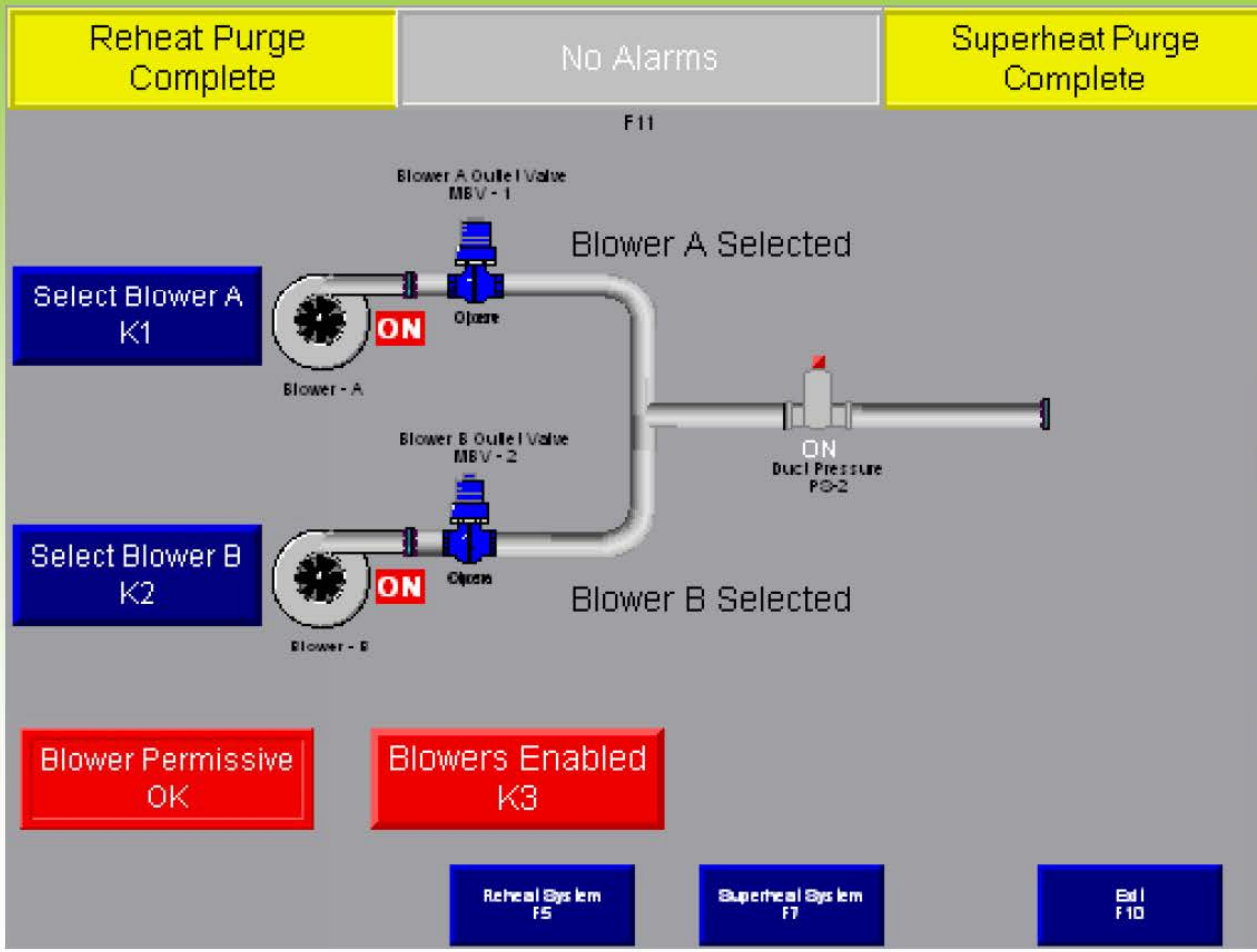
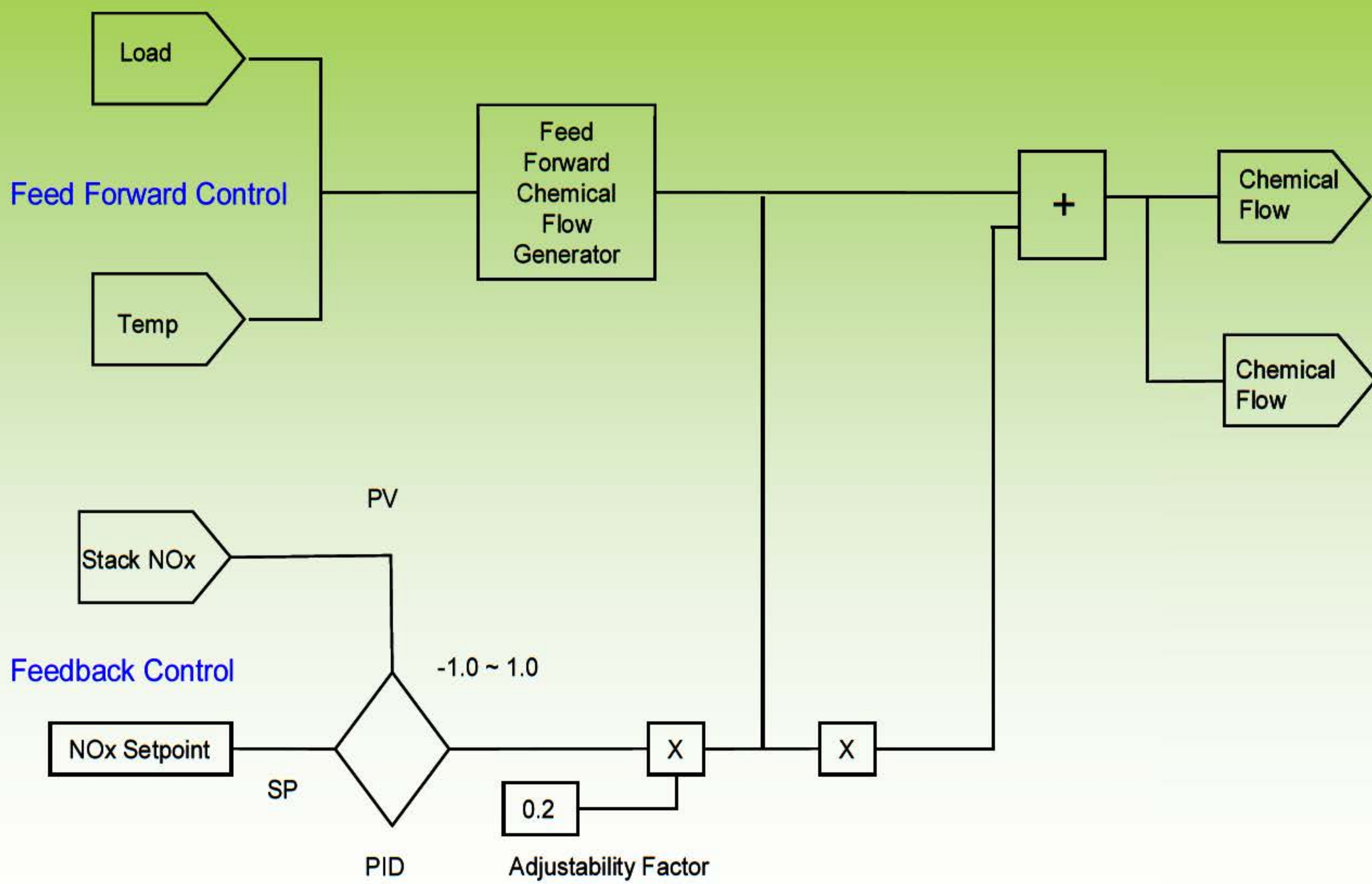
Blower Skid Screen



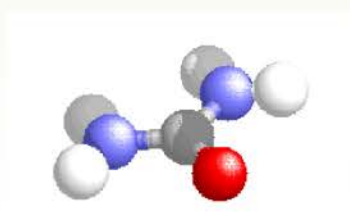
NOxOUT® SNCR Control Loop



UREA REAGENT OPTIONS

Liquid Urea Properties – NH_2CONH_2

at 60°F	NOxOUT LT		NOxOUT A		Urea Liquor	
Urea Concentration	**32.5%**	**40.0%**	**50.0%**	**60.0%**	**70.0%**	**85.0%**
Specific Gravity	1.0897	1.1113	1.1400	1.1688	1.1976	1.2407
Pounds per Gallon	9.085	9.265	9.505	9.643	9.767	9.970
Crystallization Temperature (°F)	11.3	33	62	96	135	195
Boiling Point (°F)		220	225	231	240	
Biuret	0.14	0.17	0.21	0.3 to 0.4	0.3 to 0.4	0.36
pH	7.0 to 10.0	7.0 to 10.0	7.0 to 10.0	7.0 to 10.0	7.0 to 10.0	7.0 to 10.0
lb-NH3/gallon	1.67	2.10	2.70	3.28	3.88	4.81



Urea and Dilution Water Quality

QUALITY SPECIFICATIONS – UREA				
	NOxOUT® A	NOxOUT® HP	UNSTABILIZED UREA	NOxOUT® LT
Description	Modified 50% Aqueous Solution of Urea	Modified 50% Aqueous Solution of Urea	50% Aqueous Solution of Urea	Modified 32.5% Aqueous Solution of Urea
Density (g/ml @ 25° C)	1.13 - 1.15	1.13 - 1.15	1.13 - 1.15	1.085 - 1.105
pH	7.0 - 10.8	7.0 - 10.8	7.0 - 10.8	5.0 - 10.8
Appearance	Light Yellow, Clear to Slightly Hazy	Light Yellow, Clear to Slightly Hazy	Light Yellow, Clear to Slightly Hazy	Light Yellow, Clear to Slightly Hazy
Salt Out Freeze Point	64°F (18°C)	64°F (18°C)	64°F (18°C)	40°F (4°C)
Foam (after bottle is shaken)	Foam Lasts > 15 seconds	Foam Lasts > 15 seconds	Not Applicable	Foam Lasts > 15 seconds
Free NH3	< 5000 ppm	< 5000 ppm	< 5000 ppm	< 3000 ppm
Biuret Content	< 5000 ppm	< 5000 ppm	< 5000 ppm	< 3000 ppm
Organic Phosphate	55 - 85 ppm as PO4	22 - 40 ppm as PO4	Not Applicable	55 - 85 ppm as PO4
Orthophosphate	< 6 ppm as PO4	< 6 ppm as PO4	< 2 ppm as PO4	< 6 ppm as PO4
Suspended Solids	< 10 ppm	< 10 ppm	< 10 ppm	< 10 ppm
Urea Makeup Water	Total Hardness as CaCO3 ≤ 300 ppm	Total Hardness as CaCO3 ≤ 150 ppm	Total Hardness as CaCO3 ≤ 20 ppm	Total Hardness as CaCO3 ≤ 300 ppm

QUALITY SPECIFICATIONS – DILUTION WATER				
	NOxOUT® A	NOxOUT® HP	UNSTABILIZED UREA	NOxOUT® LT
	Dilution Water Analysis	Dilution Water Analysis	Dilution Water Analysis	Dilution Water Analysis
Total Hardness as CaCO3 (ppm)	<450	<150	<20	<450
"M" Alkalinity as CaCO3 (ppm)	<300	<100	<100	<300
Conductivity (μmho)	<2500	<1000	<1000	<2500
Silica as SiO2 (ppm)	<60	<60	<60	<60
Iron as Fe (ppm)	<1.0	<1.0	<1.0	<1.0
Manganese as Mn (ppm)	<0.3	<0.3	<0.3	<0.3
Phosphate as P (ppm)	<1.0	<1.0	<1.0	<1.0
Sulfate as SO4 (ppm)	<200	<200	<200	<200
Turbidity (NTU)	< 10	< 10	< 10	< 10
pH	<8.3	<8.3	<8.3	<8.3

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Urea vs. Ammonia

- **Safety Considerations**
  - **Safety can be Engineered into the Design, but Considerations may Drive the Decision**
- **Natural Gas Pricing**
  - **Elevated Price of NG in North America is Forcing the Shutdown of NH3 Productions and an Increase in Dry Urea Imports**
  - **LNG is an Alternative but Supply Insufficient to Cover Demand**
- **On-site Ammonia Storage**
  - **DHS has Promulgated Final Rule for On-site Storage of Chemicals – Unsure How this Will Impact Anhydrous NH3 Storage for SCR's**
- **Transportation**
  - **"Chain of Custody" Regulations for TIH* Rail Shipments Driving Transportation Costs Considerably Higher, Some Carriers May Opt and are Currently Being Forced to Reroute Shipments to Avoid HTUA's**

* The TSA component of the DHS is about to implement a series of federal regulations affecting the transportation of Toxic Inhalation Hazard (TIH) materials such as Chlorine and Anhydrous Ammonia – will require "documented chain of command handoffs" along distribution zone.

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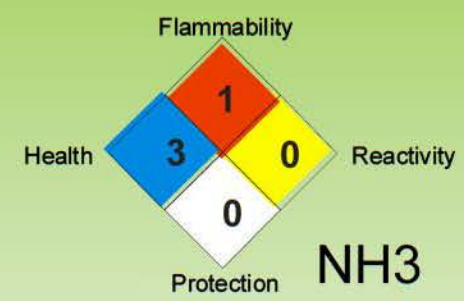
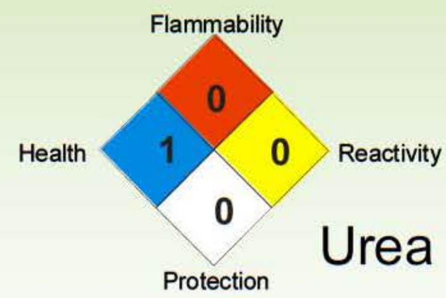
Reagent Alternatives for SNCR Systems

- **Anhydrous Ammonia**
  - **Highest Risk Reagent**
  - **Decrease in US Ammonia Production**
- **Aqueous Ammonia**
  - **19% Concentration**
  - **29% Concentration - limited availability**
- **Urea for On-Site Ammonia Generation**
  - **Significant Safety Advantages**
  - **Worldwide Availability of Urea**
  - **Equivalent SCR Performance**





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Anhydrous Ammonia – Safety Considerations

- Ammonia Storage
  - Department of Homeland Security (DHS) has indentified ammonia as a chemical of interest for anti-terrorism standards
- Transportation
  - Rail carrier risks and freight rate increases to handle anhydrous ammonia
  - Department of Transportation Restrictions
  - State and local restrictions on shipping and routing
- Safety Risks
  - *EPA Worst Case Release Analysis* – Toxic Endpoint for 60,000 Gallon Release Covers a Radius of 7 to 10 Miles[1]

1 http://yosemite.epa.gov/oswer/ceppoweb.nsf/vwResourcesByFilename/backup.pdf/$File/backup.pdf

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Aqueous Ammonia – Safety Considerations

- **Ammonia Storage**
  - Containment for possible liquid leaks/spills
- **Transportation**
  - 29% Aqueous ammonia is restricted by Department of Transportation in many areas
  - State and local restrictions on shipping and routing
- **Safety Risks**
  - Increased transportation risk due to more shipments of dilute chemical
  - 1.2 mile toxic radius for 60,000 gallon spill
  - Much higher unloading frequency at plant site raises potential incident probability

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Licensed NOxOUT Reagent Suppliers

Licensee Corporate Office	Address	Contact Person	Telephone/Fax
CDI, Inc.	P.O. Box 9083 Brea, CA 92821 -or- 471 W. Lambert Rd Suite 100 Brea, CA 92821	Luis Cervantes Rick Gross	714.990.3940 714.329.2281 (cell) 714.990.4073 (fax) (901) 867-8186 office (901) 233-2336 mobile
Distribution Points	– Crossett, AR – Casa Grande, AZ - City of Industry, CA – Imperial, CA – San Jose, CA – Stockton, CA – Greeley, CO – Jacksonville, FL – Augusta, GA – Kimberly, ID – Baltimore, MD – St. Paul, MN – Albany, NY – Elizabeth, NY – Cincinnati, OH – Lima, OH – Deer Island, OR – Russellville, SC – Memphis, TN – Houston, TX – Lufkin, TX – Pasco, WA		
Mosaic Company (formerly Cargill, Inc)	12800 Whitewater Dr MS 190 Minnetonka, MN 55343	Bob Ness	800.918.8270 763.577.2781 952.742.7313 (fax)
Distribution Points	– Brandon, FL – Baltimore, MD – St. Paul, MN – Albany, NY – Cincinnati, OH – Wellsville, OH – Philadelphia, PA – Menomonie, WI		
PCS Nitrogen, Inc	1101 Skokie Blvd Northbrook, IL 60062	Jennifer A. Zagorski	847.849.4377 (office) 847.612.5301 (cell) 847.849.4489 (fax)
Distribution Points	– Augusta, GA - Lima, OH		

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Licensed NOxOUT Reagent Suppliers

Monson Companies, Inc.	One Runway Rd P.O. Box 2405 South Portland, ME 04116-2406	Jeff Pellerin	207.885.5072 x 423 207.885.0569 (fax)
Distribution Points	– South Portland, ME		
Agrium USA	13132 Lake Fraser Dr SE Calgary, AB T2J7E8 CANADA	Gerry Kroon	403.335.7597 403.471.6473 (cell)
Distribution Points	– Stockton, CA		
The Andersons, Inc.	480 W. Dussel Drive P.O. Box 119 Maumee, OH 43537	Bill Wolf	419.897.3689
Distribution Points	– Logansport, IN – Maumee, OH		
Colonial Chemical Co.	78 Carranza Rd Tabernade, NJ 08088	Eric Wegelius	609.268.1200 x 112 609.268.2117 (fax)
Distribution Points	– Frederick, MD – Tabernacle, NJ		

Information Needed by Licensees:

- Company Name
- Location
- Scheduled Start-Up Date
- If rail delivery- specify railroad
- NOxOUT® Reagent Type Required (A, HP, LT)
- NOxOUT® Reagent Usage Rate
- NOxOUT® Reagent Storage Tank Size

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SNCR Combined with other NO_x Control Technologies

Layered NOx Reduction

- Combustion NOx Control
  - Combustion Tuning
  - Low-NOx Burners
  - OFA
- Post-Combustion NOx Control
  - Rich Reagent Injection
  - Selective Non-Catalytic Reduction
  - Selective Catalytic Reduction

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Combining NOx Reduction Technologies

Technology	Strength	Limitations
Low-NOx Burners	Low Capital and Operating	Combustion, Corrosion, CO
Combustion Mods / OFA	Low Capital and Operating	Combustion, Corrosion, CO
SNCR	Low Capital NOx Red%	NH3 Slip ABS
SCR	NOx Red% Low NH3 Slip	High Capital SO_3 Oxidation

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Retrofit Low-NOx Burner Installation

Technology	Strength	Limitations
Low-NOx Burners	Low Capital and Operating	Combustion, Corrosion, CO
Combustion Mods / OFA	Low Capital and Operating	Combustion, Corrosion, CO
SNCR	Low Capital NOx Red%	NH3 Slip ABS
SCR	NOx Red% Low NH3 Slip	High Capital SO_3 Oxidation

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Moderate Combustion Modifications

Technology	Strength	Limitations
Low-NOx Burners	<u>Low Capital and Operating</u>	Combustion, Corrosion, CO
Combustion Mods / OFA	<u>Low Capital and Operating</u>	Combustion, Corrosion, CO
SNCR	Low Capital NOx Red%	NH3 Slip ABS
SCR	NOx Red% Low NH3 Slip	High Capital SO_3 Oxidation

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Conservative SNCR application

Technology	Strength	Limitations
Low-NOx Burners	Low Capital and Operating	Combustion, Corrosion, CO
Combustion Mods / OFA	Low Capital and Operating	Combustion, Corrosion, CO
SNCR	Low Capital NOx Red%	No NH3 Slip No ABS
SCR	NOx Red% Low NH3 Slip	High Capital SO_3 Oxidation

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Aggressive SNCR application

Technology	Strength	Limitations
Low-NOx Burners	<u>Low Capital and Operating</u>	Combustion, Corrosion, CO
Combustion Mods / OFA	Low Capital and Operating	Combustion, Corrosion, CO
SNCR	Low Capital > Red%	NH3 Slip ABS
SCR	NOx Red% Low NH3 Slip	High Capital SO_3 Oxidation

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In-Duct or Small SCR Space

Technology	Strength	Limitations
Low-NOx Burners	Low Capital and Operating	Combustion, Corrosion, CO
Combustion Mods / OFA	Low Capital and Operating	Combustion, Corrosion, CO
SNCR	Low Capital > Red%	NH3 is OK Feed to SCR
Single Layer SCR	More Red% Low NH3 Slip	Mod Capital, SO_3 and Cost

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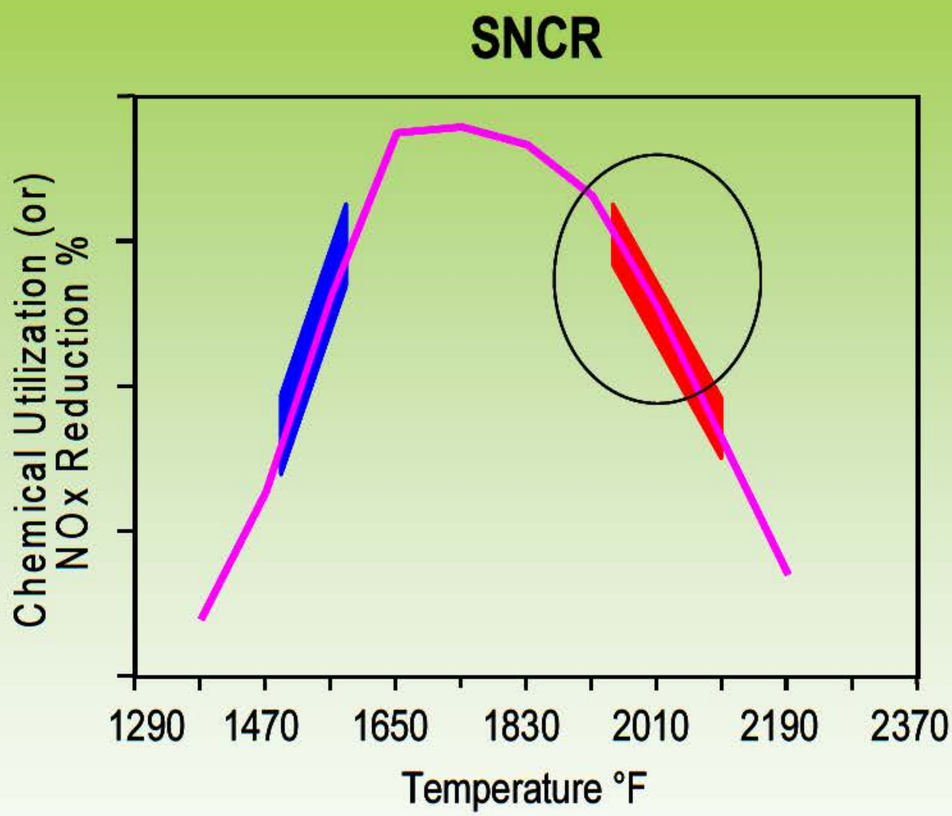
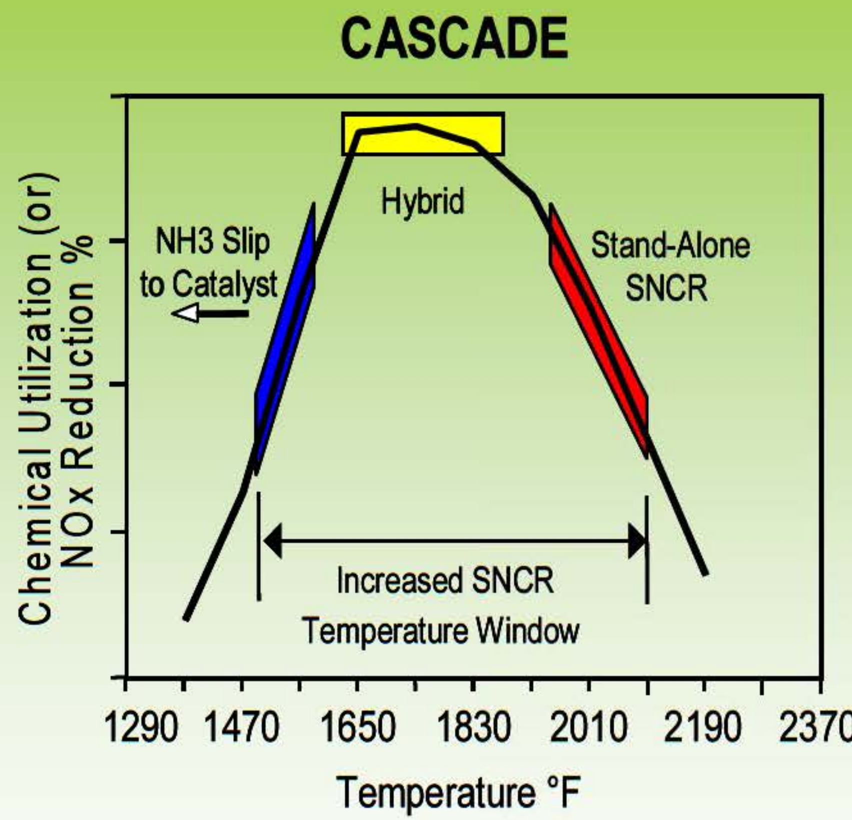
Advanced SCR Application

Technology	Reduction	Total %
Low-NOx Burners	30%	30%
Combustion Mods / OFA	30%	51%
SNCR	30%	66%
Single Layer SCR	45%	81%

Chemical Release Point Comparison





Releasing chemical at or near the top of the curve versus "right side of the slope" favors increased NOx reduction efficiency and better utilization of reagent – NH3 slip is absorbed by catalyst.

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Benefits of Hybrid SNCR + SCR System

- SNCR Not Restricted to "Right Side of Slope" Injection Strategy
- Impact of "High" CO can, in many cases, be Minimized
- Controlled Increase in Ammonia Slip (versus SNCR) is Desirable, Significant Improvement in SNCR Efficiency and Chemical Utilization
- Relax Inlet Conditions to SCR, Design for Incremental SCR Reduction and NH3 Absorption
- Pressure Drop is Minimized as a Result of Reduced Volume and Treatment Length, Allowable Gas Velocity Now Higher with State-of-the-Art Flue Gas Mixing and Straightening Devices
- Reduced Conversion of SO_2 to SO_3
- Lower Catalyst Replacement Cost, Single Layer

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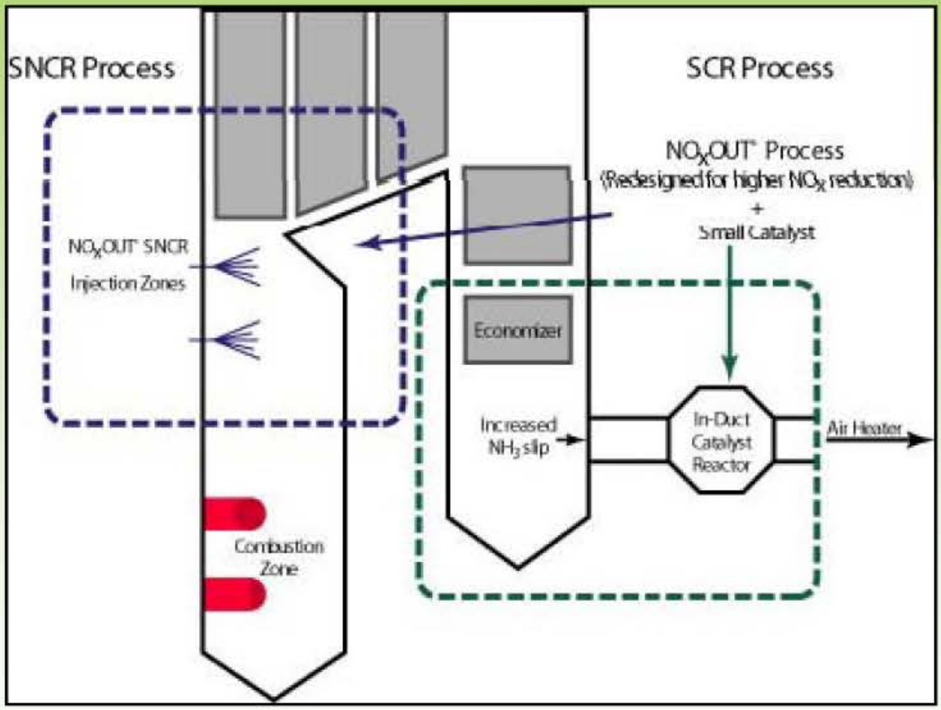
NOxOUT CASCADE® Technology Overview

- Combined SNCR/SCR Process
- Single Layer SCR Catalyst – Reduced Volume
- Improved SNCR Chemical Utilization and Reduction Efficiency with Higher, Controlled Level of Ammonia Slip
- Ammonia Slip from SNCR Provides Reagent for Catalytic Reactions
- NO_x Reduction Performance - 65-85%
- Lower Capital Cost ($30 to $75 per kW) compared to Full Scale SCR (Up to >$300/kW)
- Demonstrated Mercury Oxidation of >90% with Single Layer Catalyst for Capture with FGD System



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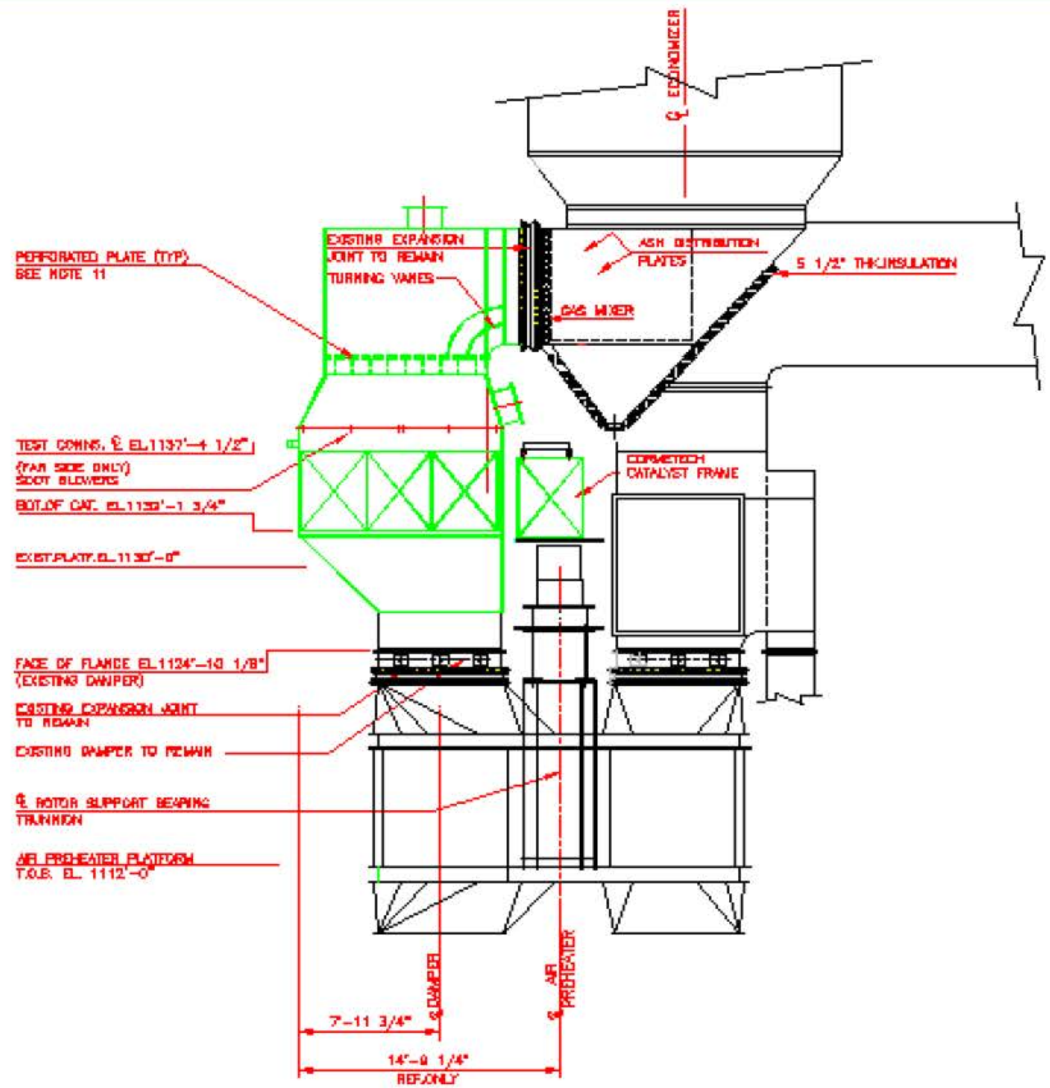
Penelec Seward Duct Modifications



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AES Greenidge – Multi-P w/ CASCADE

AES Greenidge Unit 4
(Boiler 6)

ELECTRIC POWER CONFERENCE & EXHIBITION

- Dresden, NY
- Commissioned in 1953
- 107 MW_e (net) reheat unit
- Boiler:
  - Combustion Engineering tangentially-fired, balanced draft
  - 780,000 lb/h steam flow at 1465 psig and 1005 °F
- Fuel:
  - Eastern bituminous coal
  - Biomass (waste wood) – up to 10% heat input
- Existing emission controls:
  - Overfire air (natural gas reburn not in use)
  - ESP
  - No FGD - mid-sulfur coal to meet permit limit of 3.8 lb SO_2/MMBtu

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AES Greenidge – Multi-P w/ CASCADE

- DOE Cooperative Agreement signed May 2006
- Goal: Demonstrate a Multi-pollutant Control System to Cost-effectively Reduce Emissions of NOx, SO2, Hg, Acid Gases (SO3, HCl, HF), and PM Smaller Coal-fired Power Plants
- 115 MW Coal-fired Boiler, 2.9% Sulfur Bituminous Coal, 10% Biomass
- SNCR: Two Levels of Wall Injectors, plus Multiple Nozzle Lances
- BPI Designed SCR Reactor and Delta Wing Flue Gas Mixing
- In-duct SCR Reactor, Single Layer of Catalyst
- SNCR NOx Reduction = 42%, SCR NOx Reduction = 30%
- Overall Post-combustion NOx Reduction ≈ 60%
- SNCR Chemical Utilization ≈ 40%

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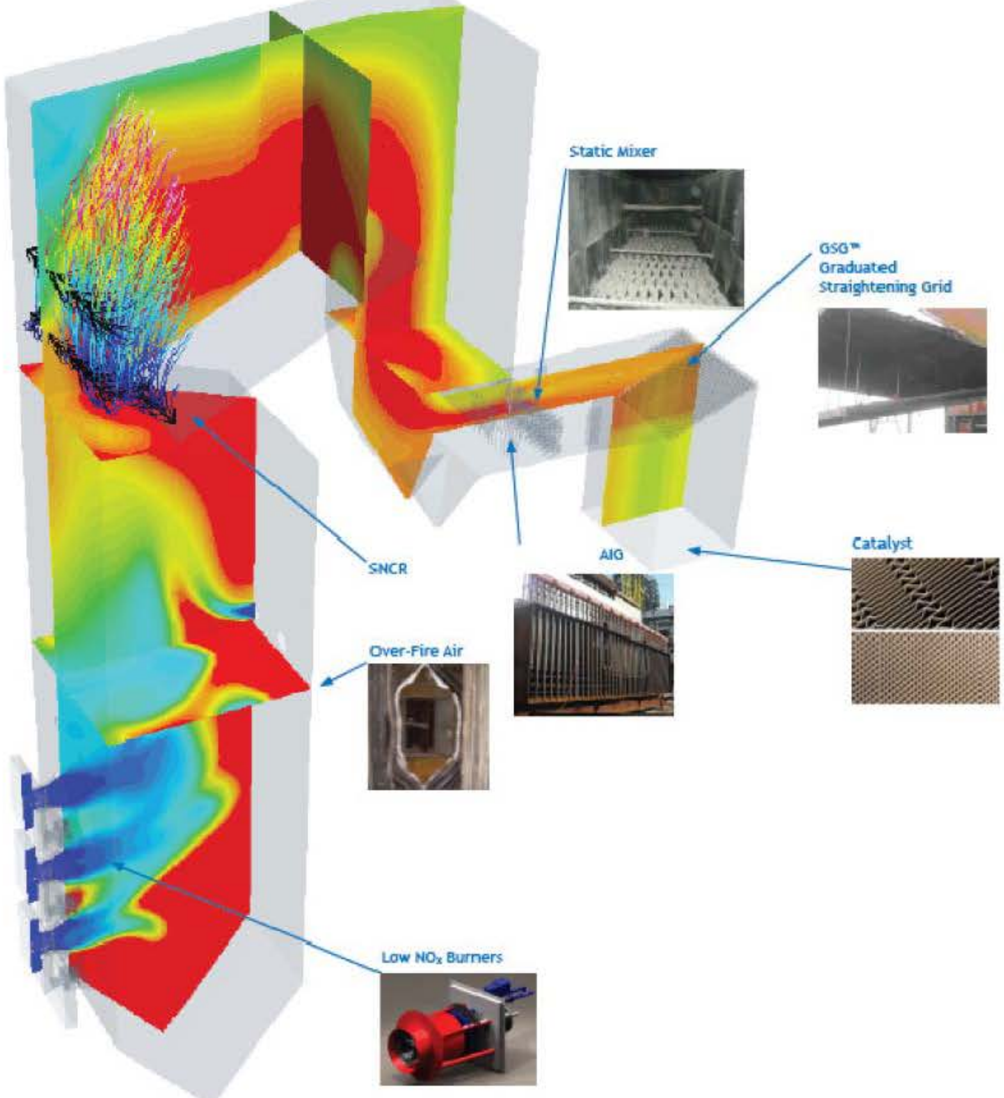
ASCR™ Advanced SCR



- 80+% NO_x Reduction
- 40-60% less than conventional SCR

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Advantages of ASCR Technology

- Capital Cost
  - Limited Structural Steel – Modify Existing, No New Steel to Grade
  - Less Catalyst
  - Less Ductwork
- Better Reagent Utilization
  - SNCR Process
  - Separate AIG
- Low Pressure Drop
- Low SO_2 to SO_3 Conversion Rate
- Broader Range of Operation
  - Lower Electrical Demand

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ASCR™ Advanced SCR

- Maximize In-furnace NOx Reduction through Combustion Modifications and Post-combustion Controls
- Apply SNCR for Maximum Performance, NH3 Slip Control
- On-site Urea Conversion with AIG for 90+% Chemical Utilization
- Employ FTI Mixing and Flow Correction Devices to Provide Uniform Flow and Distribution Across Catalyst Face
- Utilize Catalyst That Maximizes Use of Available Space
- NOx Reduction Efficiency Across Single Layer is Increased As the NOx Entering the SCR is Reduced

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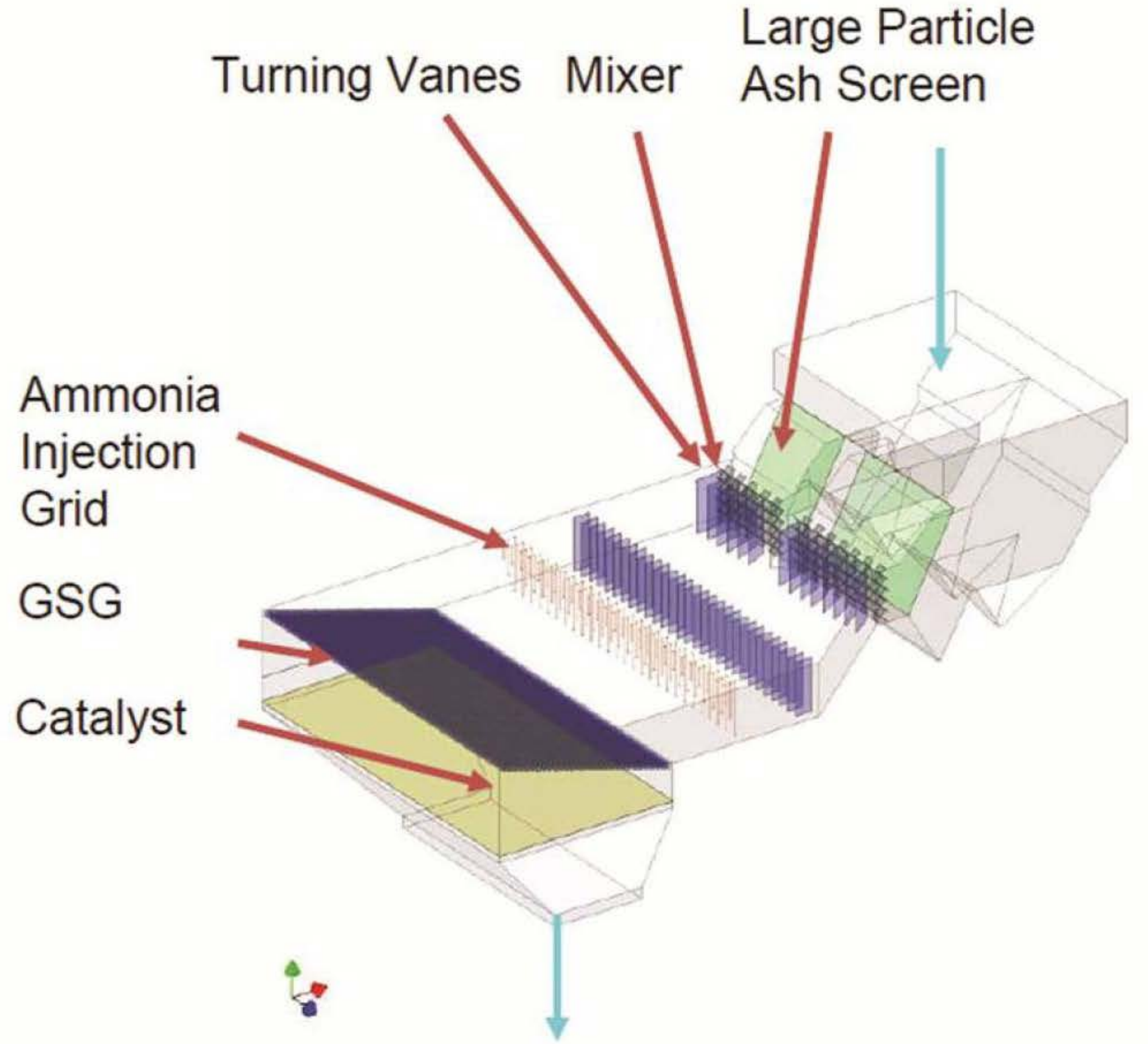
Optimized SCR System



Summary

- Flexible, Cost Effective NOx Reduction
- SNCR complementary to other NOx control technologies

Questions?

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Martin R. Schock
1121 North 29th Street
Bismarck, ND 58501

October 22, 2012

Terry L. O'Clair, Director
North Dakota Department of Health
Division of Air Quality
918 E. Divide Ave., 2nd Floor
Bismarck, ND 58501-1947

Comments on Supplemental Evaluation of NO_x BART Determination for Coal Creek Station Units 1 and 2

Dear Mr. O'Clair:

Comments are provided herein pursuant to a public notice pertaining to above subject dated the September 12, 2012. The comments address the second paragraph on page 14 of a "Supplemental Evaluation of NO_x BART Determination for Coal Creek Station Units 1 and 2" (hereafter Supplemental Evaluation) dated September 2012 and prepared by the Division of Air Quality (DAQ). The public notice states that the document is an extension of DAQ's RH SIP which was submitted to EPA and presented for public comment by EPA in the fall of 2011.

Specifically, the comments herein address DAQ's setting and discussion for CALMET variable LCALGRD, which is user controlled through a user input data stream when executing the CALMET model. Comments that follow address the DAQ's failure to disclose and justify its choice of the "False" setting rather than the "True" setting for LCALGRD.

BACKGROUND DEFAULT SETTINGS FOR LCALGRD

The US Environment Protection Agency (EPA) has specified that the default setting for LCALGRD is "True." See pages 2-31 through 2-33 in "A User's Guide for Meteorological Model CALMET (Version 5)," which explain the technical reasons for the "True" setting irrespective of whether CALMET output are used with the Long Range Transport (LRT) model CALPUFF or the LRT model CALGRID, as well as pages 4-99, 4-114 and 4-193 where the guide states that "LCALGRD is normally set to TRUE for CALPUFF applications."

The user's guide also states on page 4-190:

> "CALGRID requires three-dimensional [3-D] fields of temperature and vertical velocity which are not required by CALPUFF *for certain simple simulations*. [A] switch is provided in the CALMET [user] control file which allows the user to eliminate these variables from the CALMET.DAT output file if the generated

> meteorological fields will be used to drive CALPUFF in a mode where they are not needed. The larger version of CALMET.DAT with the extra parameters can always also be used with CALPUFF." "However, under most conditions, a full 3-D temperature field will be required by CALPUFF." (Emphasis added.)

An example of a simple situation is a single upper air observation station collocated with a single surface station.

IWAQM has specified that its preferred setting for LCALGRD is "True." See page A-2 in its "Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts" published by EPA and dated December 1998.

Once more, EPA on behalf of IWAQM indicates that the preferred setting for LCALGRD is "True." See page 5 in EPA's memo titled "Clarification on EPA and FLM Recommended Settings for CALMET" dated August 31, 2009.

In summary, EPA and IWAQM set the input for CALMET variable LCALGRD as "True," which they note is the required choice for execution of the LRT model CALGRID as well as the default, recommended or preferred choice for CALPUFF.

DAQ's HISTORICAL SETTINGS FOR LCALGRD

The DAQ now admits that it has used the "False" setting for LCALGRD. On page 14 of the Supplemental Evaluation, DAQ states:

> "The Department received a public comment that suggested that the LCALGRD setting in Calmet should be "True" instead of the "False" setting the Department has been using."

The DAQ had not previously revealed this departure from the EPA and IWAQM default or preferred setting. See, for example;

> Pages 20 through 24 in DAQ's "Calpuff Analysis of Current PSD Class I Increment Consumption in North Dakota and Eastern Montana Using Actual Annual Average SO_2 Emission Rates" dated April 2002 which describes and lists non-IWAQM settings used by DAQ and such discussion and list does not include LCALGRD. However, Appendix C, page A-2, provides the IWAQM recommended inputs including the setting for LCALGRD as "T" for "True."

> Pages 35 through 40 in DAQ's "Calpuff Analysis of Current PSD Class I Increment Consumption in North Dakota and Eastern Montana Using Actual Annual Average SO_2 Emission Rates" dated May 2003 where discussion did not disclose DAQ's use of the LCALGRD setting of "False." However, Appendix C, page A-2, provides the IWAQM recommended inputs including the setting for LCALGRD as "T" for "True."

> Pages 23 through 27 in DAQ's RH "Protocol for BART-Related Visibility Impairment Modeling Analyses in North Dakota (Final)," dated November, 2005, which states on page 26 that "NDDH settings for IWAQM-defined variables are consistent with IWAQM recommendations, with limited exceptions." The exceptions do not include LCALGRD, which apparently should have been noted in the protocol per DAQ's statement on page 14 of the Supplemental Evaluation.

The user chosen setting for LCALGRD in effect selects one of two algorithms for computing vertical temperature gradients across the domain modeled by CALMET. These algorithms compute vertical temperature gradients which affect computed mixing heights, and computed mixing heights affect computed SO_2 and SO_4 dispersion and, consequently, ground level concentrations. Because DAQ used a setting of "False" for LCALGRD, 3-D fields of temperature and vertical velocity were not included with CALMET output (CALMET.DAT) for input used with CALPUFF.

In summary, DAQ's statement on page 14 of the Supplemental Evaluation seems to conflict with documentation for applications of CALMET prior to the RH BART protocol. Rhetorically, was the setting for LCALGRD changed from "True" to "False" for the RH BART protocol or had the setting been "False" in every protocol? Clarification of the actual setting for LCALGRD in those prior applications seems warranted and if changed to "False," then an explanation as to why seems warranted.

Furthermore, the CALMET protocol actually used for RH BART deviated from the protocol described in documentation and, as confirmed by Appendix F of the Supplemental Evaluation, the results of the visibility modeling described in DAQ's RH SIP were not the results of the CALMET protocol described.

EPA's REVIEW OF DAQ'S MODELING PROTOCOL FOR REGIONAL HAZE

EPA has stated that DAQ's RH BART modeling protocol:

> "follows recommendations for modeling long range transport contained in 40 CFR part 51, appendix W ("The Guideline on Air Quality Models") and EPA's Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts. Furthermore, as discussed in Section 3 of the SIP, *Plan Development and Consultation*, the protocol was developed in consultation with EPA and FLM meteorologists."

See document number 323, section V.C, page 20907, in EPA docket EPA-R08-OAQ-2010-0406. Here, EPA apparently failed to notice that some settings for CALMET, including LCALGRD, and for CALPUFF were not IWAQM preferred settings or perhaps overlooks those alternate settings as it states that the DAQ's RH BART protocol as cited above followed, or did not deviate from, IWAQM. These EPA's statements failed to note that there were DAQ departures from IWAQM, including the CALMET user input variable LCALGRD.

NDAC REQUIREMENT

North Dakota Administrative Code, section 33-15-15-01.2, which replaces 40 CFR 52.21 (l)(r) states:

> "All estimates of ambient concentrations required under this chapter shall be based on applicable air quality models, technical data bases (including quality assured air quality monitoring results), and other requirements specified in appendix w of 40 CFR 51 ("guideline on air quality models" as it exists on July 2, 2010) as supplemented by the "North Dakota guideline for air quality modeling analyses". These documents are incorporated by reference. Technical inputs for these models shall be based upon credible technical data approved in advance by the department. In making such determinations, the department shall review such technical data to determine whether it is representative of actual source, meteorological, topographical, or local air quality circumstances."

The second paragraph on page 14 of the Supplemental Evaluation does not address this requirement of the NDAC[1] as it does not discuss whether the "False" setting for LCALGRD is more appropriate than the default or recommended "True" setting for the modeled domain. In other words, the DAQ has not justified execution of CALMET using the "False" setting over the large domain of western and central North Dakota and adjoining areas which has multiple NOAA/NWS upper air meteorological observation stations and multiple surface meteorological observation stations.[2] The large domain with multiple observation stations is not a simple situation.

ROLE OF SCIENCE

On page 14 of the Supplemental Evaluation, the DAQ also states:

> "The Department conducted modeling to evaluate the difference in the results using these two [LCALGRD] settings. The results indicate the "True" setting produces less improvement in visibility for the various control options (see Appendix D). The results shown above [on pages 13 and 14] indicate the larger visibility improvement associated with the two LCALGRD options (LCALGRD = F)."

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[1] This provision of NDAC was approved by EPA. See EPA's Technical Support Document for EPA SIP Action on the Submittal of the North Dakota Department of Health Air Pollution Control Rules 33-15-15, which is dated November 2, 2006, and is document number 0005(1) in EPA's docket number EPA-R08-OAR-2006-0502.

[2] See pages 3 through5 and pages 14 through22 in DAQ's RH "Protocol for BART-Related Visibility Impairment Modeling Analyses in North Dakota (Final)," dated November 2005. Note: the paragraph on page 13 of the Supplemental Evaluation indicates the published date was November 2006.

This paragraph and the Supplemental Evaluation in general do not address the technical merits of using a "False" setting versus using a "True" setting in the modeled domain. Instead, the Supplemental Evaluation directs readers to the modeled outcome on the source's impact on visibility using the "False" setting, which produces a greater improvement due to NO_x controls. In essence, it seems that rule of law (NDAC), EPA guidance, the CALMET user's guide and science are abandoned in favor of consistency with prior RH BART visibility modeling (see page 13 in the Supplemental Evaluation).

The DAQ paragraphs on pages 13 and 14 are confounded by the various modeling assessments of visibility impacts due to emissions at the Heskett Unit II plant. The accepted modeling protocol for visibility impacts by emissions at Unit II deviated from DAQ's 2005 RH BART protocol when using an EPA approved protocol. EPA stated:

> "The State's single-source modeling for Heskett Station Unit 2 predicted the highest maximum 24-hour 98th percentile visibility impact value to be 0.82 dv at Theodore Roosevelt and 0.58 dv at Lostwood. Since these values were close to the BART exemption threshold, MDU hired a consultant to perform a refined CALPUFF modeling analysis. We and the FLMs expressed concerns about the refined modeling. MDU agreed to remodel using an EPA approved protocol. The results of the final analysis predicted the highest maximum 24-hour 98th percentile visibility impact value to be 0.28 dv at TRNP and 0.23 dv at LWA in 2001. The refined modeling used a 1 kilometer grid size instead of 3 kilometer, speciated particulate matter emissions into several components with varying light scattering potential, and used annual average background visibility instead of the annual 20% best day's background visibility. We agree with the revised modeling results and with the State's analysis that Heskett Station Unit 2 is below the BART threshold and not subject to BART. Information on the refined modeling and the State's updated analysis was submitted with SIP Supplement No. 1 on July 27, 2010."

See footnote 13 attached to Table 4 on page 58583 in document 0001 in EPA docket EPA-R08-OAR-2010-0406. The document title is "Approval and Promulgation of Implementation Plans; North Dakota; Regional Haze State Implementation Plan; Federal Implementation Plan for Interstate Transport of Pollution Affecting Visibility and Regional Haze; Proposed Rule."

The EPA approved protocol resulted in less visibility impact as the 98th percentile value at TRNP decreased from 0.82 dv to 0.28 dv, which is significant and which was likely do in part to using an EPA setting for LCALGRD of "True."[3] See "CALPUFF Visibility Modeling Protocol: MDU Heskett Unit 2 BART Analysis" dated November 2009 by AECOM, pages 1-1 and 1-2.

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[3] There is no explanation by EPA or by the State's DAQ that this protocol satisfies NDAC 33-15-15-01.2 as an alternative to or substitute for the DAQ RH Bart protocol. And, there is no empirical demonstration which compares modeled data using the model settings of the EPA approved protocol for the source configuration, meteorological data, and geographic data for the modeled domain to available actual ambient monitored data within the modeled domain. See, for example, the Health Department's policy found in "Recommendations of the Hearing Officer to the State Health Officer of Proposed Findings and

In summary, the setting of “False” for LCALGRD versus the setting of “True” may not consistently produce greater or lesser estimates of visibility impacts or improvements for the emissions of sources scattered at locations across the modeled domain which includes central and western North Dakota as well as adjoining regions.

OBSERVATIONS

The comments herein focus on a very narrow aspect of RH BART analyses and of computer modeling analyses for estimating visibility impacts and for visibility improvement. Technical discretion in modeling is pervasive in spite of rule, abundant EPA guidance and other information.

Most if not all public citizens are not in-the-know, or do not have knowledge of analyses details; these details often affect analyses outcome. Persons, including experienced modelers, providing comments on modeling, as described by EPA in document number 0323, section V.C, in EPA docket EPA-R08-OAQ-2010-0406, would not have known that the setting for LCALGRD was “False” instead of “True,” unless they had access to and reviewed actual CALMET user control input files. The situation also appears to apply to EPA and FLMs, even though they were consulted by DAQ in its preparation of modeling protocols.

Even though model algorithms and model input data contain uncertainty, the end results of protocol execution are numbers compared to standards or thresholds, which also include uncertainty. The comparison, however, is usually a pass or fail test that often has significant consequences. This decision scenario demands clarity in documentation of modeling that begins with law and rule followed by peer-reviewed technical guidance and appropriate discretion.

The situation here regarding a) the setting for LCALGRD and b) the MDU EPA-approved protocol as applied to Heskett II versus the DAQ EPA-approved RH BART protocol as applied to other sources might cause pause by some persons as to whether discretion is fundamentally sound or flawed. The situation does not narrow the uncertainty of modeling, and it confounds the role of models in enforcement when managing air quality.

Sincerely,

/ s /
Martin R. Schock

Determination,” section 6.5; the proposed findings and determination were approved and adopted by the State Health Officer on September 7, 2005.

Response to Public Comments
Supplemental Evaluation of
NO_x BART Determination
Coal Creek Station Units 1 and 2

Purpose: This document responds to public comments that were received from October 1-30, 2012 regarding the North Dakota Department of Health's (Department) Supplemental Evaluation of the NO_x BART determination for the Coal Creek Station Units 1 and 2.

Commentor: Martin Schock – The comments relate to the LCALGRD setting used in CALMET. Mr. Schock has questioned the use of the LCALGRD setting of "False" and asserted "deviations" from the federal and State Prevention of Significant Deterioration (PSD) rules.

The Department has demonstrated in its modeling analyses that the LCALGRD setting does not significantly change the amount of anticipated visibility improvement associated with emissions control scenarios (see Appendix D. of the Supplemental Evaluation). The "False" setting produced an overall average anticipated visibility improvement for SNCR plus LNC3+ versus LNC3+ for each individual unit of only 0.056 deciviews (98^{TH} percentile). The "True" setting for LCALGRD produced an average anticipated visibility improvement of 0.044 deciviews (98^{th} percentile). In either case, the amount of anticipated visibility improvement is well below 1.0 deciview which is generally accepted as the minimum amount of visibility improvement that is perceptible and well below the amount that is defined by NDAC 33-15-25 as contributing to visibility impairment (0.50 deciviews). Based upon the Department's review, the comment regarding the LCALGRD setting does not affect the Department's decision regarding the use of SNCR at the Coal Creek station since the amount of visibility improvement is so small when using either setting.

The PSD rules (NDAC 33-15-15) are not applicable to regional haze BART determinations. BART determinations are guided by NDAC 33-15-25, Regional Haze Requirements. NDAC 33-15-25 does not reference or rely upon the PSD rules.

Comment 1: The commentor indicated that the use of the "False" setting seems to conflict with the documentation for the BART modeling.

Response: The Department has reviewed the comments of Mr. Schock and determined that there is no conflict between the Department's BART modeling and the settings used. The Department conducted modeling for the Coal Creek Station NO_x Supplemental BART determination once using the "False" setting and once using the "True" setting. The modeling results based on both "False" and "True" LCALGRD settings resolves any confusion on the intent of the BART modeling documentation.

BART analyses, other than the Coal Creek NO_x analysis, are not the subject of this public comment period. The public comment period on all other Department BART determinations began more than two years ago and was completed as of November 21, 2011, the date that all public comments to the U.S. Environmental Protection Agency (EPA)'s proposed partial

approval and partial disapproval of North Dakota's Regional Haze State Implementation Plan were due. Therefore, the BART analyses for those sources are not addressed here.
Comment 2: The commentor questioned why the Supplemental Evaluation did not address the technical merits of the LCALGRD setting of "False" versus a "True" setting.

Response: The Department provided modeling results for the top two control technologies using an LCALGRD setting of "False" and also "True." In both cases, the visibility improvement of SNCR + LNC3+ versus LNC3+ was so small that SNCR was not warranted. Therefore, no explanation of the merits of the two settings was necessary. As EPA has made clear in the preamble to the BART Guidelines, States have considerable discretion in choosing how to apply the five BART factors, which include visibility improvement.

Comment 3: The commentor quoted a section of North Dakota's Prevention of Significant Deterioration (PSD) rules (NDAC 33-15-15). The commentor indicated that the Supplemental BART Evaluation did not address this requirement of the PSD rules.

Response: While the commentor is correct that the Supplemental Evaluation does not address the modeling requirements of NDAC 33-15-15, it is because NDAC 33-15-15 is not applicable to BART determinations. BART evaluations are governed by NDAC 33-15-25 which has no requirement that the PSD rules be consulted or applied.

Comment 4: The commentor suggested that the EPA/FLM modeling protocol to determine BART applicability for Heskett Station Unit 2 does not satisfy the requirements of NDAC 33-15-15-01.2.

Response: As discussed in the Response to Comment 1, the only BART determination noticed to the public and to which comments are being taken is the Coal Creek Station Units 1 and 2. The Heskett BART applicability modeling was not the subject of this public comment period and no response is required. However, again the commentor is quoting the PSD rules (NDAC 33-15-15-01.2) which are not applicable to BART determinations.

Comment 5: The commentor observed that the "False" setting of LCALGRD may not always provide more visibility improvement than the "True" setting.

Response: The Department agrees. For the Coal Creek Supplemental Evaluation, however, as set forth in Appendix D to the Department's analysis, the "False" setting did produce more anticipated visibility improvement than the "True" setting.

<u>Commentor</u>: Lafarge North America – The comments relate to the possibility of ammonia contamination from the use of SNCR.

Comment 1: Lafarge supported the Department's Supplemental Evaluation. Lafarge supported the Department's determination that the ash could be contaminated by ammonia from the use of SNCR and encouraged recycling of the ash. Lafarge stated "There will be lost fly ash due to the operation of SNCR, it is only a question of how much is lost."

Response: The Department believes it is reasonable to accept that Lafarge has experience in purchasing and handling fly ash from power plants. Lafarge indicates that it would expect some fly ash sales will be lost from the installation of SNCR. Lafarge's comments, based on their experience, substantiate the Department's determination that fly ash sales will be lost at the Coal Creek Station if SNCR is required.

Commentor: U.S. Fish and Wildlife Service (DOI).

Comment 1: The commentor indicated that a BART determination should not be contingent on whether the amount of visibility improvement is humanly perceptible or not.

Response: In the Department's analysis, there is no discussion whether the amount of visibility improvement from SNCR + LNC3+ versus LNC3+ was perceptible or not. The maximum amount of visibility improvement was only 0.106 deciviews (98^{th} percentile) at any one Class I area and the average for all North Dakota Class I areas was 0.056 deciviews. The Department considers this amount of visibility improvement to be very small. In any event, the Department believes the federal Clean Air Act (CAA) and Regional Haze rules provide it the authority and discretion to consider whether the BART factor involving the degree of improvement in visibility to include understanding whether the degree of improvement in visibility is humanly perceptible (or not) and to what extent.

In addition, were the Department to rely on single source modeling using a clean background, as EPA has suggested States may do, the amount of visibility improvement is over predicted in that modeling. An observer can detect a change in visibility much more easily in clean air than in air which is realistically affected by emissions from a number of existing sources. Therefore, the Department determined that EPA's single source modeling will overstate a predicted change in visibility resulting from use of an emission control technology because the model assumes there are no background sources of emissions, which in reality is not the case. Single source modeling also overstates ammonia availability for the formation of the visibility-affecting species nitrate, adding to the over prediction of visibility improvement. SNCR is not warranted based on the small amount of visibility improvement.

Comment 2: The DOI believes the Department should develop a cost for the various control technologies on a dollar per deciview basis.

Response: As pointed out in previous responses to comments from the DOI, the Department believes the dollar per deciview metric is of little value for BART analyses (see ND SIP, Appendix J.1.4, Comment 12). Single source modeling does not reflect the true visibility improvement because it uses an unrealistic clean background and does not include in the modeling all sources affecting visibility in the Class I area (see Response to DOI Comment 1). Visibility improvement from single-source modeling may be less overstated if there are very few sources affecting the Class I areas and the levels of visibility impairment are minor. However, North Dakota's Class I areas sustain significant visibility impairment caused by many sources, including sources located outside the United States. In areas where there are few sources affecting the Class I area, the single source modeling may produce a less overstated prediction of visibility improvement and thus a more accurate cost on a $/deciview basis than it will in North Dakota. In addition, cost estimation methods have only a $\underline{+}$30% accuracy which can lead to as much as a 60% variation from one cost estimate to another (also cost on a dollar per deciview basis). Cost estimates accuracy may also vary from state-to-state. There is no established range of acceptable cost based on a dollar per deciview basis and the modeling performed can also vary in accuracy from state-to-state. Therefore, comparing the $/deciview results for North Dakota to the $/deciview results for another state will not result in a true comparison of cost; i.e. it would not be 'an apples-to-apples' comparison. The U.S. EPA in their Response to Comments on their proposed FIP also dismissed the use of this metric (see 77 FR 20913).

The Department did not use the dollar-per-deciview metric on any of its original BART determinations. The Department continues to believe that an evaluation of the magnitude of the difference in visibility improvement between two control options provides the most useful information. To maintain consistency with previous BART determinations and for the reasons stated above, the Department will not use the dollar-per-deciview metric.

Comments 3: The commentor believes that the Department should include the cumulative impact on all affected Class I areas, rather than just the nearest Class I area.

Response: The Department continues to believe the cumulative visibility effects analysis promoted by DOI is not scientifically sound and not in accordance with agency rule or law (see ND SIP, Appendix J.1.4, Response to Comment 6). Adding the maximum improvement value (98^{th} percentile) at one Class I area to the maximum improvement at another Class I area does not account for these maximums happening at different times nor is it physically realistic from the standpoint of an observer located at one Class I area. In addition, DOI has not defined which Class I areas should be added together to achieve the cumulative impact. The lack of a scientific basis for adding results of one Class I area to that of another and the lack of a methodology for preparing these analyses makes the analyses inconsistent and of low technical credibility and value. Importantly, the BART Guidelines only require an evaluation of the change at each receptor at the **nearest** [emphasis added] Class I area (40 CFR 51, Appendix Y, Section IV.D.5, Step 5)**.** It does not require adding these changes together for multiple Class I areas. Further, the single source modeling methodology contained in the BART Guidelines already overstates visibility improvement for a given technology (see Response to DOI Comment 1). Creating a "cumulative effects" analysis based on the flawed BART analysis only compounds the over prediction inaccuracy and misleads the reader of the SIP.

Comment 4: The Department should add a cost estimate using the original baseline emission rate of 0.22 $lb/10^6$ Btu and include the cost of Drying Fining^{TM}.

Response: The Department believes use of a current baseline emission rate of 0.20 $lb/10^6$ Btu is appropriate as outlined in pages 3-5 of the Supplemental Evaluation. As indicated on page 5 of GRE's Supplemental Analysis, the cost of Dry Fining^{TM} is $270 million dollars ($135 million per unit). Adding this amount on top of the capital cost of SNCR plus LNC3+ ($17.9 million dollars) would definitely show that the technology is not cost effective. However, the Dry Fining^{TM} technology primarily improves boiler efficiency by removing moisture from the coal. The reduction of NO_x emissions is a secondary benefit of the process. Since the process was not specifically designed for NO_x removal, separating out a cost for NO_x removal is not possible. Therefore, the Department will not attempt the suggested analysis.

Comment 5: The commentor suggested that the BART emission limit of 0.17 lb/10^6 Btu may be too high since the BART analysis used an emission rate for LNC3+ of 0.153 lb/10^6 Btu.

Response: The 0.153 lb/10^6 Btu emission rate from the use of LNC3+ is on an annual average basis. EPA requires the BART emission limit be on a 30-day rolling average basis. The Department has indicated in previous BART analyses that a 30-day rolling average is expected to be 5-15% higher than an annual average (see ND SIP, Appendix B.1 page 16). A 10% increase of the annual average emission rate would yield a 30-day rolling average of 0.17 lb/10^6 Btu (rounded to two decimal places) for Coal Creek Station Units 1 and 2. The limit, which just happens to be the same as the presumptive BART limit, is appropriate.

Comment 6: The commentor believes that since other North Dakota BART determinations were based on SNCR, SNCR should be required for the Coal Creek Station.

Response: By definition, BART is an emission limit, not a technology (see 40 CFR 51.301). The NO_x emission limit the Department has proposed for the Coal Creek Station is lower than the BART emission unit for any other BART-eligible source in North Dakota. SNCR at Coal Creek Station provides very little visibility improvement. The amount of ash sales that will be lost cannot be determined precisely. If 30% or more of the sash sales are lost, SNCR plus LNC3+ will not be cost effective. SNCR has adverse environmental effects due to the likely ammonia contamination of the fly ash, such as emissions of ammonia to the atmosphere and loss of useful land. SNCR is not warranted because LNC3+ can achieve the emission rate of 0.17 lb/10^6 Btu (30-day rolling average).

Comment 7: The commentor believes the Department should reevaluate the economic feasibility of low-dust or tail-end SCR. The commentor suggested that the price of natural gas had declined which would require a reevaluation of the economics of SCR (natural gas is used for reheating the flue for tail-end and low-dust SCR).

Response: Both the Department and EPA have previously determined that SCR (high-dust, low-dust and tail-end SCR) are not required as BART (ND SIP Appendix B2, and 76 FR 58622-58623). The commentor has provided no new information on the technical feasibility or economics of SCR to warrant a reevaluation. Even if the cost of natural gas was reduced by 50%, the cost of low-dust SCR would still be $11,385 per ton which is clearly excessive. SCR is not cost effective for the Coal Creek Station.

Commentor: National Parks Conservation Association (NPCA)

Comment 1: North Dakota's Supplemental Evaluation does not obviate EPA's lawful Federal Implementation Plan.

A. EPA properly exercised its authority to issue a Federal Implementation Plan.

Response: As set forth in its Public Notice, the Department sought public comment on the new information provided to the Department by the operator of Coal Creek Station, Great River Energy (GRE). Specifically, the Department sought comment on the "new information regarding the cost of selective non-catalytic reduction SNCR, the amount of visibility improvement expected to occur from the use of SNCR and other information provided by Great River Energy." Public Notice, September 24, 2012. In its Public Notice, the Department also stated that, "The preliminary supplemental evaluation confirms the Department's original NO_x BART determination for the Coal Creek Station." *Id.* Accordingly, public comment was requested only on the Coal Creek Station BART determination not on whether the Department's validation of its original BART determination for the Coal Creek affects EPA's Regional Haze FIP for North Dakota. Further, the question of whether EPA's disapproval of North Dakota's original BART determination was arbitrary and capricious is currently the subject of litigation pending in the Eighth Circuit Court of Appeals. *See* North Dakota v. U.S. EPA, No. 12-1844 (8th Cir. April 9, 2012), consolidated with No. 12-1961, and 12-2331. NPCA is a party to this litigation.

While NPCA's comment is not responsive to the Supplemental Evaluation of NOx BART Determination for Coal Creek Station Units 1 and 2, the Department nonetheless believes that NPCA's comments are without merit. As explained in the Supplemental Evaluation, (*see* p. 1), the Department's subsequent reevaluation of the BART determination for Coal Creek Station was necessitated because EPA discovered that GRE had used a value for ash sales based on the total sales price instead of the amount GRE would receive from the sales (s*ee* 76 FR 58603/1). GRE provided the Department with revised fly ash sales information, which the Department reviewed. The Department also requested that GRE submit a revised BART cost estimate to the NDDH. After several additional requests for information from GRE, NDDH completed its supplemental BART review for the CCS Units in July 2012.

Under the CAA, States have the authority and discretion to make BART determinations for sources within their jurisdiction. Until the GRE cost information was received neither the State, nor EPA, could determine whether the original BART determination reached by the Department needed to be revised. Accordingly, the Department's authority to conduct its BART determination for the Coal Creek Station cannot be supplanted by EPA's FIP.

B. North Dakota's Untimely Supplemental Evaluation does not supplant the FIP.

Response: As explained in the Department's Response to NPCA's Comment 1.A. above, the Department's supplemental evaluation of the Coal Creek Station was within the Department's authority under the CAA to conduct, and under the circumstances necessary. In its FIP, EPA notes that, "North Dakota always has the discretion to revise its SIP and submit the revision us. Should such a revision meet CAA requirements, we would replace our FIP with North Dakota's SIP revision. We encourage the State to revise its SIP." 77 FR 20897/2. NPCA dismisses the Department's supplemental evaluation arguing that because it reaffirms its original BART determination for Coal

Creek Station, it should not be considered by EPA. *See* NPCA Comments at p.3. EPA's FIP was clear that it would accept any additional SIP submission from the Department. The supplemental evaluation for Coal Creek Station, based upon new cost data received by the Department from GRE, provides EPA with the information necessary to affirm North Dakota's original BART determination for the Coal Creek Station.

Comment 2: North Dakota's Supplemental Analysis is internally inconsistent, technically flawed and legally deficient.

A. North Dakota's failure to consider SCR is inappropriate.

Response: The Department considered SCR (low-dust SCR) in its original determination. The cost of low-dust SCR was $13,101 per ton of NO_x removed, which is clearly excessive (see ND SIP Appendix B.2, page 16). EPA also evaluated SCR for the Coal Creek Station and determined that the cost and amount of visibility improvement did not warrant the application of SCR (76 FR 58623).

The commentor suggests that a letter from Johnson Mathey indicating that they will supply a guarantee for low-dust or tail-end SCR warrants a new review of these control options. As stated earlier, low-dust SCR was rejected by both the Department and EPA based on cost and the small improvement in visibility. Tail-end SCR will have a higher annualized cost because of increased reheating of the flue gas. A proposed guarantee for low-dust or tail-end SCR does not change the cost or visibility analysis conducted by the Department and EPA. The commentor has provided no evidence to indicate that either the Department's or EPA's cost estimate is incorrect. Therefore, no reevaluation of SCR is warranted.

B. North Dakota's evaluation of nonvisibility issues regarding SNCR is flawed.

1. The commentor contends that the baseline NO_x emission rate is too low. This is based on an analysis by Dr. Ranajet Sahu who claims the heat input and emission rate used in the Department's calculation are too low.

Response: The BART Guidelines (40 CFR 51, Appendix Y) state "The baseline emissions rate should represent a realistic depiction of **anticipated** [emphasis added] annual emissions for the source." This means that the baseline is not necessarily the same as past actual emissions. Dr. Sahu suggests a rate of 0.208 $lb/10^6$ Btu instead of the 0.201 $lb/10^6$ Btu the Department used. Dr. Sahu bases his baseline emission rate on an evaluation of past annual averages. However, Dr. Sahu ignores several monthly averages that are below 0.201 $lb/10^6$ Btu including:

Month	Emission Rate ($lb/10^6$ Btu
July 2010	0.195
October 2010	0.191
February 2011	0.175
March 2011	0.192
May 2011	0.197
June 2011	0.193
July 2011	0.187
June 2012	0.190

Each unit of the Coal Creek Station currently has an NO_x emission limit of 0.40 $lb/10^6$ Btu (annual average). There is currently no requirement or incentive to reduce NO_x emissions below the current allowable limit. Therefore, past annual averages may not be representative of future emission rates. The NO_x data from Coal Creek clearly indicates that DryFining™ will reduce emissions to 0.201 $lb/10^6$ Btu or less. The Department believes this is a reasonable estimate of future emissions (baseline emissions).

Dr. Sahu also calculated annual average heat inputs using 24-month rolling averages. However, Dr. Sahu did not use the same baseline period for both units. The Department believes this is an incorrect evaluation of baseline. When two or more units operate at an electrical generation station, the operation of the units is dependent on each other. That is, if one unit is operating at lower load or is shutdown, the other units may have to increase load to make up for the reduced load unit. Therefore, in order to establish an accurate heat input baseline, the same time period must be used for all units. Had Dr. Sahu used the same time period for both units (e.g. April 2005 through April 2007 which Dr. Sahu used for Unit 1), the difference between the Department's average heat input for the two units and his average would have been approximately 1.5%. The difference can be attributed to the Department using a two calendar year average versus Dr. Sahu's 24-month rolling average. The Department used calendar year averages to be consistent with other BART determinations it has made. The difference in baseline heat input is inconsequential.

2. The commentor suggested that the removal efficiency for SNCR used by the Department was too low. Dr. Sahu claims that a form of SNCR technology referred to as HERT™ (High Energy Reagent Technology) can produce NO_x emission rates as low as 0.10 $lb/10^6$ Btu (the Department used an emission rate of 0.122 $lb/10^6$ for SNCR plus LNC3+).

   Response: Fuel Tech, Inc., the marketer of the HERT™ equipment states in NPCA Exhibit 1b the following: "The SNCR systems provided by Fuel Tech may include NO_x Out® injectors along with HERT™ System Injection technology, using the same urea storage, handling and control components. Fuel Tech's

SNCR application relies heavily on the use of Computational Fluid Dynamics (CFD) models and Chemical Kinetics Modeling and their resulting visualization utilizing proprietary software." Dr. Sahu has provided no documentation to indicate that the fluid dynamics modeling and chemical kinetics modeling have been done for either unit at the Coal Creek Station. In addition, Fuel Tech in their slide presentation (NPCA Exhibit Reinhold_2011_KD) indicates their "Guaranteed Proven NO_x Reduction" is only 15-35% for a utility boiler. The NO_x removal efficiency at Coal Creek Station could be as low as 15%. This slide presentation also indicates that the HERT™ has only been used as a demonstration project on a boiler as large as Coal Creek Station's boilers (550+ MWe each). This demonstration project only produced a controlled NO_x emission rate of 0.29 lb/10^6 Btu (29% reduction from baseline). The NO_x emission rate for Coal Creek Station before the application of SNCR will be 0.153 lb/10^6 Btu. Importantly, EPA's Air Pollution Control Technology Fact Sheet (EPA-452-F-03-031) states "SNCR tends to be less effective at lower levels of uncontrolled NO_x."

GRE, in their November 21, 2012 Response to Comments, indicates that HERT™ has been mostly used on industrial boilers that are much smaller than the Coal Creek Station boilers. The slide presentation provided by the NPCA also indicates no permanent installations above 200 MW. This slide presentation also indicates HERT is less effective on utility boilers than industrial boilers (20-70% for industrial boilers versus 10-35% for utility boilers). GRE has supplied various documentation to suggest HERT™ may not achieve an emission rate of 0.10 lb/10^6 Btu. *See* GRE's Response to Comments.

Based on the information provided, the Department concludes that Dr. Sahu's expected emission rate of 0.10 lb/Btu from the application of HERT™ is unsupported. There is insufficient evidence to indicate HERT™ will achieve an emission rate lower than the 0.122 lb/10^6 Btu the Department evaluated for SNCR at Coal Creek Station.

3. The commentor suggested that the cost estimate for SNCR is inflated and not supported by the underlying calculations. Part of the so-called inflated cost is attributed to the use of a low baseline (see Response to Comment B.1) and the failure to consider HERT™ (see Response to Comment B.3). Dr. Sahu's analysis takes issue with the "SNCR Equipment Cost," the installation factor of 1.3, the "Retrofit Factor," "Prime Contractor Markup" and "Process Contingency."

Response: There is no documentation supplied to indicate Dr. Sahu has ever visited the Coal Creek Station or even reviewed engineering drawings of the facility. URS conducted an on-site review of the facility for Great River Energy to evaluate the installation of SNCR. The URS cost estimate has been verified by the IPM model which EPA has used to evaluate costs at electric utilities for FIPs in Arizona and Montana. In addition, the DOI in their comments states "The capital cost estimate for SNCR installation of $20/kilowatt used by DAQ [ND

Dept. of Health] seems reasonable when compared to National Park Service NO_x BART data for several BART determinations that have been proposed nationally." The Department stands by the cost estimate.

4. The commentor suggests that inclusion of any costs for lost ash sales and/or ash disposal is premature. Dr. Sahu suggests that HERT^{TM} will minimize ammonia slip which can cause lost ash sales.

Response: Fuel Tech, Inc. in their slide presentation (NPCA Exhibit Reinhold_2011_KD) only indicates that ammonia slip will be "low." Dr. Sahu does not define "low." The Department has provided references that suggest that even minimal ammonia slip (<2 ppm) can cause ash to be unusable for concrete. Dr. Sahu is merely speculating by stating "… the underlying problem simply **may not** [emphasis added] exist using SNCR/HERT^{TM}." The commentor has provided no evidence to refute the Department's conclusion that some ash sales will be lost. As indicated by Lafarge indicated in its comments, some ash sales will definitely be lost. The DOI in their comments also indicated that 30% lost ash sales was reasonable.

C. North Dakota's Rejection of SNCR is Premised on an Internally Inconsistent and Arbitrary Analysis of Incremental Visibility Improvement.

Response: The commentor refers to the Stanton Station where SNCR was required under BART. The application of LNB + OFA + SNCR at the Stanton Station was considered cost effective ($3,052/ton for lignite with an incremental cost of $6,932/ton). SNCR alone would not have been considered cost effective. The cost of SNCR + LNC3+ at Coal Creek Station is $2,195 - $4,444/ton with an incremental cost of $4,619 - $10,350/ton depending on how much of the ash sales are lost. If 30% of the ash sales are lost, the incremental cost would be $7,449/ton which the Department considers excessive. If 100% of ash sales are lost, the cost effectiveness SNCR + LNC3+ is $4,444/ton with an incremental cost of $10,350/ton, both considered excessive by the Department. Sale of ash was not an issue at the Stanton Station. Since the exact amount of ash sales that will be lost due to ammonia slip from SNCR cannot be determined, the exact cost of SNCR cannot be determined. The Department chose to weigh the cost less in the Coal Creek determination because of this uncertainty. The Department found that the visibility improvement was insignificant from the use of SNCR and there are potential adverse environmental effects associated with SNCR at Coal Creek Station.

The BART emission limit for Coal Creek Station is actually lower for Coal Creek Station (0.17 lb/10^6 Btu) without SNCR than it is for the Stanton Station with SNCR (0.23 – 0.29 lb/10^6 Btu). The Department considered all five stationary factors when determining BART for Coal Creek Station just like it did for all other BART sources including the Stanton Station.

D. The State Underestimated Visibility Improvement

1. The State underestimated visibility improvement by failing to consider cumulative visibility improvement.

   Response: See Response to Comment 3 from the DOI.

2. The State underestimated visibility improvement by considering a narrow geographic range of impacted areas and by not considering more than 98% of impacts.

   Response: The BART Guidelines (40 CFR 51, Appendix Y) state "One important element of the protocol is in establishing the receptors that will be used in the model. The receptors that you use should be located **in the nearest Class I area** [emphasis added] with sufficient density to identify the likely visibility effects of the source." Nothing in the BART Guidelines requires receptors at additional Class I areas. Even so, the Department included receptors at the four nearest Class I area (TRNP-SU, Elkhorn Ranch Unit, TRNP-NU and Lostwood Wilderness Area). Any impacts on visibility would be less at Class I areas outside of the State due to a BART control technology. In addition, neither the Department nor EPA believes the application of CALPUFF is reasonable beyond 300 km. In the Guideline on Air Quality Models (40 CFR Part 51, Appendix W) EPA states, "it was concluded from case studies that the CALPUFF dispersion model had performed in a reasonable manner, and had no apparent bias toward over or under prediction **so long as the transport distance was limited to less than 300 km**." [emphasis added]. Regarding the Department's specific implementation of CALPUFF, performance evaluations conducted by the Department are able to verify accuracy of the model only out to about 250 km.

   The Department did not consider predicted impacts greater than the 98th percentile because the BART Guidelines specify use of the 98th percentile. The model and procedure are already very conservative (see response to the DOI Comment 1), and introduction of further conservatism by using the overall maximum prediction (i.e., 100th percentile), rather than the 98th prediction, is not reasonable. Also, as noted on page 14 of the Department's analysis, the Department also considered the number of days with visibility impairment above 0.5 deciviews. The number of days per year where the impact is less than 0.5 deciviews will only increase by two days per unit through the application of SNCR. The BART Guidelines state "You have flexibility to assess improvements due to BART by **one or more methods** [emphasis added]". The Department's approach is consistent with the BART Guidelines.

E. The North Dakota's Analysis Unlawfully Fails to Consider Visibility Improvement in Relation to the Statutory Goal of Eliminating Visibility Impairment.

Response: Section 169A(g)(2) of the Clean Air Act specifies the five stationary factors that must be considered in making a BART determination.

EPA's Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program (June 1, 2007) states, "Note that for some sources determined to be subject to BART, the State will already have completed a BART analysis. Since the BART analysis is based, in part, on an assessment of many of the same factors that must be addressed in establishing the RPG, it is reasonable to conclude that any control requirements imposed in the BART determination also satisfy the RPG-related requirements for source review in the first RPG planning period. Hence, you may conclude that no additional emissions controls are necessary for these sources in the first planning period." The Department has considered the National Visibility Goal in establishing its Reasonable Progress Goals.

The commentor states that the 0.106 deciview improvement (98th percentile) or 0.020 deciviews (90th percentile) represents nearly the entire improvement needed in a single year to be on a path toward attaining natural visibility in 2064. This statement is confusing to the Department. The Department interprets this statement to mean that applying SNCR at Coal Creek will achieve the Uniform Rate of Progress. If this interpretation is accurate, the statement is utterly incorrect. In order to achieve the Uniform Rate of Progress, an additional 1.4 deciviews improvement would be required at TRNP and 2.0 deciviews at Lostwood Wilderness Area. An improvement of 0.020 deciviews (90th percentile is more closely related to the average of the 20% worst-case days which is used to calculate the Uniform Rate of Progress) will make very little difference in the rate of achieving the National Visibility Goal. (Note: The 0.020 deciview improvement is based on single source modeling. Cumulative modeling is conducted to determine the rate of visibility improvement for comparison with the Uniform Rate of Progress. The cumulative modeling would produce even smaller improvement.)

If the commentor is suggesting that SNCR at Coal Creek will produce 0.106 deciviews improvement each year, the statement is also incorrect. Improvement from SNCR does not summate year after year. The commentor does not appear to understand the Regional Haze planning process. Reasonable Progress is determined for a planning period (i.e., 10 years) and not on a yearly basis.

The comment also suggested the Department should explain its rational for determining the visibility improvement from SNCR is "small." The amount of visibility improvement from SNCR is a maximum of 0.106 deciviews (98th percentile). The ND Air Pollution Control Rules (NDAC 33-15-25-01.2) defines "Contributes to visibility impairment" as a change in visibility impairment in a Class I federal area of 0.50 deciviews or more above the natural visibility baseline (98th percentile). The improvement from SNCR is 21% of the level that contributes to visibility impairment. The Department considers 0.106 deciviews a small contribution to total visibility degradation or a small improvement in visibility.

NORTH DAKOTA
DEPARTMENT *of* HEALTH

ENVIRONMENTAL HEALTH SECTION
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August 8, 2012

FILE

Ms. Susan Johnson
National Park Service – Air
P.O. Box 25287
Denver, CO 80225-0287

Dear Ms. Johnson:

In March of 2010, the North Dakota Department of Health (Department) submitted its' Regional Haze State Implementation Plan to the U.S. Environmental Protection Agency. Subsequent to that submittal, an error was discovered in the information used to make the NO_x BART Determination for Great River Energy's Coal Creek Station. Because of that error, the Department requested and received updated information for NO_x controls at the Coal Creek Station. The Department has conducted a review of the information and its original BART Determination. Enclosed with this letter is a CD which contains our supplemental evaluation and the additional information.

Prior to conducting a public comment period regarding this supplemental evaluation, we would like to give each Federal Land Manager (FLM), the opportunity to review and comment on the supplemental evaluation. Since the supplemental evaluation is limited to only NO_x from the Coal Creek Station, we ask that any comments be provided by September 12, 2012. A thirty-day public comment period will occur immediately thereafter.

If you have any questions, please contact Tom Bachman of my staff at (701)328-5188.

Sincerely,

Terry O'Clair

Terry L. O'Clair, P.E.
Director
Division of Air Quality

TLO/TB:csc
Enc:
xc/enc: Paul Seby, Special Assistant Attorney General
Margaret Olson, Assistant Attorney General
Carl Daly, EPA Region 8
Mary Jo Roth, Great River Energy

NORTH DAKOTA
DEPARTMENT *of* HEALTH

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August 8, 2012

FILE

Mr. Tim Allen
U.S. Department of interior
U.S. Fish and Wildlife Service
National Wildlife Refuge System
Branch of Air Quality
7333 West Jefferson Ave., Ste 375
Lakewood, CO 80235-2017

Dear Mr. Allen:

In March of 2010, the North Dakota Department of Health (Department) submitted its' Regional Haze State Implementation Plan to the U.S. Environmental Protection Agency. Subsequent to that submittal, an error was discovered in the information used to make the NO_x BART Determination for Great River Energy's Coal Creek Station. Because of that error, the Department requested and received updated information for NO_x controls at the Coal Creek Station. The Department has conducted a review of the information and its original BART Determination. Enclosed with this letter is a CD which contains our supplemental evaluation and the additional information.

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If you have any questions, please contact Tom Bachman of my staff at (701)328-5188.

Sincerely,

Terry O'Clair

Terry L. O'Clair, P.E.
Director
Division of Air Quality

TLO/TB:csc
Enc:
xc/enc: Paul Seby, Special Assistant Attorney General
Margaret Olson, Assistant Attorney General
Carl Daly, EPA Region 8
Mary Jo Roth, Great River Energy

NORTH DAKOTA
DEPARTMENT *of* HEALTH

ENVIRONMENTAL HEALTH SECTION
Gold Seal Center, 918 E. Divide Ave.
Bismarck, ND 58501-1947
701.328.5200 (fax)
www.ndhealth.gov

August 8, 2012

FILE

Mr. Mark Hummel
Deputy Forest Supervisor
U.S. Department of Agriculture
Superior National Forest
8901 Grand Avenue Place
Duluth, MN 55808-1122

Dear Mr. Hummel:

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August 8, 2012

FILE

Ms. Susan Johnson
National Park Service – Air
P.O. Box 25287
Denver, CO 80225-0287

Dear Ms. Johnson:

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August 8, 2012

FILE

Mr. Tim Allen
U.S. Department of interior
U.S. Fish and Wildlife Service
National Wildlife Refuge System
Branch of Air Quality
7333 West Jefferson Ave., Ste 375
Lakewood, CO 80235-2017

Dear Mr. Allen:

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August 8, 2012

FILE

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Deputy Forest Supervisor
U.S. Department of Agriculture
Superior National Forest
8901 Grand Avenue Place
Duluth, MN 55808-1122

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September 14, 2012

FILE

Mr. Carl Daly (8P-AR)
Director, Air Programs
U.S. EPA, Region 8
1595 Wynkoop Street
Denver, CO 80202-1129

Re: Supplemental Evaluation
Coal Creek NO_x BART Determination

Dear Mr. Daly:

The Department has completed its Supplemental Evaluation of the Coal Creek Station NO_x BART determination. Prior to making a final determination, the Department will be conducting a public comment period on the Supplemental Evaluation. Enclosed with this letter is a copy of the public notice. A public comment period will be held from October 1 through October 30, 2012. Also enclosed is a CD which contains the Supplemental Evaluation and additional information.

If you or your staff have any questions, please contact Tom Bachman of my staff at (701)328-5188.

Sincerely,

Terry O'Clair

Terry L. O'Clair, P.E.
Director
Division of Air Quality

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