

## Appendix B – Facility Emission Reduction Measures Reports

B.1 – Coyote Station

B.1.a – Department Request





May 2, 2018

**FILE**

Mr. Mark Thoma  
OtterTail Power Company  
P.O. Box 496  
Fergus Falls, MN 56538-0496

Re: Regional Haze  
Second Planning Period

Dear Mr. Thoma:

The Department of Health (Department) has begun work on the second planning period (Round 2) State Implementation Plan (SIP) for regional haze. In Round 1 of the regional planning process, the emphasis was on Best Available Retrofit Technology (BART) and making reasonable progress towards the national visibility goal. In Round 2, there are no BART requirements; therefore, we will focus on making reasonable progress. The reasonable progress analysis will be made using the four factors in Section 169A(g)(1) of the Clean Air Act:

The four factors are:

1. The cost of compliance
2. The time necessary to achieve compliance
3. The energy and non-air quality environmental impact of compliance; and
4. The remaining useful life of any existing source subject to such requirements

Guidance provided by the U.S. Environmental Protection Agency (Draft Guidance on Progress Tracking Metrics, Long Term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period at [https://www.epa.gov/sites/production/files/2016-07/documents/draft\\_regional\\_haze\\_guidance\\_july\\_2016.pdf](https://www.epa.gov/sites/production/files/2016-07/documents/draft_regional_haze_guidance_july_2016.pdf)) indicates the Department must address 80% of the visibility impairment caused by in-state sources. Data from the IMPROVE monitoring sites at Theodore Roosevelt National Park (TRNP) and Lostwood Wilderness Area (LWA) indicate that sulfates and nitrates continue to be the largest contributors to visibility impairment in these areas. The primary precursors of sulfates and nitrates are emissions of sulfur dioxide (SO<sub>2</sub>) and nitrogen oxides (NO<sub>x</sub>).

Coal-fired electrical generating units have been identified as one of the largest source of sulfur dioxide and nitrogen oxides in North Dakota. Therefore, the Department requests that you prepare a "four factors" analysis for your coal-fired electrical generating units. The analysis should be prepared using the draft EPA guidance noted above. The Department will identify other sources in North Dakota that will be required to submit a four factors analysis.

The Department will be working with the Western Regional Air Partnership (WRAP) to prepare the Round 2 SIP. WRAP will be conducting air quality modeling of regional emissions reductions in early 2019. The Department asks that your "four factors" analysis be submitted by January 31, 2019.

If you have any questions, please contact David Stroh of my staff at (701)328-5188.

Sincerely,

A handwritten signature in cursive script, reading "Terry O'Clair".

Terry L. O'Clair  
Director  
Division of Air Quality

TLO/TB:saj

## B.1.b – Facility Response

215 South Cascade Street  
PO Box 496  
Fergus Falls, Minnesota 56538-0496  
218 739-8200  
www.otpco.com

January 30, 2019

Mr. Terry L. O'Clair, P.E.  
Director, Division of Air Quality  
North Dakota Department of Health  
Gold Seal Center, 918 East Divide Ave  
Bismarck, ND 58501-1947



Dear Mr. O'Clair:

Re: Regional Haze Second Planning Period: Coyote Station Reasonable Progress Analysis

As requested by your letter dated May 2, 2018, enclosed is a Regional Haze reasonable progress analysis for Coyote Station. Sargent & Lundy, L.L.C. was retained to prepare this analysis of technically feasible sulfur dioxide and nitrogen oxide emission reduction measures using the four statutory factors provided in Section 169A(g)(1) of the Clean Air Act.

As noted in the report, this analysis is subject to several important caveats and limitations, including but not limited to:

- On September 11, 2018, EPA released a "*Regional Haze Reform Roadmap*" announcing its plan to "release a series of implementation tools and guidance documents that will help focus states' efforts and reduce and streamline the time and resources needed to meet the statutory and regulatory requirements for reducing regional haze in National Parks, wildlife refuges, and wilderness areas." EPA stated that it plans to issue new guidance on Regional Haze SIP Development by Spring 2019. Otter Tail reserves the right to update and modify this four-factor analysis, as needed, to be consistent with any new guidance issued by EPA.
- The emission rates that are presented for the technically feasible control options should not be construed to represent proposed permit limits. Corresponding permit limits would need to be evaluated on a control system-specific basis to account for operating margin.
- During the first planning period, the Department of Health determined that high-dust SCR and tail-end SCR were not available, and thus, not a technically feasible NOx control option for North Dakota lignite-fired boilers. Sargent & Lundy's evaluation continues to support the conclusion that high-dust SCR and tail-end SCR are not available NOx control technologies. Nevertheless, since tail-end SCR cost data was developed for Coyote Station in the first planning period, even though tail-end SCR is a technically infeasible technology, it was carried forward in the analysis to evaluate hypothetical cost-effectiveness.

We look forward to working with the Department throughout the second planning period. If you have any questions about this report, please contact me at (218) 739-8526.

Sincerely,

A handwritten signature in black ink, appearing to read "Mark Thoma", is written over a horizontal line.

Mark Thoma  
Manager, Environmental Services

Enclosure

An Equal Opportunity Employer



COYOTE STATION UNIT 1

NORTH DAKOTA REGIONAL HAZE SECOND PLANNING PERIOD  
FOUR-FACTOR ANALYSIS

SL-014745  
Final

January 28, 2019  
Project No. 12715-011



55 East Monroe Street • Chicago, IL 60603 USA • 312-269-2000  
[www.sargentlundy.com](http://www.sargentlundy.com)

## CONTENTS

<b>EXECUTIVE SUMMARY .....</b>	<b>1</b>
<b>1. INTRODUCTION .....</b>	<b>1-1</b>
<b>2. FACILITY DESCRIPTION.....</b>	<b>2-1</b>
<b>3. FOUR-FACTOR ANALYSIS REQUIREMENTS .....</b>	<b>3-2</b>
3.1 REGIONAL HAZE RULE BACKGROUND .....	3-2
3.1.1 First Implementation Period.....	3-4
3.1.2 Second Implementation Period .....	3-5
3.2 DESCRIPTIONS OF THE FOUR STATUTORY FACTORS .....	3-7
3.2.1 Costs of Compliance .....	3-7
3.2.2 Time Necessary for Compliance .....	3-9
3.2.3 Energy and Non-Air Quality Environmental Impacts.....	3-9
3.2.4 Remaining Useful Life .....	3-10
3.2.5 Four Factor Analysis Approach .....	3-11
<b>4. BASELINE SO<sub>2</sub> AND NO<sub>x</sub> EMISSIONS .....</b>	<b>4-1</b>
<b>5. SO<sub>2</sub> AND NO<sub>x</sub> CONTROL MEASURES.....</b>	<b>5-1</b>
5.1 SO <sub>2</sub> EMISSIONS CONTROLS .....	5-3
5.1.1 Identify Available SO <sub>2</sub> Control Options .....	5-3
5.1.2 Technical Feasibility of Available SO <sub>2</sub> Control Options .....	5-3
5.1.3 Evaluate Technically Feasible SO <sub>2</sub> Control Options for Effectiveness .....	5-21
5.2 NO <sub>x</sub> EMISSIONS CONTROLS .....	5-22
5.2.1 Identify Available NO <sub>x</sub> Control Options .....	5-22
5.2.2 Technical Feasibility of Available NO <sub>x</sub> Control Options .....	5-23
5.2.3 Evaluate Technically Feasible NO <sub>x</sub> Control Options for Effectiveness .....	5-38
<b>6. COSTS OF COMPLIANCE (STATUTORY FACTOR ONE).....</b>	<b>6-1</b>
6.1 ECONOMIC EVALUATION – SO <sub>2</sub> CONTROLS .....	6-2
6.2 ECONOMIC EVALUATION – NO <sub>x</sub> CONTROLS .....	6-5

<b>7. TIME NECESSARY FOR COMPLIANCE (STATUTORY FACTOR TWO)</b>	<b>7-1</b>
<b>8. ENERGY AND NON-AIR QUALITY ENVIRONMENTAL IMPACTS (STATUTORY FACTOR THREE)</b>	<b>8-1</b>
8.1 ENVIRONMENTAL IMPACTS	8-1
8.2 ENERGY IMPACTS	8-2
8.3 ENVIRONMENTAL / ENERGY IMPACTS SUMMARY	8-3
<b>9. REMAINING USEFUL LIFE (STATUTORY FACTOR FOUR)</b>	<b>9-1</b>
<b>10. FOUR-FACTOR ANALYSIS SUMMARY</b>	<b>10-1</b>

## FIGURES/TABLES

Figure 3-1. Federal Class I Areas	3-2
Figure 3-2. Regional Planning Organization Map	3-3
Figure 5-1. Comparison of Typical SDA/FF and Coyote Unit 1 SDA/FF Arrangement	5-8
Table ES-1. SO <sub>2</sub> Control Options for Coyote Unit 1	2
Table ES-2. NO <sub>x</sub> Control Options for Coyote Unit 1	2
Table ES-3. SO <sub>2</sub> Emissions Control System Cost Effectiveness (\$2018)	3
Table ES-4. NO <sub>x</sub> Emissions Control System Cost Effectiveness (\$2018)	4
Table ES-5. SO <sub>2</sub> Emissions Control System Implementation Schedule	5
Table ES-6. NO <sub>x</sub> Emissions Control System Implementation Schedule	5
Table ES-7. Summary of Energy and Non-Air Quality Environmental Impacts	6
Table 2-1. Process Parameters	2-1
Table 3-1. Key Steps in Developing Regional Haze SIPs for Second Planning Period	3-6
Table 4-1. Coyote Unit 1 Baseline Emissions	4-2
Table 5-1. Available SO <sub>2</sub> Control Options	5-3
Table 5-2. FGD Operational Improvements and Equipment Upgrades	5-4
Table 5-3. Existing SO <sub>2</sub> Removal Efficiencies	5-11
Table 5-4. New Scrubber Vessel SO <sub>2</sub> Removal Efficiencies	5-12
Table 5-5. DSI SO <sub>2</sub> Control Technology Estimated Emissions	5-15
Table 5-6. Layered (DSI + Ca:S) SO <sub>2</sub> Control Technology Estimated Emissions	5-16
Table 5-7. Technically Feasible SO <sub>2</sub> Control Options	5-20
Table 5-8. Evaluate Technically Feasible SO <sub>2</sub> Control Options for Effectiveness	5-22
Table 5-9. Available NO <sub>x</sub> Control Options	5-23
Table 5-10. Technically Feasible NO <sub>x</sub> Control Options	5-37

Table 5-11. Evaluate Technically Feasible NO <sub>x</sub> Control Options for Effectiveness .....	5-39
Table 6-1. SO <sub>2</sub> Control Cost Summary (\$2018).....	6-3
Table 6-2. SO <sub>2</sub> Emissions Control System Cost Effectiveness (\$2018).....	6-4
Table 6-3. NO <sub>x</sub> Control Cost Summary (\$2018) .....	6-6
Table 6-4. NO <sub>x</sub> Emissions Control System Cost Effectiveness (\$2018) .....	6-6
Table 7-1. SO <sub>2</sub> Emissions Control System Implementation Schedule .....	7-2
Table 7-2. NO <sub>x</sub> Emissions Control System Implementation Schedule .....	7-2
Table 8-1. Summary of Energy and Non-Air Quality Environmental Impacts .....	8-4

## APPENDIXES

- A. Coyote Unit 1 Baseline Emissions
- B. SO<sub>2</sub> Control Cost Effectiveness Estimates
- C. NO<sub>x</sub> Control Cost Effectiveness Estimates



## ABBREVIATIONS/ACRONYMS

Abbreviation/Acronym	Explanation
BACT	Best Available Control Technology
BART	Best Available Retrofit Technology
BFP	boiler feed pump
Ca	calcium
CaO	calcium oxide
Ca(OH) <sub>2</sub>	calcium hydroxide
CaSO <sub>3</sub>	calcium sulfite
CaSO <sub>4</sub>	calcium sulfate
CAA	Clean Air Act
CDS	circulating dry scrubber
CEMS	continuous emissions monitoring system
CFR	Code of Federal Regulations
CO	carbon monoxide
CO <sub>2</sub>	carbon dioxide
DFGD	dry flue gas desulfurization
DSI	dry sorbent injection
ESP	electrostatic precipitator
EPA	Environmental Protection Agency
EGU	electric generating unit
FF	fabric filter
FGD	flue gas desulfurization
G&A	general and administration
GHG	greenhouse gas
H <sub>2</sub> SO <sub>4</sub>	sulfuric acid
LNB	Low-NO <sub>x</sub> burner
LTS	Long-term strategy
MMBtu	million British thermal units
MNL	multi-nozzle lance
MRYs	Milton R. Young Station
MW	megawatt

---

MWg	megawatt gross
Na <sub>2</sub> CO <sub>3</sub>	sodium carbonate
ND	North Dakota
NDDH	North Dakota Department of Health
NH <sub>3</sub>	ammonia
NO <sub>x</sub>	nitrogen oxides
NSR	New Source Review
NSR	normalized stoichiometric ratio
OEM	Original equipment manufacturer
OFA	overfire air
O&M	operations and maintenance
OTP	Otter Tail Power Company
PM	particulate matter
PRB	Powder River Basin
RPG	Reasonable Progress Goals
RPO	Regional Planning Organization
RRI	rich reagent injection
S	sulfur
S&L	Sargent & Lundy, L.L.C.
SBC	sodium bicarbonate
SBS	sodium bisulfate
SCR	selective catalytic reduction
SDA	spray dryer absorber
SIP	State Implementation Plan
SNCR	selective non-catalytic reduction
SO <sub>2</sub>	sulfur dioxide
SO <sub>3</sub>	sulfur trioxide
SOFA	separated overfire air
TE-SCR	tail-end SCR
URP	uniform rate of progress
WRAP	Western Region Air Partnership

---

## EXECUTIVE SUMMARY

Coyote Station, located near Beulah, ND, commenced commercial operation in 1981. The facility is a single unit station with one 451 MWg (approximate) Babcock and Wilcox cyclone boiler (Coyote Unit 1). Coyote Unit 1 is designed to fire North Dakota lignite, and is equipped with separated overfire air (SOFA) for NO<sub>x</sub> control, and dry flue gas desulfurization (DFGD or dry FGD) and fabric filter baghouse (FF) for SO<sub>2</sub> and particulate matter (PM) control. Lignite is delivered to the Station from the Coyote Creek Mine, whose primary operations are approximately 3-4 miles from the Coyote Station.

On July 1, 1999, the U.S. Environmental Protection Agency (EPA) published regulations implementing Section 169A of the CAA, establishing a comprehensive visibility protection program for Federal Class I areas (the Regional Haze Rule).<sup>1</sup> The Regional Haze Rule requires each state to develop, and submit for approval by EPA, a state implementation plan (SIP) detailing the state's plan to protect visibility in Class I areas. The Regional Haze Rule established a schedule setting forth deadlines by which the States must submit their initial regional haze SIPs and subsequent revisions to the SIPs. Regional Haze SIPs for the initial planning period were due in 2007, with subsequent SIP updates due in 2018 and every 10 years thereafter.<sup>2</sup> Second planning period Regional Haze SIPs must be submitted to EPA for review by July 31, 2021.

As part of North Dakota's SIP development for the second planning period, NDDH requested that Otter Tail prepare a "four factor" analysis for Coyote Unit 1. This evaluation reviews technically feasible SO<sub>2</sub> and NO<sub>x</sub> emissions reduction measures for the following four statutory factors:

1. The costs of compliance;
2. The time necessary for compliance;
3. The energy and non-air quality environmental impacts of compliance; and
4. The remaining useful life of any potentially affected anthropogenic source of visibility impairment.

Technically feasible SO<sub>2</sub> and NO<sub>x</sub> control strategies for Coyote Unit 1 are included in Table ES-1 and Table ES-2. The tables also show baseline emission rates and estimated emission reductions for each control option.

---

<sup>1</sup> 64 FR 35713

<sup>2</sup> On January 10, 2017, EPA made a one-time adjustment to the due date for the second implementation period SIPs (2018 – 2028) by extending the deadline from July 31, 2018 to July 31, 2021 (82 FR 3078).

**Table ES-1. SO<sub>2</sub> Control Options for Coyote Unit 1**

Control Option	SO <sub>2</sub> Emission Rate tons/yr	% Reduction from Baseline Emission Rate
Baseline (existing DFGD/FF)	12,994	-
DSI + Existing FGD	8,863	32%
FGD Operational Improvements – Increase Ca:S Stoichiometric Ratio	7,641	41%
DSI + FGD Operational Improvements	5,043	61%
FGD Upgrades - Replacing Existing Absorbers with New Absorber	4,432	66%
Dry FGD (CDS) + Existing FF	1,375	89%
Wet FGD	917	93%

**Table ES-2. NO<sub>x</sub> Control Options for Coyote Unit 1**

Control Option	NO <sub>x</sub> Emission Rate tons/yr	% Reduction from Baseline Emission Rate
Baseline (existing SOFA)	7,363	-
Combustion Optimization	6,775	8%
SNCR + Combustion Optimization	4,516	39%
SNCR + RRI + Combustion Optimization	3,226	56%
SCR – Tail-End Configuration <sup>(Note 1)</sup>	1,452	80%

Note 1. Tail-end SCR has not been installed on a North Dakota lignite-fired unit, and extended trials would be needed to better understand the design and operation of tail-end SCR on Coyote Unit 1. Nevertheless, during the initial planning period, tail-end SCR was included in the reasonable progress analysis for Coyote Unit 1, and evaluated the costs and cost-effectiveness of the control system. For consistency with the first planning period, tail-end SCR is carried forward to the Four Factor Analysis.

### Costs of Compliance (Statutory Factor One)

Capital and O&M cost estimates were developed for each of the technically feasible SO<sub>2</sub> and NO<sub>x</sub> control options. The Coyote Unit 1 cost estimates are conceptual in nature; thus, S&L did not procure equipment quotes specifically for the Unit 1 control system upgrades. Rather, equipment costs are based on conceptual designs developed for the retrofit control systems, preliminary equipment sizing developed for the major pieces of equipment (based on

Coyote Unit 1-specific design parameters, including typical fuel characteristics, full load heat input, and flue gas temperatures and flow rates), and recent pricing for similar equipment.

Table ES-3 and Table ES-4 include estimated costs for SO<sub>2</sub> and NO<sub>x</sub> control options for Coyote Unit 1. The tables provide the estimated annualized capital and operating and maintenance (O&M) costs, estimated emissions reductions, average annual cost effectiveness. The tables also include the incremental cost effectiveness that compares the costs and performance of a control option to those of the next most stringent option.

**Table ES-3. SO<sub>2</sub> Emissions Control System Cost Effectiveness (\$2018)**

SO <sub>2</sub> Control Option	Total Annualized Cost \$/yr	Expected Emission Reduction tons SO <sub>2</sub> /yr	Average Annual Cost Effectiveness (Note 1) \$/ton SO <sub>2</sub> removed	Incremental Annual Cost Effectiveness (Note 2, 3) \$/ton SO <sub>2</sub> removed
Baseline (Existing DFGD/FF)	---	---	---	---
DSI + Existing FGD	\$14,277,000	4,131	\$3,456	
FGD Operational Improvements – Increase Ca:S Stoichiometric Ratio	\$2,492,000	5,354	\$465	n/a
DSI + FGD Operational Improvements	\$16,770,000	7,952	\$2,109	\$5,496
FGD Upgrades - Replacing Existing Absorbers with New Absorber	\$22,197,000	8,563	\$2,592	\$8,879
Dry FGD (CDS) + Existing FF	\$42,246,000	11,619	\$3,636	\$6,560
Wet FGD	\$49,614,000	12,078	\$4,108	\$16,072

Note 1. Average cost effectiveness for each control option is the total annual cost divided by the expected emission reduction.

Note 2. Incremental cost effectiveness represents the incremental increase in annual costs (\$/yr) divided by the incremental increase in annual emissions reductions (tpy) between a control option and the next most effective option.

Note 3. “n/a” indicates that the next most effective control option is “inferior” (i.e., higher cost for less control)

**Table ES-4. NO<sub>x</sub> Emissions Control System Cost Effectiveness (\$2018)**

NO <sub>x</sub> Control Option	Total Annualized Cost \$/yr	Expected Emission Reduction tons NO <sub>x</sub> /yr	Average Annual Cost Effectiveness (Note 1) \$/ton NO <sub>x</sub> removed	Incremental Annual Cost Effectiveness (Note 2) \$/ton NO <sub>x</sub> removed
Baseline (Existing SOFA)	---	---	---	---
Combustion Optimization	\$0	589	\$0	\$0
SNCR + Combustion Optimization	\$4,754,000	2,847	\$1,670	\$2,105
SNCR + RRI + Combustion Optimization	\$8,617,000	4,137	\$2,083	\$2,994
SCR – Tail-End Configuration	\$41,268,000	5,912	\$6,981	\$18,402

Note 1. Average cost effectiveness for each control option is the total annual cost divided by the expected emission reduction.

Note 2. Incremental cost effectiveness represents the incremental increase in annual costs (\$/yr) divided by the incremental increase in annual emissions reductions (tpy) between a control option and the next most effective option.

*Time Necessary for Compliance (Statutory Factor Two)*

Table ES-5 and Table ES-6 provide estimated timeframes needed to implement each of the technically feasible control option. Notably, the estimated timeframes do not account for time needed for North Dakota to develop and implement the regulations; nor the amount of time needed for EPA to take proposed and final action to approve North Dakota's SIP.

**Table ES-5. SO<sub>2</sub> Emissions Control System Implementation Schedule**

SO <sub>2</sub> Control Option	Design / Specification / Procurement (months)	Detail Design / Fabrication (months)	Construction / Commissioning / Startup (months)	Total (months after SIP approval)
DSI + Existing FGD	6	6	6	18
FGD Operational Improvements – Increase Ca:S Stoichiometric Ratio	0	0	0	0
DSI + FGD Operational Improvements	6	6	6	18
FGD Upgrades - Replacing Existing Absorbers with New Absorber	8	12	12	32
Dry FGD (CDS) + Existing FF	12	20	18	50
Wet FGD	12	22	22	56

**Table ES-6. NO<sub>x</sub> Emissions Control System Implementation Schedule**

NO <sub>x</sub> Control Option	Design / Specification / Procurement (months)	Detail Design / Fabrication (months)	Construction / Commissioning / Startup (months)	Total (months after SIP approval)
Combustion Optimization	0	0	0	0
SNCR + Combustion Optimization	10	6	6	22
SNCR + RRI + Combustion Optimization	10	6	6	22
SCR – Tail-End Configuration	10	18	24	52

Energy and Non-Air Quality Environmental Impacts (Statutory Factor Three)

An evaluation of energy impacts indicates that certain control options (e.g., new FGD systems, TE-SCR) will increase auxiliary power requirements due to increased pressure drop, which would adversely impact net plant heat rate. Consequently, heat input to the boiler would need to increase to compensate for the increased auxiliary power requirements while achieving the same net plant output, or net output from the unit would decrease. Collateral environmental impacts include an increase in the solid waste generation with DSI. A summary of the environmental and energy impact analysis is provided in Table ES-7.

**Table ES-7. Summary of Energy and Non-Air Quality Environmental Impacts**

Control Option	Collateral Environmental & Energy Impacts
<b><u>SO<sub>2</sub> Control Options</u></b>	
Replace existing DFGD with New WFGD control system	<ul style="list-style-type: none"> <li>➤ Increased water consumption</li> <li>➤ Wet by-product that requires dewatering prior to disposal</li> <li>➤ FGD wastewater treatment &amp; discharge</li> <li>➤ Increased auxiliary power requirements and heat rate penalty</li> </ul>
Replace existing DFGD with New CDS/FF Control System	<ul style="list-style-type: none"> <li>➤ Increased auxiliary power requirements and heat rate penalty</li> <li>➤ Increased solid FGD by-product management and disposal</li> </ul>
Replace existing dry scrubber modules with New DFGD modules while keeping existing FF	<ul style="list-style-type: none"> <li>➤ Requires extended (approximately 12-month) outage of Coyote Unit 1 to demolish and replace the existing scrubber modules</li> </ul>
Dry Sorbent Injection	<ul style="list-style-type: none"> <li>➤ Increased solid FGD by-product management and disposal</li> <li>➤ Increased auxiliary power requirements and heat rate penalty</li> </ul>
<b><u>NO<sub>x</sub> Control Options</u></b>	
Selective Catalytic Reduction (SCR) - Tail End Configuration	<ul style="list-style-type: none"> <li>➤ Increased auxiliary power requirements and heat rate penalty</li> <li>➤ Increased ammonia slip emissions</li> <li>➤ Potential increase in SO<sub>3</sub> emissions</li> </ul>
SNCR or SNCR + RRI	<ul style="list-style-type: none"> <li>➤ Increased ammonia slip emissions</li> <li>➤ Increased auxiliary power requirements and heat rate penalty</li> </ul>



---

*Remaining Useful Life (Statutory Factor Four)*

The Coyote Station owners have not identified dates for the remaining useful life of the unit before the end of what would otherwise be the useful life of the control measures that were evaluated for Coyote Unit 1. Thus, the 20-year equipment life of the control measures was used in the four factor analysis to calculate emission reductions, amortized costs, and cost-effectiveness.

## 1. INTRODUCTION

Sargent & Lundy, L.L.C. (S&L) was retained by Otter Tail Power Company (Otter Tail) to prepare a Reasonable Progress four-factor analysis for the control of sulfur dioxide (SO<sub>2</sub>) and nitrogen oxide (NO<sub>x</sub>) emissions from Coyote Station Unit 1 (Coyote Unit 1).<sup>3</sup> The evaluation is in response to North Dakota Department of Health's (NDDH) request that Otter Tail prepare a four factor analysis for Coyote Unit 1.

The evaluation includes an assessment of potentially available emission reduction measures for the four statutory factors listed in 40 CFR 51.308(f)(2), and takes into consideration U.S. Environmental Protection Agency's (EPA's) *Draft Guidance on Progress Tracking Metrics, Long Term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period* (the "Draft EPA Guidance").<sup>4</sup> Technically feasible SO<sub>2</sub> and NO<sub>x</sub> emission reduction measures are evaluated for the following four statutory factors:

- Factor 1: The cost of compliance
- Factor 2: The time necessary to achieve compliances
- Factor 3: The energy and non-air quality environmental impact of compliance
- Factor 4: The remaining useful life of any existing source subject to such requirements

The Reasonable Progress four factor analysis for Coyote Unit 1 (the "Four Factor Analysis") is presented in the following sections:

- Section 2: Facility Description** contains information describing the facility, site location, and existing equipment.
- Section 3: Four-Factor Analysis Requirements** provides a brief description of the Regional Haze Program requirements set forth in 40 CFR 51.308.
- Section 4: Baseline SO<sub>2</sub> and NO<sub>x</sub> Emissions** establishes representative baseline SO<sub>2</sub> and NO<sub>x</sub> emissions for the period 2013 to present.

<sup>3</sup> Coyote Station is co-owned by Otter Tail Power Company (35%), Northern Municipal Power Agency (30%), Montana-Dakota Utilities Co. (25%), and NorthWestern Energy (10%).

<sup>4</sup> On September 11, 2018, EPA released a "*Regional Haze Reform Roadmap*" announcing its plan to "release a series of implementation tools and guidance documents that will help focus states' efforts and reduce and streamline the time and resources needed to meet the statutory and regulatory requirements for reducing regional haze in National Parks, wildlife refuges, and wilderness areas." EPA stated that it plans to issue a new guidance document on Regional Haze SIP Development by Spring, 2019. Otter Tail Power reserves the right to update and modify this four-factor analysis, as needed, to be consistent with any new guidance issued by the agency.

- Section 5: SO<sub>2</sub> and NO<sub>x</sub> Control Measures** identifies potentially available emission control technologies, and evaluates each control option for technical feasibility and effectiveness.
- Section 6: Costs of Compliance (Statutory Factor One)** evaluates the cost and cost-effectiveness of each technically feasible control option.
- Section 7: Time Necessary for Compliance (Statutory Factor Two)** provides typical timelines required to design, engineer, procure and install the technically feasible control options.
- Section 8: Energy and Non-Air Quality Environmental Impacts (Statutory Factor Three)** identifies the energy and non-air quality environmental impacts associated with each technically feasible control option.
- Section 9: Remaining Useful Life (Statutory Factor Four)** includes a discussion of the planned remaining useful life of Coyote Unit 1.
- Section 10: Summary and Conclusions**

**Appendix A: Coyote Unit 1 Baseline Emissions**

**Appendix B: SO<sub>2</sub> Control Cost Effectiveness Estimates**

**Appendix C: NO<sub>x</sub> Control Cost Effectiveness Estimates**

## 2. FACILITY DESCRIPTION

Coyote Station, located near Beulah, ND, commenced commercial operation in 1981. The facility is a single unit station with one 451 MWg (approximate) Babcock and Wilcox cyclone boiler (Coyote Unit 1). Coyote Unit 1 is designed to fire North Dakota lignite, and is equipped with separated overfire air (SOFA) for NO<sub>x</sub> control, and dry flue gas desulfurization (DFGD or dry FGD) and fabric filter baghouse (FF) for SO<sub>2</sub> and particulate matter (PM) control. Lignite is delivered to the Station from the Coyote Creek Mine, whose primary operations are approximately 3-4 miles from the Coyote Station.

Table 2-1 provides a summary of the process parameters used for the Coyote Unit 1 Four Factor Analysis. Process parameters listed in Table 2-1 were developed from information provided by OTP.<sup>5</sup>

**Table 2-1. Process Parameters**

Process Parameter	Coyote Unit 1
Boiler Type	Cyclone
Boiler Manufacturer	B&W
Full Load (MWg)	451
Full Load Boiler Heat Input (MMBtu/hr)	4,900
Full Load Coal Flow (lb/hr)	700,700
Boiler Excess Air (%)	14.0
Air Heater Leakage (%)	22.0
Bottom Ash/Fly Ash Ratio	65/35
Flue Gas Conditions at Air Heater Outlet	
Temperature (F)	330
Mass Flow Rate (lb/hr)	6,532,000
Volumetric Flow rate (acfm)	2,485,000
Annual Average Fuel Sulfur Content (%)	0.82 - 1.06
Annual Average Uncontrolled SO <sub>2</sub> Emissions (lb/MMBtu)	2.42 - 3.12

<sup>5</sup> These process parameters are representative of typical average conditions. They should not be construed as maximum values or unit design values.



state implementation plan (SIP) detailing the state's plan to protect visibility in Class I areas. In 2017, EPA issued a final rule revising portions of the 1999 Regional Haze Rule.<sup>7</sup> The 2017 Rule requires states to determine the baseline (2000 - 2004) visibility condition for the 20 percent most impaired days and requires that the long-term strategy and reasonable progress goals (RPGs) must provide for improvement in visibility for the most impaired days, relative to the baseline period. Specifically, states must determine the rate of improvement in visibility that would need to be maintained during each implementation period in order to reach natural conditions by 2064 for the 20 percent most impaired days, given the starting point of the baseline visibility condition.

To address the combined visibility effects of various pollution sources over a wide geographic region, EPA designated five Regional Planning Organizations (RPOs) to assist with the coordination and cooperation needed to address the visibility issue. The five RPOs are shown in Figure 3-2. North Dakota is a member of the Western Regional Air Partnership (WRAP), which serves as the RPO for visibility protection at 118 Class I areas in the 15 western states.

**Figure 3-2. Regional Planning Organization Map**



<sup>7</sup> Final Rule: Protection of Visibility: Amendments to Requirements for State Plans, 82 FR 3078, January 10, 2017

### 3.1.1 First Implementation Period

The Regional Haze Rule established a schedule setting forth deadlines by which the States must submit their initial regional haze SIPs and subsequent revisions to the SIPs. Regional Haze SIPs for the initial planning period were due in 2007, with subsequent SIP updates due in 2018 and every 10 years thereafter.<sup>8</sup>

Regional Haze SIP requirements for the first planning period required that states incorporate into their plans the core program requirements in 40 CFR 51.308(d), including: (1) establishing reasonable progress goals (RPGs) for each Class I area within the state that provide for measurable progress towards achieving natural visibility conditions; (2) developing a long-term strategy (LTS) including enforceable emissions limitations and compliance schedules to achieve the RPGs; and (3) developing plans to monitor and assess the effectiveness of the LTS to achieve the RPGs over the prior implementation period and affirmation of or revision to the RPGs.

The Regional Haze Rule requires that states determine the consistent rate of progress over time needed to attain natural visibility conditions on the 20 percent most anthropogenically impaired days by the year 2064. This “glidepath” is referred to as the uniform rate of progress (URP) line. States must consider the URP, and the emission reduction measures needed to achieve this level of improvement, when developing their RPGs and LTS. Regulations at 40 CFR 51.308(g) require each state to submit progress reports, in the form of SIP revisions, every 5 years following the submission of the initial SIP. These progress reports must evaluate the progress made towards the RPGs for Class I areas located within the state as well as those Class I areas located outside the state that may be affected by emissions from within the state.

#### 3.1.1.1 Best Available Retrofit Technology

As a one-time requirement during the first implementation period, potential best available retrofit technology (BART) controls had to be evaluated for certain large stationary sources. States were required to conduct BART determinations for “BART-eligible” sources anticipated to cause or contribute to any visibility impairment in one or more Class I area. BART-eligible sources included coal-fired electric generating units (EGUs) that were in existence on August 7, 1977, but not in operation prior to August 7, 1962. In its determination of BART, states were required to take into consideration the costs of compliance, the energy and nonair quality environmental impacts of compliance, any existing pollution control technology in use at the source, the remaining useful life of

---

<sup>8</sup> On January 10, 2017, EPA made a one-time adjustment to the due date for the second implementation period SIPs (2018 – 2028) by extending the deadline from July 31, 2018 to July 31, 2021 (82 FR 3078).



the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.<sup>9</sup> As an alternative to requiring source-specific BART controls, states also had the flexibility to adopt an emissions trading program or other alternative program as long as the alternative provided greater reasonable progress towards improving visibility than BART.

### 3.1.1.2 Reasonable Progress Control Requirements for Coyote Station during First Planning Period

Coyote Unit 1 commenced operation in 1981, and was not classified as a BART-eligible source or subject to the BART requirements. Nevertheless, during the initial planning period, the North Dakota Department of Health (NDDH) evaluated emissions from the Coyote Station as a reasonable progress source. The reasonable progress analysis prepared by NDDH concluded that no additional controls would be required on Coyote Unit 1 during the initial planning period; however, NDDH and Otter Tail reached an agreement whereby Otter Tail committed to install SOFA equipment to reduce NO<sub>x</sub> emissions. In the initial planning period SIP NDDH noted that additional SO<sub>2</sub> and NO<sub>x</sub> controls for Coyote Unit 1 would be reevaluated during future planning periods to determine if additional emissions reductions would be required.

### 3.1.2 Second Implementation Period

Second planning period Regional Haze SIPs must be submitted to EPA for review by July 31, 2021. Among other requirements, second planning period SIPs are required to include an assessment of the state's RPGs and LTS. To support states in their efforts to develop the second planning period SIPs, in July 2016 EPA released a draft guidance document titled "*Draft Guidance on Progress Tracking Metrics, Long-term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period*" ("Draft EPA Guidance").<sup>10</sup> The Draft EPA Guidance document describes key steps states should implement when developing their RPGs and LTS for the second implementation period. Key steps identified in the Draft EPA Guidance are listed in Table 3-1.

<sup>9</sup> CAA Section 169A(g)(2).

<sup>10</sup> See, EPA-457/P-16-001. On September 11, 2018, EPA released a "*Regional Haze Reform Roadmap*" announcing its plan to "release a series of implementation tools and guidance documents that will help focus states' efforts and reduce and streamline the time and resources needed to meet the statutory and regulatory requirements for reducing regional haze in National Parks, wildlife refuges, and wilderness areas." EPA stated that it plans to issue a new guidance document on Regional Haze SIP Development by Spring, 2019. Otter Tail Power reserves the right to update and modify this four-factor analysis, as needed, to be consistent with any new guidance issued by the agency.



**Table 3-1. Key Steps in Developing Regional Haze SIPs for Second Planning Period**

1. *Ambient data analysis* – Quantify baseline, current and natural conditions and the uniform rate of progress that would achieve natural conditions in 2064 (40 CFR 51.308(f)(1))
2. *Screening of sources* – Identify the pollutants and emission sources for which a full reasonable progress analysis will be completed and explain why it is appropriate to limit the full analysis to only these sources (40 CFR 51.308(f)(2))
3. *Source and emission control measure analysis* – Identify potential emission control measures for sources selected in the screening step and develop data on the four statutory factors and visibility benefits if they will be considered (40 CFR 51.308(f)(2))
4. *Decisions on the content of the LTS* – Consider applicable factors and decide on new emission controls for incorporation into the LTS (40 CFR 51.308(f)(2))
5. *Regional scale modeling* – Model the emissions reductions that will result from implementation of the LTS and other enforceable measures that will reduce visibility impairment to set the RPGs for 2028 (40 CFR 51.308(f)(3))
6. *Progress, degradation and glidepath checks* – Demonstrate that there will be an improvement on the 20 percent most impaired days. Demonstrate that there is no degradation on the 20 percent clearest days. Compare the 2028 RPG for the 20 percent most impaired days to the 2028 point on the URP line (the glidepath) and, if required, provide additional justification for the reasonableness of the RPG. Revise the LTS if additional measures are identified as necessary to make reasonable progress. (40 CFR 51.308(f)(3))
7. *Additional requirements for SIPs* – Provide additional information necessary to ensure that other requirements of the Regional Haze rule are met.

The Draft EPA Guidance recommends that states evaluate all technically feasible emission control options for stationary sources and source categories identified as having the greatest potential to impact visibility at one or more Class I area. The Draft EPA Guidance recommends several options for states to consider when evaluating potential emission reductions, including work practices, replacement and retrofit controls, existing control upgrades, fuel switching year-round operation of controls, and operating restrictions.<sup>11</sup>

Emission control evaluations must consider the four statutory factors identified in 40 CFR 51.308(f)(2)(i) (discussed in Section 3.2). In addition, the Draft EPA Guidance notes that control technology assessment recommendations presented in the BART Guidelines continue to be relevant as recommendations for how a state

<sup>11</sup> See, Draft EPA Guidance, pgs. 85-86.

should evaluate and select emission control measures for stationary sources.<sup>12</sup> Recommendations in the BART Guidelines that continue to be relevant to the Regional Progress Four Factor Analysis are listed in Appendix D of the Draft EPA Guidance, and include, in general, the recommended approach for evaluating the technical feasibility, effectiveness, costs, and cost-effectiveness of available emission control measures.<sup>13</sup>

## 3.2 DESCRIPTIONS OF THE FOUR STATUTORY FACTORS

Under 40 CFR 51.308(f)(2)(i), states must consider four statutory factors when evaluating and determining emissions reduction measures from stationary sources, or groups of sources, that are necessary to make reasonable progress towards achieving natural visibility conditions. The four statutory factors are:

5. The costs of compliance;
6. The time necessary for compliance;
7. The energy and non-air quality environmental impacts of compliance; and
8. The remaining useful life of any potentially affected anthropogenic source of visibility impairment.

A brief description of each of the four statutory factors, and EPA's recommendations for evaluating each of the four factors (from the Draft EPA Guidance) is provided below.

### 3.2.1 Costs of Compliance

Cost estimates should be developed for each technically feasible control option. Costs include the total capital costs to engineer, design, procure, and install the control technology, and annual operating and maintenance (O&M) costs. O&M costs include both fixed and variable O&M. Fixed O&M includes costs that are independent of control system operation and would be incurred even if the control system were shut down. Fixed O&M includes categories such as operating and maintenance labor, administrative charges, property taxes, and insurance. Variable O&M includes the cost of consumables, including reagent (e.g., lime or limestone, ammonia, urea, etc.), by-product management, water consumption, and auxiliary power requirements associated with operating the control system. For existing facilities, O&M cost estimates should represent the control option's incremental increase over current O&M costs.

<sup>12</sup> Draft EPA Guidance, pg. 85. The BART Guidelines are published at 40 CFR Part 51 Appendix Y.

<sup>13</sup> Draft EPA Guidance, Appendix D, pgs. 186-196.

Capital costs include all costs required to engineer, design, procure, and install equipment needed for the control system. The Draft EPA Guideline recommends that states adhere to the accounting principles described in Chapter 2 Section 1 of EPA's Air Pollution Control Cost Manual (the "Control Cost Manual") when calculating control system costs for a four factor analysis.<sup>14</sup>

Section 2.3 of the Control Cost Manual (Section 1, Chapter 2) describes the cost categories generally used to calculate the total capital cost of a retrofit control technology. Cost categories include total capital investment (TCI), which is defined to "include all costs required to purchase equipment needed for the control systems (purchased equipment costs), the costs of labor and materials for installing that equipment (direct installation costs), costs for site preparation and buildings, and certain other costs (indirect installation costs). TCI also includes costs for land, working capital, and off-site facilities." Direct installation costs include costs for foundations and supports, erecting and handling the equipment, electrical work, piping, insulation, and painting. Indirect installation costs include costs such as engineering costs; construction and field expenses (i.e., cost for construction supervisory personnel, office personnel, rental of temporary offices, etc.); contractor fees (for construction and engineering firms involved in the project); start-up and performance test costs (to get the control system running and to verify that it meets performance guarantees); and contingencies.<sup>15</sup>

The total annual cost (TAC) of a control option includes the annualized capital recovery cost plus the total annual O&M costs. The Control Cost Manual recommends using an equivalent uniform annual cash flow method to annualize the total capital investment by multiplying the total capital investment by a capital recovery factor (CRF).<sup>16</sup> The product of the total capital investment and CRF gives a uniform end-of-year payment necessary to repay the initial capital investment in "n" years at an interest rate of "i". The CRF is calculated using the following equation:

$$CRF = \frac{i * (1 + i)^n}{(1 + i)^n - 1}$$

Where:

i = interest rate; and

n = economic life of the emission control system

The Draft EPA Guidance suggests that states may use generic cost estimates or estimating algorithms for estimating

<sup>14</sup> Draft EPA Guidance, pg.89.

<sup>15</sup> EPA Air Pollution Control Cost Manual, Sixth Edition, EPA/452/B-02-001, January 2002, pg. 2-5.

<sup>16</sup> Id., at pg 2-21.

control system costs; however, source specific estimates prepared by knowledgeable engineering professionals provide more reliable information than generic cost estimates.<sup>17</sup> Source-specific cost estimate should be well documented for purposes of public comment and EPA review.<sup>18</sup>

The total annual cost of each control option (\$/yr) is divided by the total annual emissions reduction (tpy) to determine the control option's average cost-effectiveness on a \$/ton basis. Emissions reductions are calculated based on the difference between baseline annual emissions and post-control annual emissions. The Draft EPA Guidance generally recommends calculating baseline emissions based on projected 2028 emissions assuming source compliance with emission limits that have been adopted and are enforceable. As an alternative, baseline emissions may be based on representative past actual emissions, assuming there is no evident basis for using a different emissions rate.

### **3.2.2 Time Necessary for Compliance**

For stationary sources, the provisions of the BART Guidelines regarding the time necessary for compliance are relevant to reasonable progress analyses. EPA recommends that prior experiences with the planning and installation of new emission controls is the best guide to how much time a particular source will reasonably need for compliance. However, source-specific factors should be considered when evaluating the time necessary to engineer, procure, and install an available and technically feasible control option. Source-specific factors that affect the time necessary to install new emission controls should be identified and documented in the four factor analysis.

### **3.2.3 Energy and Non-Air Quality Environmental Impacts**

For stationary sources, the provisions of the BART Guidelines regarding energy impacts are relevant to reasonable progress analyses. Energy impacts of an emission control measure are a matter of engineering design and control system operation; thus, EPA recommends that prior experience at similar sources will be informative. Energy impacts may be considered in terms of kilowatt-hours or fuels used to operate the control system. The energy impact analysis should focus on direct energy consumption at the source rather than indirect energy inputs needed to produce raw materials for the construction and operation of control equipment.

---

<sup>17</sup> Draft EPA Guidance, pg. 91.

<sup>18</sup> Id.

For stationary sources, the provisions of the BART Guidelines regarding non-air quality environmental impacts are relevant to reasonable progress analyses. Non-air quality impacts include solid or hazardous waste generation, increased water consumption, wastewater discharge, land use impacts, and impacts to threatened and endangered species or their natural habitat. Characterizing the non-air quality environmental impacts should be done on a source-specific basis. Other guidance intended for use in assessments under the National Environmental Policy Act may be relevant to this evaluation.

Even though states are not required to consider GHG emission impacts, the Draft EPA Guidance encourages states to consider GHG impacts when developing their Long-Term Strategy.<sup>19</sup> As an example, some measures that would reduce emissions that contribute to visibility impairment will also reduce GHG emissions, such as measures that reduce the use of energy produced from combusting fossil fuels with relatively high GHG emissions. Conversely, control measures that require significant energy to capture visibility impairing emissions could result in increased GHG emission. Where a measure necessary to make reasonable progress towards natural visibility conditions would increase GHG emissions, Draft EPA Guidance encourages states to work to harmonize visibility and climate change objectives.<sup>20</sup>

### 3.2.4 Remaining Useful Life

For stationary sources, the provisions of the BART Guidelines regarding remaining useful life are relevant to reasonable progress analyses. In general, the remaining useful life of the source itself will be longer than the useful life of the emission control measure under consideration unless there is an enforceable requirement for the source to cease operation sooner. Thus, the useful life of the control measure will normally be used in the four factor analysis to calculate emission reductions, amortized costs, and cost-effectiveness. However, if there is an enforceable requirement for the source to cease operation by a date before the end of what would otherwise be the useful life of the control measure under consideration, then the enforceable shutdown date should be used to calculate remaining useful life and evaluate control technology cost-effectiveness.

---

<sup>19</sup> Draft EPA Guidance, pg. 92.

<sup>20</sup> Id.

### 3.2.5 Four Factor Analysis Approach

S&L used the following approach to identify SO<sub>2</sub> and NO<sub>x</sub> emission control options available to Coyote Unit 1 for inclusion in the Four Factor Analysis:

1. Establish representative baseline emissions achieved with existing controls.
2. Identify all potentially available control options.
3. Evaluate control options for technical feasibility (i.e., availability and applicability).
4. Eliminate control options that are not technically feasible or would have no practical application on Coyote Unit 1.
5. Determine the control effectiveness of each technically feasible control option.
6. Evaluate each technically feasible control option for the four statutory factors.

## 4. BASELINE SO<sub>2</sub> AND NO<sub>x</sub> EMISSIONS

The first step in developing the Four Factor Analysis is to establish Coyote Unit 1 baseline SO<sub>2</sub> and NO<sub>x</sub> emissions. To establish representative baseline emissions, S&L evaluated Coyote Unit 1 operating data for the period January 1, 2013 to June 30, 2018 to identify periods of normal operation (i.e., periods of operation when the boiler was not limited by infrequent or extraordinary operating restrictions). Based on review of fuels consumed, heat input to the boiler, boiler heat rates, power generation, and capacity factors, as well as input from OTP, it was determined that the operating periods of January 1, 2013 to December 31, 2014 and January 1, 2016 to June 30, 2018 were representative of normal operation. The year 2015 was not considered to be representative because Coyote Unit 1 was limited to approximately 50% load due to a boiler feed pump (BFP) overspeed event that damaged one of the unit's two 50% BFPs; thus, only one BFP was available throughout most of the year. Therefore, the periods January 1, 2013 to December 31, 2014, and January 1, 2016 to June 30, 2018 are representative of normal operation during the baseline period, and it was determined that SO<sub>2</sub> emissions during that period are also representative. In June 2016, Unit 1 SOFA upgrades were completed for the purpose of reducing NO<sub>x</sub> emissions; thus, the representative baseline period for NO<sub>x</sub> emissions was determined to be from July 1, 2016 to June 30, 2018.

Baseline annual SO<sub>2</sub> and NO<sub>x</sub> emissions were determined based on data obtained from the Coyote Unit 1 continuous emissions monitoring system (CEMS) that was reported to EPA's Clean Air Markets. The annual average emission rate during the representative time period was used to establish baseline annual emissions (in terms of tons per year). Representative baseline emission factors (in terms of pounds per million British Thermal Units (lb/MMBtu)) were developed using baseline annual average emissions and the respective baseline heat inputs. Table 4-1 provides a summary of the Coyote Unit 1 SO<sub>2</sub> and NO<sub>x</sub> representative baseline emissions; additional details are included in Appendix A.

**Table 4-1. Coyote Unit 1 Baseline Emissions**

Pollutant	Baseline Controls	Emissions		Heat Input	Notes
		lb/MMBtu	tons/yr	MMBtu/yr	
SO <sub>2</sub>	DFGD/FF	0.85	12,994	30,562,287	SO <sub>2</sub> emissions based on annual average tpy for period January 2013-June 2018 (excluding 2015)
NO <sub>x</sub>	SOFA	0.46	7,363	32,301,802	NO <sub>x</sub> emissions based on annual average tpy for period July 2016 to June 2018 (post-SOFA upgrades)



## 5. SO<sub>2</sub> AND NO<sub>x</sub> CONTROL MEASURES

S&L used a top-down approach to identify and evaluate the technical feasibility and effectiveness of potentially available SO<sub>2</sub> and NO<sub>x</sub> control measures. S&L followed Steps 1 thru 3 of the top-down approach described in the BART Guidelines to identify all available retrofit emission control measures, eliminate technically infeasible options, and evaluate the effectiveness of the technically feasible options.<sup>21</sup> A brief description of each step is provided below.

### *Step 1 - Identify All Available Control Options*

Available control options are those air pollution control technologies with a practical potential for application to the emission unit and the regulated pollutant under evaluation. Air pollution control technologies can include a wide variety of available methods, systems, and techniques for control of the affected pollutant, and include not only existing controls for the source category but also take into account technology transfer of controls that have been applied to similar source categories and gas streams. Technologies which have not been applied to (or permitted for) full scale operations need not be considered as available.<sup>22</sup>

In an effort to identify all potentially available emission control technologies, S&L searched a broad range of information sources including, but not necessarily limited to:

- EPA's RACT/BACT/LAER Clearinghouse;
- EPA's New Source Review (NSR) and Clean Air Technology Center (CATC) Web sites;
- BART evaluations prepared during the initial Regional Haze planning period;
- Information from control technology vendors and engineering/environmental consultants;
- Federal and State NSR permits and Best Available Control Technology (BACT) determinations for similar sources; and
- Technical journals, reports, newsletters and air pollution control seminars.

### *Step 2 - Eliminate Technically Infeasible Control Options*

In Step 2, S&L evaluated the technical feasibility of the control options identified in Step 1 with respect to source-specific and unit-specific factors. Control technologies are technically feasible if either: (1) they have been

<sup>21</sup> See, 40 CFR Part 51 Appendix Y, Section IV.D.

<sup>22</sup> Id., at IV.D.1.

installed and operated successfully for the type of source under review under similar conditions; or (2) the technology could be applied to the source under review. In order for a control option to be technically feasible, it must be “available” and “applicable” to the source under consideration. A technology is considered “available” if the source owner may obtain it through commercial channels. An available technology is “applicable” if it can reasonably be installed and operated on the source type under consideration.<sup>23</sup>

Control technologies that are technically infeasible (i.e., not available or not applicable to the source under consideration) are eliminated for further evaluation. A demonstration of technical infeasibility must be based on physical, chemical and engineering principals, and must show that technical difficulties would preclude the successful use of the control option on the emission unit under consideration. The economics of an option are not considered in the determination of technical feasibility/infeasibility.

### ***Step 3 - Evaluate Technically Feasible Control Technologies for Effectiveness***

Step 3 involves evaluating the control effectiveness of all the technically feasible control alternatives identified in Step 2 for the pollutant and emissions unit under review. Control effectiveness should be expressed using a metric that ensures an “apples-to-apples” comparison of emissions performance levels among options, and is generally expressed as the rate that a pollutant is emitted after installation of the control measure. Control technology evaluations for existing sources should consider ways to improve the performance of existing control devices. Special circumstances pertinent to the specific unit under review should be identified and taken into consideration when assessing the capability of the control alternative and determining control effectiveness.

For this evaluation, S&L assessed the technically feasible SO<sub>2</sub> and NO<sub>x</sub> control options for effectiveness on Coyote Unit 1. As discussed above, Coyote Unit 1 is an existing cyclone boiler designed to fire North Dakota lignite. The unit is equipped with SOFA for NO<sub>x</sub> control, and dry FGD and FF for SO<sub>2</sub> and PM control.

---

<sup>23</sup> A more detailed description of control technology “availability” and “applicability” is provided in 40 CFR Part 51 Appendix Y, Section IV.D.2.

## 5.1 SO<sub>2</sub> EMISSIONS CONTROLS

### 5.1.1 Identify Available SO<sub>2</sub> Control Options

Based on a review of available SO<sub>2</sub> control technologies, as well as operational practices and equipment upgrades implemented on existing control systems, potentially available options to control SO<sub>2</sub> emissions from Coyote Unit 1 are listed in Table 5-1.

**Table 5-1. Available SO<sub>2</sub> Control Options**

SO <sub>2</sub> Control Technologies
Fuel Switching
Existing DFGD Operational Improvements
Existing DFGD Equipment Upgrades
Existing DFGD + Dry Sorbent Injection (DSI)
Existing DFGD Operational Improvements + DSI
Retrofit New Dry FGD
Retrofit New Wet FGD

### 5.1.2 Technical Feasibility of Available SO<sub>2</sub> Control Options

Potentially available SO<sub>2</sub> control options identified in Table 5-1 were evaluated for technical feasibility (i.e., availability and applicability to Coyote Unit 1) based on a review of physical, chemical, and engineering principals, and an assessment of commercial availability. Options determined to be technically infeasible, or options that have no practical application to Coyote Unit 1, were eliminated from further review. S&L evaluated the effectiveness of the control options determined to be technically feasible, and established an emissions performance level (i.e., control emissions rate) for each.

#### 5.1.2.1 Fuel Switching

One potential strategy for reducing SO<sub>2</sub> emissions is to reduce the sulfur content of the coal. Limiting the amount of sulfur in the coal directly limits the amount released during the combustion process, and would reduce SO<sub>2</sub> loading to the dry scrubber. Coyote Unit 1 is a cyclone boiler designed to fire North Dakota lignite as the primary fuel. Lignite fired at the Coyote Station is mined and supplied to the station from the nearby Coyote Creek Mine. The mine, which is owned and operated by Coyote Creek Mining Company, has primary mining operations

approximately 3-4 miles southwest of Coyote Station and can be considered a mine mouth plant. Previous regulatory and court decisions have concluded that requiring a mine mouth facility to evaluate low sulfur coal would require the facility to redefine its fundamental purpose and design; therefore, fuel switching can be rejected as an available control option.<sup>24</sup> Because the use of North Dakota lignite from the Coyote Creek Mine is an inherent aspect of Coyote operation, fuel switching will not be evaluated.

#### 5.1.2.2 Existing DFGD Operational Improvements and Equipment Upgrades

Operational and other design changes/upgrades to the existing dry scrubber may provide an opportunity for additional SO<sub>2</sub> removal and allow the unit to achieve lower controlled SO<sub>2</sub> emissions. S&L, working with OTP personnel, identified a number of potentially feasible operational changes that may be available to increase SO<sub>2</sub> removal efficiency with the existing equipment. Potentially available operational and design changes to the existing control system are summarized in Table 5-2. A detailed discussion of each of these options is provided in the following sections.

**Table 5-2. FGD Operational Improvements and Equipment Upgrades**

FGD Operational Improvements
Lime Quality
Ca:S Stoichiometric Ratio
Approach to Saturation Temperature
FGD Design Changes and Equipment Upgrades
Atomizer Replacement
Slaker Replacement
Adding an Absorber Module
Replacing Existing Absorbers with New Absorber Modules

#### Lime Quality

The quantity of lime (CaO) available in a dry scrubbing system compared to the amount of SO<sub>2</sub> entering the system is called the stoichiometric ratio (generally referenced as the Ca:S stoichiometric ratio). Reagent quality directly

<sup>24</sup> In re: Prairie State Generating Company, PSD Appeal No. 05-05, Slip. Op. at 36 (2006)

affects the Ca:S stoichiometric ratio in DFGD control systems. Using a high quality lime increases the availability of hydrated lime to support process chemistry, and reduces the lime slurry injection rate needed for SO<sub>2</sub> removal.

Lime quality is measured both by the CaO content and reactivity of the lime product. In a dry scrubber, CaO is combined with water to form hydrated lime or calcium hydroxide (Ca(OH)<sub>2</sub>), which provides the calcium that is needed to react with SO<sub>2</sub> in the flue gas. With a higher quality lime, more calcium hydroxide is available to react with SO<sub>2</sub>. Lime products with a CaO content of 90% or greater are generally considered high quality lime. Lower quality lime products have a lower CaO content and higher quantity of inert material. Reactivity of the lime is measured by the temperature rise when the lime is slaked (i.e., water addition). In general, porous lime products have higher reactivity which is demonstrated by achieving a temperature rise of approximately 40 °C within 3 minutes of adding water.

Based on a review of available lime analyses, and a review of operating data from the existing lime slaking system, Coyote Unit 1 currently procures a high quality lime for use in the dry scrubbers. The typical CaO content of the lime used at Coyote is 90% or greater, and when slaked can achieve a 39.4 °C temperature rise in 3 minutes of adding water. For these reasons, changing the lime quality is not considered a technically feasible operational change available to control SO<sub>2</sub> emissions from Coyote Unit, and will not be evaluated further.

#### Ca:S Stoichiometric Ratio

Other operational changes that may be available to increase the Ca:S stoichiometry in the existing dry scrubber include: (1) increasing the byproduct recycle rate; and/or (2) increasing the quantity of fresh hydrated lime introduced to the system. Due to the cost savings that may be realized with the first option, some facilities with existing DFGD controls have opted to increase solids recycle rates to as high as 40-50% solids to achieve an incremental increase in SO<sub>2</sub> reduction, if capacity was available in the byproducts handling system. If capacity is not available, increasing fresh lime addition to the system may also be a viable option to increase the Ca:S stoichiometric ratio.

Solids from a dry scrubber consist of fly ash, reaction byproduct, and residual unreacted hydrated lime. On Coyote Unit 1, solids collected in the fabric filter hoppers are conveyed to either a dry storage silo for disposal or to a recycle fly ash silo where it is used as make-up for the reactant slurry. The recycle system is designed to utilize a portion of the unreacted lime rather than disposing of all of the solids. Recycle solids are combined with the fresh lime addition to provide the makeup lime needed for SO<sub>2</sub> reduction. Increasing the recycle rate can increase the

amount of hydrated lime added to the system (i.e., stoichiometric ratio) without increasing the quantity of fresh lime added to the system.

Based on information provided by the station, the DFGD system on Coyote Unit 1 currently operates the recycle system at approximately 24% solids. The Coyote Unit 1 recycle system is operating within the original design conditions and system capacity. The plant has tested higher recycle rates (up to 28-30% solids), but at these higher rates plant personnel reported significant problems with the atomizer wheels spilling over and pluggage of various strainers. Based on the adverse operational impacts observed during these tests, as well as the design limitations of the existing dry scrubber modules, increasing the recycle % solids is not considered a technically feasible SO<sub>2</sub> control option for Coyote Unit 1.

As an alternative to increasing the recycle rate, the Ca:S stoichiometric ratio in the system may be increased by increasing the quantity of fresh lime introduced to the system. Testing was completed in October 2018 on Coyote Unit 1 to determine the impact of increasing the amount of fresh lime slurry fed to the atomizer feed tanks while adjusting the amount of recycle slurry in order to maintain the design 24% solids to the absorber. During the test program Coyote Unit 1 was able to achieve an average controlled SO<sub>2</sub> emission rate of 0.50 lb/MMBtu without significant adverse operational impacts and represents an average emission rate that Coyote would be expected to achieve on an on-going long-term basis under normal operating conditions. The emission rate should not be construed to represent proposed permit limits. Corresponding permit limits must be evaluated on a control system-specific basis; however, an additional 10-15% margin would likely be needed to account for operating margin.

Increasing the quantity of fresh lime introduced to the system will require the existing atomizer wheels to be upgraded from the eight (8) nozzle wheel to a twelve (12) nozzle wheel to mitigate for potential plugging and spill-over issues caused by the percent solid limitation of the existing atomizer wheels (see, Section 5.1.2.2 Atomizer Replacement), and to prevent the possibility of moisture carry-over that could occur with the increase in lime slurry flow. Although upgrades to the existing atomizer wheels and nozzles will be required, increasing the Ca:S stoichiometric ratio by adding additional fresh lime to the system is considered a technically feasible SO<sub>2</sub> control option for Coyote Unit 1, and will be included in the Four Factor Analysis.

#### Approach to Saturation Temperature

The reaction of SO<sub>2</sub> with Ca(OH)<sub>2</sub> in a dry scrubber is driven by the absorber temperature. Water surrounding the lime slurry droplet allows SO<sub>2</sub> to dissolve into the liquid and facilitates the reaction between lime and SO<sub>2</sub>. The

temperature differential between the inlet and the outlet of the DFGD is used as a driving force for SO<sub>2</sub> removal; however, outlet temperatures must be maintained above the saturation temperature to ensure byproducts exiting the absorber module are dry. Residence time within the absorber vessel, drying time, and exit temperature are all important design parameters for a dry scrubbing system.

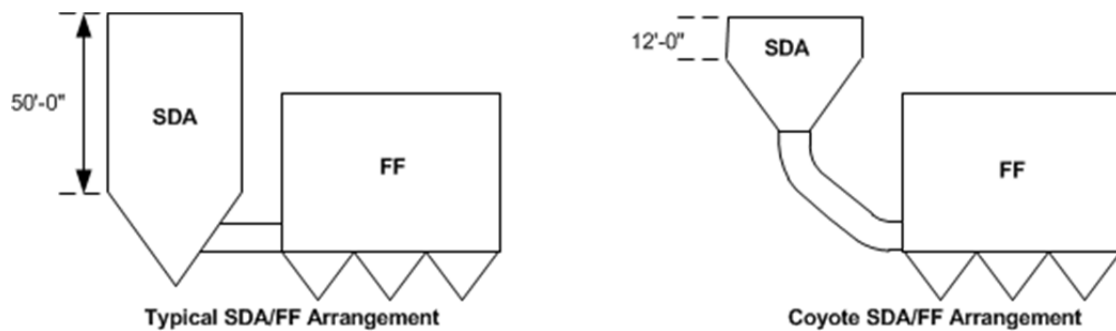
Inlet temperature to the dry scrubbing module is relatively constant; therefore, temperature differential across the module is a function of the outlet temperature. As a general rule-of-thumb, the closer the outlet temperature is to the adiabatic saturation temperature, the higher the SO<sub>2</sub> removal efficiency.

Operating a dry scrubbing system at outlet temperatures significantly above the adiabatic saturation temperature accelerates water evaporation from the reactant slurry, limits SO<sub>2</sub> absorption into the droplet, and limits the reaction between the lime and SO<sub>2</sub>. Reducing the temperature in the absorber closer to the saturation point can provide additional SO<sub>2</sub> removal. On the other hand, the absorber module may not have sufficient residence time to dry all slurry droplets if the system is operated too close to adiabatic saturation, which would result in deposits in the absorber module, corrosion, and severe operational problems. Therefore, maintaining an absorber outlet temperature close to the point of saturation, while staying above it, is vital for optimal reaction kinetics.

The Coyote Unit 1 dry scrubbers currently operate at an outlet temperature of 190-210 °F, which is approximately 55-75 °F above the adiabatic saturation temperature and within original the OEM design steady state operating parameter of 190°F at the stack. More recent dry scrubbing systems have been designed to operate at 30 °F approach to adiabatic saturation. The station has attempted to lower the outlet temperatures to 165-170°F, however, this change caused significant corrosion of the absorber vessels and downstream equipment. Corrosion was likely due to the fact that the Coyote Unit 1 scrubbers were not able to completely dry the slurry droplets because the absorber vessels were designed with a residence time of approximately 1.0 second. More recent dry scrubbers are designed with approximately 10 seconds of residence time.

Figure 5-1 provides a simplified drawing of the Coyote Unit 1 scrubber compared to more recent DFGD designs, and depicts the arrangement limitation causing Coyote's shorter residence time. The low residence time limits the scrubbers ability to dry all slurry droplets when the system is operated too close to the approach to adiabatic saturation temperature. Due to the design limitations of the existing absorber vessels, reducing the outlet temperature is not considered a technically feasible SO<sub>2</sub> control option for Coyote Unit 1, and will not be evaluated further.

**Figure 5-1. Comparison of Typical SDA/FF and Coyote Unit 1 SDA/FF Arrangement**



### Atomizer Replacement

Spray droplet size is an important parameter in the design and operation of a dry scrubber, and can improve lime utilization and SO<sub>2</sub> removal. Finer spray will increase the surface area of the slurry droplets exposed to the flue gas. Greater surface area increases the potential for SO<sub>2</sub> to absorb into the moisture of the slurry droplets. Droplet fineness also plays a role in particle drying time. Larger droplets can have a negative effect on the slurry drying time which can lead to moisture carryover to downstream equipment causing buildup and corrosion.

The Coyote Unit 1 dry scrubber, provided by Combustion Engineering, is designed with three (3) rotary atomizers, each with an eight (8) nozzle wheel in each absorber module to achieve a fine slurry spray. The design of the atomizer and speed at which the wheel rotates are controlling factors for the size and form of the droplets in the spray. The design and speed of atomizers is highly dependent on the spray pattern needed to mix with the hot flue gas in the scrubber module for optimum absorption of SO<sub>2</sub> while also preventing wetting of the absorber walls.

Based on S&L's assessment of the existing control system, previous testing completed by the station, and input from station operators, the existing DFGD system is limited in residence time, and the ability to increase the recycle ratio (solids content) to allow for more effective Ca:S contact in the scrubber vessels. The existing atomizers with eight (8) nozzle wheels would need to be upgraded to a twelve (12) nozzle wheel to mitigate for potential plugging and spill-over issues that could occur with the increased Ca:S stoichiometric ratio (discussed in Section 5.1.2.2). Based on engineering judgment, new 12 nozzle atomizers would improve spray atomization to produce slurry droplets that are smaller in size than the droplets produced by the existing nozzle design. Improved materials of construction would also allow for higher solids content in the slurry without detrimental equipment pluggage or spill-over.



Replacing the existing nozzles with a more recent 12 nozzle wheel design would provide better atomization of the slurry spray and allow for more effective Ca:S contact in the absorber vessels. However, nozzle replacement would not, on its own, be expected to provide a significant increase in SO<sub>2</sub> control. Nozzle upgrades coupled with operational changes designed to increase the Ca:S stoichiometric ratio is a technically feasible option that would be expected to provide additional SO<sub>2</sub> control (See, Section 5.1.2.2 Ca:S Stoichiometric Ratio).

#### Slaker Replacement

Lime slurry, the reagent used for SO<sub>2</sub> removal in a dry scrubber, is produced by mixing pebble lime with heated water in a slaker; this process is referred to as “slaking”. The slaker is operated at an optimum water-to-lime ratio (typically between 3:1 and 6:1) to produce lime slurry by metering the amount of water and the amount of lime added to the slaker. Slakers are typically designed to produce a lime slurry between 15-20% solids. The lime slurry is added to recycle slurry in a mix tank and then sent to the atomizer where it is sprayed into the scrubber for SO<sub>2</sub> removal.

Coyote Unit 1 still operates the original Dorr-Oliver detention slakers. The slakers operate at a 5:1 water-to-lime ratio and approximately 18% solids, which is in line with the design as well as industry practice. Therefore, replacing the slakers would not result in improved Ca:S contact in the absorber vessels or provide additional SO<sub>2</sub> removal. Replacing the lime slakers is not considered a technically feasible SO<sub>2</sub> control option for Coyote Unit 1, and will not be evaluated further.

#### Adding an Absorber Module

Another option for extending the residence time within the reactor modules and increasing Ca:S contact would be to add an additional absorber module. The existing system is designed with four absorber modules that share three fabric filter zones. The system is designed to operate with four modules at full load, three or four modules at 75% load and two modules at 50% load. At full load, the flue gas residence time in the reactor modules is approximately 1.0 second. More recent dry scrubbing systems have been designed with reaction vessel residence times of 10 seconds or more.

One potential option available to the Coyote Station to increase absorber module residence time would be to add an additional absorber module to the existing dry scrubbing system. The number of absorber modules used in a DFGD system is dependent on multiple operating parameters, including the flue gas flow rate and SO<sub>2</sub> concentrations. DFGD absorber modules are typically specified with minimum and maximum flue gas flow rates. If the absorber

modules are oversized, flue gas velocities through the module can be too low, causing solids dropout inside the vessel. If the absorber modules are undersized, flue gas velocities can be too high, causing residence time to fall below recommended levels.

Dry scrubbing units that are operating at flue gas volumes significantly above the design flow rate can benefit from adding an extra module to the system. The module would be placed in parallel with the existing modules to achieve a similar pressure drop through each vessel and to ensure equal flue gas distribution to the vessels. Although adding an absorber module would likely allow additional residence time for the SO<sub>2</sub> removal reactions to occur, it would require extensive engineering and modifications to the existing system. More importantly, the Coyote Unit 1 absorber module design is no longer available from Combustion Engineering, and it would likely not be possible to procure a commercial offering from another technology vendor that would be compatible with the existing modules. Therefore, incorporating an additional absorber module into the existing system is not a commercially available or technically feasible SO<sub>2</sub> control strategy for Coyote, and will not be evaluated further.

#### Replacing Existing Absorbers with New Absorber Modules

Replacing the existing modules with new absorber modules would require significant engineering and facility modifications. Based on a preliminary review of the control system layout, the only practical location for this option would be to construct the new vessels in the same location as the existing modules. Locating the new modules adjacent to the existing absorber modules would require flue gas to be redirected from the air heater outlets to the new absorbers and back to the existing fabric filters, which would likely result in significant solids dropout and other operational issues. Therefore, locating the new absorber modules adjacent to the existing absorber modules is not considered a technically feasible option.

Installing the new absorber vessels in the same location as the existing dry scrubber modules would require Coyote Unit 1 to be taken off-line for an extended period of time. OTP could not operate the unit while the existing modules were dismantled and removed, or while the new absorber modules, duct work, and other system tie-ins were installed. Based on construction schedules for new DFGD systems, and taking into consideration decommissioning of the existing dry scrubber modules, this option would likely require an outage of at least 12-months and would require Coyote to purchase replacement power during this period. In comparison, a typical major outage at Coyote Station is only 6-8 weeks. Outage costs would add significantly to the cost of this control option.

Although replacing the existing dry scrubber modules with new DFGD reactor vessels would require a long outage, there is no technical basis for eliminating this option from the analysis. Replacing the exiting dry scrubber modules with new absorber modules would address the design and operational limits of the existing system. The new absorber modules could be designed to provide additional Ca:S contact and residence time between the exhaust gas and the slurry, and would likely allow OTP to reduce the approach to saturation temperature, design parameters which would increase overall SO<sub>2</sub> removal.

Coyote Unit 1 consistently achieves overall removal efficiencies in the range of approximately 65-73% with the existing dry scrubbing system. Based on engineering judgment and industry practice, it is expected that the fabric filter provides approximately 10-15% of the overall removal in the DFGD system. Assuming 10-15% removal in the fabric filter, approximately 60% of the SO<sub>2</sub> removal is achieved in the existing absorber modules based on the current coal sulfur content. Estimated SO<sub>2</sub> removal efficiencies across the existing DFGD system are shown in Table 5-3.

**Table 5-3. Existing SO<sub>2</sub> Removal Efficiencies**

Existing Scrubber Modules	Existing Fabric Filter	Overall
Inlet: 2.83 lb/MMBtu Outlet: 1.14 lb/MMBtu Efficiency: 60% of uncontrolled Contribution: 85% of overall removal	Inlet: 1.14lb/MMBtu Outlet: 0.85 lb/MMBtu Efficiency: 11% of uncontrolled Contribution: 15% of overall removal	Inlet: 2.83 lb/MMBtu Outlet: 0.85 lb/MMBtu Efficiency: 70%

Based on SO<sub>2</sub> removal efficiencies achieved in practice on existing units equipped with DFGD, it is anticipated that replacing the existing absorber modules with new scrubber modules could increase removal across the scrubber to approximately 80%, and increase overall removal efficiencies to approximately 91%. It should be noted that Coyote is expected to receive higher sulfur content coal in the future; therefore, the new scrubber vessel SO<sub>2</sub> removal analysis is based on this higher sulfur content coal. The removal efficiencies for this option are shown in Table 5-4.

**Table 5-4. New Scrubber Vessel SO<sub>2</sub> Removal Efficiencies**

New Scrubber Modules	Existing Fabric Filter	Overall
Inlet: 3.12 lb/MMBtu <sup>(Note 1)</sup> Outlet: 0.62 lb/MMBtu Efficiency: 80% of uncontrolled Contribution: 88% of overall removal	Inlet: 0.62 lb/MMBtu Outlet: 0.29 lb/MMBtu Efficiency: 11% of uncontrolled Contribution: 12% of overall removal	Inlet: 3.12 lb/MMBtu Outlet: 0.29 lb/MMBtu <sup>(Note 2)</sup> Efficiency: 91%

Note 1. Inlet SO<sub>2</sub> rate based on anticipated future fuel sulfur content.

Note 2. Emission rates shown represent average emission rates that the control options would be expected to achieve on an on-going long-term basis under normal operating conditions for Coyote Unit 1. Emission rates are provided for comparative purposes, and should not be construed to represent proposed permit limits. Corresponding permit limits must be evaluated on a control system-specific basis; however, an additional 10-15% margin would likely be needed to account for operating margin.

Replacing the existing dry scrubber modules with new absorber modules is a technically feasible control technology option that would provide an incremental increase in overall SO<sub>2</sub> removal efficiency. However, this option would require Coyote Unit 1 to be taken off-line for an extended period of time (approximately 12 months). Outage costs associated with the extended outage are included in the four-factor cost impact evaluation for this option. Given the constructability issues and extended outage requirements associated with replacing the existing dry scrubber modules, this may not be a practical option for Coyote; nevertheless, it will be included as a technically feasible SO<sub>2</sub> control option in the Four Factor Analysis.

### 5.1.2.3 Existing FGD + Dry Sorbent Injection

Alkali based sorbent injection is a proven technology for the removal of sulfur trioxide (SO<sub>3</sub>) and other acid gases from coal-fired power plant flue gas, and can be used to provide SO<sub>2</sub> control. Sorbent is injected into the ductwork after the furnace and prior to the particulate collection device, where it reacts with SO<sub>2</sub> and other acid gases. Sorbent injection systems are relatively simple systems consisting of material storage, feeding mechanism, blower or transfer line, and an injection device. For SO<sub>2</sub> control on Coyote Unit 1, sorbent would be injected upstream of the dry scrubber to provide an incremental reduction in the concentration of SO<sub>2</sub> in the flue gas at the inlet to the dry scrubber.

Sorbents react with SO<sub>2</sub>, and other acid gases, in the flue gas when injected at an appropriate rate and within the proper temperature range for that sorbent. The resulting particulate matter is removed from the flue gas by the particulate control system. The process works through neutralization of the acid gases with the alkaline sorbent. The neutralization reaction occurs as long as the sorbent remains in contact with the gas in the flue gas duct work within the required temperature range.

Dry sorbents that have been used for SO<sub>2</sub> control on coal-fired boilers include:

- Hydrated Lime (Ca(OH)<sub>2</sub>)
- Trona or Sodium Bicarbonate (SBC)

The following wet sorbents have also been used for acid gas control at coal-fired power generating stations:

- Sodium Bisulfite (SBS)
- Soda Ash

Dry sorbents, including hydrated lime, Trona, and SBC would be injected pneumatically as a dry powder into the flue gas ductwork upstream of the Coyote Unit 1 dry scrubber. Trona and SBC are both sodium-based sorbents, which react with SO<sub>2</sub> to form sodium salts. Hydrated lime would react with SO<sub>2</sub> to form calcium sulfate salts. The hydrated lime reactions are the same reactions that are taking place in the existing dry scrubber.

Hydrated lime is less reactive than the sodium based dry sorbents; thus, higher injection rates and longer residence time would be required to achieve the same removal efficiency. However, hydrated lime has a lower unit cost compared to other sorbent options, offsetting the higher injection rates. It is also important to note that the hydrated lime chemistry involves the same reactions, and forms the same calcium salts, as those currently taking place in the dry scrubber reaction vessels. Therefore, using hydrated lime as the sorbent would not introduce any new constituents into the dry scrubbing system, and could potentially increase the Ca:S stoichiometry in the dry scrubber.

Because of the higher reactivity of sodium based sorbents, less reactant may be required to achieve the same removal efficiency; however, injecting a sodium-based sorbent into the flue gas upstream of the Coyote Unit 1 dry scrubber would introduce new chemical constituents into the scrubber and into the fly ash/scrubber byproduct material. This could prove problematic as sodium compounds are water soluble, and introducing sodium into the system could adversely affect the characteristics of the byproduct solids generated by the system. Detailed studies and demonstration tests would be needed to ensure that introducing relatively large amounts of sodium would not adversely affect scrubber operation or result in solids disposal issues.

SBS and soda ash (Na<sub>2</sub>CO<sub>3</sub>) injection are wet injection technologies typically used for SO<sub>3</sub> mitigation. SBS and soda ash can be injected into the flue gas upstream or downstream of the air heater as a 10% solution (by weight) using dual fluid atomizers. Both products will react with SO<sub>2</sub> and SO<sub>3</sub> to form sodium salts, which can be collected in the downstream particulate collection device. URS/Codan Associates own the patent for this SBS control process. Based on conversations with URS, their SBS technology is generally more economical using soda ash,

and all recent projects have used soda ash. However, as with the dry sodium-based injection systems, these systems would introduce sodium into the Coyote Unit 1 DFGD control system.

Sorbent injection (dry or wet) upstream of the existing dry scrubber is a technically feasible and commercially available SO<sub>2</sub> control option for Coyote Unit 1. Taking into consideration the fact that Coyote is currently equipped with a calcium-based dry scrubbing system, hydrated lime dry sorbent injection would be the most practical, and potentially the most effective, sorbent injection control option. Sodium-based systems would require extensive testing to determine the potential impacts associated with introducing significant quantities of sodium into the existing system, and are not considered practical control options for Coyote Unit 1.

Based on engineering judgment, and assuming adequate residence time in the duct work upstream of the existing dry scrubber, hydrated lime injection could reduce SO<sub>2</sub> concentrations at the dry scrubber inlet by approximately 35%. Based on future design fuel characteristics, this would reduce SO<sub>2</sub> concentrations at the dry scrubber inlet from approximately 3.12 lb/MMBtu to approximately 2.03 lb/MMBtu. Applying the current scrubber SO<sub>2</sub> removal efficiency of 71% (dry scrubber plus fabric filter), would result in a controlled SO<sub>2</sub> emission rate of 0.58 lb/MMBtu. DSI upstream of the existing dry scrubbing system is considered a technically feasible SO<sub>2</sub> control technology; however, flow modeling and field testing at Coyote Unit 1 would be needed to ensure that adequate residence time is available for SO<sub>2</sub> control and to confirm the incremental reduction in SO<sub>2</sub> emissions achievable without creating unacceptable operational issues.

**Table 5-5. DSI SO<sub>2</sub> Control Technology Estimated Emissions**

	Unit 1
Uncontrolled SO <sub>2</sub> Emissions (lb/MMBtu)	3.12
SO <sub>2</sub> Emissions at DSI Outlet (lb/MMBtu)	2.03
SO <sub>2</sub> Emissions at FF Outlet (lb/MMBtu)	0.58 <sup>1</sup>
<b>Overall Removal (%)</b>	<b>80.4</b>

Note 1. Emissions at the FF outlet were estimate by applying existing 71% SO<sub>2</sub> removal across the DFGD system ((2.03 lb/MMBtu x (1 – 0.71) = 0.58).

Note 2. Emission rates shown represent average emission rates that the control options would be expected to achieve on an on-going long-term basis under normal operating conditions for Coyote Unit 1. Emission rates are provided for comparative purposes, and should not be construed to represent proposed permit limits. Corresponding permit limits must be evaluated on a control system-specific basis; however, an additional 10-15% margin would likely be needed to account for operating margin.

#### 5.1.2.4 FGD Operational Improvements + DSI

Some of the SO<sub>2</sub> control technologies which involve improvements to the FGD can potentially be applied in combination with dry sorbent injection to provide additional SO<sub>2</sub> removal. This option would be considered a layered technology of the technically feasible FGD operational improvements discussed in Section 5.1.2.2 with dry sorbent injection discussed in Section 5.1.2.3. Technically feasible FGD operational improvements include increasing the Ca:S stoichiometric ratio of the FGD by introducing additional fresh lime to the absorber modules. Based on engineering judgement, layering FGD operational improvements with DSI could reduce SO<sub>2</sub> emissions from the baseline SO<sub>2</sub> emission rate of 0.85 lb/MMBtu to approximately 0.33 lb/MMBtu at Coyote Unit 1 as shown in Table 5-6. However, as stated previously, flow modeling and field testing at Coyote Unit 1 would be needed to ensure that adequate residence time is available for SO<sub>2</sub> control and to confirm the incremental reduction in SO<sub>2</sub> emissions achievable without creating unacceptable operational issues.

**Table 5-6. Layered (DSI + Ca:S) SO<sub>2</sub> Control Technology Estimated Emissions**

	Unit 1
Uncontrolled SO <sub>2</sub> Emissions (lb/MMBtu)	3.12
SO <sub>2</sub> Emissions at DSI Outlet (lb/MMBtu)	2.03
SO <sub>2</sub> Emissions at FF Outlet (lb/MMBtu)	0.33 <sup>1</sup>
<b>Overall Removal (%)</b>	<b>89.4</b>

Note 1. Emissions at the FF outlet were estimate by applying 84% SO<sub>2</sub> removal across the DFGD system with operational improvements ((2.03 lb/MMBtu x (1 - 0.84 lb/MMBtu) = 0.33 lb/MMBtu).

Note 2. Emission rates shown represent average emission rates that the control options would be expected to achieve on an on-going long-term basis under normal operating conditions for Coyote Unit 1. Emission rates are provided for comparative purposes, and should not be construed to represent proposed permit limits. Corresponding permit limits must be evaluated on a control system-specific basis; however, an additional 10-15% margin would likely be needed to account for operating margin.

#### 5.1.2.5 Install New Dry FGD System

Replacing the existing dry scrubber and fabric filter with new control systems would require significant engineering and modifications to the facility. Based on a preliminary review of the facility layout, the new control systems could be located northeast of Coyote Unit 1's existing dry scrubber/FF. The new DFGD/FF and all auxiliary equipment could be constructed while the unit remains on-line. The control systems could be tied-in to the existing systems during a scheduled major outage.

Various DFGD systems have been designed for use with pulverized coal-fired boilers; including the spray dryer absorber (SDA) and circulating dry scrubber (CDS). Both systems are evaluated in more detail below.

##### Spray Dryer Absorber / Fabric Filter

SDA systems have been used in large coal-fired utility applications, and have demonstrated the ability to effectively reduce uncontrolled SO<sub>2</sub> emissions from pulverized coal units. Like other dry scrubbing systems, SDA control systems use a slurry of lime and water injected into the reaction modules to remove SO<sub>2</sub> from the combustion gases. The reaction modules are designed to provide adequate contact and residence time between the exhaust gas and the slurry to produce a dry by-product. Process equipment associated with an SDA control system includes an alkaline storage tank, mixing and feed tanks, atomizer assembly, spray chamber module, integrated fabric filter, and solids recycle system. The recycle system collects solid reaction byproducts and recycles them back to the spray dryer feed system to maximize reactant utilization.



Various process parameters affect the efficiency of the SDA process including: the type and quality of the additive used for the reactant, reactant-to-sulfur stoichiometric ratio, how close the SDA is operated to saturation conditions, and the amount of solids product recycled to the atomizer. SDA systems are typically designed to operate within approximately 30 °F adiabatic approach to saturation temperature. Operating closer to the adiabatic saturation temperature may allow for higher SO<sub>2</sub> control efficiencies; however, outlet temperatures too close to the saturation temperature will result in severe operating problems including reactant build-up in the absorber modules, blinding of the fabric filter bags, and corrosion in the fabric filter and ductwork.

SO<sub>2</sub> removal efficiencies in a SDA are also dependent upon good gas-to-liquid contact. Reactant spray nozzle designs are vendor-specific, and include both dual-fluid nozzles and rotary atomizers. The atomizing nozzle assembly is typically located in the SDA penthouse and flange mounted to the roof of the absorber vessel.

Replacing the existing dry scrubber/FF with a new SDA/FF control systems is a technically feasible and commercially available control option on Coyote Unit 1. SDA/FF control systems are generally installed on units that burn lower sulfur fuels (i.e., < 3 lb SO<sub>2</sub>/MMBtu) because design limitations, including Ca:S stoichiometry, residence time, and approach to saturation typically limit total SO<sub>2</sub> removal to approximately 95%. This removal efficiency represents what the control system vendor would be willing to guarantee upon initial operation of the system. On Coyote Unit 1, 95% removal would result in an average controlled SO<sub>2</sub> emission rate of approximately 0.16 lb/MMBtu.

#### *Circulating Dry Scrubber / Fabric Filter*

A second type of dry scrubbing system is the circulating dry scrubber (CDS). Similar to other dry flue gas desulfurization systems, the CDS system would be located after the air preheater, and byproducts from the system collected in an integrated fabric filter. Unlike the SDA systems, CDS systems use a circulating fluidized bed of hydrated lime reagent to remove SO<sub>2</sub> rather than an atomized lime slurry; however, similar chemical reaction kinetics are used in the SO<sub>2</sub> removal process.

In a CDS, flue gas is treated in an absorber vessel where the flue gas stream flows through a fluidized bed of hydrated lime and recycled byproduct. Water is injected into the absorber through a venturi located at the base of the absorber for temperature control. Flue gas velocity through the vessel is maintained to keep the fluidized bed of particles suspended in the absorber. Water sprayed into the absorber cools the flue gas from approximately 300 °F at the inlet to the scrubber to approximately 160 °F at the outlet of the fabric filter. The hydrated lime absorbs SO<sub>2</sub>

from the gas and forms calcium sulfite and calcium sulfate solids. Desulfurized flue gas passes out of the absorber, along with the particulate matter (reaction products, unreacted hydrated lime, calcium carbonate, and the fly ash) to the fabric filter.

As with the SDA/FF option, replacing the existing dry scrubber/FF with a new CDS/FF control system would require significant engineering and modifications to the existing facility. For this evaluation it was assumed that the CDS/FF control systems could be located adjacent to the existing dry scrubber/FF, and that the control systems could be tied-in to the existing system during a scheduled major outage.

Replacing the existing dry scrubber and FF with a new CDS/FF control system is a technically feasible and commercially available control option for Coyote Unit 1. Based on engineering judgment, it is anticipated that the retrofit CDS/FF control option would achieve SO<sub>2</sub> removal efficiencies higher than those achieved with a SDA/FF due to the increased Ca:S contact in the fluidized bed absorber vessel. Based on recent CDS retrofit projects, and taking into consideration expected fuel characteristics, it is anticipated that the retrofit CDS/FF control system could achieve SO<sub>2</sub> removal efficiencies of approximately 97%. This removal efficiency represents what the control system vendor would be willing to guarantee upon initial operation of the system. On Coyote Unit 1, 97% removal would result in an average controlled SO<sub>2</sub> emission rate of approximately 0.09 lb/MMBtu and represents an average emission rate that Coyote would be expected to achieve on an on-going long-term basis under normal operating conditions. The emission rate should not be construed to represent proposed permit limits. Corresponding permit limits must be evaluated on a control system-specific basis; however, an additional 10-15% margin would likely be needed to account for operating margin.

#### **5.1.2.6 Install New Wet FGD System**

Another option available to the Coyote Station would be to replace the existing dry scrubbing system with a new wet FGD control system located downstream of the existing FF.

Wet FGD technology is an established SO<sub>2</sub> control technology. Wet scrubbing systems have been designed to utilize various alkaline scrubbing solutions including lime, limestone, and magnesium-enhanced lime. Wet scrubbing systems have also been designed with spray tower reactors and with reaction vessels (e.g., jet bubbling reactor). Although the flue gas/reactant contact systems may vary, the chemistry involved in all wet scrubbing systems is essentially identical. All wet scrubbing systems use an alkaline slurry that reacts with SO<sub>2</sub> in the flue gas to form insoluble calcium sulfite (CaSO<sub>3</sub>) and calcium sulfate (CaSO<sub>4</sub>) salts.

A large majority of the wet FGD systems designed to remove SO<sub>2</sub> from existing high-sulfur utility boilers have been designed as wet limestone scrubbers with spray towers and forced oxidation systems. Therefore, for this evaluation, it was assumed that the WFGD control system would be designed as a limestone spray tower scrubber with forced oxidation. Other potentially available wet scrubber designs are not included in this evaluation because the chemistry involved in all wet scrubbing systems are essentially identical, alternative designs would not provide any additional SO<sub>2</sub> control, and control system costs would be similar.

### Wet Limestone Scrubbing

In a wet limestone scrubbing system, limestone (CaCO<sub>3</sub>) is mixed with water to formulate the alkali scrubber slurry. Flue gas enters the absorber vessel and contacts the absorbent slurry in a countercurrent spray tower. SO<sub>2</sub> in the flue gas reacts with the limestone slurry to form insoluble calcium sulfite (CaSO<sub>3</sub>) and calcium sulfate (CaSO<sub>4</sub>) which is removed as a solid waste by-product. Spent absorbent is returned to the reaction tank where dissolved sulfur compounds are precipitated as calcium salts. Fresh limestone slurry is added to regenerate the spent absorbent.

The reaction tank is sized to provide sufficient time for precipitation of the sulfur compounds. From the reaction tank, regenerated absorbent slurry is recycled to the absorber. The slurry typically contains from 5 to 15% suspended solids consisting of fresh additive, absorption reaction products, and lesser amounts of fly ash. To regulate the accumulation of solids, a bleed stream from the reaction is routed to the solid/liquid separation equipment.

Forced oxidation of the scrubber slurry may be used with limestone WFGD systems to produce calcium sulfate solids (gypsum) instead of the calcium sulfite by-product. Air blown into the reaction tank provides oxygen to convert most of the calcium sulfite (CaSO<sub>3</sub>) to a relatively pure gypsum. Forced oxidation of the scrubber slurry provides a more stable by-product and reduces the potential for scaling in the spray tower. The gypsum by-product from this process must be dewatered, and may be salable if a local market for gypsum is available, reducing the quantity of solid waste that needs to be landfilled.

For this evaluation it was assumed that the existing Coyote Unit 1 dry scrubber reactor vessels would remain in place, and that the WFGD control system would be located downstream of the existing FFs and ID fans, most likely northeast of the unit's existing dry scrubber/FF. Dry scrubber reactor vessel internals would ultimately be removed to reduce pressure drop through the system. A single WFGD absorber tower would be sufficient for the Coyote

Unit 1 flue gas flow. In addition to the absorber tower and reaction vessel, the WFGD control system would require a limestone handling and preparation system and by-product dewatering systems. Because of the saturated nature of the flue gas exiting the WFGD, a new stack with a liner capable of wet flue gas operation would be required. New booster ID fans would also be required to account for the additional pressure drop through the WFGD control system.

Wet FGD technology is an established SO<sub>2</sub> control technology. Wet scrubbing systems have been installed on units that fire medium to high sulfur coals, and would be a technically feasible SO<sub>2</sub> control option for Coyote Unit 1. Based on engineering judgment and information from control system vendors, it is anticipated that a retrofit WFGD control system on a North Dakota lignite-fired unit would be designed to achieve and SO<sub>2</sub> removal efficiency of approximately 98%. This removal efficiency represents what the control system vendor would be willing to guarantee upon initial operation of the system. On Coyote Unit 1, 98% removal would result in an average controlled SO<sub>2</sub> emission rate of approximately 0.06 lb/MMBtu and represents an average emission rate that Coyote would be expected to achieve on an on-going long-term basis under normal operating conditions. The emission rate should not be construed to represent proposed permit limits. Corresponding permit limits must be evaluated on a control system-specific basis; however, an additional 10-15% margin would likely be needed to account for operating margin.

### 5.1.2.7 Technical Feasibility Summary

Table 5-7 summarizes the results of the feasibility evaluation of available control options for Coyote Unit 1.

**Table 5-7. Technically Feasible SO<sub>2</sub> Control Options**

SO <sub>2</sub> Control Option	Technically Feasible (Yes/No)	Technical Feasibility Summary
Fuel Switching	No	Fuel switching is not considered an available SO <sub>2</sub> control option for Coyote Unit 1 since the use of North Dakota lignite coal is an inherent aspect of plant operations.
Existing DFGD Operational Improvements:		
Lime Quality	No	Changing lime quality in the existing DFGD control system is not a technically feasible operational change for Coyote Unit 1.
Ca:S Stoichiometric Ratio	Yes	Increasing the Ca:S stoichiometric ratio by increase the quantity of fresh lime to the system is considered a technically feasible option for Coyote Unit 1, assuming the operational change is coupled with atomizer replacement.

SO <sub>2</sub> Control Option	Technically Feasible (Yes/No)	Technical Feasibility Summary
Approach to Saturation Temperature	No	Due to design limitations, further reducing the absorber module outlet temperature on the existing DFGD control system is not a technically feasible option for Coyote Unit 1.
Existing DFGD Equipment Upgrades:		
Atomizer Replacement	Yes	Replacing the existing atomizers is a technically feasible option for Coyote Unit 1 and would provide additional SO <sub>2</sub> control if coupled with increasing the Ca:S stoichiometric ratio.
Slaker Replacement	No	Slaker replacement would not be expected to provide additional SO <sub>2</sub> control, and is not a technically feasible equipment upgrade for Coyote Unit 1.
Adding an Absorber Module	No	Coyote Unit 1 DFGD absorber modules are no longer commercially available, thus, adding an absorber module to the existing system is not a technically feasible SO <sub>2</sub> control option.
Replacing Existing Absorbers with New Absorber Modules	Yes	Replacing the exiting absorber modules with new absorber modules is a technically feasible SO <sub>2</sub> control system upgrade for Coyote Unit 1 that would require an approximate 12-month outage.
Existing DFGD + DSI	Yes	Hydrated lime sorbent injection upstream of the existing Coyote Unit 1 absorber modules is a technically feasible SO <sub>2</sub> control option. Flow modeling and field testing would be needed to confirm that the incremental reduction in SO <sub>2</sub> emissions is achievable without creating unacceptable operational issues.
Existing DFGD Operational Improvements (Increase Ca:S Stoichiometric Ratio) + DSI	Yes	Combining operational improvements (i.e., increased Ca:S stoichiometric ratio) with hydrated lime sorbent injection is a technically feasible SO <sub>2</sub> control option for Coyote Unit 1. Flow modeling and field testing would be needed to confirm that the incremental reduction in SO <sub>2</sub> emissions is achievable without creating unacceptable operational issues.
New Retrofit DFGD (CDS/FF)	Yes	Replacing the existing DFGD control system with a new retrofit DFGD (i.e., CDS/FF) is a technically feasible SO <sub>2</sub> control option for Coyote Unit 1.
New Retrofit WFGD	Yes	Replacing the existing DFGD control system with a new retrofit WFGD is a technically feasible SO <sub>2</sub> control option for Coyote Unit 1.

### 5.1.3 Evaluate Technically Feasible SO<sub>2</sub> Control Options for Effectiveness

The technically feasible SO<sub>2</sub> control technologies are listed in Table 5-8 in descending order of control efficiency. Table 5-8 also provides control option-specific SO<sub>2</sub> emission rates in terms of lb/MMBtu. Emission rates shown in

Table 5-8 represent average emission rates that the control options would be expected to achieve during normal operations.

**Table 5-8. Evaluate Technically Feasible SO<sub>2</sub> Control Options for Effectiveness**

Control Option	SO <sub>2</sub> Emission Rate (Note 1) lb/MMBtu	% Reduction from Baseline Emission Rate
Baseline (existing DFGD/FF)	0.85	-
New Retrofit WFGD	0.06	92.9%
New Retrofit DFGD (CDS/FF)	0.09	89.4%
New Retrofit DFGD (SDA/FF)	0.16	81.1%
FGD Upgrades - Replacing Existing Absorbers with New Absorber	0.29	65.9%
DSI + FGD Operational Improvements	0.33	61.2%
FGD Operational Improvements – Increase Ca:S Stoichiometric Ratio	0.50	41.2%
DSI + Existing FGD	0.58	31.8%

Note 1. Emission rates shown in Table 5-8 represent average emission rates that the control options would be expected to achieve on an on-going long-term basis under normal operating conditions for Coyote Unit 1. Emission rates are provided for comparative purposes, and should not be construed to represent proposed permit limits. Corresponding permit limits must be evaluated on a control system-specific basis; however, an additional 10-15% margin would likely be needed to account for operating margin.

## 5.2 NO<sub>x</sub> EMISSIONS CONTROLS

### 5.2.1 Identify Available NO<sub>x</sub> Control Options

Based on a review of available NO<sub>x</sub> control technologies installed on existing cyclone coal-fired boilers, as well as operational practices and equipment upgrades implemented on existing control systems, potentially available options to control NO<sub>x</sub> emissions from Coyote Unit 1 are listed in Table 5-9.

**Table 5-9. Available NO<sub>x</sub> Control Options**

NO <sub>x</sub> Control Technologies
Combustion Optimization
Selective Non-Catalytic Reduction (SNCR)
Rich Reagent Injection (RRI)
SNCR + RRI
Gas Reburn
Innovative Technologies (i.e. NOxStar, Water Injection, LoTOX, PerNOxide, Water Injection)
Selective Catalytic Reduction - High Dust, Low Dust or Tail End Configuration (TE-SCR)

## 5.2.2 Technical Feasibility of Available NO<sub>x</sub> Control Options

Potentially available NO<sub>x</sub> control options identified in Table 5-9 were evaluated for technical feasibility (i.e. availability and applicability to Coyote Unit 1) based on a review of physical, chemical, and engineering principals, and an assessment of commercial availability. Options deemed to be technically infeasible, or options that have no practical application to Coyote Unit 1, were eliminated from further review. S&L evaluated the effectiveness of the control options determined to be technically feasible, and established an emission performance level (i.e., controlled emission rate) for each.

### 5.2.2.1 Combustion Optimization

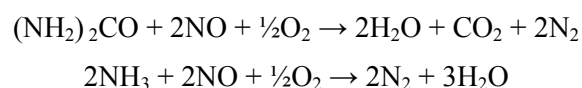
Coyote Unit 1 is equipped with twelve (12) ten (10) foot cyclones, six (6) on the front wall and six (6) each on the rear wall, two levels of three on each wall. The lignite coal requires a pre-dry system, which conveys the coal through individual crushers and into a cyclone separator for moisture separation. The dried coal is discharged from the bottom of the separator through a rotary seal, while the transport air (with a small quantity of fines) is discharged out the top and into ports above the cyclones. The coal discharged through the bottom rotary seal is blown into the cyclone through a pipe referred to as the “lift line” or known as primary air on most other similar installations. The temperature of the pre-dry air/coal temperature is regulated along with the lift line air by injecting cold (tempering) air into the hot primary air stream to regulate the outlet temperatures.

In 2016, The Babcock and Wilcox Company (B&W) installed fourteen (14) separated overfire air (SOFA) ports (seven on the front and rear wall) and modified the cyclones with smaller re-entrant throats and a  $\frac{1}{3} - \frac{2}{3}$  split secondary air damper (each having its own damper) to reduce NO<sub>x</sub> emissions. For the SOFA process, the injection of air into the boiler is staged into two zones, in which approximately 5% to 20% of the total combustion air is diverted from the burners and injected through ports located above the top burner level. Staging of the combustion air reduces NO<sub>x</sub> formation by two mechanisms. First, staged combustion results in a cooler flame which will reduce the formation of thermal NO<sub>x</sub>. Second the staged combustion results in less oxygen reacting with fuel molecules. The degree of staging is limited by operational problems since the staged combustion results in incomplete combustion conditions and a longer flame profile. The units normally operate with the  $\frac{1}{3}$ <sup>rd</sup> damper closed or nearly closed to help recirculate the coal in the cyclone and allows for increased coal retention and improved combustion. Since the SOFA installation, Coyote Unit 1 has achieved average controlled NO<sub>x</sub> emissions of approximately 0.46 lb/MMBtu.

Tuning of the cyclone boiler to optimize the combustion process and minimize the generation of NO<sub>x</sub> was recently completed at Coyote Unit 1. Tuning was completed by lowering the stoichiometry (i.e., lower the air-to-fuel ratio) in the cyclone barrel and tracking the cyclone combustion stability, while staying within the OEM specifications for best combustion engineering practice. Based on the testing results, Coyote Unit 1 was able to achieve average NO<sub>x</sub> emissions of approximately 0.42 lb/MMBtu without obvious impacts to boiler performance and with minimal slagging. Based on the results of the combustion turning tests, combustion optimization is considered a technically feasible NO<sub>x</sub> control option.

#### 5.2.2.2 Selective Non-Catalytic Reduction

Selective non-catalytic reduction (SNCR) involves the direct injection of ammonia (NH<sub>3</sub>) or urea (CO(NH<sub>2</sub>)<sub>2</sub>) at high flue gas temperatures (approximately 1,600°F – 2,100°F) in an oxidizing environment. The ammonia or urea reacts with NO<sub>x</sub> in the flue gas to produce N<sub>2</sub> and water as shown below.



Flue gas temperature at the point of reagent injection can greatly affect NO<sub>x</sub> removal efficiencies and the quantity of NH<sub>3</sub> or urea that will pass through the SNCR unreacted (referred to as NH<sub>3</sub> slip). In general, SNCR reactions are effective in the range of 1,600°F – 2,100°F. At temperatures below the desired operating range, the NO<sub>x</sub> reduction



reactions diminish and unreacted  $\text{NH}_3$  emissions increase. Above the desired temperature range,  $\text{NH}_3$  is oxidized to  $\text{NO}_x$  resulting in low  $\text{NO}_x$  reduction efficiencies.

Mixing of the reactant and flue gas within the reaction zone is an important factor to SNCR performance. In large boilers, the physical distance over which reagent must be dispersed increases, and the surface area/volume ratio of the convective pass decreases. Furnace geometry, urea spray coverage, and droplet size must be considered when developing good mixing of reagent and flue gas, delivery of reagent in the proper temperature window, and sufficient residence time of the reagent and flue gas in that temperature window. As the boiler cycles in load, the optimum injection region may change; thus, most facilities require multiple injection zones which are placed in and out of service as the unit ramps in load. This can include modifying the zones of injectors that are operating at different loads and temperatures.

Retractable multinozzle lances (MNLs) are sometimes used to improve SNCR performance, especially if the furnace exit flue gas temperatures are too high. The retractable lances allow injection into the appropriate temperature zone more so than wall injectors, depending on the unit load and temperatures. The MNLs also help improve performance by refining the spray pattern for quicker vaporization of the conveying water. MNLs are often used in conjunction with wall injection to provide optimized coverage while reducing reagent cost.

In addition to temperature and mixing, several other factors influence the performance of an SNCR system, including residence time, reagent-to- $\text{NO}_x$  ratio, and fuel sulfur content. Increasing the normalized stoichiometric ratio (NSR) can improve  $\text{NO}_x$  removal.<sup>25</sup> This can be achieved by increasing urea solution flow through the injectors or changing the concentration of urea in the solution. However, too high of reagent injection rates will increase the ammonia slip beyond the recommended 10 ppmvd limit. Above this concentration, there are expected to be major impacts to the formation of ammonia salts on the boiler tube banks, reducing heat transfer efficiency, and air heater baskets, causing corrosion.

SNCR can be applied on cyclone boilers due to having reasonable temperature windows and residence time; however, the potential  $\text{NO}_x$  reduction is boiler-specific. SNCR has been used as a retrofit  $\text{NO}_x$  control system of on pulverized coal, fluidized bed boilers, and cyclone boilers. Furthermore, SNCR can be implemented on boilers

---

<sup>25</sup> NSR defines the amount of reagent needed to achieve the targeted  $\text{NO}_x$  reduction. Based on the reaction equations in 5.2.2.2, two moles of  $\text{NO}_x$  can be removed with one mole of urea or two moles of ammonia. In practice, more than the theoretical amount of reagent needs to be injected into the boiler flue gas to obtain a specific level of  $\text{NO}_x$  reduction. This is due to the complexity of the actual chemical reactions involving  $\text{NO}_x$  and injected reagent and mixing limitations between reagent and flue gas. Factors that influence the NSR value: (1) percent  $\text{NO}_x$  reduction; (2) uncontrolled  $\text{NO}_x$  concentration in the flue gas; (3) temperature and residence time available for the  $\text{NO}_x$  reduction reactions; (4) extent of mixing achievable in the boiler; and (5) allowable ammonia slip.

equipped with low-NO<sub>x</sub> burners, overfire air, or SOFA systems. Based on the boiler residence time, temperature profile, and stoichiometry, as well as input from SNCR OEMs, it is estimated that an SNCR system could achieve an average controlled NO<sub>x</sub> emission rate of approximately 0.28 lb/MMBtu (approximately 39% below the baseline emission rate of 0.46 lb/MMBtu) at full load while limiting ammonia slip to 10 ppmvd. It should be noted that computational fluid dynamic modeling and temperature mapping of the boiler would be needed to confirm that the incremental reduction in NO<sub>x</sub> emission is achievable without creating unacceptable operational issues.

### 5.2.2.3 Rich Reagent Injection

Similar to SNCR, the concept of rich reagent injection (RRI) is to use a nitrogen-containing additive (e.g., urea) injected into a reducing environment to promote NO<sub>x</sub> removal. RRI is a commercial technology for cyclone boilers only. In contrast to SNCR, RRI typically is applied with only one injection level in the lower furnace near the cyclone barrels (temperature window of 2000°F-2600°F). The technology requires a sub-stoichiometric oxygen concentration near the barrels at less than approximately 0.95. This allows for a higher injection rate of reagent without oxidizing the nitrogen-containing reagent to NO<sub>x</sub> due to the sub-stoichiometry. Injection at this location also creates lower level of excess NH<sub>3</sub> emissions (NH<sub>3</sub> slip), while injecting at an NSR of 2.0-3.0.

Due to the changes of the lower furnace stoichiometry, RRI is often not a technically feasible option at low loads. Once the stoichiometric ratio increases to >1.0, the potential exists for NO<sub>x</sub> generation due to the reaction of NH<sub>3</sub> with oxygen, especially if the injection location and rate is not optimized. Based on these limitations, RRI is considered most effective at full load.

The RRI process is a commercially available process. Based on engineering judgment, RRI is expected to reduce NO<sub>x</sub> emissions by approximately 20-40% at Coyote Unit 1 when operating at full load with minimal ammonia slip. However, due to the cyclone combustion temperature window, this technology only provides effective NO<sub>x</sub> reduction at or near full load. At low loads, RRI does not provide effective control; however, RRI can be combined with SNCR to provide NO<sub>x</sub> control across the full range of normal operating loads. RRI is a technically feasible NO<sub>x</sub> reduction option for North Dakota lignite-fired cyclone boilers. However, due to its limited operating conditions and ineffective NO<sub>x</sub> reduction at low loads, RRI alone is not considered an available NO<sub>x</sub> control option, and will only be evaluated in conjunction with SNCR.

#### 5.2.2.4 SNCR + RRI

While RRI alone will provide beneficial NO<sub>x</sub> reduction at full load only, coupling RRI with SNCR can provide a balanced approach to NO<sub>x</sub> reduction through all load ranges. Since RRI and SNCR injectors are located at different elevations of the furnace and in different temperature windows, there are not concerns of spatial impacts. The combined system would utilize a relatively high urea injection rate, staged at multiple locations throughout the boiler. The main advantage of this combined system is that the SNCR can provide better NO<sub>x</sub> reduction at low load and at a lower NSR than RRI alone; thus, the combined system is expected to provide effective NO<sub>x</sub> control across all normal operating load ranges. Coupling RRI and SNCR is considered a technically feasible and commercially available NO<sub>x</sub> control technology option on Coyote Unit 1. Based on input from SNCR OEMs and engineering judgment, the control option is expected to achieve an average outlet NO<sub>x</sub> rate of approximately 0.20 lb/MMBtu with an ammonia slip of 10 ppmvd. It should be noted that computational fluid dynamic modeling and temperature mapping of the boiler would be needed to confirm that the incremental reduction in NO<sub>x</sub> emission is achievable without creating unacceptable operational issues.

#### 5.2.2.5 Gas Reburn

Gas reburn is a retrofit technique that has been used to control NO<sub>x</sub> emissions from coal- and oil-fired boilers. Gas reburn involves combustion in three distinct zones within the boiler: (1) a primary combustion zone, where the primary fuel is fired using conventional burners; (2) a reburn zone, where secondary fuel, typically natural gas, is introduced into the boiler; and (3) an OFA burnout zone.

In the primary zone of coal-fired boilers, coal is fired through low-NO<sub>x</sub> burners (LNBs), at a rate corresponding to approximately 80% to 90% of the total heat input. Natural gas reburn fuel is then injected above the primary combustion zone under fuel-rich conditions at a rate corresponding to approximately 10% to 20% of the total heat input (on a Btu/hour basis). The fuel-rich reburn zone creates a reducing (substoichiometric) region within the boiler where the natural gas, principally methane (CH<sub>4</sub>), breaks down to produce hydrocarbon radicals (CH and CH<sub>2</sub>). The hydrocarbon radicals react with NO<sub>x</sub> produced in the primary combustion zone to form nitrogen (N<sub>2</sub>) and water vapor. Because the natural gas is not completely combusted in the reburn zone, gases exiting the reburn zone will contain considerable CO and unburned hydrocarbons; therefore, additional OFA is introduced above the reburn zone to complete the combustion process.

Critical design parameters that affect the feasibility and performance of a gas reburn retrofit system include: (1) baseline NO<sub>x</sub> concentration; (2) reburn zone temperature, residence time, and stoichiometry; (3) OFA burnout zone temperature and residence time; and (4) mixing of the reburn fuel and overfire air with the bulk flue gas.

Gas reburn can have a positive impact on NO<sub>x</sub> emissions; however, in order to make a meaningful prediction of the NO<sub>x</sub> removal capabilities at Coyote Unit 1, extensive testing would be required because gas reburn performance is significantly dependent upon boiler operating characteristics. More importantly, the lack of natural gas available at the Coyote Station precludes the ability to test and implement this control option on Coyote Unit 1. For these reasons, gas reburn is not considered an available or technically feasible NO<sub>x</sub> control technology at Coyote Unit 1.

#### 5.2.2.6 Innovative Technologies

##### NO<sub>x</sub>Star<sup>TM</sup>

The NO<sub>x</sub>Star<sup>TM</sup> process, also known as selective autocatalytic reduction (SACR), uses a continuous controlled amount of ammonia-based reagent with relatively small amounts of hydrocarbon to reduce NO<sub>x</sub> emissions. The hydrocarbon is introduced into the flue gas at the convective pass of the boiler, at elevated temperatures. At the elevated temperatures, the hydrocarbon auto-ignites to form a plasma of free radicals that auto catalyzes the reaction of NH<sub>3</sub> and NO<sub>x</sub> to form N<sub>2</sub> and H<sub>2</sub>O. The hydrocarbon and ammonia are added through banks of nozzles in the superheat or reheat sections of the boiler. The injection location is determined by the location of the temperature windows for the "plasma creation zone" as well as the reaction zone for the ammonia.

To date, only one full-scale demonstration has been conducted to evaluate the technology on a utility-sized boiler. The process is an emerging NO<sub>x</sub> control, and there is limited information available to evaluate its technical feasibility and long-term effectiveness on a large lignite-fired boiler. Potential NO<sub>x</sub> removal efficiencies would be a function of NH<sub>3</sub>-NO<sub>x</sub> mixing, flue gas temperature, flue gas composition, and residence time downstream of the injection lances.

Because this is an emerging technology, extensive design engineering and long-term full scale demonstration testing would be required to evaluate the technical feasibility and effectiveness of the control system on Coyote Unit 1. Detailed design of the lances, mixing, optimization of the reagent supply across the boiler convective pass, flue gas temperatures, and flow distribution would have to be studied. Interference with the tube pendants in the convective pass may also make this more difficult to install. Installing a hydrocarbon distribution grid may

present a problem with large boilers because of the span needed to uniformly distribute the reagent, interference with the tube pendants in the convective pass, and an additional booster fan may be needed. For these reasons, NO<sub>x</sub>Star™ is not considered an available or technically feasible NO<sub>x</sub> control technology at Coyote Unit 1.

### PerNO<sub>x</sub>ide

PerNO<sub>x</sub>ide utilizes hydrogen peroxide (H<sub>2</sub>O<sub>2</sub>) to reduce NO<sub>x</sub> emissions. Hydrogen peroxide is injected into the ducts ahead of the air preheater and oxidizes the NO to NO<sub>2</sub>, which is then captured in a downstream FGD system. To date, the technology has only been tested on a pilot-scale, and it has not been demonstrated on any coal-fired boilers. It is likely that extensive design engineering and testing would be required to evaluate the scale-up potential and long-term effectiveness of the system on Coyote Unit 1. For these reasons, PerNO<sub>x</sub>ide is not considered an available or technically feasible NO<sub>x</sub> control technology at Coyote Unit 1.

### LoTO<sub>x</sub>®

The LoTO<sub>x</sub> system is a gas-phase, low-temperature oxidation system, wherein ozone is injected into the flue gas stream to oxidize NO and NO<sub>2</sub> to N<sub>2</sub>O<sub>5</sub> before being removed in a wet scrubber. This highly oxidized species of NO<sub>x</sub> is water-soluble and rapidly reacts with water to form nitric acid. The conversion of NO<sub>x</sub> to nitric acid occurs as the N<sub>2</sub>O<sub>5</sub> contacts liquid sprays in the scrubber. The nitric acid would react with the alkali compounds in the scrubber and would be eliminated via the scrubber waste and byproduct streams. The LoTO<sub>x</sub> system requires on-demand ozone generation from a liquid oxygen supply.

The LoTO<sub>x</sub> system has been successfully applied in refinery applications; however, there are no full scale installations on coal-fired boilers. According to the control system vendor, a demonstration test was performed on a 25-MW coal-fired boiler which showed effective NO<sub>x</sub> removal. However, it is likely that extensive design engineering and testing would be required to evaluate the scale-up potential and long-term effectiveness of the system on Coyote Unit 1. As such, LoTO<sub>x</sub> is not considered an available or technically feasible NO<sub>x</sub> control technology at Coyote Unit 1.

### Water Injection

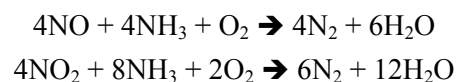
The principle behind this technology is to inject an atomized water spray into the high-NO<sub>x</sub> production zones of a cyclone burner or in the core of the flame for other furnaces. The water spray reduces the temperature and results in lower thermal NO<sub>x</sub> production within this combustion zone. Developers claim that water injection through

burners used in tangential-fired and wall-fired units will also reduce flame temperatures and lower thermal NO<sub>x</sub> production. However, to date only bench-scale test results are available to evaluate this technology's effectiveness in coal-fired applications. Extensive design engineering, pilot-scale testing, and long-term full scale demonstration testing would be required to evaluate the technical feasibility and effectiveness of the control system on Coyote Unit 1.

Water injection has been used to control the formation of thermal NO<sub>x</sub> in combustion turbine applications. However, there is insufficient experience and demonstration data in coal-fired applications. As such, water injection is not considered an available or technically feasible NO<sub>x</sub> control technology at Coyote Unit 1.

#### 5.2.2.7 Selective Catalytic Reduction

SCR is a process by which ammonia reacts with nitric oxide (NO) and nitrogen dioxide (NO<sub>2</sub>), collectively NO<sub>x</sub>, in the presence of a catalyst to reduce the NO<sub>x</sub> to nitrogen (N<sub>2</sub>) and water. SCR technology has been applied to NO<sub>x</sub>-bearing flue gases generated from power generating facilities burning various types of coal, including bituminous, subbituminous, and Texas lignite. The principal reactions resulting in NO<sub>x</sub> reduction are:



Because these reactions proceed slowly at typical boiler exit gas temperatures of a coal-fired steam electric generating unit, a catalyst is used to increase the reaction rate between NO<sub>x</sub> and ammonia. Depending on the specific constituents in the flue gas, a typical temperature range of 550°F to 780°F is necessary to achieve normal performance of the catalyst. For the typical coal-fired boiler, optimal performance will be in the range of approximately 650°F to 750°F.

In general, there are three candidate SCR configurations that can be employed on coal-fired steam electric generating units. The SCR configuration designations generally describe the location of the SCR reaction vessel in relation to other post-combustion air quality control systems. Candidate SCR configurations include:

- High-dust configuration
- Low-dust configuration
- Tail-end configuration

Each of these configurations is described below as they would be applied at Coyote Unit 1.

### High-Dust Configuration

In a high-dust configuration, the SCR reactor is located in the flue gas stream between the economizer outlet and the air heater inlet. This configuration locates the SCR within the inherently optimal temperature range environment for NO<sub>x</sub> reduction (i.e., 650°F to 750°F); however, flue gas characteristics at the economizer outlet can also have detrimental effects on the SCR catalyst. As an example, the high-dust SCR configuration exposes the SCR catalyst to high levels of fly ash loading. High levels of fly ash can result in significant erosion of the catalyst, resulting in more frequent cleaning cycles and catalyst replacement. A second major concern with the high-dust configuration at Coyote Unit 1 is the presence of high levels of sodium (both in the vapor-phase and as submicron aerosols) in the North Dakota lignite-derived flue gas. Sodium is a known SCR catalyst poison, and also affects the adhesive and cohesive characteristics of the fly ash, which in turn, would have an adverse effect on the SCR catalyst and reactor vessel.

SCR catalyst deactivation occurs through two primary mechanisms: physical deactivation and chemical poisoning. Physical deactivation is caused by either exposure of the catalyst to excessive temperatures (thermal deactivation) or masking of the catalyst due to entrainment of particulate from the flue gas stream (fouling). Chemical deactivation is caused by either an irreversible reaction of the catalyst with a contaminant in the gas stream (poisoning) or a reversible absorption of a contaminant on the surface of the catalyst (inhibition). Loss of catalyst activity through thermal degradation or poisoning is permanent, and reactivity can only be restored by replacing the catalyst.

In a North Dakota lignite application, SCR catalyst poisoning is expected to result from the presence of trace elements and strong alkaline substances in flue gas, including sodium (Na), potassium (K), and calcium (Ca). Alkaline metals can chemically attach to active catalyst pore sites and cause deactivation. Sodium and potassium are of prime concern especially in their water-soluble forms, which are more mobile and can penetrate into the catalyst pores. Earth metals, especially calcium, can react with SO<sub>3</sub> absorbed within the catalyst to form CaSO<sub>4</sub> and blind the catalyst.

North Dakota lignite contains relatively high levels of organically associated alkali and alkaline-earth elements, including Na, Ca, K, and magnesium. Sodium levels in North Dakota lignite are typically 5 to 20 times higher than sodium levels in bituminous and subbituminous coals, and sodium compounds can represent between 5% and 11% of the ash generated from firing North Dakota lignite. These sodium levels, occurring in both the vapor phase and particulate phase, along with relatively high levels of potassium and calcium, significantly increase the potential for



catalyst deactivation, plugging, and erosion. Based on the ash chemistry, a conventional high dust SCR arrangement would likely experience unacceptable catalyst deactivation rates.

To evaluate deactivation rates on a North Dakota lignite-fired boiler, EERC and several utilities and catalyst vendors conducted pilot scale testing at the Coyote Station in 2003-2004. The pilot scale test reactor SCR deployed at the Coyote Station became plugged and the catalyst pores deactivated after 2 months of operation (approximately 1,430 hours). This deactivation rate is significantly faster than the deactivation rate observed on bituminous and subbituminous coal-fired units, which can achieve catalyst life ranging between 10,000 and 30,000 operating hours. The EERC described the deactivation at the Coyote Station as extremely rapid and severe.<sup>26</sup>

NDDH prepared a comprehensive technical feasibility assessment of high dust SCR on lignite-fired boilers during the first planning period.<sup>27</sup> The Department concluded, based on the unique characteristics of North Dakota lignite-derived flue gas, that the high-dust SCR configuration was not a technically feasible or commercially available NOx control option for North Dakota lignite-fired boilers.<sup>28</sup> Reasons upon which NDDH based its conclusion that high-dust SCR was not a technically feasible option for North Dakota lignite-fired boilers included, but were not limited to:<sup>29</sup>

- 1) North Dakota lignite<sup>30</sup> has a higher organic matter content and contains a higher proportion of alkali metal constituents, especially sodium, than subbituminous coal. Approximately 75% of the total sodium in lignite is associated with the organic fraction of the lignite. During combustion, organic and water-soluble sodium vaporizes; consequently, combustion of the coal leads to higher flue-gas concentrations of alkali metals in vapor form.
- 2) The unburned or partially burned organic fraction of North Dakota lignite contains more sodium than other coals. Sodium can react with silicate particles causing a “stickiness” quality to the flue gas ash, resulting in increased ash deposition on heat transfer surfaces. Larger particles can fracture from heat-transfer surfaces (a.k.a. popcorn ash) and enter the flue gas stream. Consequently, deposition on surfaces of catalytic reactors occurs and rates of deposition are higher.
- 3) NOx reduction occurs on the flat surfaces of a catalyst and in pores within the flat surfaces. The pores are open to the flue gas passing through the catalyst reactor. Condensed vapors, alkali sulfates and alkaline-earth oxides and silicates are minute particles (less than 1 microns), which enter pores of the catalyst (a.k.a. plugging) and prevent catalytic reaction with NOx. Residual alkali vapors (Na, K, and Ca) displace hydrogen on fresh catalyst, which prevents catalytic reaction with NOx (a.k.a poisoning) and reacts with

<sup>26</sup> See, Benson, Steven A., Energy and Environmental Research Center, Ash Impacts on SCR Catalyst Performance, University of North Dakota, Grand Forks, ND.

<sup>27</sup> See, North Dakota State Implementation Plan for Regional Haze, February 24, 2010, Appendix B.5, Best Available Retrofit Technology – Selective Catalytic Reduction Technical Feasibility Analysis for North Dakota Lignite, July 2009.

<sup>28</sup> Id. at pg. 19.

<sup>29</sup> Findings and conclusions are summarized from the North Dakota Regional Haze SIP, Appendix B.5, pgs. 15-19.

<sup>30</sup> Although the BART determination specifically references Fort Union lignite, the findings would apply to all North Dakota lignites.



sulfate to cause blinding of catalyst surfaces. Pore condensation of sodium also causes catalyst deactivation, which is a major deactivation mechanism. The rate of catalyst deactivation depends on the concentration and form of alkali in the flue gas; higher Na and K accelerate catalyst poisoning, blinding and plugging.

- 4) During the development of the initial planning period SIP, NDDH found that there were no SCR systems planned, constructed, or operating in the flue gas stream of boilers fired with North Dakota lignite. North Dakota lignite has certain coal characteristics that are uniquely different than Texas or Gulf Coast lignites, such as the larger proportion of organic matter and association of alkali, sodium specifically, with that organic matter.
- 5) Slipstream SCR reactors of the same design were installed at three power plants to test SCR for NO<sub>x</sub> emissions control. One of the plants was cyclone fired with North Dakota lignite and the others with subbituminous coal. Deposition on the reactor surface after two months using the lignite was significantly greater; the deposits were rich in sodium, calcium, and sulfur. The tests confirmed catalyst blinding and plugging, but did not provide rates for catalyst deactivation. Tests also indicated that the deposits causing blinding and plugging of pores contained more sodium compared to PRB coal.

Based on a review of SCR installations on coal-fired boilers and a review of reported advances in SCR catalysts since the first planning period, deactivation rates due to soluble alkali compounds in the flue gas (including soluble sodium and potassium compounds) and the adhesive/cohesive characteristics and potential abrasive qualities of the North Dakota lignite-derived fly ash remain a concern for North Dakota lignite-fired boilers. SCR has not been installed and successfully operated on a North Dakota lignite-fired boiler, and the bench scale and pilot-scale studies needed to better understand ash behavior and catalyst blinding/erosion with North Dakota lignite-derived fly ash, and to better understand catalyst deactivation mechanisms associated with high soluble alkali compound concentrations in the flue gas have not been required or completed. Pilot-scale studies are needed to evaluate these issues to inform the development of advanced catalyst formulations, and to support the engineering and design studies needed to mitigate for potential deactivation routes (e.g., removing soluble alkali compounds from the flue gas and SCR design considerations such as catalyst formulation, catalyst pitch, reactor velocity, and catalyst surface and volume). Pilot-scale tests and engineering/design studies have not advanced since the first planning period's exhaustive analysis.

These issues have not been resolved since the first planning period and remain a significant barrier to the design and successful operation of high dust SCR on North Dakota lignite-fired boilers. The BART Guidelines state that “[a] control technique is considered available...if it has reached the stage of licensing and commercial availability.”<sup>31</sup> Commercial availability follows bench scale and laboratory testing and pilot scale testing. Consequently, the BART Guidelines state that “you would not consider technologies in the pilot scale testing stages

---

<sup>31</sup> 40 CFR Part 51 Appendix Y, Section D.2.1.

of development as ‘available’ for purposes of BART review.”<sup>32</sup> Furthermore, source owners/operators are not expected to conduct extended trials to learn how to apply a technique on a dissimilar source type.<sup>33</sup> These BART guidelines also apply as a recommendation for the development of the LTS in the second planning period and the four factor analysis.<sup>34</sup> Because there are unresolved issues associated with catalyst poisoning, catalyst blinding and plugging, and catalyst erosion; and engineering solutions have not been determined or demonstrated and the high dust configuration has not moved beyond pilot scale testing, high dust SCR is not an available technically feasible NOx control technology for Coyote Unit 1.

#### Low-Dust Configuration

In the low-dust configuration, the SCR reactor vessel is located in the flue gas stream after the particulate collection device (i.e. ESP or FF). Employing this configuration would represent a relatively low level of exposure to fly ash (with the exception of submicron ash particles), but a potentially high level of vapor-phase alkalis, such as sodium. This configuration can be used on units equipped with particulate control only or units equipped with particulate control followed by a WFGD control system. The existing dry FGD/FF control configuration at Coyote Unit 1 for SO<sub>2</sub> and particulate control would preclude the application of a low-dust SCR configuration since, by definition, the SCR would have to be located downstream of both the dry FGD and FF. At that location the SCR would be more appropriately defined as a tail-end SCR configuration, which is described in more detail in the following section. Because Coyote Unit 1 is equipped with existing dry FGD/FF controls, low-dust SCR has no practical application on the unit, and low-dust SCR is not considered a technically feasible NOx control option for Coyote Unit 1.

#### Tail-End Configuration

In the tail-end configuration, the SCR reaction vessel is located in the flue gas stream after the particulate and FGD control systems. The potential advantage of a tail-end SCR configuration at Coyote Unit 1 is that the flue gas will have passed through the dry FGD/FF system prior to the SCR catalyst. As such, there is the possibility that the mass transfer mechanism that results in the capture of SO<sub>2</sub> will also capture some of the vapor-phase sodium and the sodium-enriched submicron particles, reducing the risk of catalyst poisoning and/or deactivation.

---

<sup>32</sup> Id.

<sup>33</sup> Id.

<sup>34</sup> See, Draft EPA Guidelines, pg. 183.

Successful operation of the tail-end configuration would also require a capital and operating cost-intensive gas-to-gas heat exchanger to reheat the flue gas from approximately 200 °F downstream of the existing FF to approximately 550°F to support the SCR NO<sub>x</sub> reactions. After the flue gas passes through the SCR (at approximately 550°F), it would pass through the hot side of the gas-to-gas heat exchanger to cool the flue gas to 150°F prior to the exhaust stack. Although this stack gas temperature would be lower than the current stack temperature (190-210°F), it is still higher than the adiabatic saturation temperature of the flue gas (i.e., approximately 135°F). As such, it is likely that the existing stack could be reused without any major modifications.

During the first planning period, NDDH initially concluded, based on preliminary information provided by SCR catalyst vendors, that the tail-end SCR configuration would be a technically feasible option for units firing North Dakota lignite that are subject to BART requirements.<sup>35</sup> However, as part of the Milton R. Young Station (MRYS) NO<sub>x</sub> BACT determination process, detailed information describing the expected ash characteristics and flue gas characteristics was provided to two SCR catalyst vendors (CERAM Environmental, Inc. (CERAM) and Haldor Topsoe, Inc.). Based on their review of the data, both vendors concluded that they would not be able to provide a catalyst life guarantee for either low-dust or tail-end SCR without pilot-scale testing.<sup>36</sup>

Both vendors also made statements bringing into question the technical feasibility of either low-dust or tail-end SCR. For example, CERAM stated that the high levels of sodium oxide (Na<sub>2</sub>O) in the ash for North Dakota lignite are not commonly found in subbituminous and bituminous coals which are fired in boilers equipped with SCR systems, and that it was unaware of any SCR application experience in the industry with the level and form of sodium in the North Dakota lignite-derived MRYS ash.<sup>37</sup>

Based in part on this information provided by SCR design engineering firms and SCR catalyst vendors, NDDH concluded that the use of SCR technology, including low-dust and tail-end SCR, on the lignite-fired MRYS boilers would be technically infeasible.<sup>38</sup>

Based on a review of SCR installations on coal-fired boilers, and a review of reported advances in SCR catalysts since the first planning period, deactivation rates due to soluble alkali compounds in the flue gas (including soluble sodium and potassium compounds) remain a concern for all North Dakota lignite-fired boilers. Tail-end SCR has not been demonstrated or installed on a North Dakota lignite-fired boiler, and there are still significant technical

<sup>35</sup> See, North Dakota Regional Haze State Implementation Plan for Regional Haze, February 24, 2010, Appendix B.5, pg. 25.

<sup>36</sup> See, *United States v. Minnkota*, 831 F. Supp. 2d, at 1116- 1117.

<sup>37</sup> *Id.*, at 1115-1116.

<sup>38</sup> *Id.*, at 1118.

concerns associated with the availability of existing SCR catalysts on a North Dakota lignite-fired unit. Catalyst in a tail-end SCR will still be vulnerable to alkali poisoning, pore pluggage, and premature catalyst deactivation, and it is not known whether the comparatively high levels of soluble sodium and potassium in North Dakota lignite will be effectively removed by the upstream dry FGD/FF. Furthermore, the potential exists for fine particulate remaining in the flue gas to get into the catalyst pores reducing catalyst activity. Pilot-scale studies needed to better understand catalyst deactivation mechanisms associated with high soluble alkali compound concentrations in the flue gas have not been completed.

In order to understand the effect of North Dakota lignite-derived flue gas on the tail-end SCR catalyst, identify potential design solutions, and evaluate the technical feasibility and effectiveness of tail-end SCR at Coyote Unit 1 with any degree of certainty, extended pilot scale testing of the control configuration would be needed. Additionally, because there are unresolved issues associated with catalyst poisoning, it's unlikely that OTP could obtain a viable commercial offering for tail-end SCR on Coyote Unit 1. Therefore, tail-end SCR is not an available technically feasible NO<sub>x</sub> control technology.

### SCR Summary

During the first planning period NDDH determined that high-dust SCR and tail-end SCR are not available, and thus, not a technically feasible NO<sub>x</sub> control option for North Dakota lignite-fired boilers. The administrative record developed during the first planning period, including the BART determinations and MRYS BACT analysis, supports the conclusion that high-dust SCR and tail-end SCR are not an available NO<sub>x</sub> control option for Coyote Unit 1. An evaluation of SCR installations and reported advances in SCR catalysts since the first planning period, coupled with the fact that high-dust SCR and tail-end SCR have not been demonstrated on a North Dakota lignite-fired boiler, and the likelihood that OTP could not obtain a viable commercial offering for tail-end SCR without extended pilot-scale testing, continues to support the conclusion that high-dust SCR and tail-end SCR are not available NO<sub>x</sub> control technologies. Nevertheless, since tail-end SCR cost data was developed by the NDDH for Coyote Unit 1 in the first planning period<sup>39</sup>, even though tail-end SCR is a technically infeasible technology, it will be carried forward to the Four Factor Analysis to evaluate hypothetical cost-effectiveness. Based on controlled NO<sub>x</sub> emissions achieved in practice at existing bituminous- and subbituminous-fired unit, S&L assumed that the

---

<sup>39</sup> See North Dakota State Implementation Plan for Regional Haze, February 24, 2010, Table 9.8. Notably, this cost data was developed prior to the final MRYS BACT determination in which the NDDH concluded tail-end SCR was technically infeasible.

hypothetical tail-end SCR control option could achieve an average controlled NO<sub>x</sub> emission rate of 0.09 lb/MMBtu.

### 5.2.2.8 Technical Feasibility Summary

Table 5-10 summarizes the results of the feasibility evaluation of available control options for Coyote Unit 1.

**Table 5-10. Technically Feasible NO<sub>x</sub> Control Options**

NO <sub>x</sub> Control Option	Technically Feasible (Yes/No)	Technical Feasibility Summary
Combustion Optimization	Yes	Tuning to optimize the existing combustion system, including lower the stoichiometry in the cyclone barrels, tracking cyclone combustion stability, and adjusting the SOFA system (while staying within original OEM specifications) is a technically feasible NO <sub>x</sub> control option.
Selective Non-Catalytic Reduction (SNCR)	Yes	SNCR is considered an available and technically feasible NO <sub>x</sub> control technology for Coyote Unit 1. Computational fluid dynamic modeling and temperature mapping of the boiler would be needed to confirm that the incremental reduction in NO <sub>x</sub> emissions is achievable without creating unacceptable operational issues.
Rich Reagent Injection (RRI)	No	RRI is considered an available and technically feasible NO <sub>x</sub> control option cyclone burners at full load operation; however, at low load operation RRI does not provide effective NO <sub>x</sub> control. Therefore, RRI alone is not considered an available NO <sub>x</sub> control option, and will only be evaluated in conjunction with SNCR.
SNCR + RRI	Yes	Coupling RRI and SNCR is considered a technically feasible and commercially available NO <sub>x</sub> control technology option on Coyote Unit 1. Computational fluid dynamic modeling and temperature mapping of the boiler would be needed to confirm that the incremental reduction in NO <sub>x</sub> emissions is achievable without creating unacceptable operational issues.
Gas Reburn	No	The lack of natural gas availability at the Coyote Station precludes the ability to test and implement this control option on Coyote Unit 1. Therefore, gas reburn is not considered an available or technically feasible NO <sub>x</sub> control technology at Coyote Unit 1.
Innovative Technologies: NO <sub>x</sub> Star™ PerNO <sub>x</sub> ide LoTO <sub>x</sub> Water Injection	No	Innovative NO <sub>x</sub> control technologies are evaluated in Section 5.2.2.6. In all cases, the technologies have not been demonstrated on a large North Dakota lignite-fired boiler. Extensive testing and design engineering would be required to evaluate the technical feasibility and long-term effectiveness of each innovative control system on Coyote Unit 1. Therefore, the innovative NO <sub>x</sub> control technologies are not considered available control options and are not technically feasible NO <sub>x</sub> control options for Coyote Unit 1

NO <sub>x</sub> Control Option	Technically Feasible (Yes/No)	Technical Feasibility Summary
Selective Catalytic Reduction (SCR):		
High-dust configuration	No	Due to significant unresolved issues associated with catalyst poisoning, catalyst blinding and plugging, and catalyst erosion; and based on the finding that engineering solutions have not been determined or demonstrated and the high dust configuration has not moved beyond pilot scale testing, high dust SCR is not and available or technically feasible NO <sub>x</sub> control technology for Coyote Unit 1.
Low-dust configuration	No	Because Coyote Unit 1 is equipped with existing dry FGD/FF control systems, low-dust SCR has no practical application on the unit, and low-dust SCR is not considered an available or technically feasible NO <sub>x</sub> control option for Coyote Unit 1.
Tail-end configuration	No	Based on the continued lack of demonstration testing and commercial guarantees, tail-end SCR is considered to be a technically infeasible control option for Coyote Unit 1. Nevertheless, it will be carried forward to the four factor analysis to present hypothetical costs since tail-end SCR was included in the reasonable progress analysis for Coyote Unit 1 during the first planning period.

### 5.2.3 Evaluate Technically Feasible NO<sub>x</sub> Control Options for Effectiveness

The technically feasible NO<sub>x</sub> control technologies are listed in Table 5-11 in descending order of control efficiency. Table 5-11 also provides control option-specific NO<sub>x</sub> emission rates in terms of lb/MMBtu. Emission rates shown in Table 5-11 represent average emission rates that the control options would be expected to achieve during normal operations.

**Table 5-11. Evaluate Technically Feasible NO<sub>x</sub> Control Options for Effectiveness**

Control Technology	NO <sub>x</sub> Emission Rate <sup>(Note 1)</sup> lb/MMBtu	% Reduction from Baseline Emission Rate
Baseline (existing SOFA)	0.46	-
SCR – Tail-End Configuration <sup>(Note 2)</sup>	0.09	80.3%
SNCR + RRI + Combustion Optimization	0.20	56.2%
SNCR + Combustion Optimization	0.28	38.7%
Combustion Optimization	0.42	8.0%

Note 1. Emission rates shown in Table 5-11 represent average emission rates that the control options would be expected to achieve on an on-going long-term basis under normal operating conditions for Coyote Unit 1. Emission rates are provided for comparative purposes, and should not be construed to represent proposed emission limits. Corresponding permit limits must be evaluated on a control system-specific basis; an additional margin would likely be needed to account for operating margin. Additionally, for control options that include SNCR or RRI, computational fluid dynamic modeling and temperature mapping of the boiler would be needed to confirm that the incremental reduction in NO<sub>x</sub> emission is achievable without creating unacceptable operational issues.

Note 2. Tail-end SCR has not been installed on a North Dakota lignite-fired unit, and extended trials would be needed to better understand the design and operation of tail-end SCR on Coyote Unit 1. Nevertheless, during the initial planning period, tail-end SCR was included in the reasonable progress analysis for Coyote Unit 1, and evaluated the costs and cost-effectiveness of the control system. For consistency with the first planning period, tail-end SCR will be carried forward to the Four Factor Analysis.

## 6. COSTS OF COMPLIANCE (STATUTORY FACTOR ONE)

The economic analysis performed as part of the Four Factor analysis examines the cost-effectiveness of each technically feasible control technology, on a dollar per ton of pollutant removed basis. Annual emissions, calculated for a particular control device, are subtracted from baseline annual emissions to calculate tons of pollutant controlled per year. For units with existing controls, the base case represents existing baseline actual emissions. Annual costs for each control option are calculated relative to the base case by adding annual operation and maintenance (O&M) costs to the annualized cost of capital and, if applicable, lost revenue due to extended outage required for installation of control equipment. Capital costs and lost revenues were annualized using a capital recovery factor based on an annual interest rate of 5.25%<sup>40</sup> and equipment life of 20 years.<sup>41</sup> Cost effectiveness (\$/ton) of a particular control option is simply the annual cost (\$/yr) divided by the annual reduction in annual emissions (ton/yr). In addition to cost-effectiveness relative to the base case, the incremental cost-effectiveness to go from one level of control to the next, more stringent, level of control may also be calculated to evaluate the incremental cost effectiveness of the more stringent control.

Capital and O&M cost estimates were developed for each of the technically feasible SO<sub>2</sub> and NO<sub>x</sub> control options. The Coyote Unit 1 cost estimates are conceptual in nature; thus, S&L did not procure equipment quotes specifically for the Unit 1 control system upgrades. Rather, equipment costs are based on conceptual designs developed for the retrofit control systems, preliminary equipment sizing developed for the major pieces of equipment (based on Coyote Unit 1-specific design parameters, including typical fuel characteristics, full load heat input, and flue gas temperatures and flow rates), and recent pricing for similar equipment. S&L would characterize the cost estimates for the Coyote Unit 1 retrofit technologies as “concept screening” cost estimates generally based on parametric models, judgment, or analogy.

---

<sup>40</sup> In an email to the North Dakota Department of Health dated December 18, 2018, EPA recommended use of a 5.25% interest rate. Otter Tail does not necessarily agree that this is an appropriate percentage to use and reserves the right to update and modify this percentage at a later date. Notably, on September 26, 2018 the North Dakota Public Service Commission approved a rate of return for Otter Tail of 7.64% (See <https://psc.nd.gov/database/documents/17-0398/226-020.pdf>). This ROR represents a total weighted average cost of capital. An interest rate of 5.25% is more representative of the long-term cost of debt, which is only one component of capital structure.

<sup>41</sup> The assumed 20-year equipment life is consistent with the control system equipment life used by NDDH in its evaluation of NO<sub>x</sub> and SO<sub>2</sub> control technologies for BART-eligible sources. (see, e.g., ND Regional Haze Final SIP, Appendix C.1, “BART Determination Study for Leland Olds Station Units 1 & 2, Basin Electric Power Cooperative, August 2006, pgs. 64 (NO<sub>x</sub> controls) and 158 (SO<sub>2</sub> controls). See also, ND Regional Haze Final SIP, Appendix C4, “NO<sub>x</sub> Best Available Control Technology Study for Milton R. Young Station Unit 1, Minnkota Power Cooperative, Inc., October 2006, pg. 3-22).



Control technology equipment costs for the retrofit options were developed by scaling cost estimates prepared by S&L for other similar projects. Major equipment costs were developed based on equipment costs recently developed for similar projects, and include the equipment, material, labor, and all other direct costs needed to retrofit the units with the control technology. Sub-accounts for the capital cost estimates (e.g., mobilization and demobilization, consumables, Contractor G&A expense, freight on materials, etc.) were developed by applying ratios from detailed cost estimates that were prepared for projects with similar scopes.

Fixed O&M costs include operating labor, maintenance labor, maintenance material, and administrative labor. Variable O&M costs include the cost of consumables, including reagent, water consumption, and auxiliary power requirements.<sup>42</sup> Auxiliary power requirements reflect the additional power requirements associated with the operation of the new control technology (compared to the existing technology). All O&M costs reflect the incremental increase in O&M costs compared to the costs incurred to operate the existing dry scrubber and FF control systems.

In addition to the cost effectiveness relative to the base case, the incremental cost-effectiveness to go from one level of control to the next more stringent level of control will also be calculated to evaluate the cost effectiveness of the more stringent control.

The results of the SO<sub>2</sub> and NO<sub>x</sub> control cost evaluations are included below in Sections 6.1 and 6.2.

## 6.1 ECONOMIC EVALUATION – SO<sub>2</sub> CONTROLS

Table 6-1 presents the capital costs and annual operating costs associated with installing and operating each technically feasible SO<sub>2</sub> control system for Unit 1. Table 6-2 shows the average annual and incremental cost effectiveness for each control system. Additional cost details are provided in Appendix B.

Cost estimates were not prepared for the SDA/FF option since the capital and operating costs for the SDA/FF option would be similar to the costs for the CDS/FF option, and the CDS/FF option would likely provide the opportunity to achieve somewhat lower controlled SO<sub>2</sub> emissions (compared to SDA/FF). Therefore, of the two new DFGD system options, only the CDS/FF option was evaluated.

---

<sup>42</sup> Variable O&M costs are based on the annual average uncontrolled SO<sub>2</sub> of 2.77 lb/MMBtu

**Table 6-1. SO<sub>2</sub> Control Cost Summary (\$2018)**

SO <sub>2</sub> Control Option	Total Capital Investment \$	Annualized Capital Cost \$/yr	Annual Operating Cost \$/yr	Total Annual Cost \$/yr
DSI + Existing FGD	\$23,765,000	\$1,948,000	\$12,329,000	\$14,277,000
FGD Operational Improvements – Increase Ca:S Stoichiometric Ratio	\$526,000	\$43,000	\$2,449,000	\$2,492,000
DSI + FGD Operational Improvements	\$24,292,000	\$1,991,000	\$14,779,000	\$16,770,000
FGD Upgrades - Replacing Existing Absorbers with New Absorber	\$127,823,000	\$10,475,000	\$6,332,000	\$22,197,000 <sup>(Note 1)</sup>
Dry FGD (CDS) + Existing FF	\$242,647,000	\$19,885,000	\$22,361,000	\$42,246,000
Wet FGD	\$324,742,000	\$26,613,000	\$23,001,000	\$49,614,000

Note 1. Total annual cost for “FGD Upgrades - Replacing Existing Absorbers with New Absorber” option includes annualized lost revenue due to extended outage and replacement power required for installation (\$5,390,000).

**Table 6-2. SO<sub>2</sub> Emissions Control System Cost Effectiveness (\$2018)**

SO <sub>2</sub> Control Option	Total Annual Cost \$/yr	Expected Emission Reduction tons SO <sub>2</sub> /yr	Average Annual Cost Effectiveness (Note 1) \$/ton SO <sub>2</sub> removed	Incremental Annual Cost Effectiveness (Note 2, 3) \$/ton SO <sub>2</sub> removed
Baseline (Existing DFGD/FF)	---	---	---	---
DSI + Existing FGD	\$14,277,000	4,131	\$3,456	
FGD Operational Improvements – Increase Ca:S Stoichiometric Ratio	\$2,492,000	5,354	\$465	n/a
DSI + FGD Operational Improvements	\$16,770,000	7,952	\$2,109	\$5,496
FGD Upgrades - Replacing Existing Absorbers with New Absorber	\$22,197,000	8,563	\$2,592	\$8,879
Dry FGD (CDS) + Existing FF	\$42,246,000	11,619	\$3,636	\$6,560
Wet FGD	\$49,614,000	12,078	\$4,108	\$16,072

Note 1. Average cost effectiveness for each control option is the total annual cost divided by the expected emission reduction.

Note 2. Incremental cost effectiveness represents the incremental increase in annual costs (\$/yr) divided by the incremental increase in annual emissions reductions (tpy) between a control option and the next most effective option.

Note 3. “n/a” indicates that the next most effective control option is “inferior” (i.e., higher cost for less control)

Table 6-2 indicates that the average annual cost effectiveness of the technically feasible SO<sub>2</sub> control options for Unit 1 range from \$465 per ton (FGD Operation Improvements) to \$4,108 per ton (Wet FGD). Costs associated with equipment procurement and installation, and annual operating costs all have a significant impact on the cost of the SO<sub>2</sub> control systems.

Annual costs of the DSI system exceed the costs of the FGD Operational Improvements option, and the DSI system achieves lower SO<sub>2</sub> reductions. Therefore, the DSI system is an “inferior” control option.

The FGD Operational Improvements option would require the relatively low capital investment for upgrading the existing atomizer wheel and an increase in operating costs primarily due to increased reagent usage. This option will achieve approximately 41% SO<sub>2</sub> reduction from the baseline levels, resulting in a cost effectiveness of \$465 per ton.

The option to incorporate FGD Operational Improvements and install a DSI system will achieve approximately 61% SO<sub>2</sub> reduction from the baseline. Capital costs are primarily attributed to the DSI equipment, and high operating costs are due to a significant increase in hydrated lime use. The cost effectiveness of the DSI + FGD Operational Improvements option is \$2,109 per ton. Comparing this option to the next most effective control option, FGD Operational Improvements (without DSI), the incremental costs effectiveness is \$5,496 per ton.

Replacing the existing absorber modules with new absorber modules will require Coyote Unit 1 to be taken off-line for approximately 12 months. In addition to capital and operating costs, the Coyote Station will incur costs associated with lost production and purchase of replacement power. The cost effectiveness of the FGD Upgrade - Replacing Existing Absorbers with New Absorber option is \$2,592 per ton. Comparing this option to the next most effective control option, DSI + FGD Operational Improvements, the incremental cost effectiveness is \$8,879 per ton.

The installation of new Dry FGD (CDS) or new Wet FGD systems are high capital and annual operating cost options. The cost effectiveness for these options are \$3,636 per ton (Dry FGD) and \$4,108 per ton (Wet FGD). The incremental cost of installing a Dry FGD system, compared to FGD Upgrades, is \$6,560 per ton. The incremental cost of installing a Wet FGD system, compared to a Dry FGD system, is \$16,072 per ton.

## 6.2 ECONOMIC EVALUATION – NO<sub>x</sub> CONTROLS

Table 6-3 presents the capital costs and annual operating costs associated with building and operating each control system. Table 6-4 shows the average annual and incremental cost effectiveness for each control system. Additional cost details are provided in Appendix C.

**Table 6-3. NO<sub>x</sub> Control Cost Summary (\$2018)**

NO <sub>x</sub> Control Option	Total Capital Investment \$	Annual Capital Cost \$/yr	Annual Operating Cost \$/yr	Total Annual Cost \$/yr
Combustion Optimization	\$0	\$0	\$0	\$0
SNCR + Combustion Optimization	\$19,840,000	\$1,626,000	\$3,128,000	\$4,754,000
SNCR + RRI + Combustion Optimization	\$25,895,000	\$2,122,000	\$6,495,000	\$8,617,000
SCR – Tail-End Configuration	\$254,128,160	\$20,826,000	\$20,442,000	\$41,268,000

**Table 6-4. NO<sub>x</sub> Emissions Control System Cost Effectiveness (\$2018)**

NO <sub>x</sub> Control Option	Total Annual Cost \$/yr	Expected Emission Reduction tons NO <sub>x</sub> /yr	Average Annual Cost Effectiveness (Note 1) \$/ton NO <sub>x</sub> removed	Incremental Annual Cost Effectiveness (Note 2) \$/ton NO <sub>x</sub> removed
Baseline (Existing SOFA)	---	---	---	---
Combustion Optimization	\$0	589	\$0	\$0
SNCR + Combustion Optimization	\$4,754,000	2,847	\$1,670	\$2,105
SNCR + RRI + Combustion Optimization	\$8,617,000	4,137	\$2,083	\$2,994
SCR – Tail-End Configuration	\$41,268,000	5,912	\$6,981	\$18,402

Note 1. Average cost effectiveness for each control option is the total annual cost divided by the expected emission reduction.

Note 2. Incremental cost effectiveness represents the incremental increase in annual costs (\$/yr) divided by the incremental increase in annual emissions reductions (tpy) between a control option and the next most effective option.

Table 6-4 indicates that the average annual cost effectiveness of the technically feasible NO<sub>x</sub> control options for Unit 1 range from \$0 per ton (Combustion Optimization) to \$6,981 per ton (TE-SCR) NO<sub>x</sub> removed.

The Combustion Optimization option is expected to achieve 8% NO<sub>x</sub> reduction from baseline levels without impact to boiler performance. This option can be implemented without additional capital or operating costs; therefore, the cost effectiveness is \$0 per ton.

Installation of an SNCR system is expected to achieve approximately 39% NO<sub>x</sub> reduction. The cost effectiveness of this option is \$1,670 per ton. Compared the next most effective option, Combustion Optimization, the incremental cost effectiveness is \$2,105 per ton.

The option to install an SNCR system combined with RRI would achieve approximately 56% NO<sub>x</sub> reduction. Compared to installing SNCR alone, this option incurs additional capital costs for the RRI system and higher operating costs primarily due to increased urea consumption. The cost effectiveness of the SNCR + RRI option is \$2,083 per ton, and the incremental cost compared to SNCR alone is \$2,994 per ton.

Tail-end SCR system costs have been included to remain consistent with the reasonable progress analysis for Coyote Unit 1 during the initial planning period (i.e., evaluating the control system for costs and cost effectiveness). Based on preliminary cost estimates, the cost effectiveness of a tail-end SCR system is \$6,981 per ton. Compared to the next most effective control option, SNCR + RRI, the incremental cost effectiveness is \$18,402 per ton.

## 7. TIME NECESSARY FOR COMPLIANCE (STATUTORY FACTOR TWO)

The time necessary for compliance is generally defined as the time needed for full implementation of the technically feasible control options. This includes the time needed to develop and implement the regulations, as well as the time needed to install the selected control equipment. The time needed to install the control equipment includes time for equipment procurement, design, fabrication, and installation. If reasonable progress measures are required at Coyote Station for the Regional Haze second planning period, the anticipated compliance deadline would be July 1, 2028.<sup>43</sup> However, this compliance deadline must provide a reasonable amount of time for the source to implement the control measure.

Table 7-1 and Table 7-2 include estimated timeframes needed to implement each of the technically feasible control options. Notably, the estimated timeframes do not account for time needed for North Dakota to develop and implement the regulations; nor the amount of time needed for EPA to take proposed and final action to approve North Dakota's SIP.

---

<sup>43</sup> For the first planning period, on March 14, 2011 the North Dakota Department of Health issued permit to construct number PTC10008 that required Coyote Station to meet the approved reasonable progress limitation by July 1, 2018.

**Table 7-1. SO<sub>2</sub> Emissions Control System Implementation Schedule**

SO <sub>2</sub> Control Option	Design / Specification / Procurement (months)	Detail Design / Fabrication (months)	Construction / Commissioning / Startup (months)	Total (months after SIP approval)
DSI + Existing FGD	6	6	6	18
FGD Operational Improvements – Increase Ca:S Stoichiometric Ratio	0	0	0	0
DSI + FGD Operational Improvements	6	6	6	18
FGD Upgrades - Replacing Existing Absorbers with New Absorber	8	12	12	32
Dry FGD (CDS) + Existing FF	12	20	18	50
Wet FGD	12	22	22	56

**Table 7-2. NO<sub>x</sub> Emissions Control System Implementation Schedule**

NO <sub>x</sub> Control Option	Design / Specification / Procurement (months)	Detail Design / Fabrication (months)	Construction / Commissioning / Startup (months)	Total (months after SIP approval)
Combustion Optimization	0	0	0	0
SNCR + Combustion Optimization	10	6	6	22
SNCR + RRI + Combustion Optimization	10	6	6	22
SCR – Tail-End Configuration	10	18	24	52



## **8. ENERGY AND NON-AIR QUALITY ENVIRONMENTAL IMPACTS (STATUTORY FACTOR THREE)**

The primary purpose of the environmental impact analysis is to assess collateral environmental impacts due to control of the regulated pollutant in question. Environmental impacts may include solid or hazardous waste generation, discharges of polluted water from a control device, visibility impacts, increased emissions of other criteria or non-criteria pollutants, increased water consumption, and land use impacts from waste disposal.

### **8.1 ENVIRONMENTAL IMPACTS**

Coyote Unit 1 is currently equipped with SOFA for NO<sub>x</sub> control and dry scrubber technology for SO<sub>2</sub> control. The hydrated lime reactant used in a dry scrubbing system reacts with SO<sub>2</sub> in the flue gas to form calcium sulfate and calcium sulfite solids. The solids are captured in the existing FF particulate control system and either returned to the system for reuse or removed from the system as nonhazardous solid waste. The existing dry scrubbing system also requires water to hydrate the lime prior to injection into the reaction modules. Based on the design of the control system, Coyote Unit 1 currently uses approximately 465 gpm of water to hydrate the lime (at full load). Collateral environmental impacts associated with the existing Coyote Unit 1 control systems include water consumption and increased solid waste generation. There were no collateral impacts associated with the SOFA system.

Based on a review of potential non-air quality environmental impacts, no significant collateral environmental impacts were identified for any of the SO<sub>2</sub> and NO<sub>x</sub> control options included in this evaluation, with the exception, potentially, of the WFGD, DSI, TE-SCR and SNCR/RRI options. No significant non-air quality environmental impacts were identified for the options that include replacing the existing scrubber modules with new scrubber modules, FGD operational improvements/upgrades or combustion optimization. Collateral environmental impact identified for the sorbent injection control option includes an increase in the solid waste generation. The sorbent injection system will increase the solid waste generated by approximately 50% (47,000 lb/hr to 70,000 lb/hr).

There are a number of potential non-air quality environmental impacts associated with the WFGD control option. Unlike dry scrubbing systems that generate a dry FGD byproduct, WFGD systems generate a liquid calcium sulfate by-product that must be dewatered prior to disposal. WFGD control systems can be designed with forced oxidation that results in a gypsum-grade by-product that can be sold into the local gypsum market. If an adequate gypsum

market is not available, the gypsum by-product will require disposal. WFGD control systems also generate a wastewater stream that must be treated prior to discharge. WFGD wastewaters typically consist of a saturated solution of calcium sulfate, calcium sulfite, and sodium chloride, with trace amounts of fly ash and unreacted limestone. Traces of metal ions may also be present due to fly ash carryover from the flue gas to the WFGD scrubber liquor. WFGD wastewater treatment systems typically require calcium sulfate/sulfite desaturation, heavy metals precipitation, coagulation/precipitation, and sludge dewatering. Treated wastewater is typically discharged to surface water pursuant to an NPDES discharge permit, and solids are typically disposed of in a landfill.

WFGD systems also require significantly more water than the dry systems. Based on design criteria for wet and dry FGD control systems, WFGD systems typically require approximately 25-30% more water than a similarly sized DFGD control system. This would increase water consumption at Coyote Unit 1 on average approximately 130 gpm. Water consumption is an important factor when assessing potential non-air quality environmental impacts at facilities located in North Dakota, and could represent a significant non-air quality collateral environmental impact.

In addition, the TE-SCR, SNCR and SNCR/RRI control options have a number of collateral impacts. The TE-SCR catalyst oxidizes some of the  $\text{SO}_2$  to  $\text{SO}_3$  in addition to catalyzing the reaction between  $\text{NO}_x$  and ammonia. There could be the potential for increased  $\text{SO}_3$  emissions with the use of a TE-SCR. The  $\text{SO}_3$  will react with the moisture in the stack to form  $\text{H}_2\text{SO}_4$  emissions. In addition both the TE-SCR and SNCR, SNCR/RRI options utilize ammonia as the reagent for the reactions with  $\text{NO}_x$  to occur. There will be some ammonia slip emission from a TE-SCR in the range of 2 ppm. However the ammonia slip emission from a SCR or SNCR/RRI control technology will be significantly higher at 10 ppm. Ammonia slip emissions from the SNCR/RRI options will likely end up in the dry FGD solids, however there is no means to capture the ammonia slip emissions from the TE-SCR since it is installed prior to the stack.

## 8.2 ENERGY IMPACTS

Options that include replacing the existing Unit 1 dry scrubbing system with a CDS/FF or WFGD system or adding a TE-SCR will increase pressure drop through the control systems, increase auxiliary power requirements, and adversely affect the unit's net plant heat rate (Btu heat input per  $\text{MW}_{\text{Net}}$  output).<sup>44</sup> Consequently, heat input to the

---

<sup>44</sup> Heat rate represents the amount of heat input to the boiler (Btu) required to generate one megawatt (MW) net electric output and is reported as  $\text{Btu}/\text{MW}_{\text{Net}}$ .

boiler would need to increase to compensate for the increased auxiliary power requirements while achieving the same net plant output, or net output from the unit would decrease.

Although several of the control options have energy impacts, none of the impacts are considered significant enough as to disqualify any of the options from consideration in the four factor analysis. In order to account for potential energy impacts associated with each option, the auxiliary power cost associated with operating the control systems have been included as an annual operating cost in the economic impact assessment.

### **8.3 ENVIRONMENTAL / ENERGY IMPACTS SUMMARY**

A summary of the environmental and energy impact analysis is provided in Table 8-1.

**Table 8-1. Summary of Energy and Non-Air Quality Environmental Impacts**

Control Option	Collateral Environmental & Energy Impacts
<b>Baseline</b>	<ul style="list-style-type: none"> <li>➤ Coyote Unit 1 is currently equipped with dry scrubbing / FF control systems. Existing collateral environmental and energy impacts include:</li> <li>➤ Solid FGD by-product management and disposal</li> <li>➤ Increased water consumption</li> <li>➤ Increased auxiliary power requirements and heat rate penalty</li> </ul>
<b><u>SO<sub>2</sub> Control Options</u></b>	
Replace existing DFGD with New WFGD control system	<ul style="list-style-type: none"> <li>➤ Increased water consumption</li> <li>➤ Wet by-product that requires dewatering prior to disposal</li> <li>➤ FGD wastewater treatment &amp; discharge</li> <li>➤ Increased auxiliary power requirements and heat rate penalty</li> </ul>
Replace existing DFGD with New CDS/FF Control System	<ul style="list-style-type: none"> <li>➤ Increased auxiliary power requirements and heat rate penalty</li> <li>➤ Increased solid FGD by-product management and disposal</li> </ul>
Replace existing dry scrubber modules with New DFGD modules while keeping existing FF	<ul style="list-style-type: none"> <li>➤ Requires extended (approximately 12-month) outage of Coyote Unit 1 to demolish and replace the existing scrubber modules</li> </ul>
Dry Sorbent Injection	<ul style="list-style-type: none"> <li>➤ Increased solid FGD by-product management and disposal</li> <li>➤ Increased auxiliary power requirements and heat rate penalty</li> </ul>
<b><u>NO<sub>x</sub> Control Options</u></b>	
Selective Catalytic Reduction (SCR) - Tail End Configuration	<ul style="list-style-type: none"> <li>➤ Increased auxiliary power requirements and heat rate penalty</li> <li>➤ Increased ammonia slip emissions</li> <li>➤ Potential increase in SO<sub>3</sub> emissions</li> </ul>
SNCR or SNCR + RRI	<ul style="list-style-type: none"> <li>➤ Increased ammonia slip emissions</li> <li>➤ Increased auxiliary power requirements and heat rate penalty</li> </ul>

## 9. REMAINING USEFUL LIFE (STATUTORY FACTOR FOUR)

The evaluation of technically feasible NO<sub>x</sub> and SO<sub>2</sub> controls options should consider the source's "remaining useful life" in determining the costs of compliance. The remaining useful life is the difference between the date that controls would be put in place and the date that the facility permanently ceases operation. If the remaining useful life of the unit is shorter than the useful life of a particular control option, the remaining useful life should be used to annualize costs. If the remaining useful life exceeds the useful life of the control options, the remaining use life has no effect on the cost evaluation.

The cost of compliance for each control option (see Section 6) currently calculates the annual capital recovery cost by multiplying the total capital investment by a CRF from a formula based on a 20-year equipment lifetime. The Coyote Station owners have not identified dates for the remaining useful life of the unit before the end of what would otherwise be the useful life of the control measures that were evaluated for Coyote Unit 1. Thus, the 20-year equipment life of the control measures was used in the four factor analysis to calculate emission reductions, amortized costs, and cost-effectiveness.

## 10. FOUR-FACTOR ANALYSIS SUMMARY

At the request of NDDH, a four factor analysis was prepared for Coyote Unit 1. The analysis identified technically feasible SO<sub>2</sub> and NO<sub>x</sub> control options for Unit 1, and evaluated each of the control measures for the following four statutory factors:

1. The costs of compliance;
2. The time necessary for compliance;
3. The energy and non-air quality environmental impacts of compliance; and
4. The remaining useful life of any potentially affected anthropogenic source of visibility impairment.

The cost of compliance evaluation prepared for SO<sub>2</sub> controls indicates that the average annual cost effectiveness ranges from \$465 per ton (FGD Operation Improvements) to \$4,108 per ton (Wet FGD). The evaluation prepared for NO<sub>x</sub> controls options indicates that the average annual cost effectiveness ranges from \$0 per ton (Combustion Optimization) to \$6,981 per ton (TE-SCR) NO<sub>x</sub> removed.

The time necessary for compliance for the SO<sub>2</sub> control options ranges from 0 months (FGD operational improvements) to 56 months (new wet FGD system). For NO<sub>x</sub> control options, the time necessary for compliance ranges from 0 months (combustion optimization) to 46 months (tail-end SCR).

An evaluation of energy impacts indicates that certain control options (e.g., new FGD systems, TE-SCR) will increase auxiliary power requirements due to increased pressure drop, which would adversely impact net plant heat rate. Consequently, heat input to the boiler would need to increase to compensate for the increased auxiliary power requirements while achieving the same net plant output, or net output from the unit would decrease. Collateral environmental impacts include an increase in the solid waste generation with DSI, as well as potential incremental increase in fugitive dust emissions associated with sorbent deliveries to the facility.

Regarding remaining useful life, the Coyote Station owners have not identified dates for the remaining useful life of the unit before the end of what would otherwise be the 20-year useful life of the control measures that were evaluated for Coyote Unit 1. Therefore, the remaining useful life did not impact the annualized cost of control under the current regulatory framework.



COYOTE STATION UNIT 1

NORTH DAKOTA REGIONAL HAZE SECOND PLANNING PERIOD

FOUR-FACTOR ANALYSIS

SL-014745

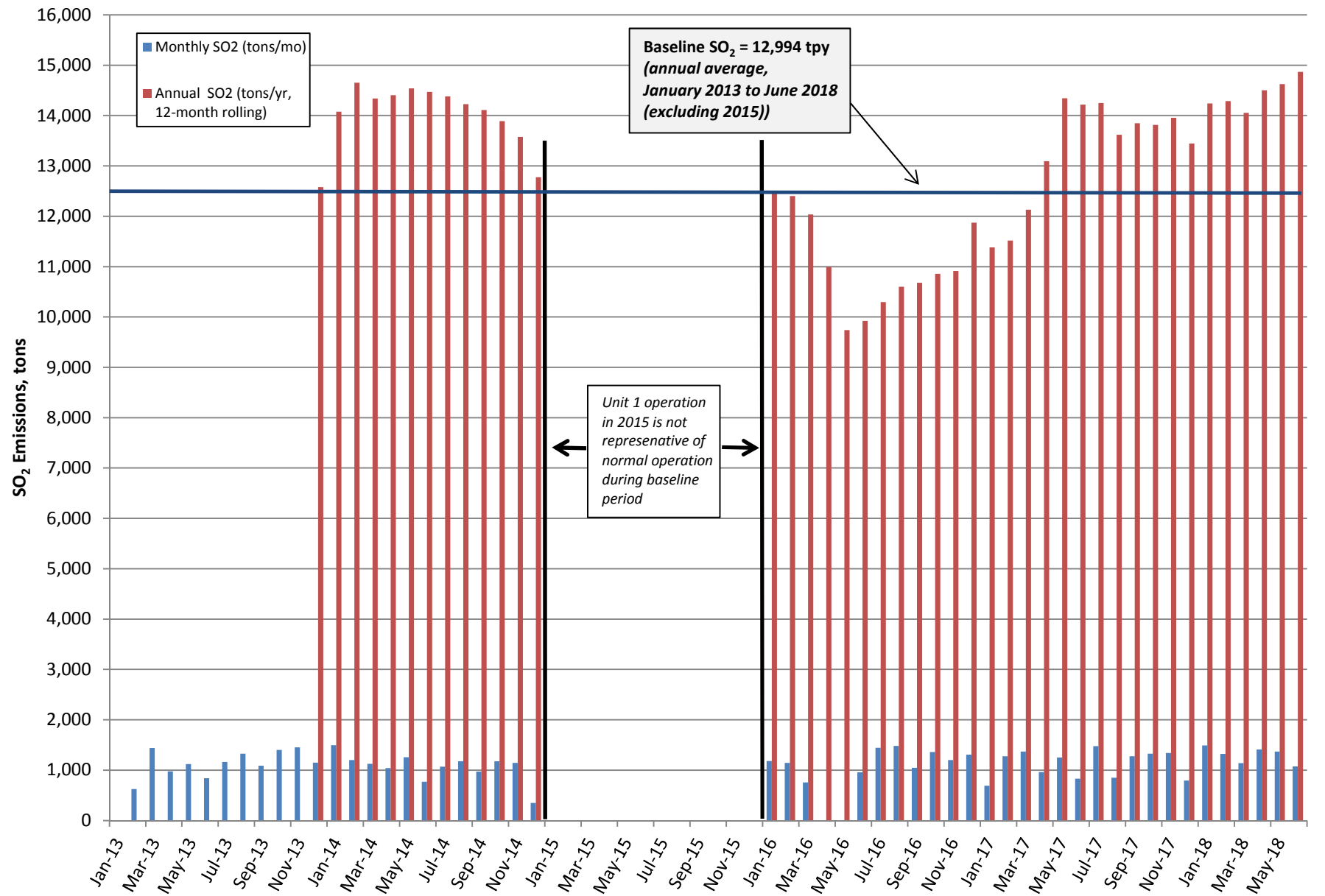
FINAL

Appendixes

## APPENDIX A

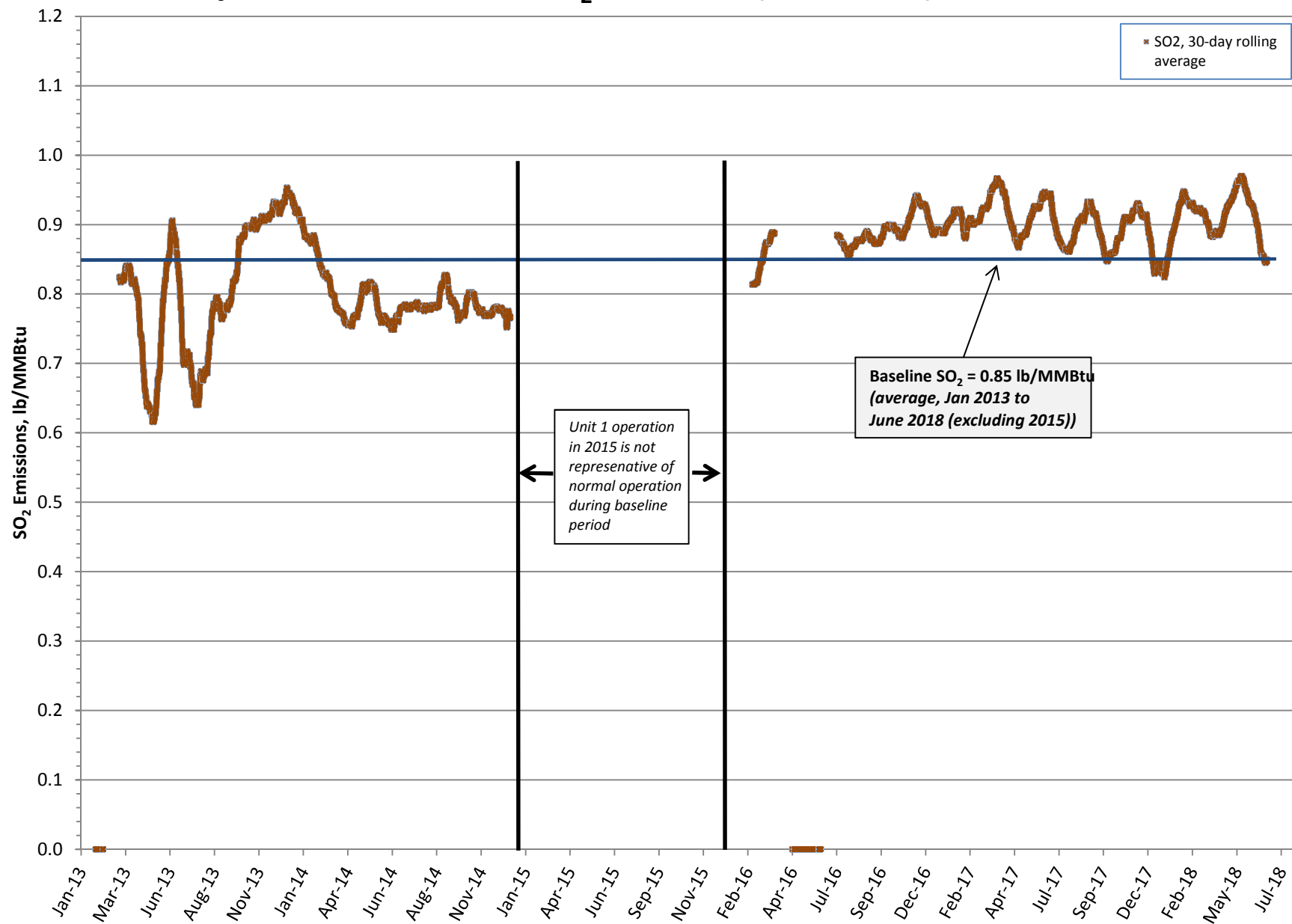
### COYOTE UNIT 1 BASELINE EMISSIONS

## Coyote Unit 1 - Baseline SO<sub>2</sub> Emissions (tons) [1/2013 to 6/2018]

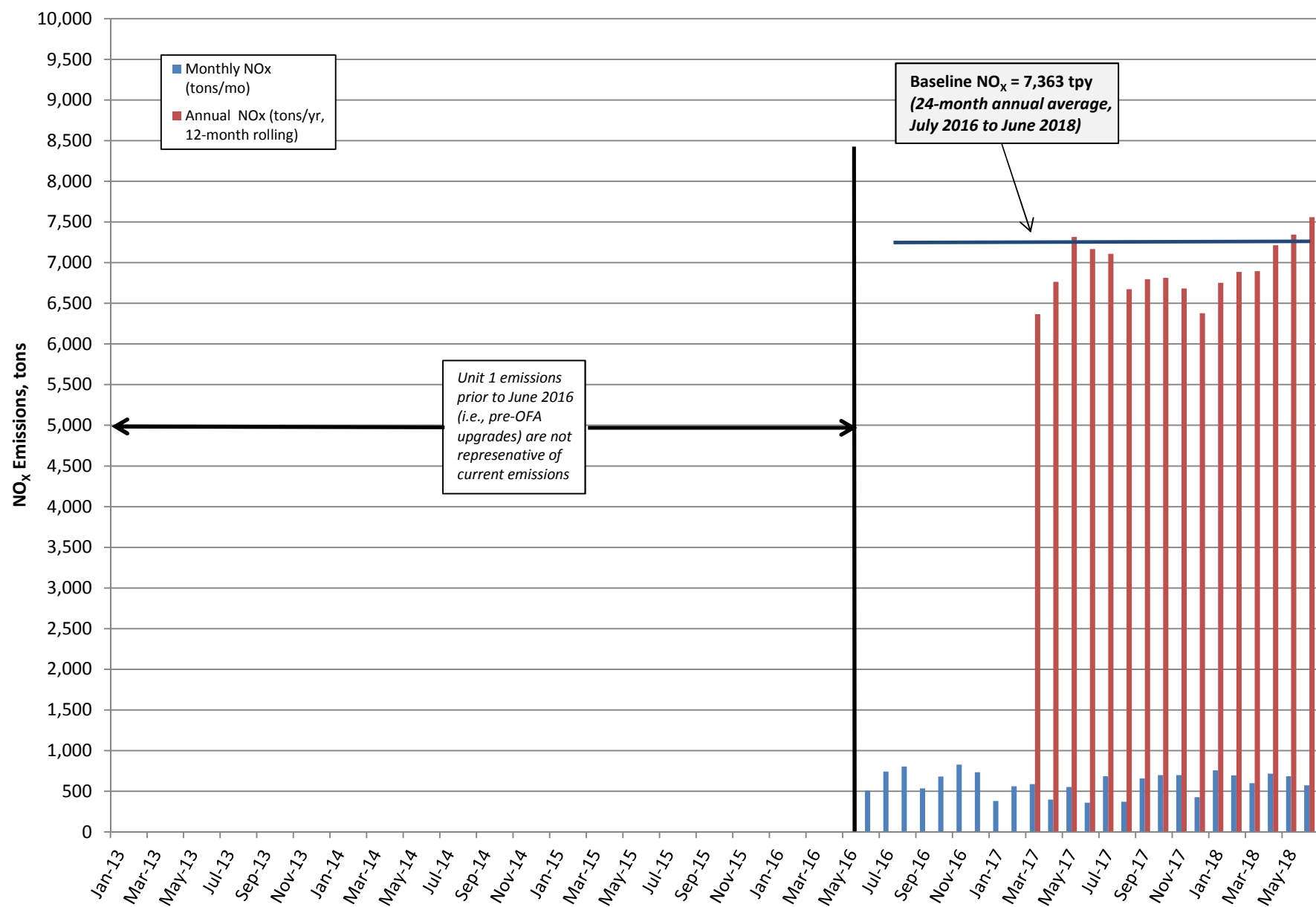




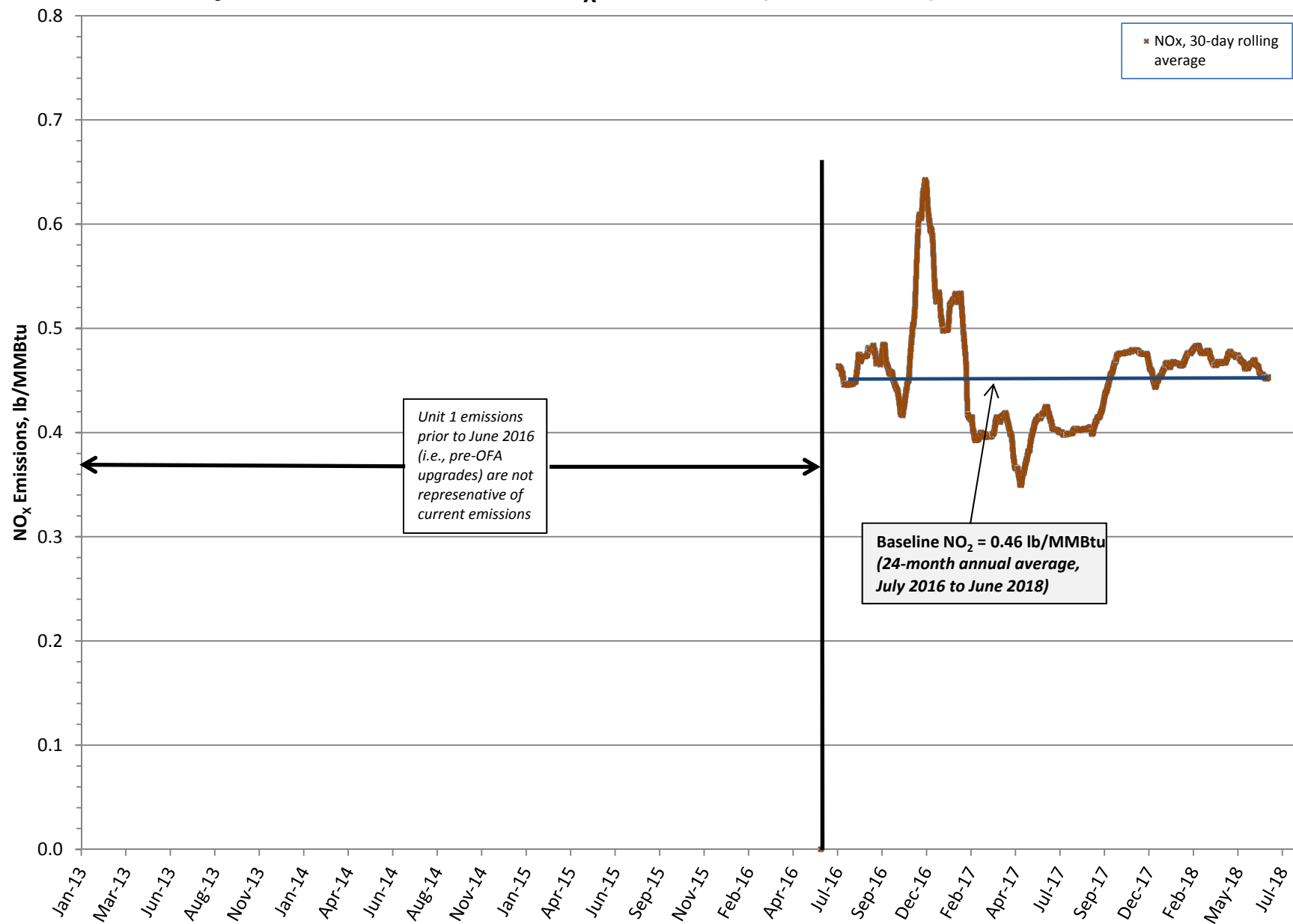
## Coyote Unit 1 - Baseline SO<sub>2</sub> Emissions (lb/MMBtu) [1/2013 to 6/2018]



## Coyote Unit 1 - Baseline NO<sub>x</sub> Emissions (tons) [1/2013 to 6/2018]



## Coyote Unit 1 - Baseline NO<sub>x</sub> Emissions (lb/MMBtu) [1/2013 to 6/2018]





## APPENDIX B

### SO<sub>2</sub> CONTROL COST EFFECTIVENESS ESTIMATES

**Coyote Station Unit 1  
SO<sub>2</sub> Control Summary**

**Table 1. Coyote Unit 1 Operating Parameters**

Parameter		Unit	Notes
Power Output	427	MW-net	Nominal
Annual Heat Input	30,562,287	MMBtu/yr	24-month annual average for period July 2016 to June 2018.
Average Capacity Factor	72%	%	Based on annual average MW-h during the baseline period.

**Table 2. Control Effectiveness**

Control Technology	Control Efficiency (%)	Expected Emissions (ton/year)	Emission Rate (lb/MMBtu)	Expected Emissions Reduction (ton/year)
Wet FGD	92.9%	917	0.06	12,078
Dry FGD (CDS) + FF	89.4%	1,375	0.09	11,619
FGD Upgrades - Replace Existing Absorbers with New Absorber	65.9%	4,432	0.29	8,563
DSI + FGD Operational Improvements	61.2%	5,043	0.33	7,952
FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio	41.2%	7,641	0.50	5,354
DSI + Existing FGD	31.8%	8,863	0.58	4,131
Baseline (DFGD/FF)		<b>12,994</b>	0.85	0

**Table 3. Cost Effectiveness**

Control Technology	Emissions (tpy)	Tons of SO <sub>2</sub> Removed (tpy)	Total Capital Requirement (\$)	Annualized Capital Cost (\$/year)	Annualized Outage Cost (\$/year)	Total Annual Operating Costs (\$/year)	Total Annual Costs (\$)	Average Cost Effectiveness (\$/ton)	Incremental Cost Effectiveness (\$/ton)
Baseline (DFGD/FF)	12,994	0	--	--		--	--		
DSI + Existing FGD	8,863	4,131	\$23,765,000	\$1,948,000	\$0	\$12,329,000	\$14,277,000	<b>\$3,456</b>	
FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio	7,641	5,354	\$526,000	\$43,000	\$0	\$2,449,000	\$2,492,000	<b>\$465</b>	
DSI + FGD Operational Improvements	5,043	7,952	\$24,292,000	\$1,991,000	\$0	\$14,779,000	\$16,770,000	<b>\$2,109</b>	\$5,496
FGD Upgrades - Replace Existing Absorbers with New Absorber	4,432	8,563	\$127,823,000	\$10,475,000	\$5,390,000	\$6,332,000	\$22,197,000	<b>\$2,592</b>	\$8,879
Dry FGD (CDS) + FF	1,375	11,619	\$242,647,000	\$19,885,000	\$0	\$22,361,000	\$42,246,000	<b>\$3,636</b>	\$6,560
Wet FGD	917	12,078	\$324,742,000	\$26,613,000	\$0	\$23,001,000	\$49,614,000	<b>\$4,108</b>	\$16,072

**Coyote Station Unit 1**  
**SO<sub>2</sub> Control Cost Evaluation**  
**DSI + Existing FGD**

SO <sub>2</sub> Control Option Description	DSI + Existing FGD
Baseline SO <sub>2</sub> Emissions, lb/MMBtu	0.85
Post Upgrade SO <sub>2</sub> Emissions, lb/MMBtu	0.58
Capacity Factor used of Cost Estimates (%)	72%

CAPITAL COSTS		Cost (2018\$)	Basis
<b>Direct Costs</b>			
<b>Purchased Equipment Costs (PEC)</b>			
Equipment and Materials	\$10,884,000		Based on Sargent & Lundy's conceptual cost estimating system. Costs include equipment and material.
Dry FGC Instrumentation	\$0		Included in equipment and materials cost
Sales Tax	\$544,000		5% of Equipment/Material Cost
Freight	\$544,000		5% of Equipment/Material Cost
<b>Total PEC</b>	<b>\$11,972,000</b>		
<b>Direct Installation Costs</b>			
Labor	\$2,886,000		Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding	\$72,000		2.5% of Labor
Mobilization / Demobilization	\$43,000		1.5% of Labor
Labor Cost Due To Overtime Inefficiency	\$144,000		5% of Labor
<b>Total Direct Installation Costs</b>	<b>\$3,145,000</b>		
<b>Total Direct Costs (PEC + Direct Installation Costs)</b>	<b>\$15,117,000</b>		
<b>Indirect Costs</b>			
Contractor's General and Administration Expense	\$1,512,000		10% of Total Direct Costs
Contractor's Profit	\$756,000		5% of Total Direct Costs
Dry FGC Engineering, Procurement, & Project Services	\$1,209,000		8% of Total Direct Costs
Construction Management/Field Engineering	\$605,000		4% of Total Direct Costs
S-U / Commissioning	\$227,000		1.5% of Total Direct Costs
Spare Parts	\$76,000		0.5% of Total Direct Costs
Owner's Cost	\$302,000		2% of Total Direct Costs
<b>Total Indirect Costs</b>	<b>\$4,687,000</b>		
<b>Contingency</b>	<b>\$3,961,000</b>		20% of Direct and Indirect Costs
<b>Total Capital Investment (TCI)</b>	<b>\$23,765,000</b>		sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$	0.0820		20 year life of equipment (years) @ 5.25% interest.
<b>Annualized Capital Costs (CRF x TCI)</b>	<b>\$1,948,000</b>		
<b>OPERATING COSTS</b>			
<b>Operating &amp; Maintenance Costs</b>			
<b>Variable O&amp;M Costs</b>			
Increased Waste Disposal Cost	\$1,991,000		Based on disposal rate of \$32.46 per ton.
Hydrated Lime Reagent Cost	\$8,993,000		Based on hydrated lime reagent cost of \$187 per ton.
Increased Auxiliary Power Cost	\$115,000		Based on auxiliary power cost of \$23 per MWh
Increased bag and cage replacement	\$52,000		Based on bag and cage cost of \$135 per bag
<b>Total Variable O&amp;M Costs</b>	<b>\$11,151,000</b>		
<b>Fixed O&amp;M Costs</b>			
Additional Operators per shift	0		Assume no additional operators
Operating Labor	\$0		N/A
Supervisor Labor	\$0		N/A
Maintenance Materials	\$227,000		Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor	\$0		Included in cost for maintenance materials.
<b>Total Fixed O&amp;M Cost</b>	<b>\$227,000</b>		
<b>Indirect Operating Cost</b>			
Property Taxes	\$238,000		1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	\$238,000		1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	\$475,000		2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
<b>Total Indirect Operating Cost</b>	<b>\$951,000</b>		
<b>Total Annual Operating Cost</b>	<b>\$12,329,000</b>		
<b>TOTAL ANNUAL COST</b>			
Annualized Capital Cost	\$1,948,000		
Annual Operating Cost	\$12,329,000		
<b>Total Annual Cost</b>	<b>\$14,277,000</b>		

**Coyote Station Unit 1**  
**SO<sub>2</sub> Control Cost Evaluation**  
**FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio**

SO <sub>2</sub> Control Option Description	FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio
Baseline SO <sub>2</sub> Emissions, lb/MMBtu	0.85
Post Upgrade SO <sub>2</sub> Emissions, lb/MMBtu	0.50
Capacity Factor used of Cost Estimates (%)	72%

CAPITAL COSTS		Cost (2018\$)	Basis
<b>Direct Costs</b>			
<b>Purchased Equipment Costs (PEC)</b>			
Equipment and Materials	\$218,000		Based on Sargent & Lundy's conceptual cost estimating system. Costs include equipment and material.
Dry FGD Instrumentation	\$0		Included in equipment and materials cost
Sales Tax	\$11,000		5% of Equipment/Material Cost
Freight	\$11,000		5% of Equipment/Material Cost
<b>Total PEC</b>	<b>\$240,000</b>		
<b>Direct Installation Costs</b>			
Labor	\$87,000		Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding	\$2,000		2.5% of Labor
Mobilization / Demobilization	\$1,000		1.5% of Labor
Labor Cost Due To Overtime Inefficiency	\$4,000		5% of Labor
<b>Total Direct Installation Costs</b>	<b>\$94,000</b>		
<b>Total Direct Costs (PEC + Direct Installation Costs)</b>	<b>\$334,000</b>		
<b>Indirect Costs</b>			
Contractor's General and Administration Expense	\$33,000		10% of Total Direct Costs
Contractor's Profit	\$17,000		5% of Total Direct Costs
Dry FGD Engineering, Procurement, & Project Services	\$27,000		8% of Total Direct Costs
Construction Management/Field Engineering	\$13,000		4% of Total Direct Costs
S-U / Commissioning	\$5,000		1% of Total Direct Costs
Spare Parts	\$2,000		0.5% of Total Direct Costs
Owner's Cost	\$7,000		2% of Total Direct Costs
<b>Total Indirect Costs</b>	<b>\$104,000</b>		
<b>Contingency</b>	<b>\$88,000</b>		20% of Direct and Indirect Costs
<b>Total Capital Investment (TCI)</b>	<b>\$526,000</b>		sum of direct costs, indirect costs, and contingency
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$	0.0820		20 year life of equipment (years) @ 5.25% interest.
<b>Annualized Capital Costs (CRF x TCI)</b>	<b>\$43,000</b>		
<b>OPERATING COSTS</b>			
<b>Operating &amp; Maintenance Costs</b>			
<b>Variable O&amp;M Costs</b>			
Increased Waste Disposal Cost	\$711,000		Based on disposal rate of \$32.46 per ton.
Increased Lime Reagent Cost	\$1,706,000		Based on lime reagent cost of \$128 per ton.
Increased Auxiliary Power Cost	\$4,000		Based on auxiliary power cost of \$23 per MWh
Increased Water Cost	\$2,000		Based on water cost of \$1.00 per 1000 gallons.
<b>Total Variable O&amp;M Costs</b>	<b>\$2,423,000</b>		
<b>Fixed O&amp;M Costs</b>			
Additional Operators per shift	0		Assume no additional operators
Operating Labor	\$0		N/A
Supervisor Labor	\$0		N/A
Maintenance Materials	\$5,000		Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor	\$0		Included in cost for maintenance materials.
<b>Total Fixed O&amp;M Cost</b>	<b>\$5,000</b>		
<b>Indirect Operating Cost</b>			
Property Taxes	\$5,000		1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	\$5,000		1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	\$11,000		2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
<b>Total Indirect Operating Cost</b>	<b>\$21,000</b>		
<b>Total Annual Operating Cost</b>	<b>\$2,449,000</b>		
<b>TOTAL ANNUAL COST</b>			
Annualized Capital Cost	\$43,000		
Annual Operating Cost	\$2,449,000		
<b>Total Annual Cost</b>	<b>\$2,492,000</b>		

**Coyote Station Unit 1**  
**SO<sub>2</sub> Control Cost Evaluation**  
**DSI + FGD Operational Improvements**

SO <sub>2</sub> Control Option Description	DSI + FGD Operational Improvements
Baseline SO <sub>2</sub> Emissions, lb/MMBtu	0.85
Post Upgrade SO <sub>2</sub> Emissions, lb/MMBtu	0.33
Capacity Factor used of Cost Estimates (%)	72%

CAPITAL COSTS		Cost (2018\$)	Basis
<b>Direct Costs</b>			
<b>Purchased Equipment Costs (PEC)</b>			
Equipment and Materials		\$11,102,000	Based on Sargent & Lundy's conceptual cost estimating system. Costs include equipment and material.
Dry FGI Instrumentation		\$0	Included in equipment and materials cost
Sales Tax		\$555,000	5% of Equipment/Material Cost
Freight		\$555,000	5% of Equipment/Material Cost
<b>Total PEC</b>		<b>\$12,212,000</b>	
<b>Direct Installation Costs</b>			
Labor		\$2,973,000	Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding		\$74,000	2.5% of Labor
Mobilization / Demobilization		\$45,000	1.5% of Labor
Labor Cost Due To Overtime Inefficiency		\$149,000	5% of Labor
<b>Total Direct Installation Costs</b>		<b>\$3,241,000</b>	
<b>Total Direct Costs (PEC + Direct Installation Costs)</b>		<b>\$15,453,000</b>	
<b>Indirect Costs</b>			
Contractor's General and Administration Expense		\$1,545,000	10% of Total Direct Costs
Contractor's Profit		\$773,000	5% of Total Direct Costs
Dry FGI Engineering, Procurement, & Project Services		\$1,236,000	8% of Total Direct Costs
Construction Management/Field Engineering		\$618,000	4% of Total Direct Costs
S-U / Commissioning		\$232,000	1.5% of Total Direct Costs
Spare Parts		\$77,000	0.5% of Total Direct Costs
Owner's Cost		\$309,000	2% of Total Direct Costs
<b>Total Indirect Costs</b>		<b>\$4,790,000</b>	
<b>Contingency</b>		<b>\$4,049,000</b>	20% of Direct and Indirect Costs
<b>Total Capital Investment (TCI)</b>		<b>\$24,292,000</b>	sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor (CRF) = $(1+i)^n / (1+i)^n - 1$		0.0820	20 year life of equipment (years) @ 5.25% interest.
<b>Annualized Capital Costs (CRF x TCI)</b>		<b>\$1,991,000</b>	
<b>OPERATING COSTS</b>			
<b>Operating &amp; Maintenance Costs</b>			
<b>Variable O&amp;M Costs</b>			
Increased Waste Disposal Cost		\$2,702,000	Based on disposal rate of \$32.46 per ton.
Increased Lime Reagent Cost		\$1,706,400	Based on lime reagent cost of \$128 per ton.
Hydrated Lime Reagent Cost		\$8,993,000	Based on hydrated lime reagent cost of \$187 per ton.
Increased Auxiliary Power Cost		\$119,000	Based on auxiliary power cost of \$23 per MWh
Increased bag and cage replacement		\$52,000	Based on bag and cage cost of \$135 per bag
<b>Total Variable O&amp;M Costs</b>		<b>\$13,574,700</b>	
<b>Fixed O&amp;M Costs</b>			
Additional Operators per shift		0	Assume no additional operators
Operating Labor		\$0	N/A
Supervisor Labor		\$0	N/A
Maintenance Materials		\$232,000	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor		\$0	Included in cost for maintenance materials.
<b>Total Fixed O&amp;M Cost</b>		<b>\$232,000</b>	
<b>Indirect Operating Cost</b>			
Property Taxes		\$243,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance		\$243,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration		\$486,000	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
<b>Total Indirect Operating Cost</b>		<b>\$972,000</b>	
<b>Total Annual Operating Cost</b>		<b>\$14,779,000</b>	
<b>TOTAL ANNUAL COST</b>			
Annualized Capital Cost		\$1,991,000	
Annual Operating Cost		\$14,779,000	
<b>Total Annual Cost</b>		<b>\$16,770,000</b>	



Coyote Station Unit 1  
SO<sub>2</sub> Control Cost Evaluation  
FGD Upgrades - Replace Existing Absorbers with New Absorber

SO <sub>2</sub> Control Option Description	FGD Upgrades - Replace Existing Absorbers with New Absorber
Baseline SO <sub>2</sub> Emissions, lb/MMBtu	0.85
Post Upgrade SO <sub>2</sub> Emissions, lb/MMBtu	0.29
Capacity Factor used of Cost Estimates (%)	72%

CAPITAL COSTS		Cost (2018\$)	Basis
<b>Direct Costs</b>			
<b>Purchased Equipment Costs (PEC)</b>			
Equipment and Materials		\$42,282,000	Based on Sargent & Lundy's conceptual cost estimating system. Costs include equipment and material.
Dry FGD Instrumentation		\$0	Included in equipment and materials cost
Sales Tax		\$2,114,000	5% of Equipment/Material Cost
Freight		\$2,114,000	5% of Equipment/Material Cost
<b>Total PEC</b>		<b>\$46,510,000</b>	
<b>Direct Installation Costs</b>			
Labor		\$31,929,000	Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding		\$798,000	2.5% of Labor
Mobilization / Demobilization		\$479,000	1.5% of Labor
Labor Cost Due To Overtime Inefficiency		\$1,596,000	5% of Labor
<b>Total Direct Installation Costs</b>		<b>\$34,802,000</b>	
<b>Total Direct Costs (PEC + Direct Installation Costs)</b>		<b>\$81,312,000</b>	
<b>Indirect Costs</b>			
Contractor's General and Administration Expense		\$8,131,000	10% of Total Direct Costs
Contractor's Profit		\$4,066,000	5% of Total Direct Costs
Dry FGD Engineering, Procurement, & Project Services		\$6,505,000	8% of Total Direct Costs
Construction Management/Field Engineering		\$3,252,000	4% of Total Direct Costs
S-U / Commissioning		\$1,220,000	1.5% of Total Direct Costs
Spare Parts		\$407,000	0.5% of Total Direct Costs
Owner's Cost		\$1,626,000	2% of Total Direct Costs
<b>Total Indirect Costs</b>		<b>\$25,207,000</b>	
<b>Contingency</b>		<b>\$21,304,000</b>	20% of Direct and Indirect Costs
<b>Total Capital Investment (TCI)</b>		<b>\$127,823,000</b>	sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$		0.0820	20 year life of equipment (years) @ 5.25% interest.
<b>Annualized Capital Costs (CRF x TCI)</b>		<b>\$10,475,000</b>	
<b>OUTAGE COSTS</b>			
<b>Outage Costs</b>			
Standard Outage Duration (weeks/yr)		8	
Outage Duration due to Retrofit (weeks/yr)		52	
<b>Lost Revenue due to Retrofit</b>		<b>\$51,979,000</b>	
<b>Replacement Power Cost due to Retrofit</b>		<b>\$13,786,000</b>	Based on the difference in cost for Coyote to generate power at \$23.00 per MWh and cost for Coyote to purchase replacement power.
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$		0.0820	20 year life of equipment (years) @ 7% interest.
<b>Annualized Outage Costs (CRF x TCI)</b>		<b>\$5,390,000</b>	
<b>OPERATING COSTS</b>			
<b>Operating &amp; Maintenance Costs</b>			
<b>Variable O&amp;M Costs</b>			
<b>Total Variable O&amp;M Costs</b>		<b>\$0</b>	No incremental increases in variable O&M for absorber replacement
<b>Fixed O&amp;M Costs</b>			
Additional Operators per shift		0	Assume no additional operators
Operating Labor		\$0	N/A
Supervisor Labor		\$0	N/A
Maintenance Materials		\$1,220,000	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor		\$0	Included in cost for maintenance materials.
<b>Total Fixed O&amp;M Cost</b>		<b>\$1,220,000</b>	
<b>Indirect Operating Cost</b>			
Property Taxes		\$1,278,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance		\$1,278,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration		\$2,556,000	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
<b>Total Indirect Operating Cost</b>		<b>\$5,112,000</b>	
<b>Total Annual Operating Cost</b>		<b>\$6,332,000</b>	
<b>TOTAL ANNUAL COST</b>			
Annualized Capital Cost		\$10,475,000	
Annualized Outage Cost		\$5,390,000	
Annual Operating Cost		\$6,332,000	
<b>Total Annual Cost</b>		<b>\$22,197,000</b>	

**Coyote Station Unit 1**  
**SO<sub>2</sub> Control Cost Evaluation**  
**Dry FGD (CDS) + FF**

SO <sub>2</sub> Control Option Description	Dry FGD (CDS) + FF
Baseline SO <sub>2</sub> Emissions, lb/MMBtu	0.85
Post Upgrade SO <sub>2</sub> Emissions, lb/MMBtu	0.09
Capacity Factor used of Cost Estimates (%)	72%

CAPITAL COSTS		Cost (2018\$)	Basis
<b>Direct Costs</b>			
<b>Purchased Equipment Costs (PEC)</b>			
Equipment and Materials	\$61,993,000		Based on Sargent & Lundy's conceptual cost estimating system. Costs include equipment and material.
Dry FGD Instrumentation	\$0		Included in equipment and materials cost
Sales Tax	\$3,100,000		5% of Equipment/Material Cost
Freight	\$3,100,000		5% of Equipment/Material Cost
<b>Total PEC</b>	<b>\$68,193,000</b>		
<b>Direct Installation Costs</b>			
Labor	\$79,049,000		Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding	\$1,976,000		2.5% of Labor
Mobilization / Demobilization	\$1,186,000		1.5% of Labor
Labor Cost Due To Overtime Inefficiency	\$3,952,000		5% of Labor
<b>Total Direct Installation Costs</b>	<b>\$86,163,000</b>		
<b>Total Direct Costs (PEC + Direct Installation Costs)</b>	<b>\$154,356,000</b>		
<b>Indirect Costs</b>			
Contractor's General and Administration Expense	\$15,436,000		10% of Total Direct Costs
Contractor's Profit	\$7,718,000		5% of Total Direct Costs
Dry FGD Engineering, Procurement, & Project Services	\$12,348,000		8% of Total Direct Costs
Construction Management/Field Engineering	\$6,174,000		4% of Total Direct Costs
S-U / Commissioning	\$2,315,000		1.5% of Total Direct Costs
Spare Parts	\$772,000		0.5% of Total Direct Costs
Owner's Cost	\$3,087,000		2% of Total Direct Costs
<b>Total Indirect Costs</b>	<b>\$47,850,000</b>		
<b>Contingency</b>	<b>\$40,441,000</b>		20% of Direct and Indirect Costs
<b>Total Capital Investment (TCI)</b>	<b>\$242,647,000</b>		sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$	0.0820		20 year life of equipment (years) @ 5.25% interest.
<b>Annualized Capital Costs (CRF x TCI)</b>	<b>\$19,885,000</b>		
<b>OPERATING COSTS</b>			
<b>Operating &amp; Maintenance Costs</b>			
<b>Variable O&amp;M Costs</b>			
Increased Waste Disposal Cost	\$2,743,000		Based on disposal rate of \$32.46 per ton.
Increased Lime Reagent Cost	\$6,998,000		Based on lime reagent cost of \$128 per ton.
Increased Auxiliary Power Cost	\$428,000		Based on auxiliary power cost of \$23 per MWh
Increased Water Cost	\$32,000		Based on water cost of \$1.00 per 1000 gallons.
Increased bag and cage replacement	\$140,000		Based on bag and cage cost of \$135 per bag
<b>Total Variable O&amp;M Costs</b>	<b>\$10,341,000</b>		
<b>Fixed O&amp;M Costs</b>			
Additional Operators per shift	0		Assume no additional operators
Operating Labor	\$0		N/A
Supervisor Labor	\$0		N/A
Maintenance Materials	\$2,315,000		Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor	\$0		Included in cost for maintenance materials.
<b>Total Fixed O&amp;M Cost</b>	<b>\$2,315,000</b>		
<b>Indirect Operating Cost</b>			
Property Taxes	\$2,426,000		1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	\$2,426,000		1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	\$4,853,000		2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
<b>Total Indirect Operating Cost</b>	<b>\$9,705,000</b>		
<b>Total Annual Operating Cost</b>	<b>\$22,361,000</b>		
<b>TOTAL ANNUAL COST</b>			
Annualized Capital Cost	\$19,885,000		
Annual Operating Cost	\$22,361,000		
<b>Total Annual Cost</b>	<b>\$42,246,000</b>		

**Coyote Station Unit 1**  
**SO<sub>2</sub> Control Cost Evaluation**  
**Wet FGD**

SO <sub>2</sub> Control Option Description	Wet FGD
Baseline SO <sub>2</sub> Emissions, lb/MMBtu	0.85
Post Upgrade SO <sub>2</sub> Emissions, lb/MMBtu	0.06
Capacity Factor used of Cost Estimates (%)	72%

CAPITAL COSTS		Cost (2018\$)	Basis
<b>Direct Costs</b>			
<b>Purchased Equipment Costs (PEC)</b>			
Equipment and Materials		\$112,208,000	Based on Sargent & Lundy's conceptual cost estimating system. Costs include equipment and material.
Dry FGD Instrumentation		\$0	Included in equipment and materials cost
Sales Tax		\$5,610,000	5% of Equipment/Material Cost
Freight		\$5,610,000	5% of Equipment/Material Cost
<b>Total PEC</b>		<b>\$123,428,000</b>	
<b>Direct Installation Costs</b>			
Labor		\$76,285,000	Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding		\$1,907,000	2.5% of Labor
Mobilization / Demobilization		\$1,144,000	1.5% of Labor
Labor Cost Due To Overtime Inefficiency		\$3,814,000	5% of Labor
<b>Total Direct Installation Costs</b>		<b>\$83,150,000</b>	
<b>Total Direct Costs (PEC + Direct Installation Costs)</b>		<b>\$206,578,000</b>	
<b>Indirect Costs</b>			
Contractor's General and Administration Expense		\$20,658,000	10% of Total Direct Costs
Contractor's Profit		\$10,329,000	5% of Total Direct Costs
Dry FGD Engineering, Procurement, & Project Services		\$16,526,000	8% of Total Direct Costs
Construction Management/Field Engineering		\$8,263,000	4% of Total Direct Costs
S-U / Commissioning		\$3,099,000	1.5% of Total Direct Costs
Spare Parts		\$1,033,000	0.5% of Total Direct Costs
Owner's Cost		\$4,132,000	2% of Total Direct Costs
<b>Total Indirect Costs</b>		<b>\$64,040,000</b>	
<b>Contingency</b>		<b>\$54,124,000</b>	20% of Direct and Indirect Costs
<b>Total Capital Investment (TCI)</b>		<b>\$324,742,000</b>	sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$		0.0820	20 year life of equipment (years) @ 5.25% interest.
<b>Annualized Capital Costs (CRF x TCI)</b>		<b>\$26,613,000</b>	
<b>OPERATING COSTS</b>			
<b>Operating &amp; Maintenance Costs</b>			
<b>Variable O&amp;M Costs</b>			
Increased Waste Disposal Cost		\$2,182,000	Based on disposal rate of \$32.46 per ton.
Increased Lime Reagent Cost		-\$3,679,000	Based on lime reagent cost of \$128 per ton.
Limestone Reagent Cost		\$4,895,000	Based on limestone reagent cost of \$70 per ton.
Increased Auxiliary Power Cost		\$949,000	Based on auxiliary power cost of \$23 per MWh
Increased Water Cost		\$68,000	Based on water cost of \$1.00 per 1000 gallons.
<b>Total Variable O&amp;M Costs</b>		<b>\$4,415,000</b>	
<b>Fixed O&amp;M Costs</b>			
Additional Operators per Shift		4	
Operating Labor		\$2,172,000	Assume \$62/hr for each additional operator
Supervisor Labor		\$326,000	15% of Operating Labor. EPA Cost Manual Section 1, Chapter 2, page 2-31.
Maintenance Materials		\$3,099,000	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor		\$0	Included in cost for maintenance materials.
<b>Total Fixed O&amp;M Cost</b>		<b>\$5,597,000</b>	
<b>Indirect Operating Cost</b>			
Property Taxes		\$3,247,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance		\$3,247,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration		\$6,495,000	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
<b>Total Indirect Operating Cost</b>		<b>\$12,989,000</b>	
<b>Total Annual Operating Cost</b>		<b>\$23,001,000</b>	
<b>TOTAL ANNUAL COST</b>			
Annualized Capital Cost		\$26,613,000	
Annual Operating Cost		\$23,001,000	
<b>Total Annual Cost</b>		<b>\$49,614,000</b>	



COYOTE STATION UNIT 1

NORTH DAKOTA REGIONAL HAZE SECOND PLANNING PERIOD

FOUR-FACTOR ANALYSIS

SL-014745

FINAL

Appendixes

## APPENDIX C

### NO<sub>x</sub> CONTROL COST EFFECTIVENESS ESTIMATES

Coyote Station Unit 1  
NO<sub>x</sub> Control Summary

Table 1. Coyote Unit 1 Operating Parameters

Parameter		Unit	Notes
Power Output	427	MW-net	Nominal
Annual Average Heat Input	32,301,802	MMBtu/yr	24-month annual average for period July 2016 to June 2018 (post-SOFA upgrades)
Average Capacity Factor	79%	%	Based on annual average MW-h during the baseline period.

Table 2. Control Effectiveness

Control Technology	Control Efficiency (%)	Expected Emissions (ton/year)	Emission Rate (lb/MMBtu)	Expected Emissions Reduction (ton/year)
Tail-End SCR	80.3%	1,452	0.09	5,912
SNCR + RRI	56.2%	3,226	0.20	4,137
SNCR	38.7%	4,516	0.28	2,847
Combustion Optimization	8.0%	6,775	0.42	589
Baseline (SOFA)		<b>7,363</b>	0.46	0

Table 3. Cost Effectiveness

Control Technology	Emissions (tpy)	Tons of NO <sub>x</sub> Removed (tpy)	Total Capital Requirement (\$)	Annualized Capital Cost (\$/year)	Annualized Outage Cost (\$/year)	Total Annual Operating Costs (\$/year)	Total Annual Costs (\$)	Average Cost Effectiveness (\$/ton)	Incremental Cost Effectiveness (\$/ton)
Baseline (SOFA)	7,363	0	--	--	--	--	--		
Combustion Optimization	6,775	589	\$0	\$0	\$0	\$0	\$0	<b>\$0</b>	
SNCR	4,516	2,847	\$19,840,000	\$1,626,000	\$0	\$3,128,000	\$4,754,000	<b>\$1,670</b>	\$2,105
SNCR + RRI	3,226	4,137	\$25,895,000	\$2,122,000	\$0	\$6,495,000	\$8,617,000	<b>\$2,083</b>	\$2,994
Tail-End SCR	1,452	5,912	\$254,128,000	\$20,826,000	\$0	\$20,442,000	\$41,268,000	<b>\$6,981</b>	\$18,402

Coyote Station Unit 1  
NO<sub>x</sub> Control Cost Evaluation  
Combustion Optimization

NO <sub>x</sub> Control Option Description	Combustion Optimization
Baseline NO <sub>x</sub> Emissions, lb/MMBtu	0.46
Post Upgrade NO <sub>x</sub> Emissions, lb/MMBtu	0.42
Capacity Factor used of Cost Estimates (%)	79%

CAPITAL COSTS		Cost (2018\$)	Basis
<b>Direct Costs</b>			
<b>Purchased Equipment Costs (PEC)</b>			
Equipment and Materials	\$0		
Instrumentation	\$0		
Sales Tax	\$0		
Freight	\$0		
<b>Total PEC</b>	\$0		
<b>Direct Installation Costs</b>			
Labor	\$0		
Scaffolding	\$0		
Mobilization / Demobilization	\$0		
Labor Cost Due To Overtime Inefficiency	\$0		
<b>Total Direct Installation Costs</b>	\$0		
Total Direct Costs (PEC + Direct Installation Costs)	\$0		
<b>Indirect Costs</b>			
Contractor's General and Administration Expense	\$0		
Contractor's Profit	\$0		
Engineering, Procurement, & Project Services	\$0		
Construction Management/Field Engineering	\$0		
S-U / Commissioning	\$0		
Spare Parts	\$0		
Owner's Cost	\$0		
Total Indirect Costs	\$0		
Contingency	\$0		
<b>Total Capital Investment (TCI)</b>	\$0		
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$	0.0820		20 year life of equipment (years) @ 5.25% interest.
<b>Annualized Capital Costs (CRF x TCI)</b>	\$0		
OPERATING COSTS			Basis
<b>Operating &amp; Maintenance Costs</b>			
<b>Variable O&amp;M Costs</b>			
Dry Urea Reagent Cost	\$0		Based on dry urea reagent cost of \$354 per ton.
Ammonia Reagent Cost	\$0		Based on ammonia reagent cost of \$700 per ton.
RO Water Cost	\$0		Based on water cost of \$1.00 per 1,000 gallons.
Steam Cost	\$0		Based on steam cost of \$1.06 per MMBtu.
Hydrated Lime Cost	\$0		Based on hydrated lime cost of \$187 per ton.
Catalyst Replacement Cost	\$0		Based on catalyst cost of \$8,000 per m3 and catalyst replacement cost of \$1,000 per m3.
Auxiliary Power Cost	\$0		Based on auxiliary power cost of \$23 per MWh
<b>Total Variable O&amp;M Costs</b>	\$0		
<b>Fixed O&amp;M Costs</b>			
Additional Operators per shift	0		Assume no additional operators
Operating Labor	\$0		N/A
Supervisor Labor	\$0		N/A
Maintenance Materials	\$0		Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor	\$0		Included in cost for maintenance materials.
<b>Total Fixed O&amp;M Cost</b>	\$0		
<b>Indirect Operating Cost</b>			
Property Taxes	\$0		1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	\$0		1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	\$0		2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
<b>Total Indirect Operating Cost</b>	\$0		
<b>Total Annual Operating Cost</b>	\$0		
TOTAL ANNUAL COST			
Annualized Capital Cost	\$0		
Annual Operating Cost	\$0		
<b>Total Annual Cost</b>	\$0		

**Coyote Station Unit 1**  
**NO<sub>x</sub> Control Cost Evaluation**  
**SNCR**

NO <sub>x</sub> Control Option Description	SNCR
Baseline NO <sub>x</sub> Emissions, lb/MMBtu	0.46
Post Upgrade NO <sub>x</sub> Emissions, lb/MMBtu	0.28
Capacity Factor used of Cost Estimates (%)	79%

CAPITAL COSTS		Cost (2018\$)	Basis
<b>Direct Costs</b>			
<b>Purchased Equipment Costs (PEC)</b>			
Equipment and Materials	\$8,718,000		Based on Sargent & Lundy's conceptual cost estimating system. Costs include equipment and material.
Instrumentation	\$0		Included in equipment and materials cost
Sales Tax	\$436,000		5% of Equipment/Material Cost
Freight	\$436,000		5% of Equipment/Material Cost
<b>Total PEC</b>	<b>\$9,590,000</b>		
<b>Direct Installation Costs</b>			
Labor	\$2,780,000		Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding	\$70,000		2.5% of Labor
Mobilization / Demobilization	\$42,000		1.5% of Labor
Labor Cost Due To Overtime Inefficiency	\$139,000		5% of Labor
<b>Total Direct Installation Costs</b>	<b>\$3,031,000</b>		
<b>Total Direct Costs (PEC + Direct Installation Costs)</b>	<b>\$12,621,000</b>		
<b>Indirect Costs</b>			
Contractor's General and Administration Expense	\$1,262,000		10% of Total Direct Costs
Contractor's Profit	\$631,000		5% of Total Direct Costs
Engineering, Procurement, & Project Services	\$1,010,000		8% of Total Direct Costs
Construction Management/Field Engineering	\$505,000		4% of Total Direct Costs
S-U / Commissioning	\$189,000		1.5% of Total Direct Costs
Spare Parts	\$63,000		0.5% of Total Direct Costs
Owner's Cost	\$252,000		2% of Total Direct Costs
<b>Total Indirect Costs</b>	<b>\$3,912,000</b>		
Contingency	\$3,307,000		20% of Direct and Indirect Costs
<b>Total Capital Investment (TCI)</b>	<b>\$19,840,000</b>		sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$	0.0820		20 year life of equipment (years) @ 5.25% interest.
<b>Annualized Capital Costs (CRF x TCI)</b>	<b>\$1,626,000</b>		
OPERATING COSTS			Basis
<b>Operating &amp; Maintenance Costs</b>			
<b>Variable O&amp;M Costs</b>			
Dry Urea Reagent Cost	\$1,401,000		Based on dry urea reagent cost of \$354 per ton.
Ammonia Reagent Cost	\$0		Based on ammonia reagent cost of \$700 per ton.
Water Cost	\$82,000		Based on water cost of \$1.00 per 1,000 gallons.
Steam Cost	\$32,000		Based on steam cost of \$1.06 per MMBtu.
Hydrated Lime Cost	\$0		Based on hydrated lime cost of \$187 per ton.
Catalyst Replacement Cost	\$0		Based on catalyst cost of \$8,000 per m3 and catalyst replacement cost of \$1,000 per m3.
Auxiliary Power Cost	\$7,000		Based on auxiliary power cost of \$23 per MWh
<b>Total Variable O&amp;M Costs</b>	<b>\$1,522,000</b>		
<b>Fixed O&amp;M Costs</b>			
Additional Operators per shift	1		
Operating Labor	\$543,000		Assume \$62/hr for each additional operator
Supervisor Labor	\$81,000		15% of Operating Labor. EPA Cost Manual Section 1, Chapter 2, page 2-31.
Maintenance Materials	\$189,000		Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor	\$0		Included in cost for maintenance materials.
<b>Total Fixed O&amp;M Cost</b>	<b>\$813,000</b>		
<b>Indirect Operating Cost</b>			
Property Taxes	\$198,000		1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	\$198,000		1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	\$397,000		2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
<b>Total Indirect Operating Cost</b>	<b>\$793,000</b>		
<b>Total Annual Operating Cost</b>	<b>\$3,128,000</b>		
TOTAL ANNUAL COST			
Annualized Capital Cost	\$1,626,000		
Annual Operating Cost	\$3,128,000		
<b>Total Annual Cost</b>	<b>\$4,754,000</b>		

**Coyote Station Unit 1**  
**NO<sub>x</sub> Control Cost Evaluation**  
**SNCR + RRI**

NO <sub>x</sub> Control Option Description	SNCR + RRI
Baseline NO <sub>x</sub> Emissions, lb/MMBtu	0.46
Post Upgrade NO <sub>x</sub> Emissions, lb/MMBtu	0.20
Capacity Factor used of Cost Estimates (%)	79%

CAPITAL COSTS		Cost (2018\$)	Basis
<b>Direct Costs</b>			
<b>Purchased Equipment Costs (PEC)</b>			
Equipment and Materials	\$11,179,000		Based on Sargent & Lundy's conceptual cost estimating system. Costs include equipment and material.
Instrumentation	\$0		Included in equipment and materials cost
Sales Tax	\$559,000		5% of Equipment/Material Cost
Freight	\$559,000		5% of Equipment/Material Cost
<b>Total PEC</b>	<b>\$12,297,000</b>		
<b>Direct Installation Costs</b>			
Labor	\$3,831,000		Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding	\$96,000		2.5% of Labor
Mobilization / Demobilization	\$57,000		1.5% of Labor
Labor Cost Due To Overtime Inefficiency	\$192,000		5% of Labor
<b>Total Direct Installation Costs</b>	<b>\$4,176,000</b>		
<b>Total Direct Costs (PEC + Direct Installation Costs)</b>	<b>\$16,473,000</b>		
<b>Indirect Costs</b>			
Contractor's General and Administration Expense	\$1,647,000		10% of Total Direct Costs
Contractor's Profit	\$824,000		5% of Total Direct Costs
Engineering, Procurement, & Project Services	\$1,318,000		8% of Total Direct Costs
Construction Management/Field Engineering	\$659,000		4% of Total Direct Costs
S-U / Commissioning	\$247,000		1.5% of Total Direct Costs
Spare Parts	\$82,000		0.5% of Total Direct Costs
Owner's Cost	\$329,000		2% of Total Direct Costs
<b>Total Indirect Costs</b>	<b>\$5,106,000</b>		
Contingency	<b>\$4,316,000</b>		20% of Direct and Indirect Costs
<b>Total Capital Investment (TCI)</b>	<b>\$25,895,000</b>		sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$	0.0820		20 year life of equipment (years) @ 5.25% interest.
<b>Annualized Capital Costs (CRF x TCI)</b>	<b>\$2,122,000</b>		
<b>OPERATING COSTS</b>			
<b>Operating &amp; Maintenance Costs</b>			
<b>Variable O&amp;M Costs</b>			
Dry Urea Reagent Cost	\$4,300,000		Based on dry urea reagent cost of \$354 per ton.
Ammonia Reagent Cost	\$0		Based on ammonia reagent cost of \$700 per ton.
RO Water Cost	\$179,000		Based on water cost of \$1.00 per 1,000 gallons.
Steam Cost	\$99,000		Based on steam cost of \$1.06 per MMBtu.
Hydrated Lime Cost	\$0		Based on hydrated lime cost of \$187 per ton.
Catalyst Replacement Cost	\$0		Based on catalyst cost of \$8,000 per m3 and catalyst replacement cost of \$1,000 per m3.
Auxiliary Power Cost	\$10,000		Based on auxiliary power cost of \$23 per MWh
<b>Total Variable O&amp;M Costs</b>	<b>\$4,588,000</b>		
<b>Fixed O&amp;M Costs</b>			
Additional Operators per shift	1		
Operating Labor	\$543,000		Assume \$62/hr for each additional operator
Supervisor Labor	\$81,000		15% of Operating Labor. EPA Cost Manual Section 1, Chapter 2, page 2-31.
Maintenance Materials	\$247,000		Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor	\$0		Included in cost for maintenance materials.
<b>Total Fixed O&amp;M Cost</b>	<b>\$871,000</b>		
<b>Indirect Operating Cost</b>			
Property Taxes	\$259,000		1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	\$259,000		1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	\$518,000		2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
<b>Total Indirect Operating Cost</b>	<b>\$1,036,000</b>		
<b>Total Annual Operating Cost</b>	<b>\$6,495,000</b>		
<b>TOTAL ANNUAL COST</b>			
Annualized Capital Cost	\$2,122,000		
Annual Operating Cost	\$6,495,000		
<b>Total Annual Cost</b>	<b>\$8,617,000</b>		



**Coyote Station Unit 1**  
**NO<sub>x</sub> Control Cost Evaluation**  
**Tail-End SCR**

NO <sub>x</sub> Control Option Description	Tail-End SCR
Baseline NO <sub>x</sub> Emissions, lb/MMBtu	0.46
Post Upgrade NO <sub>x</sub> Emissions, lb/MMBtu	0.09
Capacity Factor used of Cost Estimates (%)	79%

CAPITAL COSTS		Cost (2018\$)	Basis
<b>Direct Costs</b>			
<b>Purchased Equipment Costs (PEC)</b>			
Equipment and Materials	\$85,566,000		Based on Sargent & Lundy's conceptual cost estimating system. Costs include equipment and material.
Instrumentation	\$0		Included in equipment and materials cost
Sales Tax	\$4,278,000		5% of Equipment/Material Cost
Freight	\$4,278,000		5% of Equipment/Material Cost
<b>Total PEC</b>	<b>\$94,122,000</b>		
<b>Direct Installation Costs</b>			
Labor	\$61,961,000		Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding	\$1,549,000		2.5% of Labor
Mobilization / Demobilization	\$929,000		1.5% of Labor
Labor Cost Due To Overtime Inefficiency	\$3,098,000		5% of Labor
<b>Total Direct Installation Costs</b>	<b>\$67,537,000</b>		
<b>Total Direct Costs (PEC + Direct Installation Costs)</b>	<b>\$161,659,000</b>		
<b>Indirect Costs</b>			
Contractor's General and Administration Expense	\$16,166,000		10% of Total Direct Costs
Contractor's Profit	\$8,083,000		5% of Total Direct Costs
Engineering, Procurement, & Project Services	\$12,933,000		8% of Total Direct Costs
Construction Management/Field Engineering	\$6,466,000		4% of Total Direct Costs
S-U / Commissioning	\$2,425,000		1.5% of Total Direct Costs
Spare Parts	\$808,000		0.5% of Total Direct Costs
Owner's Cost	\$3,233,000		2% of Total Direct Costs
<b>Total Indirect Costs</b>	<b>\$50,114,000</b>		
Contingency	\$42,355,000		20% of Direct and Indirect Costs
<b>Total Capital Investment (TCI)</b>	<b>\$254,128,000</b>		sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$	0.0820		20 year life of equipment (years) @ 5.25% interest.
<b>Annualized Capital Costs (CRF x TCI)</b>	<b>\$20,826,000</b>		
<b>OPERATING COSTS</b>			
<b>Operating &amp; Maintenance Costs</b>			
<b>Variable O&amp;M Costs</b>			
Dry Urea Reagent Cost	\$0		Based on dry urea reagent cost of \$354 per ton.
Ammonia Reagent Cost	\$1,724,000		Based on ammonia reagent cost of \$700 per ton.
RO Water Cost	\$0		Based on water cost of \$1.00 per 1,000 gallons.
Steam Cost	\$0		Based on steam cost of \$1.06 per MMBtu.
Hydrated Lime Cost	\$298,000		Based on hydrated lime cost of \$187 per ton.
Catalyst Replacement and Disposal Cost	\$4,257,000		Based on catalyst cost of \$8,000 per m3 and catalyst replacement cost of \$1,000 per m3.
Auxiliary Power Cost	\$1,074,000		Based on auxiliary power cost of \$23 per MWh
<b>Total Variable O&amp;M Costs</b>	<b>\$7,353,000</b>		
<b>Fixed O&amp;M Costs</b>			
Additional Operators per Shift	1		
Operating Labor	\$434,000		Assume \$49.5/hr for each additional operator
Supervisor Labor	\$65,000		
Maintenance Materials	\$2,425,000		15% of Operating Labor. EPA Cost Manual Section 1, Chapter 2, page 2-31. Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor	\$0		Included in cost for maintenance materials.
<b>Total Fixed O&amp;M Cost</b>	<b>\$2,924,000</b>		
<b>Indirect Operating Cost</b>			
Property Taxes	\$2,541,000		1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	\$2,541,000		1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	\$5,083,000		2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
<b>Total Indirect Operating Cost</b>	<b>\$10,165,000</b>		
<b>Total Annual Operating Cost</b>	<b>\$20,442,000</b>		
<b>TOTAL ANNUAL COST</b>			
Annualized Capital Cost	\$20,826,000		
Annual Operating Cost	\$20,442,000		
<b>Total Annual Cost</b>	<b>\$41,268,000</b>		

May 10, 2019

Mr. Jim Semerad  
Director, Division of Air Quality  
North Dakota Department of Environmental Quality  
Gold Seal Center, 918 East Divide Ave  
Bismarck, ND 58501-1947



Dear Mr. Semerad:

Re: Four Factor Analysis - Coyote Station

Thank you for the North Dakota Department of Environmental Quality's (NDDEQ) review of the Coyote Station Regional Haze reasonable progress report (Four-Factor Analysis). Below are Otter Tail Power Company's (OTP) responses to the NDDEQ's March 20, 2019 comments. Additionally, two hardcopies of a revised report are enclosed.

- 1) Summary of NDDEQ Comment: "...since you are anticipating a higher sulfur content in the future lignite combusted, past emissions do not represent a realistic estimate of anticipated emissions... The SO<sub>2</sub> analysis should be edited using a more appropriate baseline rate."

OTP Response: The NDDEQ is correct that, as compared to recent years, Coyote Station is expecting an increase in future coal sulfur content. However, this future sulfur content is projected to be similar to the sulfur content of the lignite that was combusted from the years 2000-2008. On March 29, 2019 OTP provided a spreadsheet to the NDDEQ showing that Coyote Station has been able to maintain consistent SO<sub>2</sub> lb/mmBtu emission rates throughout the expected range of future coal sulfur content. For example, in year 2004, the average lignite sulfur content was 1.09%, and Coyote had an annual average emission rate of 0.85 lb/mmBtu. This emission rate is very similar to year 2018, in which Coyote had an average sulfur content of 0.83% and an annual average emission rate of 0.86 lb/mmBtu. Therefore, no adjustment is needed to the SO<sub>2</sub> baseline emission rate presented in the Four-Factor Analysis.

- 2) NDDEQ Comment: "We also believe the inlet SO<sub>2</sub> rate to possible control options (3.12 lb/MBtu) is high. Using the AP-42 emission factor, we calculate an inlet emission rate of approximately 2.3 lb/MBtu for 1.06% sulfur in the lignite. We believe this will affect the Total Annual Cost and cost effectiveness of the various control options. The analysis should be changed based on a more realistic inlet SO<sub>2</sub> rate."

OTP Response: We appreciate the NDDEQ's comment regarding calculation of the baseline SO<sub>2</sub> inlet rate. Sargent & Lundy (S&L) used projected future fuel analyses (sulfur and higher heating value) provided by OTP to calculate the baseline inlet SO<sub>2</sub> rate, assuming 100% conversion of fuel sulfur to SO<sub>2</sub> and without taking into account any inherent SO<sub>2</sub> conversion/capture. As pointed out by the NDDEQ, using the uncontrolled emission rate

factor provided by AP-42<sup>1</sup> as the basis for inlet SO<sub>2</sub> would provide for a lower number of approximately 2.3 lb/mmBtu.

Regarding revising the cost estimate consistent with the recommendation for inlet SO<sub>2</sub>, the majority of the capital costs are a function of the flue gas flow rate and not the fuel sulfur content. Therefore, changing the inlet rate to 2.3 lb/MBtu would change the capital cost estimate slightly but not enough to affect the economic impact evaluation. The reagent prep and dewatering systems and byproduct handling systems are a very small portion of the overall cost of the retrofit FGD control system. For the DSI system, the main cost is attributable to the variable O&M cost of reagent which was based on 2.77 lb SO<sub>2</sub>/MBtu as stated in Footnote 42 of the Four-Factor Analysis. The inlet SO<sub>2</sub> rate primarily impacts the variable O&M costs of the SO<sub>2</sub> control alternatives. Variable O&M costs that are impacted include reagent consumption (i.e., lime and limestone) and the byproduct or waste disposal. The difference between 2.3 lb SO<sub>2</sub>/MBtu and 2.77 lb SO<sub>2</sub>/MBtu will not have a significant impact on the FGD cost-effectiveness analysis because variable O&M costs are relatively small in relation to the capital cost portion of the SO<sub>2</sub> control alternatives. Nevertheless, S&L has revised the variable O&M costs to reflect a baseline SO<sub>2</sub> inlet rate of 2.3 lb SO<sub>2</sub>/MBtu.

- 3) Summary of NDDEQ Comment: *"...high dust, low dust and tail-end SCR are not technically feasible for cyclone boilers combusting North Dakota lignite...Since tail-end SCR is not a technically feasible option, we suggest that it be removed from Tables 5-11, 6-3 and 6-4."*

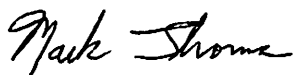
OTP Response: The Four-Factor Analysis has been revised to remove tail-end SCR from Tables 5-11, 6-3, and 6-4. Portions of the text were also updated to be consistent with this change.

- 4) NDDEQ Comment: *"Many cost estimates throughout the analysis are based on Sargent & Lundy's (S&L) conceptual cost estimating system with major equipment costs based on recently developed projects. When cost estimates are not based on EPA's Control Cost Manual, more documentation is required to substantiate costs. Please provide the documentation to support costs that are not based on the Control Cost Manual."*

OTP Response: Please see the attached memorandum from Sargent & Lundy addressing this comment.

Thank you for the attention given to the Coyote Station Four-Factor Analysis. If you have any further questions on the revised report, please contact me at (218) 739-8526.

Sincerely,



Mark Thoma  
Manager, Environmental Services

Enclosure

---

<sup>1</sup> The AP-42 uncontrolled factor assumes that the alkali content of lignite has an effect on sulfur conversion and acts as a built-in sorbent for SO<sub>x</sub> removal.

TECHNICAL MEMORANDUM

**From:** Wayshalee Patel  
**Date:** May 8, 2019  
**Project No.:** A12715.011

**Client:** Otter Tail Power  
**Station:** Coyote Station

**Subject:** Agency Comments to Four Factor Analysis

The purpose of this memorandum is to provide a response to the North Dakota Department of Environmental Quality (NDDEQ) comments on the Coyote Station Four Factor Analysis.

- 1. NDDEQ Comment:** *Many cost estimates throughout the analysis are based on Sargent & Lundy's (S&L) conceptual cost estimating system with major equipment costs based on recently developed projects. When cost estimates are not based on EPA's Control Cost Manual, more documentation is required to substantiate costs. Please provide the documentation to support costs that are not based on the Control Cost Manual.*

S&L Response: S&L has considerable experience with the federal and state environmental regulations affecting power plant operations, as well as the specification, evaluation, selection, and implementation of emission control technologies for both gas- and coal-fueled utility power facilities, including extensive experience with air pollution control technologies. For example, since 2000, S&L has provided, or is currently providing, engineering services for the implementation of over 40 wet FGD projects, 30 dry FGD projects, 25 dry sorbent injection (DSI) projects, 60 selective catalytic reduction projects (SCR) and 30 selective non-catalytic reduction (SNCR) projects all of which are technologies that were analyzed as part of the Four-Factor Analysis.

Cost estimates for the OTP Four-Factor Analysis were, to the extent practical, prepared in accordance with the methodology described in EPA's Control Cost Manual and represent study-level cost estimates. Capital costs for major equipment were developed using equipment costs for similar sized units (adjusted for actual equipment sizing), an approach allowed by the Control Cost Manual. Site-specific balance-of-plant (BOP) costs that Coyote Unit 1 would incur to retrofit the control system onto the existing unit were estimated based on site-specific general arrangements and project-specific indirect cost factors. Where possible, default factors from EPA's Control Cost Manual were used to calculate indirect costs. Specifically, cost estimates were prepared with the following general approach and site-specific information:

- Boiler operating parameters were reviewed and mass balances were prepared to calculate flue gas flows across the range of operating conditions and to size the air pollution control equipment.
- Fuel characteristics were evaluated and used to size the material handling, material storage, and piping systems.
- Plant design data were used to estimate absorber sizing, reagent storage and preparation systems, dewatering systems and byproduct handling systems for air pollution control equipment.
- Aerial views of the plant were used to identify the general vicinity in which major equipment would be located.

The capital cost estimates were prepared for the major control system components, equipment, material, labor, instrumentation, etc. Capital costs were annualized using the methodology described in the Control Cost Manual, and annual operating and maintenance (O&M) costs were added to the annualized cost of capital to generate a total annual cost. Detailed cost effectiveness worksheets were provided identifying the O&M costs including, variable O&M costs (i.e. reagent, waste disposal, auxiliary power and water), indirect operating costs (i.e. property taxes, insurance, and administrative services) and fixed O&M costs (i.e. operating personnel as well as maintenance material and labor) for all of the air pollution control options. Where possible, default factors from EPA's Control Cost Manual were used to calculate O&M costs. The approach used by S&L to generate capital cost estimates, O&M costs, and total annual costs is in general accordance with the methodology outlined in the Control Cost Manual.



COYOTE STATION UNIT 1

**NORTH DAKOTA REGIONAL HAZE SECOND PLANNING PERIOD  
FOUR-FACTOR ANALYSIS**

SL-014745

Final Rev 1

May 8, 2019

Project No. 12715-011

**Sargent & Lundy**

55 East Monroe Street • Chicago, IL 60603 USA • 312-269-2000  
[www.sargentlundy.com](http://www.sargentlundy.com)



## CONTENTS

<b>EXECUTIVE SUMMARY .....</b>	<b>1</b>
<b>1. INTRODUCTION .....</b>	<b>1-1</b>
<b>2. FACILITY DESCRIPTION.....</b>	<b>2-1</b>
<b>3. FOUR-FACTOR ANALYSIS REQUIREMENTS .....</b>	<b>3-2</b>
3.1 REGIONAL HAZE RULE BACKGROUND .....	3-2
3.1.1 First Implementation Period.....	3-4
3.1.2 Second Implementation Period .....	3-5
3.2 DESCRIPTIONS OF THE FOUR STATUTORY FACTORS .....	3-7
3.2.1 Costs of Compliance .....	3-7
3.2.2 Time Necessary for Compliance .....	3-9
3.2.3 Energy and Non-Air Quality Environmental Impacts.....	3-9
3.2.4 Remaining Useful Life .....	3-10
3.2.5 Four Factor Analysis Approach .....	3-11
<b>4. BASELINE SO<sub>2</sub> AND NO<sub>x</sub> EMISSIONS .....</b>	<b>4-1</b>
<b>5. SO<sub>2</sub> AND NO<sub>x</sub> CONTROL MEASURES.....</b>	<b>5-1</b>
5.1 SO <sub>2</sub> EMISSIONS CONTROLS .....	5-3
5.1.1 Identify Available SO <sub>2</sub> Control Options .....	5-3
5.1.2 Technical Feasibility of Available SO <sub>2</sub> Control Options .....	5-3
5.1.3 Evaluate Technically Feasible SO <sub>2</sub> Control Options for Effectiveness .....	5-21
5.2 NO <sub>x</sub> EMISSIONS CONTROLS .....	5-22
5.2.1 Identify Available NO <sub>x</sub> Control Options .....	5-22
5.2.2 Technical Feasibility of Available NO <sub>x</sub> Control Options .....	5-23
5.2.3 Evaluate Technically Feasible NO <sub>x</sub> Control Options for Effectiveness .....	5-38
<b>6. COSTS OF COMPLIANCE (STATUTORY FACTOR ONE).....</b>	<b>6-1</b>
6.1 ECONOMIC EVALUATION – SO <sub>2</sub> CONTROLS .....	6-2
6.2 ECONOMIC EVALUATION – NO <sub>x</sub> CONTROLS .....	6-5

<b>7. TIME NECESSARY FOR COMPLIANCE (STATUTORY FACTOR TWO)</b>	<b>7-1</b>
<b>8. ENERGY AND NON-AIR QUALITY ENVIRONMENTAL IMPACTS (STATUTORY FACTOR THREE)</b>	<b>8-1</b>
8.1 ENVIRONMENTAL IMPACTS	8-1
8.2 ENERGY IMPACTS	8-2
8.3 ENVIRONMENTAL / ENERGY IMPACTS SUMMARY	8-3
<b>9. REMAINING USEFUL LIFE (STATUTORY FACTOR FOUR)</b>	<b>9-1</b>
<b>10. FOUR-FACTOR ANALYSIS SUMMARY</b>	<b>10-1</b>

## FIGURES/TABLES

Figure 3-1. Federal Class I Areas	3-2
Figure 3-2. Regional Planning Organization Map	3-3
Figure 5-1. Comparison of Typical SDA/FF and Coyote Unit 1 SDA/FF Arrangement	5-8
Table ES-1. SO <sub>2</sub> Control Options for Coyote Unit 1	2
Table ES-2. NO <sub>x</sub> Control Options for Coyote Unit 1	2
Table ES-3. SO <sub>2</sub> Emissions Control System Cost Effectiveness (\$2018)	3
Table ES-4. NO <sub>x</sub> Emissions Control System Cost Effectiveness (\$2018)	4
Table ES-5. SO <sub>2</sub> Emissions Control System Implementation Schedule	5
Table ES-6. NO <sub>x</sub> Emissions Control System Implementation Schedule	5
Table ES-7. Summary of Energy and Non-Air Quality Environmental Impacts	6
Table 2-1. Process Parameters	2-1
Table 3-1. Key Steps in Developing Regional Haze SIPs for Second Planning Period	3-6
Table 4-1. Coyote Unit 1 Baseline Emissions	4-2
Table 5-1. Available SO <sub>2</sub> Control Options	5-3
Table 5-2. FGD Operational Improvements and Equipment Upgrades	5-4
Table 5-3. Existing SO <sub>2</sub> Removal Efficiencies	5-11
Table 5-4. New Scrubber Vessel SO <sub>2</sub> Removal Efficiencies	5-12
Table 5-5. DSI SO <sub>2</sub> Control Technology Estimated Emissions	5-15
Table 5-6. Layered (DSI + Ca:S) SO <sub>2</sub> Control Technology Estimated Emissions	5-16
Table 5-7. Technically Feasible SO <sub>2</sub> Control Options	5-20
Table 5-8. Evaluate Technically Feasible SO <sub>2</sub> Control Options for Effectiveness	5-22
Table 5-9. Available NO <sub>x</sub> Control Options	5-23
Table 5-10. Technically Feasible NO <sub>x</sub> Control Options	5-37



Table 5-11. Evaluate Technically Feasible NO <sub>x</sub> Control Options for Effectiveness .....	5-38
Table 6-1. SO <sub>2</sub> Control Cost Summary (\$2018).....	6-3
Table 6-2. SO <sub>2</sub> Emissions Control System Cost Effectiveness (\$2018).....	6-4
Table 6-3. NO <sub>x</sub> Control Cost Summary (\$2018) .....	6-5
Table 6-4. NO <sub>x</sub> Emissions Control System Cost Effectiveness (\$2018) .....	6-6
Table 7-1. SO <sub>2</sub> Emissions Control System Implementation Schedule .....	7-2
Table 7-2. NO <sub>x</sub> Emissions Control System Implementation Schedule .....	7-2
Table 8-1. Summary of Energy and Non-Air Quality Environmental Impacts .....	8-4

## APPENDIXES

- A. Coyote Unit 1 Baseline Emissions
- B. SO<sub>2</sub> Control Cost Effectiveness Estimates
- C. NO<sub>x</sub> Control Cost Effectiveness Estimates

## ABBREVIATIONS/ACRONYMS

Abbreviation/Acronym	Explanation
BACT	Best Available Control Technology
BART	Best Available Retrofit Technology
BFP	boiler feed pump
Ca	calcium
CaO	calcium oxide
Ca(OH) <sub>2</sub>	calcium hydroxide
CaSO <sub>3</sub>	calcium sulfite
CaSO <sub>4</sub>	calcium sulfate
CAA	Clean Air Act
CDS	circulating dry scrubber
CEMS	continuous emissions monitoring system
CFR	Code of Federal Regulations
CO	carbon monoxide
CO <sub>2</sub>	carbon dioxide
DFGD	dry flue gas desulfurization
DSI	dry sorbent injection
ESP	electrostatic precipitator
EPA	Environmental Protection Agency
EGU	electric generating unit
FF	fabric filter
FGD	flue gas desulfurization
G&A	general and administration
GHG	greenhouse gas
H <sub>2</sub> SO <sub>4</sub>	sulfuric acid
LNB	Low-NO <sub>x</sub> burner
LTS	Long-term strategy
MMBtu	million British thermal units
MNL	multi-nozzle lance
MRYS	Milton R. Young Station
MW	megawatt

---

MWg	megawatt gross
Na <sub>2</sub> CO <sub>3</sub>	sodium carbonate
ND	North Dakota
NDDEQ	North Dakota Department of Environmental Quality
NH <sub>3</sub>	ammonia
NO <sub>x</sub>	nitrogen oxides
NSR	New Source Review
NSR	normalized stoichiometric ratio
OEM	Original equipment manufacturer
OFA	overfire air
O&M	operations and maintenance
OTP	Otter Tail Power Company
PM	particulate matter
PRB	Powder River Basin
RPG	Reasonable Progress Goals
RPO	Regional Planning Organization
RRI	rich reagent injection
S	sulfur
S&L	Sargent & Lundy, L.L.C.
SBC	sodium bicarbonate
SBS	sodium bisulfate
SCR	selective catalytic reduction
SDA	spray dryer absorber
SIP	State Implementation Plan
SNCR	selective non-catalytic reduction
SO <sub>2</sub>	sulfur dioxide
SO <sub>3</sub>	sulfur trioxide
SOFA	separated overfire air
TE-SCR	tail-end SCR
URP	uniform rate of progress
WRAP	Western Region Air Partnership

---

## EXECUTIVE SUMMARY

Coyote Station, located near Beulah, ND, commenced commercial operation in 1981. The facility is a single unit station with one 451 MWg (approximate) Babcock and Wilcox cyclone boiler (Coyote Unit 1). Coyote Unit 1 is designed to fire North Dakota lignite, and is equipped with separated overfire air (SOFA) for NO<sub>x</sub> control, and dry flue gas desulfurization (DFGD or dry FGD) and fabric filter baghouse (FF) for SO<sub>2</sub> and particulate matter (PM) control. Lignite is delivered to the Station from the Coyote Creek Mine, whose primary operations are approximately 3-4 miles from the Coyote Station.

On July 1, 1999, the U.S. Environmental Protection Agency (EPA) published regulations implementing Section 169A of the CAA, establishing a comprehensive visibility protection program for Federal Class I areas (the Regional Haze Rule).<sup>1</sup> The Regional Haze Rule requires each state to develop, and submit for approval by EPA, a state implementation plan (SIP) detailing the state's plan to protect visibility in Class I areas. The Regional Haze Rule established a schedule setting forth deadlines by which the States must submit their initial regional haze SIPs and subsequent revisions to the SIPs. Regional Haze SIPs for the initial planning period were due in 2007, with subsequent SIP updates due in 2018 and every 10 years thereafter.<sup>2</sup> Second planning period Regional Haze SIPs must be submitted to EPA for review by July 31, 2021.

As part of North Dakota's SIP development for the second planning period, NDDEQ requested that Otter Tail prepare a "four factor" analysis for Coyote Unit 1. This evaluation reviews technically feasible SO<sub>2</sub> and NO<sub>x</sub> emissions reduction measures for the following four statutory factors:

1. The costs of compliance;
2. The time necessary for compliance;
3. The energy and non-air quality environmental impacts of compliance; and
4. The remaining useful life of any potentially affected anthropogenic source of visibility impairment.

Technically feasible SO<sub>2</sub> and NO<sub>x</sub> control strategies for Coyote Unit 1 are included in Table ES-1 and Table ES-2. The tables also show baseline emission rates and estimated emission reductions for each control option.

---

<sup>1</sup> 64 FR 35713

<sup>2</sup> On January 10, 2017, EPA made a one-time adjustment to the due date for the second implementation period SIPs (2018 – 2028) by extending the deadline from July 31, 2018 to July 31, 2021 (82 FR 3078).



Table ES-1. SO<sub>2</sub> Control Options for Coyote Unit 1

Control Option	SO <sub>2</sub> Emission Rate tons/yr	% Reduction from Baseline Emission Rate
Baseline (existing DFGD/FF)	12,994	-
DSI + Existing FGD	8,863	32%
FGD Operational Improvements – Increase Ca:S Stoichiometric Ratio	7,641	41%
DSI + FGD Operational Improvements	5,043	61%
FGD Upgrades - Replacing Existing Absorbers with New Absorber	4,432	66%
Dry FGD (CDS) + Existing FF	1,375	89%
Wet FGD	917	93%

Table ES-2. NO<sub>x</sub> Control Options for Coyote Unit 1

Control Option	NO <sub>x</sub> Emission Rate tons/yr	% Reduction from Baseline Emission Rate
Baseline (existing SOFA)	7,363	-
Combustion Optimization	6,775	8%
SNCR + Combustion Optimization	4,516	39%
SNCR + RRI + Combustion Optimization	3,226	56%

### Costs of Compliance (Statutory Factor One)

Capital and O&M cost estimates were developed for each of the technically feasible SO<sub>2</sub> and NO<sub>x</sub> control options. The Coyote Unit 1 cost estimates are conceptual in nature; thus, S&L did not procure equipment quotes specifically for the Unit 1 control system upgrades. Rather, equipment costs are based on conceptual designs developed for the retrofit control systems, preliminary equipment sizing developed for the major pieces of equipment (based on Coyote Unit 1-specific design parameters, including typical fuel characteristics, full load heat input, and flue gas temperatures and flow rates), and recent pricing for similar equipment.

Table ES-3 and Table ES-4 include estimated costs for SO<sub>2</sub> and NO<sub>x</sub> control options for Coyote Unit 1. The tables provide the estimated annualized capital and operating and maintenance (O&M) costs, estimated emissions reductions, average annual cost effectiveness. The tables also include the incremental cost effectiveness that compares the costs and performance of a control option to those of the next most stringent option.

**Table ES-3. SO<sub>2</sub> Emissions Control System Cost Effectiveness (\$2018)**

SO <sub>2</sub> Control Option	Total Annualized Cost	Expected Emission Reduction	Average Annual Cost Effectiveness (Note 1)	Incremental Annual Cost Effectiveness (Note 2, 3)
	\$/yr	tons SO <sub>2</sub> /yr	\$/ton SO <sub>2</sub> removed	\$/ton SO <sub>2</sub> removed
Baseline (Existing DFGD/FF)	---	---	---	---
DSI + Existing FGD	\$12,371,000	4,131	\$2,994	
FGD Operational Improvements – Increase Ca:S Stoichiometric Ratio	\$2,085,000	5,354	\$389	n/a
DSI + FGD Operational Improvements	\$14,456,000	7,952	\$1,818	\$4,762
FGD Upgrades - Replacing Existing Absorbers with New Absorber	\$22,197,000	8,563	\$2,592	\$12,664
Dry FGD (CDS) + Existing FF	\$40,495,000	11,619	\$3,485	\$5,987
Wet FGD	\$49,094,000	12,078	\$4,065	\$18,757

Note 1. Average cost effectiveness for each control option is the total annual cost divided by the expected emission reduction.

Note 2. Incremental cost effectiveness represents the incremental increase in annual costs (\$/yr) divided by the incremental increase in annual emissions reductions (tpy) between a control option and the next most effective option.

Note 3. "n/a" indicates that the next most effective control option is "inferior" (i.e., higher cost for less control)

**Table ES-4. NO<sub>x</sub> Emissions Control System Cost Effectiveness (\$2018)**

NO <sub>x</sub> Control Option	Total Annualized Cost \$/yr	Expected Emission Reduction tons NO <sub>x</sub> /yr	Average Annual Cost Effectiveness (Note 1) \$/ton NO <sub>x</sub> removed	Incremental Annual Cost Effectiveness (Note 2) \$/ton NO <sub>x</sub> removed
Baseline (Existing SOFA)	---	---	---	---
Combustion Optimization	\$0	589	\$0	\$0
SNCR + Combustion Optimization	\$4,754,000	2,847	\$1,670	\$2,105
SNCR + RRI + Combustion Optimization	\$8,617,000	4,137	\$2,083	\$2,994

Note 1. Average cost effectiveness for each control option is the total annual cost divided by the expected emission reduction.

Note 2. Incremental cost effectiveness represents the incremental increase in annual costs (\$/yr) divided by the incremental increase in annual emissions reductions (tpy) between a control option and the next most effective option.

#### Time Necessary for Compliance (Statutory Factor Two)

Table ES-5 and Table ES-6 provide estimated timeframes needed to implement each of the technically feasible control option. Notably, the estimated timeframes do not account for time needed for North Dakota to develop and implement the regulations; nor the amount of time needed for EPA to take proposed and final action to approve North Dakota's SIP.



Table ES-5. SO<sub>2</sub> Emissions Control System Implementation Schedule

SO <sub>2</sub> Control Option	Design / Specification / Procurement (months)	Detail Design / Fabrication (months)	Construction / Commissioning / Startup (months)	Total (months after SIP approval)
DSI + Existing FGD	6	6	6	18
FGD Operational Improvements – Increase Ca:S Stoichiometric Ratio	0	0	0	0
DSI + FGD Operational Improvements	6	6	6	18
FGD Upgrades - Replacing Existing Absorbers with New Absorber	8	12	12	32
Dry FGD (CDS) + Existing FF	12	20	18	50
Wet FGD	12	22	22	56

Table ES-6. NO<sub>x</sub> Emissions Control System Implementation Schedule

NO <sub>x</sub> Control Option	Design / Specification / Procurement (months)	Detail Design / Fabrication (months)	Construction / Commissioning / Startup (months)	Total (months after SIP approval)
Combustion Optimization	0	0	0	0
SNCR + Combustion Optimization	10	6	6	22
SNCR + RRI + Combustion Optimization	10	6	6	22



### Energy and Non-Air Quality Environmental Impacts (Statutory Factor Three)

An evaluation of energy impacts indicates that certain control options (e.g., new FGD systems) will increase auxiliary power requirements due to increased pressure drop, which would adversely impact net plant heat rate. Consequently, heat input to the boiler would need to increase to compensate for the increased auxiliary power requirements while achieving the same net plant output, or net output from the unit would decrease. Collateral environmental impacts include an increase in the solid waste generation with DSI. A summary of the environmental and energy impact analysis is provided in Table ES-7.

**Table ES-7. Summary of Energy and Non-Air Quality Environmental Impacts**

Control Option	Collateral Environmental & Energy Impacts
<b><u>SO<sub>2</sub> Control Options</u></b>	
Replace existing DFGD with New WFGD control system	<ul style="list-style-type: none"> <li>➤ Increased water consumption</li> <li>➤ Wet by-product that requires dewatering prior to disposal</li> <li>➤ FGD wastewater treatment &amp; discharge</li> <li>➤ Increased auxiliary power requirements and heat rate penalty</li> </ul>
Replace existing DFGD with New CDS/FF Control System	<ul style="list-style-type: none"> <li>➤ Increased auxiliary power requirements and heat rate penalty</li> <li>➤ Increased solid FGD by-product management and disposal</li> </ul>
Replace existing dry scrubber modules with New DFGD modules while keeping existing FF	<ul style="list-style-type: none"> <li>➤ Requires extended (approximately 12-month) outage of Coyote Unit 1 to demolish and replace the existing scrubber modules</li> </ul>
Dry Sorbent Injection	<ul style="list-style-type: none"> <li>➤ Increased solid FGD by-product management and disposal</li> <li>➤ Increased auxiliary power requirements and heat rate penalty</li> </ul>
<b><u>NO<sub>x</sub> Control Options</u></b>	
SNCR or SNCR + RRI	<ul style="list-style-type: none"> <li>➤ Increased ammonia slip emissions</li> <li>➤ Increased auxiliary power requirements and heat rate penalty</li> </ul>

### Remaining Useful Life (Statutory Factor Four)

The Coyote Station owners have not identified dates for the remaining useful life of the unit before the end of what would otherwise be the useful life of the control measures that were evaluated for Coyote Unit 1. Thus, the 20-year

equipment life of the control measures was used in the four factor analysis to calculate emission reductions, amortized costs, and cost-effectiveness.

## 1. INTRODUCTION

Sargent & Lundy, L.L.C. (S&L) was retained by Otter Tail Power Company (Otter Tail) to prepare a Reasonable Progress four-factor analysis for the control of sulfur dioxide (SO<sub>2</sub>) and nitrogen oxide (NO<sub>x</sub>) emissions from Coyote Station Unit 1 (Coyote Unit 1).<sup>3</sup> The evaluation is in response to North Dakota Department of Environmental Quality's (NDDEQ) request that Otter Tail prepare a four factor analysis for Coyote Unit 1.

The evaluation includes an assessment of potentially available emission reduction measures for the four statutory factors listed in 40 CFR 51.308(f)(2), and takes into consideration U.S. Environmental Protection Agency's (EPA's) *Draft Guidance on Progress Tracking Metrics, Long Term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period* (the "Draft EPA Guidance").<sup>4</sup> Technically feasible SO<sub>2</sub> and NO<sub>x</sub> emission reduction measures are evaluated for the following four statutory factors:

- Factor 1: The cost of compliance
- Factor 2: The time necessary to achieve compliances
- Factor 3: The energy and non-air quality environmental impact of compliance
- Factor 4: The remaining useful life of any existing source subject to such requirements

The Reasonable Progress four factor analysis for Coyote Unit 1 (the "Four Factor Analysis") is presented in the following sections:

- Section 2: Facility Description** contains information describing the facility, site location, and existing equipment.
- Section 3: Four-Factor Analysis Requirements** provides a brief description of the Regional Haze Program requirements set forth in 40 CFR 51.308.
- Section 4: Baseline SO<sub>2</sub> and NO<sub>x</sub> Emissions** establishes representative baseline SO<sub>2</sub> and NO<sub>x</sub> emissions for the period 2013 to present.

<sup>3</sup> Coyote Station is co-owned by Otter Tail Power Company (35%), Northern Municipal Power Agency (30%), Montana-Dakota Utilities Co. (25%), and NorthWestern Energy (10%).

<sup>4</sup> On September 11, 2018, EPA released a "Regional Haze Reform Roadmap" announcing its plan to "release a series of implementation tools and guidance documents that will help focus states' efforts and reduce and streamline the time and resources needed to meet the statutory and regulatory requirements for reducing regional haze in National Parks, wildlife refuges, and wilderness areas." EPA stated that it plans to issue a new guidance document on Regional Haze SIP Development by Spring, 2019. Otter Tail Power reserves the right to update and modify this four-factor analysis, as needed, to be consistent with any new guidance issued by the agency.

**Section 5: SO<sub>2</sub> and NO<sub>x</sub> Control Measures** identifies potentially available emission control technologies, and evaluates each control option for technical feasibility and effectiveness.

**Section 6: Costs of Compliance (Statutory Factor One)** evaluates the cost and cost-effectiveness of each technically feasible control option.

**Section 7: Time Necessary for Compliance (Statutory Factor Two)** provides typical timelines required to design, engineer, procure and install the technically feasible control options.

**Section 8: Energy and Non-Air Quality Environmental Impacts (Statutory Factor Three)** identifies the energy and non-air quality environmental impacts associated with each technically feasible control option.

**Section 9: Remaining Useful Life (Statutory Factor Four)** includes a discussion of the planned remaining useful life of Coyote Unit 1.

**Section 10: Summary and Conclusions**

**Appendix A: Coyote Unit 1 Baseline Emissions**

**Appendix B: SO<sub>2</sub> Control Cost Effectiveness Estimates**

**Appendix C: NO<sub>x</sub> Control Cost Effectiveness Estimates**



## 2. FACILITY DESCRIPTION

Coyote Station, located near Beulah, ND, commenced commercial operation in 1981. The facility is a single unit station with one 451 MWg (approximate) Babcock and Wilcox cyclone boiler (Coyote Unit 1). Coyote Unit 1 is designed to fire North Dakota lignite, and is equipped with separated overfire air (SOFA) for NO<sub>x</sub> control, and dry flue gas desulfurization (DFGD or dry FGD) and fabric filter baghouse (FF) for SO<sub>2</sub> and particulate matter (PM) control. Lignite is delivered to the Station from the Coyote Creek Mine, whose primary operations are approximately 3-4 miles from the Coyote Station.

Table 2-1 provides a summary of the process parameters used for the Coyote Unit 1 Four Factor Analysis. Process parameters listed in Table 2-1 were developed from information provided by OTP.<sup>5</sup>

Table 2-1. Process Parameters

Process Parameter	Coyote Unit 1
Boiler Type	Cyclone
Boiler Manufacturer	B&W
Full Load (MWg)	451
Full Load Boiler Heat Input (MMBtu/hr)	4,900
Full Load Coal Flow (lb/hr)	700,700
Boiler Excess Air (%)	14.0
Air Heater Leakage (%)	22.0
Bottom Ash/Fly Ash Ratio	65/35
Flue Gas Conditions at Air Heater Outlet	
Temperature (F)	330
Mass Flow Rate (lb/hr)	6,532,000
Volumetric Flow rate (acfm)	2,485,000
Annual Average Fuel Sulfur Content (%)	0.82 - 1.06
Annual Average Uncontrolled SO <sub>2</sub> Emissions <sup>6</sup> (lb/MMBtu)	2.42 - 3.12

<sup>5</sup> These process parameters are representative of typical average conditions. They should not be construed as maximum values or unit design values.

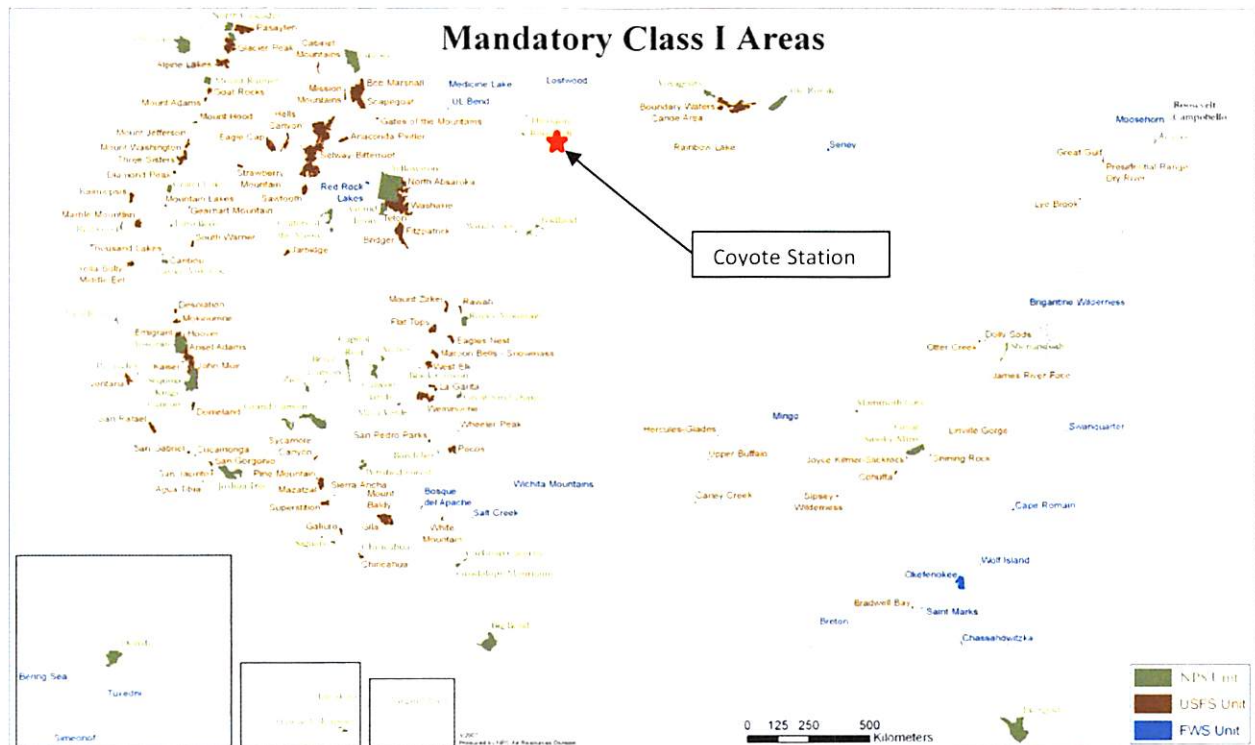
<sup>6</sup> Assuming 100% conversion of fuel sulfur to SO<sub>2</sub>.

### 3. FOUR-FACTOR ANALYSIS REQUIREMENTS

#### 3.1 REGIONAL HAZE RULE BACKGROUND

Section 169A of the 1977 Amendments to the Clean Air Act (CAA) sets forth a program for protecting visibility in Federal Class I areas which calls for the “prevention of any future, and the remedying of any existing, impairment of visibility in mandatory Federal Class I areas which impairment results from manmade air pollution.” Federal Class I areas include national parks, memorial parks, and wilderness areas over a certain size. Figure 3-1 shows the locations of the 156 federally mandated Class I areas. Federal Class I areas located within North Dakota include the Theodore Roosevelt National Park and the Lostwood National Wildlife Refuge.

Figure 3-1. Federal Class I Areas



On July 1, 1999, the U.S. Environmental Protection Agency (EPA) published regulations implementing Section 169A of the CAA, establishing a comprehensive visibility protection program for Federal Class I areas (the Regional Haze Rule).<sup>7</sup> The Regional Haze Rule requires each state to develop, and submit for approval by EPA, a

<sup>7</sup> 64 FR 35713

state implementation plan (SIP) detailing the state's plan to protect visibility in Class I areas. In 2017, EPA issued a final rule revising portions of the 1999 Regional Haze Rule.<sup>8</sup> The 2017 Rule requires states to determine the baseline (2000 - 2004) visibility condition for the 20 percent most impaired days and requires that the long-term strategy and reasonable progress goals (RPGs) must provide for improvement in visibility for the most impaired days, relative to the baseline period. Specifically, states must determine the rate of improvement in visibility that would need to be maintained during each implementation period in order to reach natural conditions by 2064 for the 20 percent most impaired days, given the starting point of the baseline visibility condition.

To address the combined visibility effects of various pollution sources over a wide geographic region, EPA designated five Regional Planning Organizations (RPOs) to assist with the coordination and cooperation needed to address the visibility issue. The five RPOs are shown in Figure 3-2. North Dakota is a member of the Western Regional Air Partnership (WRAP), which serves as the RPO for visibility protection at 118 Class I areas in the 15 western states.

**Figure 3-2. Regional Planning Organization Map**



<sup>8</sup> Final Rule: Protection of Visibility: Amendments to Requirements for State Plans, 82 FR 3078, January 10, 2017



### 3.1.1 First Implementation Period

The Regional Haze Rule established a schedule setting forth deadlines by which the States must submit their initial regional haze SIPs and subsequent revisions to the SIPs. Regional Haze SIPs for the initial planning period were due in 2007, with subsequent SIP updates due in 2018 and every 10 years thereafter.<sup>9</sup>

Regional Haze SIP requirements for the first planning period required that states incorporate into their plans the core program requirements in 40 CFR 51.308(d), including: (1) establishing reasonable progress goals (RPGs) for each Class I area within the state that provide for measurable progress towards achieving natural visibility conditions; (2) developing a long-term strategy (LTS) including enforceable emissions limitations and compliance schedules to achieve the RPGs; and (3) developing plans to monitor and assess the effectiveness of the LTS to achieve the RPGs over the prior implementation period and affirmation of or revision to the RPGs.

The Regional Haze Rule requires that states determine the consistent rate of progress over time needed to attain natural visibility conditions on the 20 percent most anthropogenically impaired days by the year 2064. This “glidepath” is referred to as the uniform rate of progress (URP) line. States must consider the URP, and the emission reduction measures needed to achieve this level of improvement, when developing their RPGs and LTS. Regulations at 40 CFR 51.308(g) require each state to submit progress reports, in the form of SIP revisions, every 5 years following the submission of the initial SIP. These progress reports must evaluate the progress made towards the RPGs for Class I areas located within the state as well as those Class I areas located outside the state that may be affected by emissions from within the state.

#### 3.1.1.1 Best Available Retrofit Technology

As a one-time requirement during the first implementation period, potential best available retrofit technology (BART) controls had to be evaluated for certain large stationary sources. States were required to conduct BART determinations for “BART-eligible” sources anticipated to cause or contribute to any visibility impairment in one or more Class I area. BART-eligible sources included coal-fired electric generating units (EGUs) that were in existence on August 7, 1977, but not in operation prior to August 7, 1962. In its determination of BART, states were required to take into consideration the costs of compliance, the energy and nonair quality environmental impacts of compliance, any existing pollution control technology in use at the source, the remaining useful life of

---

<sup>9</sup> On January 10, 2017, EPA made a one-time adjustment to the due date for the second implementation period SIPs (2018 – 2028) by extending the deadline from July 31, 2018 to July 31, 2021 (82 FR 3078).



the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.<sup>10</sup> As an alternative to requiring source-specific BART controls, states also had the flexibility to adopt an emissions trading program or other alternative program as long as the alternative provided greater reasonable progress towards improving visibility than BART.

#### 3.1.1.2 Reasonable Progress Control Requirements for Coyote Station during First Planning Period

Coyote Unit 1 commenced operation in 1981, and was not classified as a BART-eligible source or subject to the BART requirements. Nevertheless, during the initial planning period, the North Dakota Department of Environmental Quality (NDDEQ) evaluated emissions from the Coyote Station as a reasonable progress source. The reasonable progress analysis prepared by NDDEQ concluded that no additional controls would be required on Coyote Unit 1 during the initial planning period; however, NDDEQ and Otter Tail reached an agreement whereby Otter Tail committed to install SOFA equipment to reduce NO<sub>x</sub> emissions. In the initial planning period SIP NDDEQ noted that additional SO<sub>2</sub> and NO<sub>x</sub> controls for Coyote Unit 1 would be reevaluated during future planning periods to determine if additional emissions reductions would be required.

#### 3.1.2 Second Implementation Period

Second planning period Regional Haze SIPs must be submitted to EPA for review by July 31, 2021. Among other requirements, second planning period SIPs are required to include an assessment of the state's RPGs and LTS. To support states in their efforts to develop the second planning period SIPs, in July 2016 EPA released a draft guidance document titled "*Draft Guidance on Progress Tracking Metrics, Long-term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period*" ("Draft EPA Guidance").<sup>11</sup> The Draft EPA Guidance document describes key steps states should implement when developing their RPGs and LTS for the second implementation period. Key steps identified in the Draft EPA Guidance are listed in Table 3-1.

<sup>10</sup> CAA Section 169A(g)(2).

<sup>11</sup> See, EPA-457/P-16-001. On September 11, 2018, EPA released a "*Regional Haze Reform Roadmap*" announcing its plan to "release a series of implementation tools and guidance documents that will help focus states' efforts and reduce and streamline the time and resources needed to meet the statutory and regulatory requirements for reducing regional haze in National Parks, wildlife refuges, and wilderness areas." EPA stated that it plans to issue a new guidance document on Regional Haze SIP Development by Spring, 2019. Otter Tail Power reserves the right to update and modify this four-factor analysis, as needed, to be consistent with any new guidance issued by the agency.

Table 3-1. Key Steps in Developing Regional Haze SIPs for Second Planning Period

1. *Ambient data analysis* – Quantify baseline, current and natural conditions and the uniform rate of progress that would achieve natural conditions in 2064 (40 CFR 51.308(f)(1))
2. *Screening of sources* – Identify the pollutants and emission sources for which a full reasonable progress analysis will be completed and explain why it is appropriate to limit the full analysis to only these sources (40 CFR 51.308(f)(2))
3. *Source and emission control measure analysis* – Identify potential emission control measures for sources selected in the screening step and develop data on the four statutory factors and visibility benefits if they will be considered (40 CFR 51.308(f)(2))
4. *Decisions on the content of the LTS* – Consider applicable factors and decide on new emission controls for incorporation into the LTS (40 CFR 51.308(f)(2))
5. *Regional scale modeling* – Model the emissions reductions that will result from implementation of the LTS and other enforceable measures that will reduce visibility impairment to set the RPGs for 2028 (40 CFR 51.308(f)(3))
6. *Progress, degradation and glidepath checks* – Demonstrate that there will be an improvement on the 20 percent most impaired days. Demonstrate that there is no degradation on the 20 percent clearest days. Compare the 2028 RPG for the 20 percent most impaired days to the 2028 point on the URP line (the glidepath) and, if required, provide additional justification for the reasonableness of the RPG. Revise the LTS if additional measures are identified as necessary to make reasonable progress. (40 CFR 51.308(f)(3))
7. *Additional requirements for SIPs* – Provide additional information necessary to ensure that other requirements of the Regional Haze rule are met.

The Draft EPA Guidance recommends that states evaluate all technically feasible emission control options for stationary sources and source categories identified as having the greatest potential to impact visibility at one or more Class I area. The Draft EPA Guidance recommends several options for states to consider when evaluating potential emission reductions, including work practices, replacement and retrofit controls, existing control upgrades, fuel switching year-round operation of controls, and operating restrictions.<sup>12</sup>

Emission control evaluations must consider the four statutory factors identified in 40 CFR 51.308(f)(2)(i) (discussed in Section 3.2). In addition, the Draft EPA Guidance notes that control technology assessment recommendations presented in the BART Guidelines continue to be relevant as recommendations for how a state

<sup>12</sup> See, Draft EPA Guidance, pgs. 85-86.



should evaluate and select emission control measures for stationary sources.<sup>13</sup> Recommendations in the BART Guidelines that continue to be relevant to the Regional Progress Four Factor Analysis are listed in Appendix D of the Draft EPA Guidance, and include, in general, the recommended approach for evaluating the technical feasibility, effectiveness, costs, and cost-effectiveness of available emission control measures.<sup>14</sup>

## 3.2 DESCRIPTIONS OF THE FOUR STATUTORY FACTORS

Under 40 CFR 51.308(f)(2)(i), states must consider four statutory factors when evaluating and determining emissions reduction measures from stationary sources, or groups of sources, that are necessary to make reasonable progress towards achieving natural visibility conditions. The four statutory factors are:

5. The costs of compliance;
6. The time necessary for compliance;
7. The energy and non-air quality environmental impacts of compliance; and
8. The remaining useful life of any potentially affected anthropogenic source of visibility impairment.

A brief description of each of the four statutory factors, and EPA's recommendations for evaluating each of the four factors (from the Draft EPA Guidance) is provided below.

### 3.2.1 Costs of Compliance

Cost estimates should be developed for each technically feasible control option. Costs include the total capital costs to engineer, design, procure, and install the control technology, and annual operating and maintenance (O&M) costs. O&M costs include both fixed and variable O&M. Fixed O&M includes costs that are independent of control system operation and would be incurred even if the control system were shut down. Fixed O&M includes categories such as operating and maintenance labor, administrative charges, property taxes, and insurance. Variable O&M includes the cost of consumables, including reagent (e.g., lime or limestone, ammonia, urea, etc.), by-product management, water consumption, and auxiliary power requirements associated with operating the control system. For existing facilities, O&M cost estimates should represent the control option's incremental increase over current O&M costs.

<sup>13</sup> Draft EPA Guidance, pg. 85. The BART Guidelines are published at 40 CFR Part 51 Appendix Y.

<sup>14</sup> Draft EPA Guidance, Appendix D, pgs. 186-196.

Capital costs include all costs required to engineer, design, procure, and install equipment needed for the control system. The Draft EPA Guideline recommends that states adhere to the accounting principles described in Chapter 2 Section 1 of EPA's Air Pollution Control Cost Manual (the "Control Cost Manual") when calculating control system costs for a four factor analysis.<sup>15</sup>

Section 2.3 of the Control Cost Manual (Section 1, Chapter 2) describes the cost categories generally used to calculate the total capital cost of a retrofit control technology. Cost categories include total capital investment (TCI), which is defined to "include all costs required to purchase equipment needed for the control systems (purchased equipment costs), the costs of labor and materials for installing that equipment (direct installation costs), costs for site preparation and buildings, and certain other costs (indirect installation costs). TCI also includes costs for land, working capital, and off-site facilities." Direct installation costs include costs for foundations and supports, erecting and handling the equipment, electrical work, piping, insulation, and painting. Indirect installation costs include costs such as engineering costs; construction and field expenses (i.e., cost for construction supervisory personnel, office personnel, rental of temporary offices, etc.); contractor fees (for construction and engineering firms involved in the project); start-up and performance test costs (to get the control system running and to verify that it meets performance guarantees); and contingencies.<sup>16</sup>

The total annual cost (TAC) of a control option includes the annualized capital recovery cost plus the total annual O&M costs. The Control Cost Manual recommends using an equivalent uniform annual cash flow method to annualize the total capital investment by multiplying the total capital investment by a capital recovery factor (CRF).<sup>17</sup> The product of the total capital investment and CRF gives a uniform end-of-year payment necessary to repay the initial capital investment in "n" years at an interest rate of "i". The CRF is calculated using the following equation:

$$CRF = \frac{i * (1 + i)^n}{(1 + i)^n - 1}$$

Where:

i = interest rate; and

n = economic life of the emission control system

The Draft EPA Guidance suggests that states may use generic cost estimates or estimating algorithms for estimating

<sup>15</sup> Draft EPA Guidance, pg.89.

<sup>16</sup> EPA Air Pollution Control Cost Manual, Sixth Edition, EPA/452/B-02-001, January 2002, pg. 2-5.

<sup>17</sup> Id., at pg 2-21.

control system costs; however, source specific estimates prepared by knowledgeable engineering professionals provide more reliable information than generic cost estimates.<sup>18</sup> Source-specific cost estimate should be well documented for purposes of public comment and EPA review.<sup>19</sup>

The total annual cost of each control option (\$/yr) is divided by the total annual emissions reduction (tpy) to determine the control option's average cost-effectiveness on a \$/ton basis. Emissions reductions are calculated based on the difference between baseline annual emissions and post-control annual emissions. The Draft EPA Guidance generally recommends calculating baseline emissions based on projected 2028 emissions assuming source compliance with emission limits that have been adopted and are enforceable. As an alternative, baseline emissions may be based on representative past actual emissions, assuming there is no evident basis for using a different emissions rate.

### 3.2.2 Time Necessary for Compliance

For stationary sources, the provisions of the BART Guidelines regarding the time necessary for compliance are relevant to reasonable progress analyses. EPA recommends that prior experiences with the planning and installation of new emission controls is the best guide to how much time a particular source will reasonably need for compliance. However, source-specific factors should be considered when evaluating the time necessary to engineer, procure, and install an available and technically feasible control option. Source-specific factors that affect the time necessary to install new emission controls should be identified and documented in the four factor analysis.

### 3.2.3 Energy and Non-Air Quality Environmental Impacts

For stationary sources, the provisions of the BART Guidelines regarding energy impacts are relevant to reasonable progress analyses. Energy impacts of an emission control measure are a matter of engineering design and control system operation; thus, EPA recommends that prior experience at similar sources will be informative. Energy impacts may be considered in terms of kilowatt-hours or fuels used to operate the control system. The energy impact analysis should focus on direct energy consumption at the source rather than indirect energy inputs needed to produce raw materials for the construction and operation of control equipment.

---

<sup>18</sup> Draft EPA Guidance, pg. 91.

<sup>19</sup> Id.



For stationary sources, the provisions of the BART Guidelines regarding non-air quality environmental impacts are relevant to reasonable progress analyses. Non-air quality impacts include solid or hazardous waste generation, increased water consumption, wastewater discharge, land use impacts, and impacts to threatened and endangered species or their natural habitat. Characterizing the non-air quality environmental impacts should be done on a source-specific basis. Other guidance intended for use in assessments under the National Environmental Policy Act may be relevant to this evaluation.

Even though states are not required to consider GHG emission impacts, the Draft EPA Guidance encourages states to consider GHG impacts when developing their Long-Term Strategy.<sup>20</sup> As an example, some measures that would reduce emissions that contribute to visibility impairment will also reduce GHG emissions, such as measures that reduce the use of energy produced from combusting fossil fuels with relatively high GHG emissions. Conversely, control measures that require significant energy to capture visibility impairing emissions could result in increased GHG emission. Where a measure necessary to make reasonable progress towards natural visibility conditions would increase GHG emissions, Draft EPA Guidance encourages states to work to harmonize visibility and climate change objectives.<sup>21</sup>

### 3.2.4 Remaining Useful Life

For stationary sources, the provisions of the BART Guidelines regarding remaining useful life are relevant to reasonable progress analyses. In general, the remaining useful life of the source itself will be longer than the useful life of the emission control measure under consideration unless there is an enforceable requirement for the source to cease operation sooner. Thus, the useful life of the control measure will normally be used in the four factor analysis to calculate emission reductions, amortized costs, and cost-effectiveness. However, if there is an enforceable requirement for the source to cease operation by a date before the end of what would otherwise be the useful life of the control measure under consideration, then the enforceable shutdown date should be used to calculate remaining useful life and evaluate control technology cost-effectiveness.

---

<sup>20</sup> Draft EPA Guidance, pg. 92.

<sup>21</sup> Id.

### 3.2.5 Four Factor Analysis Approach

S&L used the following approach to identify SO<sub>2</sub> and NO<sub>x</sub> emission control options available to Coyote Unit 1 for inclusion in the Four Factor Analysis:

1. Establish representative baseline emissions achieved with existing controls.
2. Identify all potentially available control options.
3. Evaluate control options for technical feasibility (i.e., availability and applicability).
4. Eliminate control options that are not technically feasible or would have no practical application on Coyote Unit 1.
5. Determine the control effectiveness of each technically feasible control option.
6. Evaluate each technically feasible control option for the four statutory factors.

## 4. BASELINE SO<sub>2</sub> AND NO<sub>x</sub> EMISSIONS

The first step in developing the Four Factor Analysis is to establish Coyote Unit 1 baseline SO<sub>2</sub> and NO<sub>x</sub> emissions. To establish representative baseline emissions, S&L evaluated Coyote Unit 1 operating data for the period January 1, 2013 to June 30, 2018 to identify periods of normal operation (i.e., periods of operation when the boiler was not limited by infrequent or extraordinary operating restrictions). Based on review of fuels consumed, heat input to the boiler, boiler heat rates, power generation, and capacity factors, as well as input from OTP, it was determined that the operating periods of January 1, 2013 to December 31, 2014 and January 1, 2016 to June 30, 2018 were representative of normal operation. The year 2015 was not considered to be representative because Coyote Unit 1 was limited to approximately 50% load due to a boiler feed pump (BFP) overspeed event that damaged one of the unit's two 50% BFPs; thus, only one BFP was available throughout most of the year. Therefore, the periods January 1, 2013 to December 31, 2014, and January 1, 2016 to June 30, 2018 are representative of normal operation during the baseline period, and it was determined that SO<sub>2</sub> emissions during that period are also representative. In June 2016, Unit 1 SOFA upgrades were completed for the purpose of reducing NO<sub>x</sub> emissions; thus, the representative baseline period for NO<sub>x</sub> emissions was determined to be from July 1, 2016 to June 30, 2018.

Baseline annual SO<sub>2</sub> and NO<sub>x</sub> emissions were determined based on data obtained from the Coyote Unit 1 continuous emissions monitoring system (CEMS) that was reported to EPA's Clean Air Markets. The annual average emission rate during the representative time period was used to establish baseline annual emissions (in terms of tons per year). Representative baseline emission factors (in terms of pounds per million British Thermal Units (lb/MMBtu)) were developed using baseline annual average emissions and the respective baseline heat inputs. Table 4-1 provides a summary of the Coyote Unit 1 SO<sub>2</sub> and NO<sub>x</sub> representative baseline emissions; additional details are included in Appendix A.



Table 4-1. Coyote Unit 1 Baseline Emissions

Pollutant	Baseline Controls	Emissions		Heat Input	Notes
		lb/MMBtu	tons/yr	MMBtu/yr	
SO <sub>2</sub>	DFGD/FF	0.85	12,994	30,562,287	SO <sub>2</sub> emissions based on annual average tpy for period January 2013-June 2018 (excluding 2015)
NO <sub>x</sub>	SOFA	0.46	7,363	32,301,802	NO <sub>x</sub> emissions based on annual average tpy for period July 2016 to June 2018 (post-SOFA upgrades)

## 5. SO<sub>2</sub> AND NO<sub>x</sub> CONTROL MEASURES

S&L used a top-down approach to identify and evaluate the technical feasibility and effectiveness of potentially available SO<sub>2</sub> and NO<sub>x</sub> control measures. S&L followed Steps 1 thru 3 of the top-down approach described in the BART Guidelines to identify all available retrofit emission control measures, eliminate technically infeasible options, and evaluate the effectiveness of the technically feasible options.<sup>22</sup> A brief description of each step is provided below.

### *Step 1 - Identify All Available Control Options*

Available control options are those air pollution control technologies with a practical potential for application to the emission unit and the regulated pollutant under evaluation. Air pollution control technologies can include a wide variety of available methods, systems, and techniques for control of the affected pollutant, and include not only existing controls for the source category but also take into account technology transfer of controls that have been applied to similar source categories and gas streams. Technologies which have not been applied to (or permitted for) full scale operations need not be considered as available.<sup>23</sup>

In an effort to identify all potentially available emission control technologies, S&L searched a broad range of information sources including, but not necessarily limited to:

- EPA's RACT/BACT/LAER Clearinghouse;
- EPA's New Source Review (NSR) and Clean Air Technology Center (CATC) Web sites;
- BART evaluations prepared during the initial Regional Haze planning period;
- Information from control technology vendors and engineering/environmental consultants;
- Federal and State NSR permits and Best Available Control Technology (BACT) determinations for similar sources; and
- Technical journals, reports, newsletters and air pollution control seminars.

### *Step 2 - Eliminate Technically Infeasible Control Options*

In Step 2, S&L evaluated the technical feasibility of the control options identified in Step 1 with respect to source-specific and unit-specific factors. Control technologies are technically feasible if either: (1) they have been

<sup>22</sup> See, 40 CFR Part 51 Appendix Y, Section IV.D.

<sup>23</sup> Id., at IV.D.1.

installed and operated successfully for the type of source under review under similar conditions; or (2) the technology could be applied to the source under review. In order for a control option to be technically feasible, it must be “available” and “applicable” to the source under consideration. A technology is considered “available” if the source owner may obtain it through commercial channels. An available technology is “applicable” if it can reasonably be installed and operated on the source type under consideration.<sup>24</sup>

Control technologies that are technically infeasible (i.e., not available or not applicable to the source under consideration) are eliminated for further evaluation. A demonstration of technical infeasibility must be based on physical, chemical and engineering principals, and must show that technical difficulties would preclude the successful use of the control option on the emission unit under consideration. The economics of an option are not considered in the determination of technical feasibility/infeasibility.

### *Step 3 - Evaluate Technically Feasible Control Technologies for Effectiveness*

Step 3 involves evaluating the control effectiveness of all the technically feasible control alternatives identified in Step 2 for the pollutant and emissions unit under review. Control effectiveness should be expressed using a metric that ensures an “apples-to-apples” comparison of emissions performance levels among options, and is generally expressed as the rate that a pollutant is emitted after installation of the control measure. Control technology evaluations for existing sources should consider ways to improve the performance of existing control devices. Special circumstances pertinent to the specific unit under review should be identified and taken into consideration when assessing the capability of the control alternative and determining control effectiveness.

For this evaluation, S&L assessed the technically feasible SO<sub>2</sub> and NO<sub>x</sub> control options for effectiveness on Coyote Unit 1. As discussed above, Coyote Unit 1 is an existing cyclone boiler designed to fire North Dakota lignite. The unit is equipped with SOFA for NO<sub>x</sub> control, and dry FGD and FF for SO<sub>2</sub> and PM control.

---

<sup>24</sup> A more detailed description of control technology “availability” and “applicability” is provided in 40 CFR Part 51 Appendix Y, Section IV.D.2.



## 5.1 SO<sub>2</sub> EMISSIONS CONTROLS

### 5.1.1 Identify Available SO<sub>2</sub> Control Options

Based on a review of available SO<sub>2</sub> control technologies, as well as operational practices and equipment upgrades implemented on existing control systems, potentially available options to control SO<sub>2</sub> emissions from Coyote Unit 1 are listed in Table 5-1.

**Table 5-1. Available SO<sub>2</sub> Control Options**

SO <sub>2</sub> Control Technologies
Fuel Switching
Existing DFGD Operational Improvements
Existing DFGD Equipment Upgrades
Existing DFGD + Dry Sorbent Injection (DSI)
Existing DFGD Operational Improvements + DSI
Retrofit New Dry FGD
Retrofit New Wet FGD

### 5.1.2 Technical Feasibility of Available SO<sub>2</sub> Control Options

Potentially available SO<sub>2</sub> control options identified in Table 5-1 were evaluated for technical feasibility (i.e., availability and applicability to Coyote Unit 1) based on a review of physical, chemical, and engineering principals, and an assessment of commercial availability. Options determined to be technically infeasible, or options that have no practical application to Coyote Unit 1, were eliminated from further review. S&L evaluated the effectiveness of the control options determined to be technically feasible, and established an emissions performance level (i.e., control emissions rate) for each.

#### 5.1.2.1 Fuel Switching

One potential strategy for reducing SO<sub>2</sub> emissions is to reduce the sulfur content of the coal. Limiting the amount of sulfur in the coal directly limits the amount released during the combustion process, and would reduce SO<sub>2</sub> loading to the dry scrubber. Coyote Unit 1 is a cyclone boiler designed to fire North Dakota lignite as the primary fuel. Lignite fired at the Coyote Station is mined and supplied to the station from the nearby Coyote Creek Mine. The mine, which is owned and operated by Coyote Creek Mining Company, has primary mining operations

approximately 3-4 miles southwest of Coyote Station and can be considered a mine mouth plant. Previous regulatory and court decisions have concluded that requiring a mine mouth facility to evaluate low sulfur coal would require the facility to redefine its fundamental purpose and design; therefore, fuel switching can be rejected as an available control option.<sup>25</sup> Because the use of North Dakota lignite from the Coyote Creek Mine is an inherent aspect of Coyote operation, fuel switching will not be evaluated.

#### 5.1.2.2 Existing DFGD Operational Improvements and Equipment Upgrades

Operational and other design changes/upgrades to the existing dry scrubber may provide an opportunity for additional SO<sub>2</sub> removal and allow the unit to achieve lower controlled SO<sub>2</sub> emissions. S&L, working with OTP personnel, identified a number of potentially feasible operational changes that may be available to increase SO<sub>2</sub> removal efficiency with the existing equipment. Potentially available operational and design changes to the existing control system are summarized in Table 5-2. A detailed discussion of each of these options is provided in the following sections.

**Table 5-2. FGD Operational Improvements and Equipment Upgrades**

<b>FGD Operational Improvements</b>
Lime Quality
Ca:S Stoichiometric Ratio
Approach to Saturation Temperature
<b>FGD Design Changes and Equipment Upgrades</b>
Atomizer Replacement
Slaker Replacement
Adding an Absorber Module
Replacing Existing Absorbers with New Absorber Modules

#### Lime Quality

The quantity of lime (CaO) available in a dry scrubbing system compared to the amount of SO<sub>2</sub> entering the system is called the stoichiometric ratio (generally referenced as the Ca:S stoichiometric ratio). Reagent quality directly

<sup>25</sup> In re: Prairie State Generating Company, PSD Appeal No. 05-05, Slip. Op. at 36 (2006)

affects the Ca:S stoichiometric ratio in DFGD control systems. Using a high quality lime increases the availability of hydrated lime to support process chemistry, and reduces the lime slurry injection rate needed for SO<sub>2</sub> removal.

Lime quality is measured both by the CaO content and reactivity of the lime product. In a dry scrubber, CaO is combined with water to form hydrated lime or calcium hydroxide (Ca(OH)<sub>2</sub>), which provides the calcium that is needed to react with SO<sub>2</sub> in the flue gas. With a higher quality lime, more calcium hydroxide is available to react with SO<sub>2</sub>. Lime products with a CaO content of 90% or greater are generally considered high quality lime. Lower quality lime products have a lower CaO content and higher quantity of inert material. Reactivity of the lime is measured by the temperature rise when the lime is slaked (i.e., water addition). In general, porous lime products have higher reactivity which is demonstrated by achieving a temperature rise of approximately 40 °C within 3 minutes of adding water.

Based on a review of available lime analyses, and a review of operating data from the existing lime slaking system, Coyote Unit 1 currently procures a high quality lime for use in the dry scrubbers. The typical CaO content of the lime used at Coyote is 90% or greater, and when slaked can achieve a 39.4 °C temperature rise in 3 minutes of adding water. For these reasons, changing the lime quality is not considered a technically feasible operational change available to control SO<sub>2</sub> emissions from Coyote Unit, and will not be evaluated further.

#### Ca:S Stoichiometric Ratio

Other operational changes that may be available to increase the Ca:S stoichiometry in the existing dry scrubber include: (1) increasing the byproduct recycle rate; and/or (2) increasing the quantity of fresh hydrated lime introduced to the system. Due to the cost savings that may be realized with the first option, some facilities with existing DFGD controls have opted to increase solids recycle rates to as high as 40-50% solids to achieve an incremental increase in SO<sub>2</sub> reduction, if capacity was available in the byproducts handling system. If capacity is not available, increasing fresh lime addition to the system may also be a viable option to increase the Ca:S stoichiometric ratio.

Solids from a dry scrubber consist of fly ash, reaction byproduct, and residual unreacted hydrated lime. On Coyote Unit 1, solids collected in the fabric filter hoppers are conveyed to either a dry storage silo for disposal or to a recycle fly ash silo where it is used as make-up for the reactant slurry. The recycle system is designed to utilize a portion of the unreacted lime rather than disposing of all of the solids. Recycle solids are combined with the fresh lime addition to provide the makeup lime needed for SO<sub>2</sub> reduction. Increasing the recycle rate can increase the



amount of hydrated lime added to the system (i.e., stoichiometric ratio) without increasing the quantity of fresh lime added to the system.

Based on information provided by the station, the DFGD system on Coyote Unit 1 currently operates the recycle system at approximately 24% solids. The Coyote Unit 1 recycle system is operating within the original design conditions and system capacity. The plant has tested higher recycle rates (up to 28-30% solids), but at these higher rates plant personnel reported significant problems with the atomizer wheels spilling over and pluggage of various strainers. Based on the adverse operational impacts observed during these tests, as well as the design limitations of the existing dry scrubber modules, increasing the recycle % solids is not considered a technically feasible SO<sub>2</sub> control option for Coyote Unit 1.

As an alternative to increasing the recycle rate, the Ca:S stoichiometric ratio in the system may be increased by increasing the quantity of fresh lime introduced to the system. Testing was completed in October 2018 on Coyote Unit 1 to determine the impact of increasing the amount of fresh lime slurry fed to the atomizer feed tanks while adjusting the amount of recycle slurry in order to maintain the design 24% solids to the absorber. During the test program Coyote Unit 1 was able to achieve an average controlled SO<sub>2</sub> emission rate of 0.50 lb/MMBtu without significant adverse operational impacts and represents an average emission rate that Coyote would be expected to achieve on an on-going long-term basis under normal operating conditions. The emission rate should not be construed to represent proposed permit limits. Corresponding permit limits must be evaluated on a control system-specific basis; however, an additional 10-15% margin would likely be needed to account for operating margin.

Increasing the quantity of fresh lime introduced to the system will require the existing atomizer wheels to be upgraded from the eight (8) nozzle wheel to a twelve (12) nozzle wheel to mitigate for potential plugging and spill-over issues caused by the percent solid limitation of the existing atomizer wheels (see, Section 5.1.2.2 Atomizer Replacement), and to prevent the possibility of moisture carry-over that could occur with the increase in lime slurry flow. Although upgrades to the existing atomizer wheels and nozzles will be required, increasing the Ca:S stoichiometric ratio by adding additional fresh lime to the system is considered a technically feasible SO<sub>2</sub> control option for Coyote Unit 1, and will be included in the Four Factor Analysis.

#### Approach to Saturation Temperature

The reaction of SO<sub>2</sub> with Ca(OH)<sub>2</sub> in a dry scrubber is driven by the absorber temperature. Water surrounding the lime slurry droplet allows SO<sub>2</sub> to dissolve into the liquid and facilitates the reaction between lime and SO<sub>2</sub>. The

temperature differential between the inlet and the outlet of the DFGD is used as a driving force for SO<sub>2</sub> removal; however, outlet temperatures must be maintained above the saturation temperature to ensure byproducts exiting the absorber module are dry. Residence time within the absorber vessel, drying time, and exit temperature are all important design parameters for a dry scrubbing system.

Inlet temperature to the dry scrubbing module is relatively constant; therefore, temperature differential across the module is a function of the outlet temperature. As a general rule-of-thumb, the closer the outlet temperature is to the adiabatic saturation temperature, the higher the SO<sub>2</sub> removal efficiency.

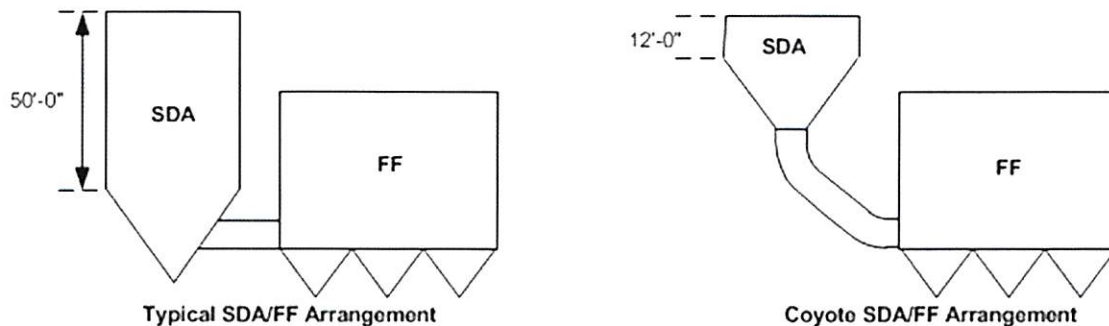
Operating a dry scrubbing system at outlet temperatures significantly above the adiabatic saturation temperature accelerates water evaporation from the reactant slurry, limits SO<sub>2</sub> absorption into the droplet, and limits the reaction between the lime and SO<sub>2</sub>. Reducing the temperature in the absorber closer to the saturation point can provide additional SO<sub>2</sub> removal. On the other hand, the absorber module may not have sufficient residence time to dry all slurry droplets if the system is operated too close to adiabatic saturation, which would result in deposits in the absorber module, corrosion, and severe operational problems. Therefore, maintaining an absorber outlet temperature close to the point of saturation, while staying above it, is vital for optimal reaction kinetics.

The Coyote Unit 1 dry scrubbers currently operate at an outlet temperature of 190-210 °F, which is approximately 55-75 °F above the adiabatic saturation temperature and within original the OEM design steady state operating parameter of 190°F at the stack. More recent dry scrubbing systems have been designed to operate at 30 °F approach to adiabatic saturation. The station has attempted to lower the outlet temperatures to 165-170°F, however, this change caused significant corrosion of the absorber vessels and downstream equipment. Corrosion was likely due to the fact that the Coyote Unit 1 scrubbers were not able to completely dry the slurry droplets because the absorber vessels were designed with a residence time of approximately 1.0 second. More recent dry scrubbers are designed with approximately 10 seconds of residence time.

Figure 5-1 provides a simplified drawing of the Coyote Unit 1 scrubber compared to more recent DFGD designs, and depicts the arrangement limitation causing Coyote's shorter residence time. The low residence time limits the scrubbers ability to dry all slurry droplets when the system is operated too close to the approach to adiabatic saturation temperature. Due to the design limitations of the existing absorber vessels, reducing the outlet temperature is not considered a technically feasible SO<sub>2</sub> control option for Coyote Unit 1, and will not be evaluated further.



Figure 5-1. Comparison of Typical SDA/FF and Coyote Unit 1 SDA/FF Arrangement



### Atomizer Replacement

Spray droplet size is an important parameter in the design and operation of a dry scrubber, and can improve lime utilization and  $\text{SO}_2$  removal. Finer spray will increase the surface area of the slurry droplets exposed to the flue gas. Greater surface area increases the potential for  $\text{SO}_2$  to absorb into the moisture of the slurry droplets. Droplet fineness also plays a role in particle drying time. Larger droplets can have a negative effect on the slurry drying time which can lead to moisture carryover to downstream equipment causing buildup and corrosion.

The Coyote Unit 1 dry scrubber, provided by Combustion Engineering, is designed with three (3) rotary atomizers, each with an eight (8) nozzle wheel in each absorber module to achieve a fine slurry spray. The design of the atomizer and speed at which the wheel rotates are controlling factors for the size and form of the droplets in the spray. The design and speed of atomizers is highly dependent on the spray pattern needed to mix with the hot flue gas in the scrubber module for optimum absorption of  $\text{SO}_2$  while also preventing wetting of the absorber walls.

Based on S&L's assessment of the existing control system, previous testing completed by the station, and input from station operators, the existing DFGD system is limited in residence time, and the ability to increase the recycle ratio (solids content) to allow for more effective Ca:S contact in the scrubber vessels. The existing atomizers with eight (8) nozzle wheels would need to be upgraded to a twelve (12) nozzle wheel to mitigate for potential plugging and spill-over issues that could occur with the increased Ca:S stoichiometric ratio (discussed in Section 5.1.2.2). Based on engineering judgment, new 12 nozzle atomizers would improve spray atomization to produce slurry droplets that are smaller in size than the droplets produced by the existing nozzle design. Improved materials of construction would also allow for higher solids content in the slurry without detrimental equipment pluggage or spill-over.

Replacing the existing nozzles with a more recent 12 nozzle wheel design would provide better atomization of the slurry spray and allow for more effective Ca:S contact in the absorber vessels. However, nozzle replacement would not, on its own, be expected to provide a significant increase in SO<sub>2</sub> control. Nozzle upgrades coupled with operational changes designed to increase the Ca:S stoichiometric ratio is a technically feasible option that would be expected to provide additional SO<sub>2</sub> control (See, Section 5.1.2.2 Ca:S Stoichiometric Ratio).

#### Slaker Replacement

Lime slurry, the reagent used for SO<sub>2</sub> removal in a dry scrubber, is produced by mixing pebble lime with heated water in a slaker; this process is referred to as “slaking”. The slaker is operated at an optimum water-to-lime ratio (typically between 3:1 and 6:1) to produce lime slurry by metering the amount of water and the amount of lime added to the slaker. Slakers are typically designed to produce a lime slurry between 15-20% solids. The lime slurry is added to recycle slurry in a mix tank and then sent to the atomizer where it is sprayed into the scrubber for SO<sub>2</sub> removal.

Coyote Unit 1 still operates the original Dorr-Oliver detention slakers. The slakers operate at a 5:1 water-to-lime ratio and approximately 18% solids, which is in line with the design as well as industry practice. Therefore, replacing the slakers would not result in improved Ca:S contact in the absorber vessels or provide additional SO<sub>2</sub> removal. Replacing the lime slakers is not considered a technically feasible SO<sub>2</sub> control option for Coyote Unit 1, and will not be evaluated further.

#### Adding an Absorber Module

Another option for extending the residence time within the reactor modules and increasing Ca:S contact would be to add an additional absorber module. The existing system is designed with four absorber modules that share three fabric filter zones. The system is designed to operate with four modules at full load, three or four modules at 75% load and two modules at 50% load. At full load, the flue gas residence time in the reactor modules is approximately 1.0 second. More recent dry scrubbing systems have been designed with reaction vessel residence times of 10 seconds or more.

One potential option available to the Coyote Station to increase absorber module residence time would be to add an additional absorber module to the existing dry scrubbing system. The number of absorber modules used in a DFGD system is dependent on multiple operating parameters, including the flue gas flow rate and SO<sub>2</sub> concentrations. DFGD absorber modules are typically specified with minimum and maximum flue gas flow rates. If the absorber



modules are oversized, flue gas velocities through the module can be too low, causing solids dropout inside the vessel. If the absorber modules are undersized, flue gas velocities can be too high, causing residence time to fall below recommended levels.

Dry scrubbing units that are operating at flue gas volumes significantly above the design flow rate can benefit from adding an extra module to the system. The module would be placed in parallel with the existing modules to achieve a similar pressure drop through each vessel and to ensure equal flue gas distribution to the vessels. Although adding an absorber module would likely allow additional residence time for the SO<sub>2</sub> removal reactions to occur, it would require extensive engineering and modifications to the existing system. More importantly, the Coyote Unit 1 absorber module design is no longer available from Combustion Engineering, and it would likely not be possible to procure a commercial offering from another technology vendor that would be compatible with the existing modules. Therefore, incorporating an additional absorber module into the existing system is not a commercially available or technically feasible SO<sub>2</sub> control strategy for Coyote, and will not be evaluated further.

#### Replacing Existing Absorbers with New Absorber Modules

Replacing the existing modules with new absorber modules would require significant engineering and facility modifications. Based on a preliminary review of the control system layout, the only practical location for this option would be to construct the new vessels in the same location as the existing modules. Locating the new modules adjacent to the existing absorber modules would require flue gas to be redirected from the air heater outlets to the new absorbers and back to the existing fabric filters, which would likely result in significant solids dropout and other operational issues. Therefore, locating the new absorber modules adjacent to the existing absorber modules is not considered a technically feasible option.

Installing the new absorber vessels in the same location as the existing dry scrubber modules would require Coyote Unit 1 to be taken off-line for an extended period of time. OTP could not operate the unit while the existing modules were dismantled and removed, or while the new absorber modules, duct work, and other system tie-ins were installed. Based on construction schedules for new DFGD systems, and taking into consideration decommissioning of the existing dry scrubber modules, this option would likely require an outage of at least 12-months and would require Coyote to purchase replacement power during this period. In comparison, a typical major outage at Coyote Station is only 6-8 weeks. Outage costs would add significantly to the cost of this control option.

Although replacing the existing dry scrubber modules with new DFGD reactor vessels would require a long outage, there is no technical basis for eliminating this option from the analysis. Replacing the exiting dry scrubber modules with new absorber modules would address the design and operational limits of the existing system. The new absorber modules could be designed to provide additional Ca:S contact and residence time between the exhaust gas and the slurry, and would likely allow OTP to reduce the approach to saturation temperature, design parameters which would increase overall SO<sub>2</sub> removal.

Coyote Unit 1 consistently achieves overall removal efficiencies in the range of approximately 65-73% with the existing dry scrubbing system. Based on engineering judgment and industry practice, it is expected that the fabric filter provides approximately 10-15% of the overall removal in the DFGD system. Assuming 10-15% removal in the fabric filter, approximately 60% of the SO<sub>2</sub> removal is achieved in the existing absorber modules based on the current coal sulfur content. Estimated SO<sub>2</sub> removal efficiencies across the existing DFGD system are shown in Table 5-3.

**Table 5-3. Existing SO<sub>2</sub> Removal Efficiencies**

Existing Scrubber Modules	Existing Fabric Filter	Overall
Inlet: 2.83 lb/MMBtu Outlet: 1.14 lb/MMBtu Efficiency: 60% of uncontrolled Contribution: 85% of overall removal	Inlet: 1.14lb/MMBtu Outlet: 0.85 lb/MMBtu Efficiency: 11% of uncontrolled Contribution: 15% of overall removal	Inlet: 2.83 lb/MMBtu Outlet: 0.85 lb/MMBtu Efficiency: 70%

Based on SO<sub>2</sub> removal efficiencies achieved in practice on existing units equipped with DFGD, it is anticipated that replacing the existing absorber modules with new scrubber modules could increase removal across the scrubber to approximately 80%, and increase overall removal efficiencies to approximately 91%. It should be noted that Coyote is expected to receive higher sulfur content coal in the future; therefore, the new scrubber vessel SO<sub>2</sub> removal analysis is based on this higher sulfur content coal. The removal efficiencies for this option are shown in Table 5-4.



Table 5-4. New Scrubber Vessel SO<sub>2</sub> Removal Efficiencies

New Scrubber Modules		Existing Fabric Filter	Overall
Inlet:	3.12 lb/MMBtu <sup>(Note 1)</sup>	Inlet:	0.62 lb/MMBtu
Outlet:	0.62 lb/MMBtu	Outlet:	0.29 lb/MMBtu
Efficiency:	80% of uncontrolled	Efficiency:	11% of uncontrolled
Contribution:	88% of overall removal	Contribution:	12% of overall removal
			Inlet: 3.12 lb/MMBtu
			Outlet: 0.29 lb/MMBtu <sup>(Note 2)</sup>
			Efficiency: 91%

Note 1. Inlet SO<sub>2</sub> rate based on anticipated future fuel sulfur content.

Note 2. Emission rates shown represent average emission rates that the control options would be expected to achieve on an on-going long-term basis under normal operating conditions for Coyote Unit 1. Emission rates are provided for comparative purposes, and should not be construed to represent proposed permit limits. Corresponding permit limits must be evaluated on a control system-specific basis; however, an additional 10-15% margin would likely be needed to account for operating margin.

Replacing the existing dry scrubber modules with new absorber modules is a technically feasible control technology option that would provide an incremental increase in overall SO<sub>2</sub> removal efficiency. However, this option would require Coyote Unit 1 to be taken off-line for an extended period of time (approximately 12 months). Outage costs associated with the extended outage are included in the four-factor cost impact evaluation for this option. Given the constructability issues and extended outage requirements associated with replacing the existing dry scrubber modules, this may not be a practical option for Coyote; nevertheless, it will be included as a technically feasible SO<sub>2</sub> control option in the Four Factor Analysis.

### 5.1.2.3 Existing FGD + Dry Sorbent Injection

Alkali based sorbent injection is a proven technology for the removal of sulfur trioxide (SO<sub>3</sub>) and other acid gases from coal-fired power plant flue gas, and can be used to provide SO<sub>2</sub> control. Sorbent is injected into the ductwork after the furnace and prior to the particulate collection device, where it reacts with SO<sub>2</sub> and other acid gases. Sorbent injection systems are relatively simple systems consisting of material storage, feeding mechanism, blower or transfer line, and an injection device. For SO<sub>2</sub> control on Coyote Unit 1, sorbent would be injected upstream of the dry scrubber to provide an incremental reduction in the concentration of SO<sub>2</sub> in the flue gas at the inlet to the dry scrubber.

Sorbents react with SO<sub>2</sub>, and other acid gases, in the flue gas when injected at an appropriate rate and within the proper temperature range for that sorbent. The resulting particulate matter is removed from the flue gas by the particulate control system. The process works through neutralization of the acid gases with the alkaline sorbent. The neutralization reaction occurs as long as the sorbent remains in contact with the gas in the flue gas duct work within the required temperature range.

Dry sorbents that have been used for SO<sub>2</sub> control on coal-fired boilers include:

- Hydrated Lime (Ca(OH)<sub>2</sub>)
- Trona or Sodium Bicarbonate (SBC)

The following wet sorbents have also been used for acid gas control at coal-fired power generating stations:

- Sodium Bisulfite (SBS)
- Soda Ash

Dry sorbents, including hydrated lime, Trona, and SBC would be injected pneumatically as a dry powder into the flue gas ductwork upstream of the Coyote Unit 1 dry scrubber. Trona and SBC are both sodium-based sorbents, which react with SO<sub>2</sub> to form sodium salts. Hydrated lime would react with SO<sub>2</sub> to form calcium sulfate salts. The hydrated lime reactions are the same reactions that are taking place in the existing dry scrubber.

Hydrated lime is less reactive than the sodium based dry sorbents; thus, higher injection rates and longer residence time would be required to achieve the same removal efficiency. However, hydrated lime has a lower unit cost compared to other sorbent options, offsetting the higher injection rates. It is also important to note that the hydrated lime chemistry involves the same reactions, and forms the same calcium salts, as those currently taking place in the dry scrubber reaction vessels. Therefore, using hydrated lime as the sorbent would not introduce any new constituents into the dry scrubbing system, and could potentially increase the Ca:S stoichiometry in the dry scrubber.

Because of the higher reactivity of sodium based sorbents, less reactant may be required to achieve the same removal efficiency; however, injecting a sodium-based sorbent into the flue gas upstream of the Coyote Unit 1 dry scrubber would introduce new chemical constituents into the scrubber and into the fly ash/scrubber byproduct material. This could prove problematic as sodium compounds are water soluble, and introducing sodium into the system could adversely affect the characteristics of the byproduct solids generated by the system. Detailed studies and demonstration tests would be needed to ensure that introducing relatively large amounts of sodium would not adversely affect scrubber operation or result in solids disposal issues.

SBS and soda ash (Na<sub>2</sub>CO<sub>3</sub>) injection are wet injection technologies typically used for SO<sub>3</sub> mitigation. SBS and soda ash can be injected into the flue gas upstream or downstream of the air heater as a 10% solution (by weight) using dual fluid atomizers. Both products will react with SO<sub>2</sub> and SO<sub>3</sub> to form sodium salts, which can be collected in the downstream particulate collection device. URS/Codan Associates own the patent for this SBS control process. Based on conversations with URS, their SBS technology is generally more economical using soda ash,



and all recent projects have used soda ash. However, as with the dry sodium-based injection systems, these systems would introduce sodium into the Coyote Unit 1 DFGD control system.

Sorbent injection (dry or wet) upstream of the existing dry scrubber is a technically feasible and commercially available SO<sub>2</sub> control option for Coyote Unit 1. Taking into consideration the fact that Coyote is currently equipped with a calcium-based dry scrubbing system, hydrated lime dry sorbent injection would be the most practical, and potentially the most effective, sorbent injection control option. Sodium-based systems would require extensive testing to determine the potential impacts associated with introducing significant quantities of sodium into the existing system, and are not considered practical control options for Coyote Unit 1.

Based on engineering judgment, and assuming adequate residence time in the duct work upstream of the existing dry scrubber, hydrated lime injection could reduce SO<sub>2</sub> concentrations at the dry scrubber inlet by approximately 35%. Based on future design fuel characteristics, this would reduce SO<sub>2</sub> concentrations at the dry scrubber inlet from approximately 3.12 lb/MMBtu to approximately 2.03 lb/MMBtu. Applying the current scrubber SO<sub>2</sub> removal efficiency of 71% (dry scrubber plus fabric filter), would result in a controlled SO<sub>2</sub> emission rate of 0.58 lb/MMBtu. DSI upstream of the existing dry scrubbing system is considered a technically feasible SO<sub>2</sub> control technology; however, flow modeling and field testing at Coyote Unit 1 would be needed to ensure that adequate residence time is available for SO<sub>2</sub> control and to confirm the incremental reduction in SO<sub>2</sub> emissions achievable without creating unacceptable operational issues.



**Table 5-5. DSI SO<sub>2</sub> Control Technology Estimated Emissions**

	<b>Unit 1</b>
Uncontrolled SO <sub>2</sub> Emissions (lb/MMBtu)	3.12
SO <sub>2</sub> Emissions at DSI Outlet (lb/MMBtu)	2.03
SO <sub>2</sub> Emissions at FF Outlet (lb/MMBtu)	0.58 <sup>1</sup>
<b>Overall Removal (%)</b>	<b>80.4</b>

Note 1. Emissions at the FF outlet were estimate by applying existing 71% SO<sub>2</sub> removal across the DFGD system ( $(2.03 \text{ lb/MMBtu} \times (1 - 0.71)) = 0.58$ ).

Note 2. Emission rates shown represent average emission rates that the control options would be expected to achieve on an on-going long-term basis under normal operating conditions for Coyote Unit 1. Emission rates are provided for comparative purposes, and should not be construed to represent proposed permit limits. Corresponding permit limits must be evaluated on a control system-specific basis; however, an additional 10-15% margin would likely be needed to account for operating margin.

#### 5.1.2.4 FGD Operational Improvements + DSI

Some of the SO<sub>2</sub> control technologies which involve improvements to the FGD can potentially be applied in combination with dry sorbent injection to provide additional SO<sub>2</sub> removal. This option would be considered a layered technology of the technically feasible FGD operational improvements discussed in Section 5.1.2.2 with dry sorbent injection discussed in Section 5.1.2.3. Technically feasible FGD operational improvements include increasing the Ca:S stoichiometric ratio of the FGD by introducing additional fresh lime to the absorber modules. Based on engineering judgement, layering FGD operational improvements with DSI could reduce SO<sub>2</sub> emissions from the baseline SO<sub>2</sub> emission rate of 0.85 lb/MMBtu to approximately 0.33 lb/MMBtu at Coyote Unit 1 as shown in Table 5-6. However, as stated previously, flow modeling and field testing at Coyote Unit 1 would be needed to ensure that adequate residence time is available for SO<sub>2</sub> control and to confirm the incremental reduction in SO<sub>2</sub> emissions achievable without creating unacceptable operational issues.

Table 5-6. Layered (DSI + Ca:S) SO<sub>2</sub> Control Technology Estimated Emissions

	Unit 1
Uncontrolled SO <sub>2</sub> Emissions (lb/MMBtu)	3.12
SO <sub>2</sub> Emissions at DSI Outlet (lb/MMBtu)	2.03
SO <sub>2</sub> Emissions at FF Outlet (lb/MMBtu)	0.33 <sup>1</sup>
<b>Overall Removal (%)</b>	<b>89.4</b>

Note 1. Emissions at the FF outlet were estimate by applying 84% SO<sub>2</sub> removal across the DFGD system with operational improvements ((2.03 lb/MMBtu x (1 - 0.84 lb/MMBtu) = 0.33 lb/MMBtu).

Note 2. Emission rates shown represent average emission rates that the control options would be expected to achieve on an on-going long-term basis under normal operating conditions for Coyote Unit 1. Emission rates are provided for comparative purposes, and should not be construed to represent proposed permit limits. Corresponding permit limits must be evaluated on a control system-specific basis; however, an additional 10-15% margin would likely be needed to account for operating margin.

#### 5.1.2.5 Install New Dry FGD System

Replacing the existing dry scrubber and fabric filter with new control systems would require significant engineering and modifications to the facility. Based on a preliminary review of the facility layout, the new control systems could be located northeast of Coyote Unit 1's existing dry scrubber/FF. The new DFGD/FF and all auxiliary equipment could be constructed while the unit remains on-line. The control systems could be tied-in to the existing systems during a scheduled major outage.

Various DFGD systems have been designed for use with pulverized coal-fired boilers; including the spray dryer absorber (SDA) and circulating dry scrubber (CDS). Both systems are evaluated in more detail below.

##### Spray Dryer Absorber / Fabric Filter

SDA systems have been used in large coal-fired utility applications, and have demonstrated the ability to effectively reduce uncontrolled SO<sub>2</sub> emissions from pulverized coal units. Like other dry scrubbing systems, SDA control systems use a slurry of lime and water injected into the reaction modules to remove SO<sub>2</sub> from the combustion gases. The reaction modules are designed to provide adequate contact and residence time between the exhaust gas and the slurry to produce a dry by-product. Process equipment associated with an SDA control system includes an alkaline storage tank, mixing and feed tanks, atomizer assembly, spray chamber module, integrated fabric filter, and solids recycle system. The recycle system collects solid reaction byproducts and recycles them back to the spray dryer feed system to maximize reactant utilization.

Various process parameters affect the efficiency of the SDA process including: the type and quality of the additive used for the reactant, reactant-to-sulfur stoichiometric ratio, how close the SDA is operated to saturation conditions, and the amount of solids product recycled to the atomizer. SDA systems are typically designed to operate within approximately 30 °F adiabatic approach to saturation temperature. Operating closer to the adiabatic saturation temperature may allow for higher SO<sub>2</sub> control efficiencies; however, outlet temperatures too close to the saturation temperature will result in severe operating problems including reactant build-up in the absorber modules, blinding of the fabric filter bags, and corrosion in the fabric filter and ductwork.

SO<sub>2</sub> removal efficiencies in a SDA are also dependent upon good gas-to-liquid contact. Reactant spray nozzle designs are vendor-specific, and include both dual-fluid nozzles and rotary atomizers. The atomizing nozzle assembly is typically located in the SDA penthouse and flange mounted to the roof of the absorber vessel.

Replacing the existing dry scrubber/FF with a new SDA/FF control systems is a technically feasible and commercially available control option on Coyote Unit 1. SDA/FF control systems are generally installed on units that burn lower sulfur fuels (i.e., < 3 lb SO<sub>2</sub>/MMBtu) because design limitations, including Ca:S stoichiometry, residence time, and approach to saturation typically limit total SO<sub>2</sub> removal to approximately 95%. This removal efficiency represents what the control system vendor would be willing to guarantee upon initial operation of the system. On Coyote Unit 1, 95% removal would result in an average controlled SO<sub>2</sub> emission rate of approximately 0.16 lb/MMBtu.

#### Circulating Dry Scrubber / Fabric Filter

A second type of dry scrubbing system is the circulating dry scrubber (CDS). Similar to other dry flue gas desulfurization systems, the CDS system would be located after the air preheater, and byproducts from the system collected in an integrated fabric filter. Unlike the SDA systems, CDS systems use a circulating fluidized bed of hydrated lime reagent to remove SO<sub>2</sub> rather than an atomized lime slurry; however, similar chemical reaction kinetics are used in the SO<sub>2</sub> removal process.

In a CDS, flue gas is treated in an absorber vessel where the flue gas stream flows through a fluidized bed of hydrated lime and recycled byproduct. Water is injected into the absorber through a venturi located at the base of the absorber for temperature control. Flue gas velocity through the vessel is maintained to keep the fluidized bed of particles suspended in the absorber. Water sprayed into the absorber cools the flue gas from approximately 300 °F at the inlet to the scrubber to approximately 160 °F at the outlet of the fabric filter. The hydrated lime absorbs SO<sub>2</sub>



from the gas and forms calcium sulfite and calcium sulfate solids. Desulfurized flue gas passes out of the absorber, along with the particulate matter (reaction products, unreacted hydrated lime, calcium carbonate, and the fly ash) to the fabric filter.

As with the SDA/FF option, replacing the existing dry scrubber/FF with a new CDS/FF control system would require significant engineering and modifications to the existing facility. For this evaluation it was assumed that the CDS/FF control systems could be located adjacent to the existing dry scrubber/FF, and that the control systems could be tied-in to the existing system during a scheduled major outage.

Replacing the existing dry scrubber and FF with a new CDS/FF control system is a technically feasible and commercially available control option for Coyote Unit 1. Based on engineering judgment, it is anticipated that the retrofit CDS/FF control option would achieve SO<sub>2</sub> removal efficiencies higher than those achieved with a SDA/FF due to the increased Ca:S contact in the fluidized bed absorber vessel. Based on recent CDS retrofit projects, and taking into consideration expected fuel characteristics, it is anticipated that the retrofit CDS/FF control system could achieve SO<sub>2</sub> removal efficiencies of approximately 97%. This removal efficiency represents what the control system vendor would be willing to guarantee upon initial operation of the system. On Coyote Unit 1, 97% removal would result in an average controlled SO<sub>2</sub> emission rate of approximately 0.09 lb/MMBtu and represents an average emission rate that Coyote would be expected to achieve on an on-going long-term basis under normal operating conditions. The emission rate should not be construed to represent proposed permit limits. Corresponding permit limits must be evaluated on a control system-specific basis; however, an additional 10-15% margin would likely be needed to account for operating margin.

#### **5.1.2.6 Install New Wet FGD System**

Another option available to the Coyote Station would be to replace the existing dry scrubbing system with a new wet FGD control system located downstream of the existing FF.

Wet FGD technology is an established SO<sub>2</sub> control technology. Wet scrubbing systems have been designed to utilize various alkaline scrubbing solutions including lime, limestone, and magnesium-enhanced lime. Wet scrubbing systems have also been designed with spray tower reactors and with reaction vessels (e.g., jet bubbling reactor). Although the flue gas/reactant contact systems may vary, the chemistry involved in all wet scrubbing systems is essentially identical. All wet scrubbing systems use an alkaline slurry that reacts with SO<sub>2</sub> in the flue gas to form insoluble calcium sulfite (CaSO<sub>3</sub>) and calcium sulfate (CaSO<sub>4</sub>) salts.

A large majority of the wet FGD systems designed to remove SO<sub>2</sub> from existing high-sulfur utility boilers have been designed as wet limestone scrubbers with spray towers and forced oxidation systems. Therefore, for this evaluation, it was assumed that the WFGD control system would be designed as a limestone spray tower scrubber with forced oxidation. Other potentially available wet scrubber designs are not included in this evaluation because the chemistry involved in all wet scrubbing systems are essentially identical, alternative designs would not provide any additional SO<sub>2</sub> control, and control system costs would be similar.

### Wet Limestone Scrubbing

In a wet limestone scrubbing system, limestone (CaCO<sub>3</sub>) is mixed with water to formulate the alkali scrubber slurry. Flue gas enters the absorber vessel and contacts the absorbent slurry in a countercurrent spray tower. SO<sub>2</sub> in the flue gas reacts with the limestone slurry to form insoluble calcium sulfite (CaSO<sub>3</sub>) and calcium sulfate (CaSO<sub>4</sub>) which is removed as a solid waste by-product. Spent absorbent is returned to the reaction tank where dissolved sulfur compounds are precipitated as calcium salts. Fresh limestone slurry is added to regenerate the spent absorbent.

The reaction tank is sized to provide sufficient time for precipitation of the sulfur compounds. From the reaction tank, regenerated absorbent slurry is recycled to the absorber. The slurry typically contains from 5 to 15% suspended solids consisting of fresh additive, absorption reaction products, and lesser amounts of fly ash. To regulate the accumulation of solids, a bleed stream from the reaction is routed to the solid/liquid separation equipment.

Forced oxidation of the scrubber slurry may be used with limestone WFGD systems to produce calcium sulfate solids (gypsum) instead of the calcium sulfite by-product. Air blown into the reaction tank provides oxygen to convert most of the calcium sulfite (CaSO<sub>3</sub>) to a relatively pure gypsum. Forced oxidation of the scrubber slurry provides a more stable by-product and reduces the potential for scaling in the spray tower. The gypsum by-product from this process must be dewatered, and may be salable if a local market for gypsum is available, reducing the quantity of solid waste that needs to be landfilled.

For this evaluation it was assumed that the existing Coyote Unit 1 dry scrubber reactor vessels would remain in place, and that the WFGD control system would be located downstream of the existing FFs and ID fans, most likely northeast of the unit's existing dry scrubber/FF. Dry scrubber reactor vessel internals would ultimately be removed to reduce pressure drop through the system. A single WFGD absorber tower would be sufficient for the Coyote



Unit 1 flue gas flow. In addition to the absorber tower and reaction vessel, the WFGD control system would require a limestone handling and preparation system and by-product dewatering systems. Because of the saturated nature of the flue gas exiting the WFGD, a new stack with a liner capable of wet flue gas operation would be required. New booster ID fans would also be required to account for the additional pressure drop through the WFGD control system.

Wet FGD technology is an established SO<sub>2</sub> control technology. Wet scrubbing systems have been installed on units that fire medium to high sulfur coals, and would be a technically feasible SO<sub>2</sub> control option for Coyote Unit 1. Based on engineering judgment and information from control system vendors, it is anticipated that a retrofit WFGD control system on a North Dakota lignite-fired unit would be designed to achieve and SO<sub>2</sub> removal efficiency of approximately 98%. This removal efficiency represents what the control system vendor would be willing to guarantee upon initial operation of the system. On Coyote Unit 1, 98% removal would result in an average controlled SO<sub>2</sub> emission rate of approximately 0.06 lb/MMBtu and represents an average emission rate that Coyote would be expected to achieve on an on-going long-term basis under normal operating conditions. The emission rate should not be construed to represent proposed permit limits. Corresponding permit limits must be evaluated on a control system-specific basis; however, an additional 10-15% margin would likely be needed to account for operating margin.

#### 5.1.2.7 Technical Feasibility Summary

Table 5-7 summarizes the results of the feasibility evaluation of available control options for Coyote Unit 1.

**Table 5-7. Technically Feasible SO<sub>2</sub> Control Options**

SO <sub>2</sub> Control Option	Technically Feasible (Yes/No)	Technical Feasibility Summary
Fuel Switching	No	Fuel switching is not considered an available SO <sub>2</sub> control option for Coyote Unit 1 since the use of North Dakota lignite coal is an inherent aspect of plant operations.
Existing DFGD Operational Improvements:		
Lime Quality	No	Changing lime quality in the existing DFGD control system is not a technically feasible operational change for Coyote Unit 1.
Ca:S Stoichiometric Ratio	Yes	Increasing the Ca:S stoichiometric ratio by increase the quantity of fresh lime to the system is considered a technically feasible option for Coyote Unit 1, assuming the operational change is coupled with atomizer replacement.



SO <sub>2</sub> Control Option	Technically Feasible (Yes/No)	Technical Feasibility Summary
Approach to Saturation Temperature	No	Due to design limitations, further reducing the absorber module outlet temperature on the existing DFGD control system is not a technically feasible option for Coyote Unit 1.
Existing DFGD Equipment Upgrades:		
Atomizer Replacement	Yes	Replacing the existing atomizers is a technically feasible option for Coyote Unit 1 and would provide additional SO <sub>2</sub> control if coupled with increasing the Ca:S stoichiometric ratio.
Slaker Replacement	No	Slaker replacement would not be expected to provide additional SO <sub>2</sub> control, and is not a technically feasible equipment upgrade for Coyote Unit 1.
Adding an Absorber Module	No	Coyote Unit 1 DFGD absorber modules are no longer commercially available, thus, adding an absorber module to the existing system is not a technically feasible SO <sub>2</sub> control option.
Replacing Existing Absorbers with New Absorber Modules	Yes	Replacing the exiting absorber modules with new absorber modules is a technically feasible SO <sub>2</sub> control system upgrade for Coyote Unit 1 that would require an approximate 12-month outage.
Existing DFGD + DSI	Yes	Hydrated lime sorbent injection upstream of the existing Coyote Unit 1 absorber modules is a technically feasible SO <sub>2</sub> control option. Flow modeling and field testing would be needed to confirm that the incremental reduction in SO <sub>2</sub> emissions is achievable without creating unacceptable operational issues.
Existing DFGD Operational Improvements (Increase Ca:S Stoichiometric Ratio) + DSI	Yes	Combining operational improvements (i.e., increased Ca:S stoichiometric ratio) with hydrated lime sorbent injection is a technically feasible SO <sub>2</sub> control option for Coyote Unit 1. Flow modeling and field testing would be needed to confirm that the incremental reduction in SO <sub>2</sub> emissions is achievable without creating unacceptable operational issues.
New Retrofit DFGD (CDS/FF)	Yes	Replacing the existing DFGD control system with a new retrofit DFGD (i.e., CDS/FF) is a technically feasible SO <sub>2</sub> control option for Coyote Unit 1.
New Retrofit WFGD	Yes	Replacing the existing DFGD control system with a new retrofit WFGD is a technically feasible SO <sub>2</sub> control option for Coyote Unit 1.

### 5.1.3 Evaluate Technically Feasible SO<sub>2</sub> Control Options for Effectiveness

The technically feasible SO<sub>2</sub> control technologies are listed in Table 5-8 in descending order of control efficiency. Table 5-8 also provides control option-specific SO<sub>2</sub> emission rates in terms of lb/MMBtu. Emission rates shown in

Table 5-8 represent average emission rates that the control options would be expected to achieve during normal operations.

**Table 5-8. Evaluate Technically Feasible SO<sub>2</sub> Control Options for Effectiveness**

Control Option	SO <sub>2</sub> Emission Rate (Note 1) lb/MMBtu	% Reduction from Baseline Emission Rate
Baseline (existing DFGD/FF)	0.85	-
New Retrofit WFGD	0.06	92.9%
New Retrofit DFGD (CDS/FF)	0.09	89.4%
New Retrofit DFGD (SDA/FF)	0.16	81.1%
FGD Upgrades - Replacing Existing Absorbers with New Absorber	0.29	65.9%
DSI + FGD Operational Improvements	0.33	61.2%
FGD Operational Improvements – Increase Ca:S Stoichiometric Ratio	0.50	41.2%
DSI + Existing FGD	0.58	31.8%

Note 1. Emission rates shown in Table 5-8 represent average emission rates that the control options would be expected to achieve on an on-going long-term basis under normal operating conditions for Coyote Unit 1. Emission rates are provided for comparative purposes, and should not be construed to represent proposed permit limits. Corresponding permit limits must be evaluated on a control system-specific basis; however, an additional 10-15% margin would likely be needed to account for operating margin.

## 5.2 NO<sub>x</sub> EMISSIONS CONTROLS

### 5.2.1 Identify Available NO<sub>x</sub> Control Options

Based on a review of available NO<sub>x</sub> control technologies installed on existing cyclone coal-fired boilers, as well as operational practices and equipment upgrades implemented on existing control systems, potentially available options to control NO<sub>x</sub> emissions from Coyote Unit 1 are listed in Table 5-9.

Table 5-9. Available NO<sub>x</sub> Control Options

NO <sub>x</sub> Control Technologies
Combustion Optimization
Selective Non-Catalytic Reduction (SNCR)
Rich Reagent Injection (RRI)
SNCR + RRI
Gas Reburn
Innovative Technologies (i.e. NOxStar, Water Injection, LoTOX, PerNOxide, Water Injection)
Selective Catalytic Reduction - High Dust, Low Dust or Tail End Configuration (TE-SCR)

## 5.2.2 Technical Feasibility of Available NO<sub>x</sub> Control Options

Potentially available NO<sub>x</sub> control options identified in Table 5-9 were evaluated for technical feasibility (i.e. availability and applicability to Coyote Unit 1) based on a review of physical, chemical, and engineering principals, and an assessment of commercial availability. Options deemed to be technically infeasible, or options that have no practical application to Coyote Unit 1, were eliminated from further review. S&L evaluated the effectiveness of the control options determined to be technically feasible, and established an emission performance level (i.e., controlled emission rate) for each.

### 5.2.2.1 Combustion Optimization

Coyote Unit 1 is equipped with twelve (12) ten (10) foot cyclones, six (6) on the front wall and six (6) each on the rear wall, two levels of three on each wall. The lignite coal requires a pre-dry system, which conveys the coal through individual crushers and into a cyclone separator for moisture separation. The dried coal is discharged from the bottom of the separator through a rotary seal, while the transport air (with a small quantity of fines) is discharged out the top and into ports above the cyclones. The coal discharged through the bottom rotary seal is blown into the cyclone through a pipe referred to as the “lift line” or known as primary air on most other similar installations. The temperature of the pre-dry air/coal temperature is regulated along with the lift line air by injecting cold (tempering) air into the hot primary air stream to regulate the outlet temperatures.

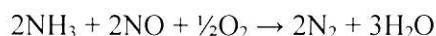
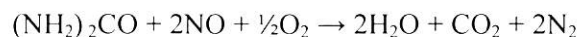


In 2016, The Babcock and Wilcox Company (B&W) installed fourteen (14) separated overfire air (SOFA) ports (seven on the front and rear wall) and modified the cyclones with smaller re-entrant throats and a  $\frac{1}{3} - \frac{2}{3}$  split secondary air damper (each having its own damper) to reduce NO<sub>x</sub> emissions. For the SOFA process, the injection of air into the boiler is staged into two zones, in which approximately 5% to 20% of the total combustion air is diverted from the burners and injected through ports located above the top burner level. Staging of the combustion air reduces NO<sub>x</sub> formation by two mechanisms. First, staged combustion results in a cooler flame which will reduce the formation of thermal NO<sub>x</sub>. Second the staged combustion results in less oxygen reacting with fuel molecules. The degree of staging is limited by operational problems since the staged combustion results in incomplete combustion conditions and a longer flame profile. The units normally operate with the  $\frac{1}{3}$ <sup>rd</sup> damper closed or nearly closed to help recirculate the coal in the cyclone and allows for increased coal retention and improved combustion. Since the SOFA installation, Coyote Unit 1 has achieved average controlled NO<sub>x</sub> emissions of approximately 0.46 lb/MMBtu.

Tuning of the cyclone boiler to optimize the combustion process and minimize the generation of NO<sub>x</sub> was recently completed at Coyote Unit 1. Tuning was completed by lowering the stoichiometry (i.e., lower the air-to-fuel ratio) in the cyclone barrel and tracking the cyclone combustion stability, while staying within the OEM specifications for best combustion engineering practice. Based on the testing results, Coyote Unit 1 was able to achieve average NO<sub>x</sub> emissions of approximately 0.42 lb/MMBtu without obvious impacts to boiler performance and with minimal slagging. Based on the results of the combustion turning tests, combustion optimization is considered a technically feasible NO<sub>x</sub> control option.

#### 5.2.2.2 Selective Non-Catalytic Reduction

Selective non-catalytic reduction (SNCR) involves the direct injection of ammonia (NH<sub>3</sub>) or urea (CO(NH<sub>2</sub>)<sub>2</sub>) at high flue gas temperatures (approximately 1,600°F – 2,100°F) in an oxidizing environment. The ammonia or urea reacts with NO<sub>x</sub> in the flue gas to produce N<sub>2</sub> and water as shown below.



Flue gas temperature at the point of reagent injection can greatly affect NO<sub>x</sub> removal efficiencies and the quantity of NH<sub>3</sub> or urea that will pass through the SNCR unreacted (referred to as NH<sub>3</sub> slip). In general, SNCR reactions are effective in the range of 1,600°F – 2,100°F. At temperatures below the desired operating range, the NO<sub>x</sub> reduction

reactions diminish and unreacted  $\text{NH}_3$  emissions increase. Above the desired temperature range,  $\text{NH}_3$  is oxidized to  $\text{NO}_x$  resulting in low  $\text{NO}_x$  reduction efficiencies.

Mixing of the reactant and flue gas within the reaction zone is an important factor to SNCR performance. In large boilers, the physical distance over which reagent must be dispersed increases, and the surface area/volume ratio of the convective pass decreases. Furnace geometry, urea spray coverage, and droplet size must be considered when developing good mixing of reagent and flue gas, delivery of reagent in the proper temperature window, and sufficient residence time of the reagent and flue gas in that temperature window. As the boiler cycles in load, the optimum injection region may change; thus, most facilities require multiple injection zones which are placed in and out of service as the unit ramps in load. This can include modifying the zones of injectors that are operating at different loads and temperatures.

Retractable multinozzle lances (MNLs) are sometimes used to improve SNCR performance, especially if the furnace exit flue gas temperatures are too high. The retractable lances allow injection into the appropriate temperature zone more so than wall injectors, depending on the unit load and temperatures. The MNLs also help improve performance by refining the spray pattern for quicker vaporization of the conveying water. MNLs are often used in conjunction with wall injection to provide optimized coverage while reducing reagent cost.

In addition to temperature and mixing, several other factors influence the performance of an SNCR system, including residence time, reagent-to- $\text{NO}_x$  ratio, and fuel sulfur content. Increasing the normalized stoichiometric ratio (NSR) can improve  $\text{NO}_x$  removal.<sup>26</sup> This can be achieved by increasing urea solution flow through the injectors or changing the concentration of urea in the solution. However, too high of reagent injection rates will increase the ammonia slip beyond the recommended 10 ppmvd limit. Above this concentration, there are expected to be major impacts to the formation of ammonia salts on the boiler tube banks, reducing heat transfer efficiency, and air heater baskets, causing corrosion.

SNCR can be applied on cyclone boilers due to having reasonable temperature windows and residence time; however, the potential  $\text{NO}_x$  reduction is boiler-specific. SNCR has been used as a retrofit  $\text{NO}_x$  control system of on pulverized coal, fluidized bed boilers, and cyclone boilers. Furthermore, SNCR can be implemented on boilers

---

<sup>26</sup> NSR defines the amount of reagent needed to achieve the targeted  $\text{NO}_x$  reduction. Based on the reaction equations in 5.2.2.2, two moles of  $\text{NO}_x$  can be removed with one mole of urea or two moles of ammonia. In practice, more than the theoretical amount of reagent needs to be injected into the boiler flue gas to obtain a specific level of  $\text{NO}_x$  reduction. This is due to the complexity of the actual chemical reactions involving  $\text{NO}_x$  and injected reagent and mixing limitations between reagent and flue gas. Factors that influence the NSR value: (1) percent  $\text{NO}_x$  reduction; (2) uncontrolled  $\text{NO}_x$  concentration in the flue gas; (3) temperature and residence time available for the  $\text{NO}_x$  reduction reactions; (4) extent of mixing achievable in the boiler; and (5) allowable ammonia slip.



equipped with low-NO<sub>x</sub> burners, overfire air, or SOFA systems. Based on the boiler residence time, temperature profile, and stoichiometry, as well as input from SNCR OEMs, it is estimated that an SNCR system could achieve an average controlled NO<sub>x</sub> emission rate of approximately 0.28 lb/MMBtu (approximately 39% below the baseline emission rate of 0.46 lb/MMBtu) at full load while limiting ammonia slip to 10 ppmvd. It should be noted that computational fluid dynamic modeling and temperature mapping of the boiler would be needed to confirm that the incremental reduction in NO<sub>x</sub> emission is achievable without creating unacceptable operational issues.

### 5.2.2.3 Rich Reagent Injection

Similar to SNCR, the concept of rich reagent injection (RRI) is to use a nitrogen-containing additive (e.g., urea) injected into a reducing environment to promote NO<sub>x</sub> removal. RRI is a commercial technology for cyclone boilers only. In contrast to SNCR, RRI typically is applied with only one injection level in the lower furnace near the cyclone barrels (temperature window of 2000°F-2600°F). The technology requires a sub-stoichiometric oxygen concentration near the barrels at less than approximately 0.95. This allows for a higher injection rate of reagent without oxidizing the nitrogen-containing reagent to NO<sub>x</sub> due to the sub-stoichiometry. Injection at this location also creates lower level of excess NH<sub>3</sub> emissions (NH<sub>3</sub> slip), while injecting at an NSR of 2.0-3.0.

Due to the changes of the lower furnace stoichiometry, RRI is often not a technically feasible option at low loads. Once the stoichiometric ratio increases to >1.0, the potential exists for NO<sub>x</sub> generation due to the reaction of NH<sub>3</sub> with oxygen, especially if the injection location and rate is not optimized. Based on these limitations, RRI is considered most effective at full load.

The RRI process is a commercially available process. Based on engineering judgment, RRI is expected to reduce NO<sub>x</sub> emissions by approximately 20-40% at Coyote Unit 1 when operating at full load with minimal ammonia slip. However, due to the cyclone combustion temperature window, this technology only provides effective NO<sub>x</sub> reduction at or near full load. At low loads, RRI does not provide effective control; however, RRI can be combined with SNCR to provide NO<sub>x</sub> control across the full range of normal operating loads. RRI is a technically feasible NO<sub>x</sub> reduction option for North Dakota lignite-fired cyclone boilers. However, due to its limited operating conditions and ineffective NO<sub>x</sub> reduction at low loads, RRI alone is not considered an available NO<sub>x</sub> control option, and will only be evaluated in conjunction with SNCR.



#### 5.2.2.4 SNCR + RRI

While RRI alone will provide beneficial NO<sub>x</sub> reduction at full load only, coupling RRI with SNCR can provide a balanced approach to NO<sub>x</sub> reduction through all load ranges. Since RRI and SNCR injectors are located at different elevations of the furnace and in different temperature windows, there are not concerns of spatial impacts. The combined system would utilize a relatively high urea injection rate, staged at multiple locations throughout the boiler. The main advantage of this combined system is that the SNCR can provide better NO<sub>x</sub> reduction at low load and at a lower NSR than RRI alone; thus, the combined system is expected to provide effective NO<sub>x</sub> control across all normal operating load ranges. Coupling RRI and SNCR is considered a technically feasible and commercially available NO<sub>x</sub> control technology option on Coyote Unit 1. Based on input from SNCR OEMs and engineering judgment, the control option is expected to achieve an average outlet NO<sub>x</sub> rate of approximately 0.20 lb/MMBtu with an ammonia slip of 10 ppmvd. It should be noted that computational fluid dynamic modeling and temperature mapping of the boiler would be needed to confirm that the incremental reduction in NO<sub>x</sub> emission is achievable without creating unacceptable operational issues.

#### 5.2.2.5 Gas Reburn

Gas reburn is a retrofit technique that has been used to control NO<sub>x</sub> emissions from coal- and oil-fired boilers. Gas reburn involves combustion in three distinct zones within the boiler: (1) a primary combustion zone, where the primary fuel is fired using conventional burners; (2) a reburn zone, where secondary fuel, typically natural gas, is introduced into the boiler; and (3) an OFA burnout zone.

In the primary zone of coal-fired boilers, coal is fired through low-NO<sub>x</sub> burners (LNBs), at a rate corresponding to approximately 80% to 90% of the total heat input. Natural gas reburn fuel is then injected above the primary combustion zone under fuel-rich conditions at a rate corresponding to approximately 10% to 20% of the total heat input (on a Btu/hour basis). The fuel-rich reburn zone creates a reducing (substoichiometric) region within the boiler where the natural gas, principally methane (CH<sub>4</sub>), breaks down to produce hydrocarbon radicals (CH and CH<sub>2</sub>). The hydrocarbon radicals react with NO<sub>x</sub> produced in the primary combustion zone to form nitrogen (N<sub>2</sub>) and water vapor. Because the natural gas is not completely combusted in the reburn zone, gases exiting the reburn zone will contain considerable CO and unburned hydrocarbons; therefore, additional OFA is introduced above the reburn zone to complete the combustion process.

Critical design parameters that affect the feasibility and performance of a gas reburn retrofit system include: (1) baseline NO<sub>x</sub> concentration; (2) reburn zone temperature, residence time, and stoichiometry; (3) OFA burnout zone temperature and residence time; and (4) mixing of the reburn fuel and overfire air with the bulk flue gas.

Gas reburn can have a positive impact on NO<sub>x</sub> emissions; however, in order to make a meaningful prediction of the NO<sub>x</sub> removal capabilities at Coyote Unit 1, extensive testing would be required because gas reburn performance is significantly dependent upon boiler operating characteristics. More importantly, the lack of natural gas available at the Coyote Station precludes the ability to test and implement this control option on Coyote Unit 1. For these reasons, gas reburn is not considered an available or technically feasible NO<sub>x</sub> control technology at Coyote Unit 1.

#### 5.2.2.6 Innovative Technologies

##### NO<sub>x</sub>Star<sup>TM</sup>

The NO<sub>x</sub>Star<sup>TM</sup> process, also known as selective autocatalytic reduction (SACR), uses a continuous controlled amount of ammonia-based reagent with relatively small amounts of hydrocarbon to reduce NO<sub>x</sub> emissions. The hydrocarbon is introduced into the flue gas at the convective pass of the boiler, at elevated temperatures. At the elevated temperatures, the hydrocarbon auto-ignites to form a plasma of free radicals that auto catalyzes the reaction of NH<sub>3</sub> and NO<sub>x</sub> to form N<sub>2</sub> and H<sub>2</sub>O. The hydrocarbon and ammonia are added through banks of nozzles in the superheat or reheat sections of the boiler. The injection location is determined by the location of the temperature windows for the "plasma creation zone" as well as the reaction zone for the ammonia.

To date, only one full-scale demonstration has been conducted to evaluate the technology on a utility-sized boiler. The process is an emerging NO<sub>x</sub> control, and there is limited information available to evaluate its technical feasibility and long-term effectiveness on a large lignite-fired boiler. Potential NO<sub>x</sub> removal efficiencies would be a function of NH<sub>3</sub>-NO<sub>x</sub> mixing, flue gas temperature, flue gas composition, and residence time downstream of the injection lances.

Because this is an emerging technology, extensive design engineering and long-term full scale demonstration testing would be required to evaluate the technical feasibility and effectiveness of the control system on Coyote Unit 1. Detailed design of the lances, mixing, optimization of the reagent supply across the boiler convective pass, flue gas temperatures, and flow distribution would have to be studied. Interference with the tube pendants in the convective pass may also make this more difficult to install. Installing a hydrocarbon distribution grid may



present a problem with large boilers because of the span needed to uniformly distribute the reagent, interference with the tube pendants in the convective pass, and an additional booster fan may be needed. For these reasons, NO<sub>x</sub>Star™ is not considered an available or technically feasible NO<sub>x</sub> control technology at Coyote Unit 1.

#### PerNO<sub>x</sub>ide

PerNO<sub>x</sub>ide utilizes hydrogen peroxide (H<sub>2</sub>O<sub>2</sub>) to reduce NO<sub>x</sub> emissions. Hydrogen peroxide is injected into the ducts ahead of the air preheater and oxidizes the NO to NO<sub>2</sub>, which is then captured in a downstream FGD system. To date, the technology has only been tested on a pilot-scale, and it has not been demonstrated on any coal-fired boilers. It is likely that extensive design engineering and testing would be required to evaluate the scale-up potential and long-term effectiveness of the system on Coyote Unit 1. For these reasons, PerNO<sub>x</sub>ide is not considered an available or technically feasible NO<sub>x</sub> control technology at Coyote Unit 1.

#### LoTO<sub>x</sub><sup>®</sup>

The LoTO<sub>x</sub> system is a gas-phase, low-temperature oxidation system, wherein ozone is injected into the flue gas stream to oxidize NO and NO<sub>2</sub> to N<sub>2</sub>O<sub>5</sub> before being removed in a wet scrubber. This highly oxidized species of NO<sub>x</sub> is water-soluble and rapidly reacts with water to form nitric acid. The conversion of NO<sub>x</sub> to nitric acid occurs as the N<sub>2</sub>O<sub>5</sub> contacts liquid sprays in the scrubber. The nitric acid would react with the alkali compounds in the scrubber and would be eliminated via the scrubber waste and byproduct streams. The LoTO<sub>x</sub> system requires on-demand ozone generation from a liquid oxygen supply.

The LoTO<sub>x</sub> system has been successfully applied in refinery applications; however, there are no full scale installations on coal-fired boilers. According to the control system vendor, a demonstration test was performed on a 25-MW coal-fired boiler which showed effective NO<sub>x</sub> removal. However, it is likely that extensive design engineering and testing would be required to evaluate the scale-up potential and long-term effectiveness of the system on Coyote Unit 1. As such, LoTO<sub>x</sub> is not considered an available or technically feasible NO<sub>x</sub> control technology at Coyote Unit 1.

#### Water Injection

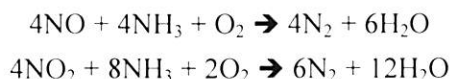
The principle behind this technology is to inject an atomized water spray into the high-NO<sub>x</sub> production zones of a cyclone burner or in the core of the flame for other furnaces. The water spray reduces the temperature and results in lower thermal NO<sub>x</sub> production within this combustion zone. Developers claim that water injection through

burners used in tangential-fired and wall-fired units will also reduce flame temperatures and lower thermal NO<sub>x</sub> production. However, to date only bench-scale test results are available to evaluate this technology's effectiveness in coal-fired applications. Extensive design engineering, pilot-scale testing, and long-term full scale demonstration testing would be required to evaluate the technical feasibility and effectiveness of the control system on Coyote Unit 1.

Water injection has been used to control the formation of thermal NO<sub>x</sub> in combustion turbine applications. However, there is insufficient experience and demonstration data in coal-fired applications. As such, water injection is not considered an available or technically feasible NO<sub>x</sub> control technology at Coyote Unit 1.

#### 5.2.2.7 Selective Catalytic Reduction

SCR is a process by which ammonia reacts with nitric oxide (NO) and nitrogen dioxide (NO<sub>2</sub>), collectively NO<sub>x</sub>, in the presence of a catalyst to reduce the NO<sub>x</sub> to nitrogen (N<sub>2</sub>) and water. SCR technology has been applied to NO<sub>x</sub>-bearing flue gases generated from power generating facilities burning various types of coal, including bituminous, subbituminous, and Texas lignite. The principal reactions resulting in NO<sub>x</sub> reduction are:



Because these reactions proceed slowly at typical boiler exit gas temperatures of a coal-fired steam electric generating unit, a catalyst is used to increase the reaction rate between NO<sub>x</sub> and ammonia. Depending on the specific constituents in the flue gas, a typical temperature range of 550°F to 780°F is necessary to achieve normal performance of the catalyst. For the typical coal-fired boiler, optimal performance will be in the range of approximately 650°F to 750°F.

In general, there are three candidate SCR configurations that can be employed on coal-fired steam electric generating units. The SCR configuration designations generally describe the location of the SCR reaction vessel in relation to other post-combustion air quality control systems. Candidate SCR configurations include:

- High-dust configuration
- Low-dust configuration
- Tail-end configuration

Each of these configurations is described below as they would be applied at Coyote Unit 1.



### High-Dust Configuration

In a high-dust configuration, the SCR reactor is located in the flue gas stream between the economizer outlet and the air heater inlet. This configuration locates the SCR within the inherently optimal temperature range environment for NO<sub>x</sub> reduction (i.e., 650°F to 750°F); however, flue gas characteristics at the economizer outlet can also have detrimental effects on the SCR catalyst. As an example, the high-dust SCR configuration exposes the SCR catalyst to high levels of fly ash loading. High levels of fly ash can result in significant erosion of the catalyst, resulting in more frequent cleaning cycles and catalyst replacement. A second major concern with the high-dust configuration at Coyote Unit 1 is the presence of high levels of sodium (both in the vapor-phase and as submicron aerosols) in the North Dakota lignite-derived flue gas. Sodium is a known SCR catalyst poison, and also affects the adhesive and cohesive characteristics of the fly ash, which in turn, would have an adverse effect on the SCR catalyst and reactor vessel.

SCR catalyst deactivation occurs through two primary mechanisms: physical deactivation and chemical poisoning. Physical deactivation is caused by either exposure of the catalyst to excessive temperatures (thermal deactivation) or masking of the catalyst due to entrainment of particulate from the flue gas stream (fouling). Chemical deactivation is caused by either an irreversible reaction of the catalyst with a contaminant in the gas stream (poisoning) or a reversible absorption of a contaminant on the surface of the catalyst (inhibition). Loss of catalyst activity through thermal degradation or poisoning is permanent, and reactivity can only be restored by replacing the catalyst.

In a North Dakota lignite application, SCR catalyst poisoning is expected to result from the presence of trace elements and strong alkaline substances in flue gas, including sodium (Na), potassium (K), and calcium (Ca). Alkaline metals can chemically attach to active catalyst pore sites and cause deactivation. Sodium and potassium are of prime concern especially in their water-soluble forms, which are more mobile and can penetrate into the catalyst pores. Earth metals, especially calcium, can react with SO<sub>3</sub> absorbed within the catalyst to form CaSO<sub>4</sub> and blind the catalyst.

North Dakota lignite contains relatively high levels of organically associated alkali and alkaline-earth elements, including Na, Ca, K, and magnesium. Sodium levels in North Dakota lignite are typically 5 to 20 times higher than sodium levels in bituminous and subbituminous coals, and sodium compounds can represent between 5% and 11% of the ash generated from firing North Dakota lignite. These sodium levels, occurring in both the vapor phase and particulate phase, along with relatively high levels of potassium and calcium, significantly increase the potential for

catalyst deactivation, plugging, and erosion. Based on the ash chemistry, a conventional high dust SCR arrangement would likely experience unacceptable catalyst deactivation rates.

To evaluate deactivation rates on a North Dakota lignite-fired boiler, EERC and several utilities and catalyst vendors conducted pilot scale testing at the Coyote Station in 2003-2004. The pilot scale test reactor SCR deployed at the Coyote Station became plugged and the catalyst pores deactivated after 2 months of operation (approximately 1,430 hours). This deactivation rate is significantly faster than the deactivation rate observed on bituminous and subbituminous coal-fired units, which can achieve catalyst life ranging between 10,000 and 30,000 operating hours. The EERC described the deactivation at the Coyote Station as extremely rapid and severe.<sup>27</sup>

NDDEQ prepared a comprehensive technical feasibility assessment of high dust SCR on lignite-fired boilers during the first planning period.<sup>28</sup> The Department concluded, based on the unique characteristics of North Dakota lignite-derived flue gas, that the high-dust SCR configuration was not a technically feasible or commercially available NOx control option for North Dakota lignite-fired boilers.<sup>29</sup> Reasons upon which NDDEQ based its conclusion that high-dust SCR was not a technically feasible option for North Dakota lignite-fired boilers included, but were not limit to:<sup>30</sup>

- 1) North Dakota lignite<sup>31</sup> has a higher organic matter content and contains a higher proportion of alkali metal constituents, especially sodium, than subbituminous coal. Approximately 75% of the total sodium in lignite is associated with the organic fraction of the lignite. During combustion, organic and water-soluble sodium vaporizes; consequently, combustion of the coal leads to higher flue-gas concentrations of alkali metals in vapor form.
- 2) The unburned or partially burned organic fraction of North Dakota lignite contains more sodium than other coals. Sodium can react with silicate particles causing a “stickiness” quality to the flue gas ash, resulting in increased ash deposition on heat transfer surfaces. Larger particles can fracture from heat-transfer surfaces (a.k.a. popcorn ash) and enter the flue gas stream. Consequently, deposition on surfaces of catalytic reactors occurs and rates of deposition are higher.
- 3) NOx reduction occurs on the flat surfaces of a catalyst and in pores within the flat surfaces. The pores are open to the flue gas passing through the catalyst reactor. Condensed vapors, alkali sulfates and alkaline-earth oxides and silicates are minute particles (less than 1 microns), which enter pores of the catalyst (a.k.a. plugging) and prevent catalytic reaction with NOx. Residual alkali vapors (Na, K, and Ca) displace hydrogen on fresh catalyst, which prevents catalytic reaction with NOx (a.k.a poisoning) and reacts with

<sup>27</sup> See, Benson, Steven A., Energy and Environmental Research Center, Ash Impacts on SCR Catalyst Performance, University of North Dakota, Grand Forks, ND.

<sup>28</sup> See, North Dakota State Implementation Plan for Regional Haze, February 24, 2010, Appendix B.5, Best Available Retrofit Technology – Selective Catalytic Reduction Technical Feasibility Analysis for North Dakota Lignite, July 2009.

<sup>29</sup> Id. at pg. 19.

<sup>30</sup> Findings and conclusions are summarized from the North Dakota Regional Haze SIP, Appendix B.5, pgs. 15-19.

<sup>31</sup> Although the BART determination specifically references Fort Union lignite, the findings would apply to all North Dakota lignites.



sulfate to cause blinding of catalyst surfaces. Pore condensation of sodium also causes catalyst deactivation, which is a major deactivation mechanism. The rate of catalyst deactivation depends on the concentration and form of alkali in the flue gas; higher Na and K accelerate catalyst poisoning, blinding and plugging.

- 4) During the development of the initial planning period SIP, NDDEQ found that there were no SCR systems planned, constructed, or operating in the flue gas stream of boilers fired with North Dakota lignite. North Dakota lignite has certain coal characteristics that are uniquely different than Texas or Gulf Coast lignites, such as the larger proportion of organic matter and association of alkali, sodium specifically, with that organic matter.
- 5) Slipstream SCR reactors of the same design were installed at three power plants to test SCR for NO<sub>x</sub> emissions control. One of the plants was cyclone fired with North Dakota lignite and the others with subbituminous coal. Deposition on the reactor surface after two months using the lignite was significantly greater; the deposits were rich in sodium, calcium, and sulfur. The tests confirmed catalyst blinding and plugging, but did not provide rates for catalyst deactivation. Tests also indicated that the deposits causing blinding and plugging of pores contained more sodium compared to PRB coal.

Based on a review of SCR installations on coal-fired boilers and a review of reported advances in SCR catalysts since the first planning period, deactivation rates due to soluble alkali compounds in the flue gas (including soluble sodium and potassium compounds) and the adhesive/cohesive characteristics and potential abrasive qualities of the North Dakota lignite-derived fly ash remain a concern for North Dakota lignite-fired boilers. SCR has not been installed and successfully operated on a North Dakota lignite-fired boiler, and the bench scale and pilot-scale studies needed to better understand ash behavior and catalyst blinding/erosion with North Dakota lignite-derived fly ash, and to better understand catalyst deactivation mechanisms associated with high soluble alkali compound concentrations in the flue gas have not been required or completed. Pilot-scale studies are needed to evaluate these issues to inform the development of advanced catalyst formulations, and to support the engineering and design studies needed to mitigate for potential deactivation routes (e.g., removing soluble alkali compounds from the flue gas and SCR design considerations such as catalyst formulation, catalyst pitch, reactor velocity, and catalyst surface and volume). Pilot-scale tests and engineering/design studies have not advanced since the first planning period's exhaustive analysis.

These issues have not been resolved since the first planning period and remain a significant barrier to the design and successful operation of high dust SCR on North Dakota lignite-fired boilers. The BART Guidelines state that "[a] control technique is considered available...if it has reached the stage of licensing and commercial availability."<sup>32</sup> Commercial availability follows bench scale and laboratory testing and pilot scale testing. Consequently, the BART Guidelines state that "you would not consider technologies in the pilot scale testing stages

<sup>32</sup> 40 CFR Part 51 Appendix Y, Section D.2.1.

of development as ‘available’ for purposes of BART review.”<sup>33</sup> Furthermore, source owners/operators are not expected to conduct extended trials to learn how to apply a technique on a dissimilar source type.<sup>34</sup> These BART guidelines also apply as a recommendation for the development of the LTS in the second planning period and the four factor analysis.<sup>35</sup> Because there are unresolved issues associated with catalyst poisoning, catalyst blinding and plugging, and catalyst erosion; and engineering solutions have not been determined or demonstrated and the high dust configuration has not moved beyond pilot scale testing, high dust SCR is not an available technically feasible NOx control technology for Coyote Unit 1.

### Low-Dust Configuration

In the low-dust configuration, the SCR reactor vessel is located in the flue gas stream after the particulate collection device (i.e. ESP or FF). Employing this configuration would represent a relatively low level of exposure to fly ash (with the exception of submicron ash particles), but a potentially high level of vapor-phase alkalis, such as sodium. This configuration can be used on units equipped with particulate control only or units equipped with particulate control followed by a WFGD control system. The existing dry FGD/FF control configuration at Coyote Unit 1 for SO<sub>2</sub> and particulate control would preclude the application of a low-dust SCR configuration since, by definition, the SCR would have to be located downstream of both the dry FGD and FF. At that location the SCR would be more appropriately defined as a tail-end SCR configuration, which is described in more detail in the following section. Because Coyote Unit 1 is equipped with existing dry FGD/FF controls, low-dust SCR has no practical application on the unit, and low-dust SCR is not considered a technically feasible NOx control option for Coyote Unit 1.

### Tail-End Configuration

In the tail-end configuration, the SCR reaction vessel is located in the flue gas stream after the particulate and FGD control systems. The potential advantage of a tail-end SCR configuration at Coyote Unit 1 is that the flue gas will have passed through the dry FGD/FF system prior to the SCR catalyst. As such, there is the possibility that the mass transfer mechanism that results in the capture of SO<sub>2</sub> will also capture some of the vapor-phase sodium and the sodium-enriched submicron particles, reducing the risk of catalyst poisoning and/or deactivation.

---

<sup>33</sup> Id.

<sup>34</sup> Id.

<sup>35</sup> See, Draft EPA Guidelines, pg. 183.



Successful operation of the tail-end configuration would also require a capital and operating cost-intensive gas-to-gas heat exchanger to reheat the flue gas from approximately 200 °F downstream of the existing FF to approximately 550°F to support the SCR NO<sub>x</sub> reactions. After the flue gas passes through the SCR (at approximately 550°F), it would pass through the hot side of the gas-to-gas heat exchanger to cool the flue gas to 150°F prior to the exhaust stack. Although this stack gas temperature would be lower than the current stack temperature (190-210°F), it is still higher than the adiabatic saturation temperature of the flue gas (i.e., approximately 135°F). As such, it is likely that the existing stack could be reused without any major modifications.

During the first planning period, NDDEQ initially concluded, based on preliminary information provided by SCR catalyst vendors, that the tail-end SCR configuration would be a technically feasible option for units firing North Dakota lignite that are subject to BART requirements.<sup>36</sup> However, as part of the Milton R. Young Station (MRYS) NO<sub>x</sub> BACT determination process, detailed information describing the expected ash characteristics and flue gas characteristics was provided to two SCR catalyst vendors (CERAM Environmental, Inc. (CERAM) and Haldor Topsoe, Inc.). Based on their review of the data, both vendors concluded that they would not be able to provide a catalyst life guarantee for either low-dust or tail-end SCR without pilot-scale testing.<sup>37</sup>

Both vendors also made statements bringing into question the technical feasibility of either low-dust or tail-end SCR. For example, CERAM stated that the high levels of sodium oxide (Na<sub>2</sub>O) in the ash for North Dakota lignite are not commonly found in subbituminous and bituminous coals which are fired in boilers equipped with SCR systems, and that it was unaware of any SCR application experience in the industry with the level and form of sodium in the North Dakota lignite-derived MRYS ash.<sup>38</sup>

Based in part on this information provided by SCR design engineering firms and SCR catalyst vendors, NDDEQ concluded that the use of SCR technology, including low-dust and tail-end SCR, on the lignite-fired MRYS boilers would be technically infeasible.<sup>39</sup>

Based on a review of SCR installations on coal-fired boilers, and a review of reported advances in SCR catalysts since the first planning period, deactivation rates due to soluble alkali compounds in the flue gas (including soluble sodium and potassium compounds) remain a concern for all North Dakota lignite-fired boilers. Tail-end SCR has not been demonstrated or installed on a North Dakota lignite-fired boiler, and there are still significant technical

<sup>36</sup> See, North Dakota Regional Haze State Implementation Plan for Regional Haze, February 24, 2010, Appendix B.5, pg. 25.

<sup>37</sup> See, *United States v. Minnkota*, 831 F. Supp. 2d, at 1116- 1117.

<sup>38</sup> *Id.*, at 1115-1116.

<sup>39</sup> *Id.*, at 1118.

concerns associated with the availability of existing SCR catalysts on a North Dakota lignite-fired unit. Catalyst in a tail-end SCR will still be vulnerable to alkali poisoning, pore pluggage, and premature catalyst deactivation, and it is not known whether the comparatively high levels of soluble sodium and potassium in North Dakota lignite will be effectively removed by the upstream dry FGD/FF. Furthermore, the potential exists for fine particulate remaining in the flue gas to get into the catalyst pores reducing catalyst activity. Pilot-scale studies needed to better understand catalyst deactivation mechanisms associated with high soluble alkali compound concentrations in the flue gas have not been completed.

In order to understand the effect of North Dakota lignite-derived flue gas on the tail-end SCR catalyst, identify potential design solutions, and evaluate the technical feasibility and effectiveness of tail-end SCR at Coyote Unit 1 with any degree of certainty, extended pilot scale testing of the control configuration would be needed. Additionally, because there are unresolved issues associated with catalyst poisoning, it's unlikely that OTP could obtain a viable commercial offering for tail-end SCR on Coyote Unit 1. Therefore, tail-end SCR is not an available technically feasible NOx control technology.

#### SCR Summary

During the first planning period NDDEQ determined that high-dust SCR and tail-end SCR are not available, and thus, not a technically feasible NOx control option for North Dakota lignite-fired boilers. The administrative record developed during the first planning period, including the BART determinations and MRYS BACT analysis, supports the conclusion that high-dust SCR and tail-end SCR are not an available NOx control option for Coyote Unit 1. An evaluation of SCR installations and reported advances in SCR catalysts since the first planning period, coupled with the fact that high-dust SCR and tail-end SCR have not been demonstrated on a North Dakota lignite-fired boiler, and the likelihood that OTP could not obtain a viable commercial offering for tail-end SCR without extended pilot-scale testing, continues to support the conclusion that high-dust SCR and tail-end SCR are not available NOx control technologies.

#### **5.2.2.8 Technical Feasibility Summary**

Table 5-10 summarizes the results of the feasibility evaluation of available control options for Coyote Unit 1.



Table 5-10. Technically Feasible NO<sub>x</sub> Control Options

NO <sub>x</sub> Control Option	Technically Feasible (Yes/No)	Technical Feasibility Summary
Combustion Optimization	Yes	Tuning to optimize the existing combustion system, including lower the stoichiometry in the cyclone barrels, tracking cyclone combustion stability, and adjusting the SOFA system (while staying within original OEM specifications) is a technically feasible NO <sub>x</sub> control option.
Selective Non-Catalytic Reduction (SNCR)	Yes	SNCR is considered an available and technically feasible NO <sub>x</sub> control technology for Coyote Unit 1. Computational fluid dynamic modeling and temperature mapping of the boiler would be needed to confirm that the incremental reduction in NO <sub>x</sub> emissions is achievable without creating unacceptable operational issues.
Rich Reagent Injection (RRI)	No	RRI is considered an available and technically feasible NO <sub>x</sub> control option cyclone burners at full load operation; however, at low load operation RRI does not provide effective NO <sub>x</sub> control. Therefore, RRI alone is not considered an available NO <sub>x</sub> control option, and will only be evaluated in conjunction with SNCR.
SNCR + RRI	Yes	Coupling RRI and SNCR is considered a technically feasible and commercially available NO <sub>x</sub> control technology option on Coyote Unit 1. Computational fluid dynamic modeling and temperature mapping of the boiler would be needed to confirm that the incremental reduction in NO <sub>x</sub> emissions is achievable without creating unacceptable operational issues.
Gas Reburn	No	The lack of natural gas availability at the Coyote Station precludes the ability to test and implement this control option on Coyote Unit 1. Therefore, gas reburn is not considered an available or technically feasible NO <sub>x</sub> control technology at Coyote Unit 1.
Innovative Technologies: NOxStar™ PerNO <sub>x</sub> ide LoTO <sub>x</sub> Water Injection	No	Innovative NO <sub>x</sub> control technologies are evaluated in Section 5.2.2.6. In all cases, the technologies have not been demonstrated on a large North Dakota lignite-fired boiler. Extensive testing and design engineering would be required to evaluate the technical feasibility and long-term effectiveness of each innovative control system on Coyote Unit 1. Therefore, the innovative NO <sub>x</sub> control technologies are not considered available control options and are not technically feasible NO <sub>x</sub> control options for Coyote Unit 1
Selective Catalytic Reduction (SCR):		
High-dust configuration	No	Due to significant unresolved issues associated with catalyst poisoning, catalyst blinding and plugging, and catalyst erosion; and based on the finding that engineering solutions have not been determined or demonstrated and the high dust configuration has not moved beyond pilot scale testing, high dust SCR is not and available or technically feasible NO <sub>x</sub> control technology for Coyote Unit 1.
Low-dust configuration	No	Because Coyote Unit 1 is equipped with existing dry FGD/FF



NO <sub>x</sub> Control Option	Technically Feasible (Yes/No)	Technical Feasibility Summary
		control systems, low-dust SCR has no practical application on the unit, and low-dust SCR is not considered an available or technically feasible NO <sub>x</sub> control option for Coyote Unit 1.
Tail-end configuration	No	Based on the continued lack of demonstration testing and commercial guarantees, tail-end SCR is not considered to be a technically feasible control option for Coyote Unit 1.

### 5.2.3 Evaluate Technically Feasible NO<sub>x</sub> Control Options for Effectiveness

The technically feasible NO<sub>x</sub> control technologies are listed in Table 5-11 in descending order of control efficiency. Table 5-11 also provides control option-specific NO<sub>x</sub> emission rates in terms of lb/MMBtu. Emission rates shown in Table 5-11 represent average emission rates that the control options would be expected to achieve during normal operations.

**Table 5-11. Evaluate Technically Feasible NO<sub>x</sub> Control Options for Effectiveness**

Control Technology	NO <sub>x</sub> Emission Rate <sup>(Note 1)</sup> lb/MMBtu	% Reduction from Baseline Emission Rate
Baseline (existing SOFA)	0.46	-
SNCR + RRI + Combustion Optimization	0.20	56.2%
SNCR + Combustion Optimization	0.28	38.7%
Combustion Optimization	0.42	8.0%

Note 1. Emission rates shown in Table 5-11 represent average emission rates that the control options would be expected to achieve on an on-going long-term basis under normal operating conditions for Coyote Unit 1. Emission rates are provided for comparative purposes, and should not be construed to represent proposed emission limits. Corresponding permit limits must be evaluated on a control system-specific basis; an additional margin would likely be needed to account for operating margin. Additionally, for control options that include SNCR or RRI, computational fluid dynamic modeling and temperature mapping of the boiler would be needed to confirm that the incremental reduction in NO<sub>x</sub> emission is achievable without creating unacceptable operational issues.

## 6. COSTS OF COMPLIANCE (STATUTORY FACTOR ONE)

The economic analysis performed as part of the Four Factor analysis examines the cost-effectiveness of each technically feasible control technology, on a dollar per ton of pollutant removed basis. Annual emissions, calculated for a particular control device, are subtracted from baseline annual emissions to calculate tons of pollutant controlled per year. For units with existing controls, the base case represents existing baseline actual emissions. Annual costs for each control option are calculated relative to the base case by adding annual operation and maintenance (O&M) costs to the annualized cost of capital and, if applicable, lost revenue due to extended outage required for installation of control equipment. Capital costs and lost revenues were annualized using a capital recovery factor based on an annual interest rate of 5.25%<sup>41</sup> and equipment life of 20 years.<sup>42</sup> Cost effectiveness (\$/ton) of a particular control option is simply the annual cost (\$/yr) divided by the annual reduction in annual emissions (ton/yr). In addition to cost-effectiveness relative to the base case, the incremental cost-effectiveness to go from one level of control to the next, more stringent, level of control may also be calculated to evaluate the incremental cost effectiveness of the more stringent control.

Capital and O&M cost estimates were developed for each of the technically feasible SO<sub>2</sub> and NO<sub>x</sub> control options. The Coyote Unit 1 cost estimates are conceptual in nature; thus, S&L did not procure equipment quotes specifically for the Unit 1 control system upgrades. Rather, equipment costs are based on conceptual designs developed for the retrofit control systems, preliminary equipment sizing developed for the major pieces of equipment (based on Coyote Unit 1-specific design parameters, including typical fuel characteristics, full load heat input, and flue gas temperatures and flow rates), and recent pricing for similar equipment. S&L would characterize the cost estimates for the Coyote Unit 1 retrofit technologies as “concept screening” cost estimates generally based on parametric models, judgment, or analogy.

<sup>41</sup> In an email to the North Dakota Department of Health dated December 18, 2018, EPA recommended use of a 5.25% interest rate. Otter Tail does not necessarily agree that this is an appropriate percentage to use and reserves the right to update and modify this percentage at a later date. Notably, on September 26, 2018 the North Dakota Public Service Commission approved a rate of return for Otter Tail of 7.64% (See <https://psc.nd.gov/database/documents/17-0398/226-020.pdf>). This ROR represents a total weighted average cost of capital. An interest rate of 5.25% is more representative of the long-term cost of debt, which is only one component of capital structure.

<sup>42</sup> The assumed 20-year equipment life is consistent with the control system equipment life used by NDDEQ in its evaluation of NO<sub>x</sub> and SO<sub>2</sub> control technologies for BART-eligible sources. (see, e.g., ND Regional Haze Final SIP, Appendix C.1, “BART Determination Study for Leland Olds Station Units 1 & 2, Basin Electric Power Cooperative, August 2006, pgs. 64 (NO<sub>x</sub> controls) and 158 (SO<sub>2</sub> controls). See also, ND Regional Haze Final SIP, Appendix C4, “NO<sub>x</sub> Best Available Control Technology Study for Milton R. Young Station Unit 1, Minnkota Power Cooperative, Inc., October 2006, pg. 3-22).



Control technology equipment costs for the retrofit options were developed by scaling cost estimates prepared by S&L for other similar projects. Major equipment costs were developed based on equipment costs recently developed for similar projects, and include the equipment, material, labor, and all other direct costs needed to retrofit the units with the control technology. Sub-accounts for the capital cost estimates (e.g., mobilization and demobilization, consumables, Contractor G&A expense, freight on materials, etc.) were developed by applying ratios from detailed cost estimates that were prepared for projects with similar scopes.

Fixed O&M costs include operating labor, maintenance labor, maintenance material, and administrative labor. Variable O&M costs include the cost of consumables, including reagent, water consumption, and auxiliary power requirements.<sup>43</sup> Auxiliary power requirements reflect the additional power requirements associated with the operation of the new control technology (compared to the existing technology). All O&M costs reflect the incremental increase in O&M costs compared to the costs incurred to operate the existing dry scrubber and FF control systems.

In addition to the cost effectiveness relative to the base case, the incremental cost-effectiveness to go from one level of control to the next more stringent level of control will also be calculated to evaluate the cost effectiveness of the more stringent control.

The results of the SO<sub>2</sub> and NO<sub>x</sub> control cost evaluations are included below in Sections 6.1 and 6.2.

## 6.1 ECONOMIC EVALUATION – SO<sub>2</sub> CONTROLS

Table 6-1 presents the capital costs and annual operating costs associated with installing and operating each technically feasible SO<sub>2</sub> control system for Unit 1. Table 6-2 shows the average annual and incremental cost effectiveness for each control system. Additional cost details are provided in Appendix B.

Cost estimates were not prepared for the SDA/FF option since the capital and operating costs for the SDA/FF option would be similar to the costs for the CDS/FF option, and the CDS/FF option would likely provide the opportunity to achieve somewhat lower controlled SO<sub>2</sub> emissions (compared to SDA/FF). Therefore, of the two new DFGD system options, only the CDS/FF option was evaluated.

---

<sup>43</sup> Variable O&M costs are based on an uncontrolled SO<sub>2</sub> of 2.3 lb/MMBtu as recommended by the NDDEQ.

Table 6-1. SO<sub>2</sub> Control Cost Summary (\$2018)

SO <sub>2</sub> Control Option	Total Capital Investment \$	Annualized Capital Cost \$/yr	Annual Operating Cost \$/yr	Total Annual Cost \$/yr
DSI + Existing FGD	\$23,765,000	\$1,948,000	\$10,423,000	\$12,371,000
FGD Operational Improvements – Increase Ca:S Stoichiometric Ratio	\$526,000	\$43,000	\$2,042,000	\$2,085,000
DSI + FGD Operational Improvements	\$24,292,000	\$1,991,000	\$12,465,000	\$14,456,000
FGD Upgrades - Replacing Existing Absorbers with New Absorber	\$127,823,000	\$10,475,000	\$6,332,000	\$22,197,000 <sup>(Note 1)</sup>
Dry FGD (CDS) + Existing FF	\$242,647,000	\$19,885,000	\$20,610,000	\$40,495,000
Wet FGD	\$324,742,000	\$26,613,000	\$22,481,000	\$49,094,000

Note 1. Total annual cost for “FGD Upgrades - Replacing Existing Absorbers with New Absorber” option includes annualized lost revenue due to extended outage and replacement power required for installation (\$5,390,000).

Table 6-2. SO<sub>2</sub> Emissions Control System Cost Effectiveness (\$2018)

SO <sub>2</sub> Control Option	Total Annual Cost \$/yr	Expected Emission Reduction tons SO <sub>2</sub> /yr	Average Annual Cost Effectiveness (Note 1) \$/ton SO <sub>2</sub> removed	Incremental Annual Cost Effectiveness (Note 2, 3) \$/ton SO <sub>2</sub> removed
Baseline (Existing DFGD/FF)	---	---	---	---
DSI + Existing FGD	\$12,371,000	4,131	\$2,994	
FGD Operational Improvements – Increase Ca:S Stoichiometric Ratio	\$2,085,000	5,354	\$389	n/a
DSI + FGD Operational Improvements	\$14,456,000	7,952	\$1,818	\$4,762
FGD Upgrades - Replacing Existing Absorbers with New Absorber	\$22,197,000	8,563	\$2,592	\$12,664
Dry FGD (CDS) + Existing FF	\$40,495,000	11,619	\$3,485	\$5,987
Wet FGD	\$49,094,000	12,078	\$4,065	\$18,757

Note 1. Average cost effectiveness for each control option is the total annual cost divided by the expected emission reduction.

Note 2. Incremental cost effectiveness represents the incremental increase in annual costs (\$/yr) divided by the incremental increase in annual emissions reductions (tpy) between a control option and the next most effective option.

Note 3. "n/a" indicates that the next most effective control option is "inferior" (i.e., higher cost for less control)

Table 6-2 indicates that the average annual cost effectiveness of the technically feasible SO<sub>2</sub> control options for Unit 1 range from \$389 per ton (FGD Operation Improvements) to \$4,065 per ton (Wet FGD). Costs associated with equipment procurement and installation, and annual operating costs all have a significant impact on the cost of the SO<sub>2</sub> control systems.

Annual costs of the DSI system exceed the costs of the FGD Operational Improvements option, and the DSI system achieves lower SO<sub>2</sub> reductions. Therefore, the DSI system is an "inferior" control option.

The FGD Operational Improvements option would require the relatively low capital investment for upgrading the existing atomizer wheel and an increase in operating costs primarily due to increased reagent usage. This option will achieve approximately 41% SO<sub>2</sub> reduction from the baseline levels, resulting in a cost effectiveness of \$465 per ton.



The option to incorporate FGD Operational Improvements and install a DSI system will achieve approximately 61% SO<sub>2</sub> reduction from the baseline. Capital costs are primarily attributed to the DSI equipment, and high operating costs are due to a significant increase in hydrated lime use. The cost effectiveness of the DSI + FGD Operational Improvements option is \$1,818 per ton. Comparing this option to the next most effective control option, FGD Operational Improvements (without DSI), the incremental costs effectiveness is \$4,762 per ton.

Replacing the existing absorber modules with new absorber modules will require Coyote Unit 1 to be taken off-line for approximately 12 months. In addition to capital and operating costs, the Coyote Station will incur costs associated with lost production and purchase of replacement power. The cost effectiveness of the FGD Upgrade - Replacing Existing Absorbers with New Absorber option is \$2,592 per ton. Comparing this option to the next most effective control option, DSI + FGD Operational Improvements, the incremental cost effectiveness is \$12,664 per ton.

The installation of new Dry FGD (CDS) or new Wet FGD systems are high capital and annual operating cost options. The cost effectiveness for these options are \$3,485 per ton (Dry FGD) and \$4,065 per ton (Wet FGD). The incremental cost of installing a Dry FGD system, compared to FGD Upgrades, is \$5,987 per ton. The incremental cost of installing a Wet FGD system, compared to a Dry FGD system, is \$18,757 per ton.

## 6.2 ECONOMIC EVALUATION – NO<sub>x</sub> CONTROLS

Table 6-3 presents the capital costs and annual operating costs associated with building and operating each control system. Table 6-4 shows the average annual and incremental cost effectiveness for each control system. Additional cost details are provided in Appendix C.

**Table 6-3. NO<sub>x</sub> Control Cost Summary (\$2018)**

NO <sub>x</sub> Control Option	Total Capital Investment \$	Annual Capital Cost \$/yr	Annual Operating Cost \$/yr	Total Annual Cost \$/yr
Combustion Optimization	\$0	\$0	\$0	\$0
SNCR + Combustion Optimization	\$19,840,000	\$1,626,000	\$3,128,000	\$4,754,000
SNCR + RRI + Combustion Optimization	\$25,895,000	\$2,122,000	\$6,495,000	\$8,617,000

Table 6-4. NO<sub>x</sub> Emissions Control System Cost Effectiveness (\$2018)

NO <sub>x</sub> Control Option	Total Annual Cost \$/yr	Expected Emission Reduction tons NO <sub>x</sub> /yr	Average Annual Cost Effectiveness (Note 1) \$/ton NO <sub>x</sub> removed	Incremental Annual Cost Effectiveness (Note 2) \$/ton NO <sub>x</sub> removed
Baseline (Existing SOFA)	---	---	---	---
Combustion Optimization	\$0	589	\$0	\$0
SNCR + Combustion Optimization	\$4,754,000	2,847	\$1,670	\$2,105
SNCR + RRI + Combustion Optimization	\$8,617,000	4,137	\$2,083	\$2,994

Note 1. Average cost effectiveness for each control option is the total annual cost divided by the expected emission reduction.

Note 2. Incremental cost effectiveness represents the incremental increase in annual costs (\$/yr) divided by the incremental increase in annual emissions reductions (tpy) between a control option and the next most effective option.

Table 6-4 indicates that the average annual cost effectiveness of the technically feasible NO<sub>x</sub> control options for Unit 1 range from \$0 per ton (Combustion Optimization) to \$2,083 per ton (SNCR + RRI) NO<sub>x</sub> removed.

The Combustion Optimization option is expected to achieve 8% NO<sub>x</sub> reduction from baseline levels without impact to boiler performance. This option can be implemented without additional capital or operating costs; therefore, the cost effectiveness is \$0 per ton.

Installation of an SNCR system is expected to achieve approximately 39% NO<sub>x</sub> reduction. The cost effectiveness of this option is \$1,670 per ton. Compared the next most effective option, Combustion Optimization, the incremental cost effectiveness is \$2,105 per ton.

The option to install an SNCR system combined with RRI would achieve approximately 56% NO<sub>x</sub> reduction. Compared to installing SNCR alone, this option incurs additional capital costs for the RRI system and higher operating costs primarily due to increased urea consumption. The cost effectiveness of the SNCR + RRI option is \$2,083 per ton, and the incremental cost compared to SNCR alone is \$2,994 per ton.

## 7. TIME NECESSARY FOR COMPLIANCE (STATUTORY FACTOR TWO)

The time necessary for compliance is generally defined as the time needed for full implementation of the technically feasible control options. This includes the time needed to develop and implement the regulations, as well as the time needed to install the selected control equipment. The time needed to install the control equipment includes time for equipment procurement, design, fabrication, and installation. If reasonable progress measures are required at Coyote Station for the Regional Haze second planning period, the anticipated compliance deadline would be July 1, 2028.<sup>44</sup> However, this compliance deadline must provide a reasonable amount of time for the source to implement the control measure.

Table 7-1 and Table 7-2 include estimated timeframes needed to implement each of the technically feasible control options. Notably, the estimated timeframes do not account for time needed for North Dakota to develop and implement the regulations; nor the amount of time needed for EPA to take proposed and final action to approve North Dakota's SIP.

---

<sup>44</sup> For the first planning period, on March 14, 2011 the North Dakota Department of Health issued permit to construct number PTC10008 that required Coyote Station to meet the approved reasonable progress limitation by July 1, 2018.



Table 7-1. SO<sub>2</sub> Emissions Control System Implementation Schedule

SO <sub>2</sub> Control Option	Design / Specification / Procurement (months)	Detail Design / Fabrication (months)	Construction / Commissioning / Startup (months)	Total (months after SIP approval)
DSI + Existing FGD	6	6	6	18
FGD Operational Improvements – Increase Ca:S Stoichiometric Ratio	0	0	0	0
DSI + FGD Operational Improvements	6	6	6	18
FGD Upgrades - Replacing Existing Absorbers with New Absorber	8	12	12	32
Dry FGD (CDS) + Existing FF	12	20	18	50
Wet FGD	12	22	22	56

Table 7-2. NO<sub>x</sub> Emissions Control System Implementation Schedule

NO <sub>x</sub> Control Option	Design / Specification / Procurement (months)	Detail Design / Fabrication (months)	Construction / Commissioning / Startup (months)	Total (months after SIP approval)
Combustion Optimization	0	0	0	0
SNCR + Combustion Optimization	10	6	6	22
SNCR + RRI + Combustion Optimization	10	6	6	22

## 8. ENERGY AND NON-AIR QUALITY ENVIRONMENTAL IMPACTS (STATUTORY FACTOR THREE)

The primary purpose of the environmental impact analysis is to assess collateral environmental impacts due to control of the regulated pollutant in question. Environmental impacts may include solid or hazardous waste generation, discharges of polluted water from a control device, visibility impacts, increased emissions of other criteria or non-criteria pollutants, increased water consumption, and land use impacts from waste disposal.

### 8.1 ENVIRONMENTAL IMPACTS

Coyote Unit 1 is currently equipped with SOFA for NO<sub>x</sub> control and dry scrubber technology for SO<sub>2</sub> control. The hydrated lime reactant used in a dry scrubbing system reacts with SO<sub>2</sub> in the flue gas to form calcium sulfate and calcium sulfite solids. The solids are captured in the existing FF particulate control system and either returned to the system for reuse or removed from the system as nonhazardous solid waste. The existing dry scrubbing system also requires water to hydrate the lime prior to injection into the reaction modules. Based on the design of the control system, Coyote Unit 1 currently uses approximately 465 gpm of water to hydrate the lime (at full load). Collateral environmental impacts associated with the existing Coyote Unit 1 control systems include water consumption and increased solid waste generation. There were no collateral impacts associated with the SOFA system.

Based on a review of potential non-air quality environmental impacts, no significant collateral environmental impacts were identified for any of the SO<sub>2</sub> and NO<sub>x</sub> control options included in this evaluation, with the exception, potentially, of the WFGD, DSI, and SNCR/RRI options. No significant non-air quality environmental impacts were identified for the options that include replacing the existing scrubber modules with new scrubber modules, FGD operational improvements/upgrades or combustion optimization. Collateral environmental impact identified for the sorbent injection control option includes an increase in the solid waste generation. The sorbent injection system will increase the solid waste generated by approximately 50% (47,000 lb/hr to 70,000 lb/hr).

There are a number of potential non-air quality environmental impacts associated with the WFGD control option. Unlike dry scrubbing systems that generate a dry FGD byproduct, WFGD systems generate a liquid calcium sulfate by-product that must be dewatered prior to disposal. WFGD control systems can be designed with forced oxidation that results in a gypsum-grade by-product that can be sold into the local gypsum market. If an adequate gypsum



market is not available, the gypsum by-product will require disposal. WFGD control systems also generate a wastewater stream that must be treated prior to discharge. WFGD wastewaters typically consist of a saturated solution of calcium sulfate, calcium sulfite, and sodium chloride, with trace amounts of fly ash and unreacted limestone. Traces of metal ions may also be present due to fly ash carryover from the flue gas to the WFGD scrubber liquor. WFGD wastewater treatment systems typically require calcium sulfate/sulfite desaturation, heavy metals precipitation, coagulation/precipitation, and sludge dewatering. Treated wastewater is typically discharged to surface water pursuant to an NPDES discharge permit, and solids are typically disposed of in a landfill.

WFGD systems also require significantly more water than the dry systems. Based on design criteria for wet and dry FGD control systems, WFGD systems typically require approximately 25-30% more water than a similarly sized DFGD control system. This would increase water consumption at Coyote Unit 1 on average approximately 130 gpm. Water consumption is an important factor when assessing potential non-air quality environmental impacts at facilities located in North Dakota, and could represent a significant non-air quality collateral environmental impact.

In addition, the SNCR and SNCR/RR1 control options have the collateral impact of ammonia slip emissions at 10 ppm since these options utilize ammonia as the reagent for the reactions with NO<sub>x</sub> to occur. Ammonia slip emissions from the SNCR/RR1 options will likely end up in the dry FGD solids.

## 8.2 ENERGY IMPACTS

Options that include replacing the existing Unit 1 dry scrubbing system with a CDS/FF or WFGD system will increase pressure drop through the control systems, increase auxiliary power requirements, and adversely affect the unit's net plant heat rate (Btu heat input per MW<sub>Net</sub> output).<sup>45</sup> Consequently, heat input to the boiler would need to increase to compensate for the increased auxiliary power requirements while achieving the same net plant output, or net output from the unit would decrease.

Although several of the control options have energy impacts, none of the impacts are considered significant enough as to disqualify any of the options from consideration in the four factor analysis. In order to account for potential energy impacts associated with each option, the auxiliary power cost associated with operating the control systems have been included as an annual operating cost in the economic impact assessment.

---

<sup>45</sup> Heat rate represents the amount of heat input to the boiler (Btu) required to generate one megawatt (MW) net electric output and is reported as Btu/MW<sub>Net</sub>.

### 8.3 ENVIRONMENTAL / ENERGY IMPACTS SUMMARY

A summary of the environmental and energy impact analysis is provided in Table 8-1.

Table 8-1. Summary of Energy and Non-Air Quality Environmental Impacts

Control Option	Collateral Environmental & Energy Impacts
<b>Baseline</b>	<ul style="list-style-type: none"> <li>➤ Coyote Unit 1 is currently equipped with dry scrubbing / FF control systems. Existing collateral environmental and energy impacts include:</li> <li>➤ Solid FGD by-product management and disposal</li> <li>➤ Increased water consumption</li> <li>➤ Increased auxiliary power requirements and heat rate penalty</li> </ul>
<b><u>SO<sub>2</sub> Control Options</u></b>	
Replace existing DFGD with New WFGD control system	<ul style="list-style-type: none"> <li>➤ Increased water consumption</li> <li>➤ Wet by-product that requires dewatering prior to disposal</li> <li>➤ FGD wastewater treatment &amp; discharge</li> <li>➤ Increased auxiliary power requirements and heat rate penalty</li> </ul>
Replace existing DFGD with New CDS/FF Control System	<ul style="list-style-type: none"> <li>➤ Increased auxiliary power requirements and heat rate penalty</li> <li>➤ Increased solid FGD by-product management and disposal</li> </ul>
Replace existing dry scrubber modules with New DFGD modules while keeping existing FF	<ul style="list-style-type: none"> <li>➤ Requires extended (approximately 12-month) outage of Coyote Unit 1 to demolish and replace the existing scrubber modules</li> </ul>
Dry Sorbent Injection	<ul style="list-style-type: none"> <li>➤ Increased solid FGD by-product management and disposal</li> <li>➤ Increased auxiliary power requirements and heat rate penalty</li> </ul>
<b><u>NO<sub>x</sub> Control Options</u></b>	
SNCR or SNCR + RRI	<ul style="list-style-type: none"> <li>➤ Increased ammonia slip emissions</li> <li>➤ Increased auxiliary power requirements and heat rate penalty</li> </ul>

## 9. REMAINING USEFUL LIFE (STATUTORY FACTOR FOUR)

The evaluation of technically feasible NO<sub>x</sub> and SO<sub>2</sub> controls options should consider the source's "remaining useful life" in determining the costs of compliance. The remaining useful life is the difference between the date that controls would be put in place and the date that the facility permanently ceases operation. If the remaining useful life of the unit is shorter than the useful life of a particular control option, the remaining useful life should be used to annualize costs. If the remaining useful life exceeds the useful life of the control options, the remaining use life has no effect on the cost evaluation.

The cost of compliance for each control option (see Section 6) currently calculates the annual capital recovery cost by multiplying the total capital investment by a CRF from a formula based on a 20-year equipment lifetime. The Coyote Station owners have not identified dates for the remaining useful life of the unit before the end of what would otherwise be the useful life of the control measures that were evaluated for Coyote Unit 1. Thus, the 20-year equipment life of the control measures was used in the four factor analysis to calculate emission reductions, amortized costs, and cost-effectiveness.



## 10. FOUR-FACTOR ANALYSIS SUMMARY

At the request of NDDEQ, a four factor analysis was prepared for Coyote Unit 1. The analysis identified technically feasible SO<sub>2</sub> and NO<sub>x</sub> control options for Unit 1, and evaluated each of the control measures for the following four statutory factors:

1. The costs of compliance;
2. The time necessary for compliance;
3. The energy and non-air quality environmental impacts of compliance; and
4. The remaining useful life of any potentially affected anthropogenic source of visibility impairment.

The cost of compliance evaluation prepared for SO<sub>2</sub> controls indicates that the average annual cost effectiveness ranges from \$389 per ton (FGD Operation Improvements) to \$4,065 per ton (Wet FGD). The evaluation prepared for NO<sub>x</sub> controls options indicates that the average annual cost effectiveness ranges from \$0 per ton (Combustion Optimization) to \$2,083 per ton (SNCR + RRI) NO<sub>x</sub> removed.

The time necessary for compliance for the SO<sub>2</sub> control options ranges from 0 months (FGD operational improvements) to 56 months (new wet FGD system). For NO<sub>x</sub> control options, the time necessary for compliance ranges from 0 months (combustion optimization) to 22 months (SNCR + RRI).

An evaluation of energy impacts indicates that certain control options (e.g., new FGD systems) will increase auxiliary power requirements due to increased pressure drop, which would adversely impact net plant heat rate. Consequently, heat input to the boiler would need to increase to compensate for the increased auxiliary power requirements while achieving the same net plant output, or net output from the unit would decrease. Collateral environmental impacts include an increase in the solid waste generation with DSI, as well as potential incremental increase in fugitive dust emissions associated with sorbent deliveries to the facility.

Regarding remaining useful life, the Coyote Station owners have not identified dates for the remaining useful life of the unit before the end of what would otherwise be the 20-year useful life of the control measures that were evaluated for Coyote Unit 1. Therefore, the remaining useful life did not impact the annualized cost of control under the current regulatory framework.





COYOTE STATION UNIT 1

**NORTH DAKOTA REGIONAL HAZE SECOND PLANNING PERIOD**

**FOUR-FACTOR ANALYSIS**

SL-014745

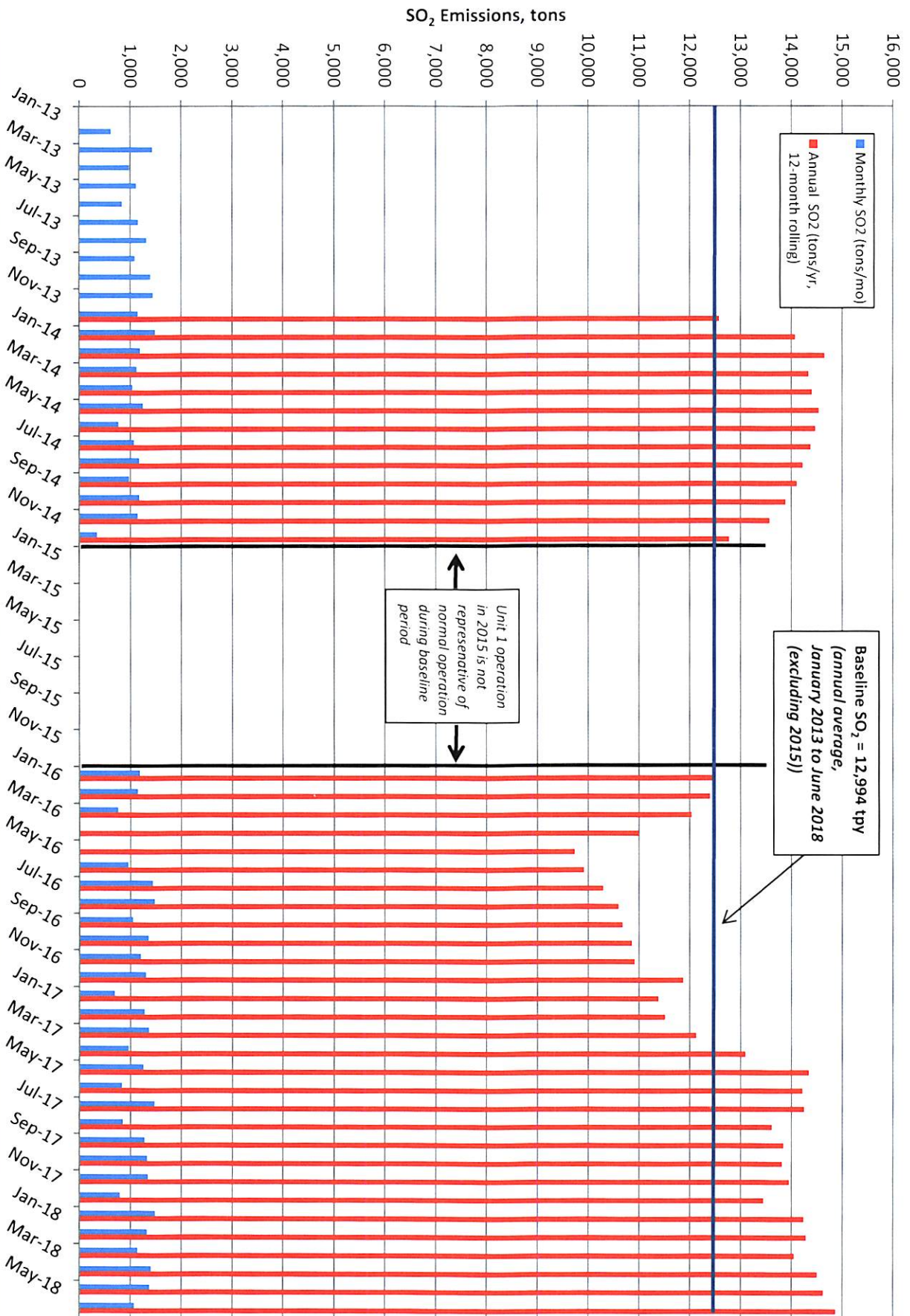
**FINAL REV 1**

Appendixes

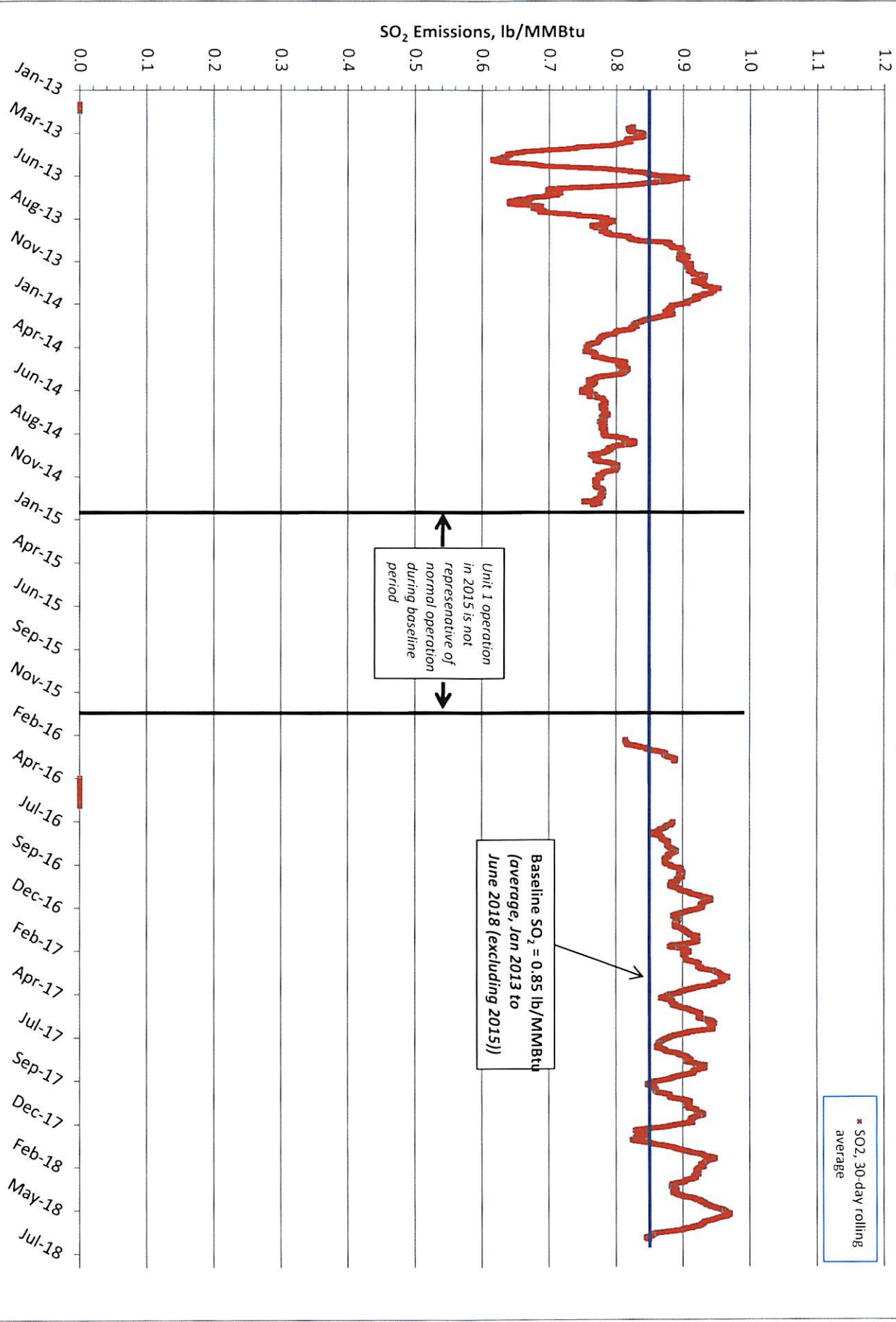
## APPENDIX A

### COYOTE UNIT 1 BASELINE EMISSIONS

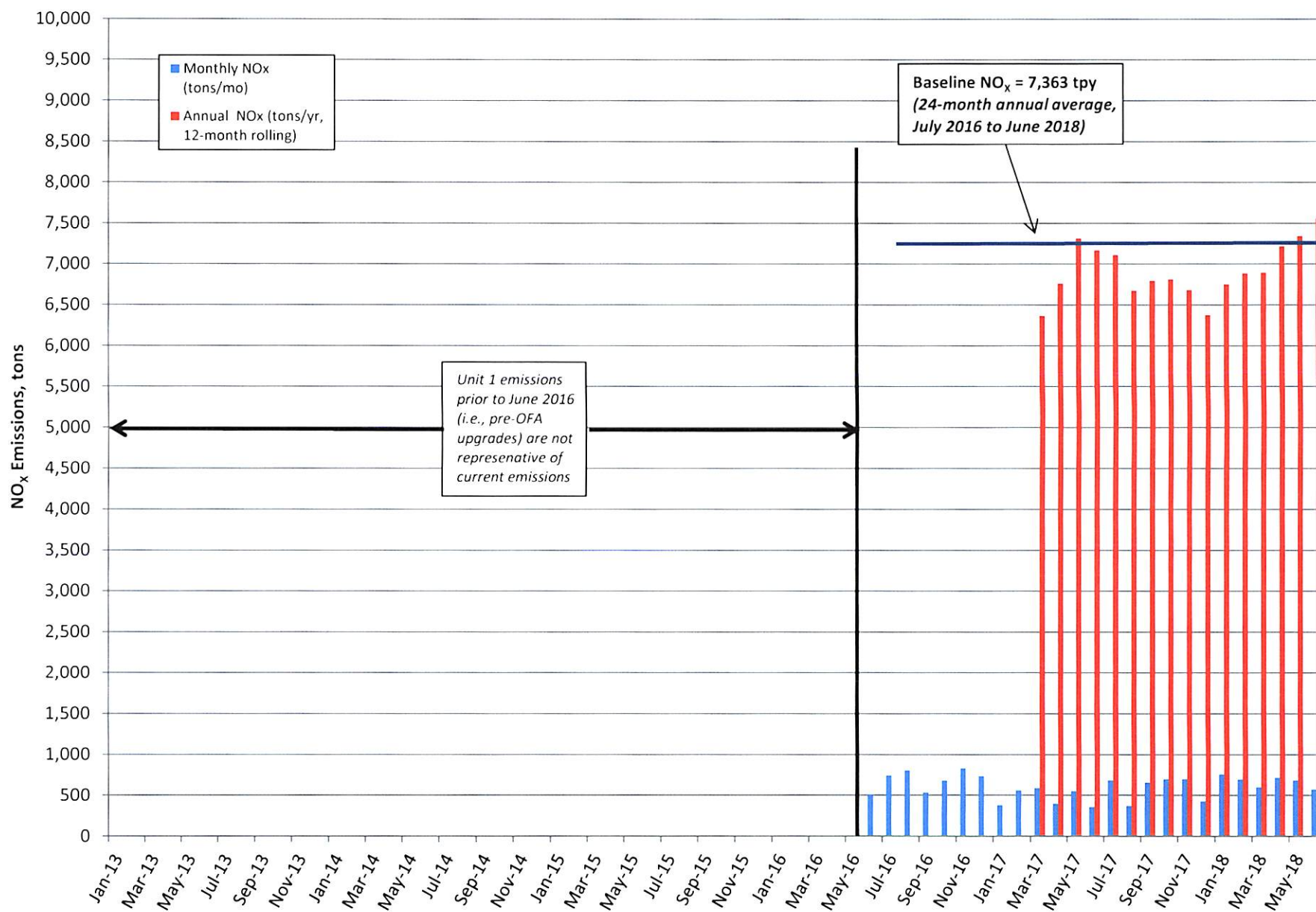
# Coyote Unit 1 - Baseline SO<sub>2</sub> Emissions (tons) [1/2013 to 6/2018]



# Coyote Unit 1 - Baseline SO<sub>2</sub> Emissions (lb/MMBtu) [1/2013 to 6/2018]

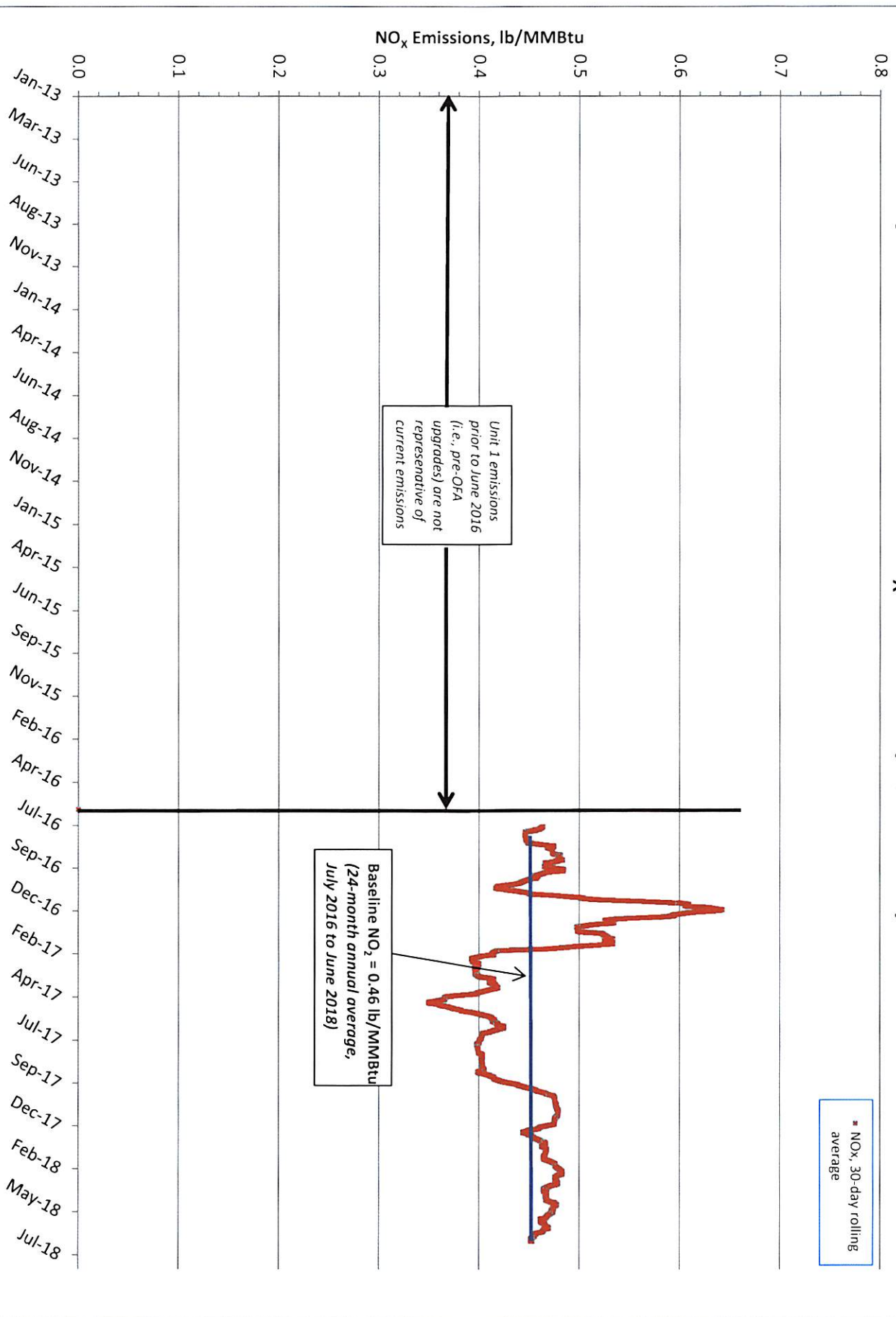


## Coyote Unit 1 - Baseline NO<sub>x</sub> Emissions (tons) [1/2013 to 6/2018]





# Coyote Unit 1 - Baseline NO<sub>x</sub> Emissions (lb/MMBtu) [1/2013 to 6/2018]





## APPENDIX B

### SO<sub>2</sub> CONTROL COST EFFECTIVENESS ESTIMATES

Coyote Station Unit 1  
SO<sub>2</sub> Control Summary

Table 1. Coyote Unit 1 Operating Parameters

Parameter		Unit	Notes
Power Output	427	MW-net	Nominal
Annual Heat Input	30,562,287	MMBtu/yr	24-month annual average for period July 2016 to June 2018.
Average Capacity Factor	72%	%	Based on annual average MW-h during the baseline period.

Table 2. Control Effectiveness

Control Technology	Control Efficiency (%)	Expected Emissions (ton/year)	Emission Rate (lb/MMBtu)	Expected Emissions Reduction (ton/year)
Wet FGD	92.9%	917	0.06	12,078
Dry FGD (CDS) + FF	89.4%	1,375	0.09	11,619
FGD Upgrades - Replace Existing Absorbers with New Absorber	65.9%	4,432	0.29	8,563
DSI + FGD Operational Improvements	61.2%	5,043	0.33	7,952
FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio	41.2%	7,641	0.50	5,354
DSI + Existing FGD	31.8%	8,863	0.58	4,131
Baseline (DFGD/FF)		12,994	0.85	0

Table 3. Cost Effectiveness

Control Technology	Emissions (tpy)	Tons of SO <sub>2</sub> Removed (tpy)	Total Capital Requirement (\$)	Annualized Capital Cost (\$/year)	Annualized Outage Cost (\$/year)	Total Annual Operating Costs (\$/year)	Total Annual Costs (\$)	Average Cost Effectiveness (\$/ton)	Incremental Cost Effectiveness (\$/ton)
Baseline (DFGD/FF)	12,994	0	--	--		--	--		
DSI + Existing FGD	8,863	4,131	\$23,765,000	\$1,948,000	\$0	\$10,423,000	\$12,371,000	\$2,994	
FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio	7,641	5,354	\$526,000	\$43,000	\$0	\$2,042,000	\$2,085,000	\$389	
DSI + FGD Operational Improvements	5,043	7,952	\$24,292,000	\$1,991,000	\$0	\$12,465,000	\$14,456,000	\$1,818	\$4,762
FGD Upgrades - Replace Existing Absorbers with New Absorber	4,432	8,563	\$127,823,000	\$10,475,000	\$5,390,000	\$6,332,000	\$22,197,000	\$2,592	\$12,664
Dry FGD (CDS) + FF	1,375	11,619	\$242,647,000	\$19,885,000	\$0	\$20,610,000	\$40,495,000	\$3,485	\$5,987
Wet FGD	917	12,078	\$324,742,000	\$26,613,000	\$0	\$22,481,000	\$49,094,000	\$4,065	\$18,757

Coyote Station Unit 1  
SO<sub>2</sub> Control Cost Evaluation  
DSI + Existing FGD

SO <sub>2</sub> Control Option Description	DSI + Existing FGD
Baseline SO <sub>2</sub> Emissions, lb/MMBtu	0.85
Post Upgrade SO <sub>2</sub> Emissions, lb/MMBtu	0.58
Capacity Factor used of Cost Estimates (%)	72%

CAPITAL COSTS		Cost (2018\$)	Basis
<b>Direct Costs</b>			
<b>Purchased Equipment Costs (PEC)</b>			
Equipment and Materials		\$10,884,000	Based on Sargent & Lundy's conceptual cost estimating system. Costs include equipment and material.
Dry FGI Instrumentation		\$0	Included in equipment and materials cost
Sales Tax		\$544,000	5% of Equipment/Material Cost
Freight		\$544,000	5% of Equipment/Material Cost
<b>Total PEC</b>		<b>\$11,972,000</b>	
<b>Direct Installation Costs</b>			
Labor		\$2,886,000	Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding		\$72,000	2.5% of Labor
Mobilization / Demobilization		\$43,000	1.5% of Labor
Labor Cost Due To Overtime Inefficiency		\$144,000	5% of Labor
<b>Total Direct Installation Costs</b>		<b>\$3,145,000</b>	
<b>Total Direct Costs (PEC + Direct Installation Costs)</b>		<b>\$15,117,000</b>	
<b>Indirect Costs</b>			
Contractor's General and Administration Expense		\$1,512,000	10% of Total Direct Costs
Contractor's Profit		\$756,000	5% of Total Direct Costs
Dry FGI Engineering, Procurement, & Project Services		\$1,209,000	8% of Total Direct Costs
Construction Management/Field Engineering		\$605,000	4% of Total Direct Costs
S-U / Commissioning		\$227,000	1.5% of Total Direct Costs
Spare Parts		\$76,000	0.5% of Total Direct Costs
Owner's Cost		\$302,000	2% of Total Direct Costs
<b>Total Indirect Costs</b>		<b>\$4,687,000</b>	
<b>Contingency</b>		<b>\$3,961,000</b>	20% of Direct and Indirect Costs
<b>Total Capital Investment (TCI)</b>		<b>\$23,765,000</b>	sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$		0.0820	20 year life of equipment (years) @ 5.25% interest.
<b>Annualized Capital Costs (CRF x TCI)</b>		<b>\$1,948,000</b>	
<b>OPERATING COSTS</b>			
<b>Operating &amp; Maintenance Costs</b>			
<b>Variable O&amp;M Costs</b>			
Increased Waste Disposal Cost		\$1,652,000	Based on disposal rate of \$32.46 per ton.
Hydrated Lime Reagent Cost		\$7,426,000	Based on hydrated lime reagent cost of \$187 per ton.
Increased Auxiliary Power Cost		\$115,000	Based on auxiliary power cost of \$23 per MWh
Increased bag and cage replacement		\$52,000	Based on bag and cage cost of \$135 per bag
<b>Total Variable O&amp;M Costs</b>		<b>\$9,245,000</b>	
<b>Fixed O&amp;M Costs</b>			
Additional Operators per shift		0	Assume no additional operators
Operating Labor		\$0	N/A
Supervisor Labor		\$0	N/A
Maintenance Materials		\$227,000	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor		\$0	Included in cost for maintenance materials.
<b>Total Fixed O&amp;M Cost</b>		<b>\$227,000</b>	
<b>Indirect Operating Cost</b>			
Property Taxes		\$238,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance		\$238,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration		\$475,000	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
<b>Total Indirect Operating Cost</b>		<b>\$951,000</b>	
<b>Total Annual Operating Cost</b>		<b>\$10,423,000</b>	
<b>TOTAL ANNUAL COST</b>			
Annualized Capital Cost		\$1,948,000	
Annual Operating Cost		\$10,423,000	
<b>Total Annual Cost</b>		<b>\$12,371,000</b>	

Coyote Station Unit 1  
SO<sub>2</sub> Control Cost Evaluation  
FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio

SO <sub>2</sub> Control Option Description	FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio
Baseline SO <sub>2</sub> Emissions, lb/MMBtu	0.85
Post Upgrade SO <sub>2</sub> Emissions, lb/MMBtu	0.50
Capacity Factor used of Cost Estimates (%)	72%

CAPITAL COSTS		Cost (2018\$)	Basis
<b>Direct Costs</b>			
<b>Purchased Equipment Costs (PEC)</b>			
Equipment and Materials	\$218,000		Based on Sargent & Lundy's conceptual cost estimating system. Costs include equipment and material.
Dry FGI Instrumentation	\$0		Included in equipment and materials cost
Sales Tax	\$11,000		5% of Equipment/Material Cost
Freight	\$11,000		5% of Equipment/Material Cost
<b>Total PEC</b>	<b>\$240,000</b>		
<b>Direct Installation Costs</b>			
Labor	\$87,000		Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding	\$2,000		2.5% of Labor
Mobilization / Demobilization	\$1,000		1.5% of Labor
Labor Cost Due To Overtime Inefficiency	\$4,000		5% of Labor
<b>Total Direct Installation Costs</b>	<b>\$94,000</b>		
<b>Total Direct Costs (PEC + Direct Installation Costs)</b>	<b>\$334,000</b>		
<b>Indirect Costs</b>			
Contractor's General and Administration Expense	\$33,000		10% of Total Direct Costs
Contractor's Profit	\$17,000		5% of Total Direct Costs
Dry FGI Engineering, Procurement, & Project Services	\$27,000		8% of Total Direct Costs
Construction Management/Field Engineering	\$13,000		4% of Total Direct Costs
S-U / Commissioning	\$5,000		1% of Total Direct Costs
Spare Parts	\$2,000		0.5% of Total Direct Costs
Owner's Cost	\$7,000		2% of Total Direct Costs
<b>Total Indirect Costs</b>	<b>\$104,000</b>		
<b>Contingency</b>	<b>\$88,000</b>		20% of Direct and Indirect Costs
<b>Total Capital Investment (TCI)</b>	<b>\$526,000</b>		sum of direct costs, indirect costs, and contingency
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$	0.0820		20 year life of equipment (years) @ 5.25% interest.
<b>Annualized Capital Costs (CRF x TCI)</b>	<b>\$43,000</b>		
<b>OPERATING COSTS</b>			
<b>Operating &amp; Maintenance Costs</b>			
<b>Variable O&amp;M Costs</b>			
Increased Waste Disposal Cost	\$591,000		Based on disposal rate of \$32.46 per ton.
Increased Lime Reagent Cost	\$1,418,000		Based on lime reagent cost of \$128 per ton.
Increased Auxiliary Power Cost	\$4,000		Based on auxiliary power cost of \$23 per MWh
Increased Water Cost	\$3,000		Based on water cost of \$1.00 per 1000 gallons.
<b>Total Variable O&amp;M Costs</b>	<b>\$2,016,000</b>		
<b>Fixed O&amp;M Costs</b>			
Additional Operators per shift	0		Assume no additional operators
Operating Labor	\$0		N/A
Supervisor Labor	\$0		N/A
Maintenance Materials	\$5,000		Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor	\$0		Included in cost for maintenance materials.
<b>Total Fixed O&amp;M Cost</b>	<b>\$5,000</b>		
<b>Indirect Operating Cost</b>			
Property Taxes	\$5,000		1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	\$5,000		1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	\$11,000		2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
<b>Total Indirect Operating Cost</b>	<b>\$21,000</b>		
<b>Total Annual Operating Cost</b>	<b>\$2,042,000</b>		
<b>TOTAL ANNUAL COST</b>			
Annualized Capital Cost	\$43,000		
Annual Operating Cost	\$2,042,000		
<b>Total Annual Cost</b>	<b>\$2,085,000</b>		

Coyote Station Unit 1  
SO<sub>2</sub> Control Cost Evaluation  
DSI + FGD Operational Improvements

SO <sub>2</sub> Control Option Description	DSI + FGD Operational Improvements
Baseline SO <sub>2</sub> Emissions, lb/MMBtu	0.85
Post Upgrade SO <sub>2</sub> Emissions, lb/MMBtu	0.33
Capacity Factor used of Cost Estimates (%)	72%

CAPITAL COSTS		Cost (2018\$)	Basis
<b>Direct Costs</b>			
<b>Purchased Equipment Costs (PEC)</b>			
Equipment and Materials	\$11,102,000		Based on Sargent & Lundy's conceptual cost estimating system. Costs include equipment and material.
Dry FGI Instrumentation	\$0		Included in equipment and materials cost
Sales Tax	\$555,000		5% of Equipment/Material Cost
Freight	\$555,000		5% of Equipment/Material Cost
<b>Total PEC</b>	<b>\$12,212,000</b>		
<b>Direct Installation Costs</b>			
Labor	\$2,973,000		Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding	\$74,000		2.5% of Labor
Mobilization / Demobilization	\$45,000		1.5% of Labor
Labor Cost Due To Overtime Inefficiency	\$149,000		5% of Labor
<b>Total Direct Installation Costs</b>	<b>\$3,241,000</b>		
<b>Total Direct Costs (PEC + Direct Installation Costs)</b>	<b>\$15,453,000</b>		
<b>Indirect Costs</b>			
Contractor's General and Administration Expense	\$1,545,000		10% of Total Direct Costs
Contractor's Profit	\$773,000		5% of Total Direct Costs
Dry FGI Engineering, Procurement, & Project Services	\$1,236,000		8% of Total Direct Costs
Construction Management/Field Engineering	\$618,000		4% of Total Direct Costs
S-U / Commissioning	\$232,000		1.5% of Total Direct Costs
Spare Parts	\$77,000		0.5% of Total Direct Costs
Owner's Cost	\$309,000		2% of Total Direct Costs
<b>Total Indirect Costs</b>	<b>\$4,790,000</b>		
<b>Contingency</b>	<b>\$4,049,000</b>		20% of Direct and Indirect Costs
<b>Total Capital Investment (TCI)</b>	<b>\$24,292,000</b>		sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor (CRF) = $(1 + i)^n / (1 + i)^n - 1$	0.0820		20 year life of equipment (years) @ 5.25% interest.
<b>Annualized Capital Costs (CRF x TCI)</b>	<b>\$1,991,000</b>		
<b>OPERATING COSTS</b>			
<b>Operating &amp; Maintenance Costs</b>			
<b>Variable O&amp;M Costs</b>			
Increased Waste Disposal Cost	\$2,243,000		Based on disposal rate of \$32.46 per ton.
Increased Lime Reagent Cost	\$1,417,600		Based on lime reagent cost of \$128 per ton.
Hydrated Lime Reagent Cost	\$7,426,000		Based on hydrated lime reagent cost of \$187 per ton.
Increased Auxiliary Power Cost	\$119,000		Based on auxiliary power cost of \$23 per MWh
Increased bag and cage replacement	\$52,000		Based on bag and cage cost of \$135 per bag
<b>Total Variable O&amp;M Costs</b>	<b>\$11,260,600</b>		
<b>Fixed O&amp;M Costs</b>			
Additional Operators per shift	0		Assume no additional operators
Operating Labor	\$0		N/A
Supervisor Labor	\$0		N/A
Maintenance Materials	\$232,000		Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor	\$0		Included in cost for maintenance materials.
<b>Total Fixed O&amp;M Cost</b>	<b>\$232,000</b>		
<b>Indirect Operating Cost</b>			
Property Taxes	\$243,000		1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	\$243,000		1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34
Administration	\$486,000		2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34
<b>Total Indirect Operating Cost</b>	<b>\$972,000</b>		
<b>Total Annual Operating Cost</b>	<b>\$12,465,000</b>		
<b>TOTAL ANNUAL COST</b>			
Annualized Capital Cost	\$1,991,000		
Annual Operating Cost	\$12,465,000		
<b>Total Annual Cost</b>	<b>\$14,456,000</b>		



Coyote Station Unit 1  
SO<sub>2</sub> Control Cost Evaluation  
FGD Upgrades - Replace Existing Absorbers with New Absorber

SO <sub>2</sub> Control Option Description	FGD Upgrades - Replace Existing Absorbers with New Absorber
Baseline SO <sub>2</sub> Emissions, lb/MMBtu	0.85
Post Upgrade SO <sub>2</sub> Emissions, lb/MMBtu	0.29
Capacity Factor used of Cost Estimates (%)	72%

CAPITAL COSTS		Cost (2018\$)	Basis
<b>Direct Costs</b>			
Purchased Equipment Costs (PEC)			
Equipment and Materials		\$42,282,000	Based on Sargent & Lundy's conceptual cost estimating system. Costs include equipment and material.
Dry FGD Instrumentation		\$0	Included in equipment and materials cost
Sales Tax		\$2,114,000	5% of Equipment/Material Cost
Freight		\$2,114,000	5% of Equipment/Material Cost
Total PEC		\$46,510,000	
<b>Direct Installation Costs</b>			
Labor		\$31,929,000	Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding		\$798,000	2.5% of Labor
Mobilization / Demobilization		\$479,000	1.5% of Labor
Labor Cost Due To Overtime Inefficiency		\$1,596,000	5% of Labor
Total Direct Installation Costs		\$34,802,000	
Total Direct Costs (PEC + Direct Installation Costs)		\$81,312,000	
<b>Indirect Costs</b>			
Contractor's General and Administration Expense		\$8,131,000	10% of Total Direct Costs
Contractor's Profit		\$4,066,000	5% of Total Direct Costs
Dry FGD Engineering, Procurement, & Project Services		\$6,505,000	8% of Total Direct Costs
Construction Management/Field Engineering		\$3,252,000	4% of Total Direct Costs
S-U / Commissioning		\$1,220,000	1.5% of Total Direct Costs
Spare Parts		\$407,000	0.5% of Total Direct Costs
Owner's Cost		\$1,626,000	2% of Total Direct Costs
Total Indirect Costs		\$25,207,000	
Contingency		\$21,304,000	20% of Direct and Indirect Costs
Total Capital Investment (TCI)		\$127,823,000	sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor (CRF) = $(1+i)^n / (1+i)^n - 1$		0.0820	20 year life of equipment (years) @ 5.25% interest.
Annualized Capital Costs (CRF x TCI)		\$10,475,000	
<b>OUTAGE COSTS</b>			
<b>Outage Costs</b>			
Standard Outage Duration (weeks/yr)		8	
Outage Duration due to Retrofit (weeks/yr)		52	
Lost Revenue due to Retrofit		\$51,979,000	
Replacement Power Cost due to Retrofit		\$13,786,000	Based on the difference in cost for Coyote to generate power at \$23.00 per MWh and cost for Coyote to purchase replacement power.
Capital Recovery Factor (CRF) = $(1+i)^n / (1+i)^n - 1$		0.0820	20 year life of equipment (years) @ 7% interest.
Annualized Outage Costs (CRF x TCI)		\$5,390,000	
<b>OPERATING COSTS</b>			
<b>Operating &amp; Maintenance Costs</b>			
<b>Variable O&amp;M Costs</b>			
Total Variable O&M Costs		\$0	No incremental increases in variable O&M for absorber replacement
<b>Fixed O&amp;M Costs</b>			
Additional Operators per shift		0	Assume no additional operators
Operating Labor		\$0	N/A
Supervisor Labor		\$0	N/A
Maintenance Materials		\$1,220,000	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor		\$0	Included in cost for maintenance materials
Total Fixed O&M Cost		\$1,220,000	
<b>Indirect Operating Cost</b>			
Property Taxes		\$1,278,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance		\$1,278,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration		\$2,556,000	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Total Indirect Operating Cost		\$5,112,000	
Total Annual Operating Cost		\$6,332,000	
<b>TOTAL ANNUAL COST</b>			
Annualized Capital Cost		\$10,475,000	
Annualized Outage Cost		\$5,390,000	
Annual Operating Cost		\$6,332,000	
Total Annual Cost		\$22,197,000	

Coyote Station Unit 1  
SO<sub>2</sub> Control Cost Evaluation  
Dry FGD (CDS) + FF

SO <sub>2</sub> Control Option Description	Dry FGD (CDS) + FF
Baseline SO <sub>2</sub> Emissions, lb/MMBtu	0.85
Post Upgrade SO <sub>2</sub> Emissions, lb/MMBtu	0.09
Capacity Factor used of Cost Estimates (%)	72%

CAPITAL COSTS		Cost (2018\$)	Basis
<b>Direct Costs</b>			
<b>Purchased Equipment Costs (PEC)</b>			
Equipment and Materials	\$61,993,000		Based on Sargent & Lundy's conceptual cost estimating system. Costs include equipment and material.
Dry FGD Instrumentation	\$0		Included in equipment and materials cost
Sales Tax	\$3,100,000		5% of Equipment/Material Cost
Freight	\$3,100,000		5% of Equipment/Material Cost
<b>Total PEC</b>	<b>\$68,193,000</b>		
<b>Direct Installation Costs</b>			
Labor	\$79,049,000		Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding	\$1,976,000		2.5% of Labor
Mobilization / Demobilization	\$1,186,000		1.5% of Labor
Labor Cost Due To Overtime Inefficiency	\$3,952,000		5% of Labor
<b>Total Direct Installation Costs</b>	<b>\$86,163,000</b>		
<b>Total Direct Costs (PEC + Direct Installation Costs)</b>	<b>\$154,356,000</b>		
<b>Indirect Costs</b>			
Contractor's General and Administration Expense	\$15,436,000		10% of Total Direct Costs
Contractor's Profit	\$7,718,000		5% of Total Direct Costs
Dry FGD Engineering, Procurement, & Project Services	\$12,348,000		8% of Total Direct Costs
Construction Management/Field Engineering	\$6,174,000		4% of Total Direct Costs
S-U / Commissioning	\$2,315,000		1.5% of Total Direct Costs
Spare Parts	\$772,000		0.5% of Total Direct Costs
Owner's Cost	\$3,087,000		2% of Total Direct Costs
<b>Total Indirect Costs</b>	<b>\$47,850,000</b>		
<b>Contingency</b>	<b>\$40,441,000</b>		20% of Direct and Indirect Costs
<b>Total Capital Investment (TCI)</b>	<b>\$242,647,000</b>		sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$	0.0820		20 year life of equipment (years) @ 5.25% interest.
<b>Annualized Capital Costs (CRF x TCI)</b>	<b>\$19,885,000</b>		
<b>OPERATING COSTS</b>			
<b>Operating &amp; Maintenance Costs</b>			
<b>Variable O&amp;M Costs</b>			
Increased Waste Disposal Cost	\$2,175,000		Based on disposal rate of \$32.46 per ton.
Increased Lime Reagent Cost	\$5,815,000		Based on lime reagent cost of \$128 per ton.
Increased Auxiliary Power Cost	\$428,000		Based on auxiliary power cost of \$23 per MWh
Increased Water Cost	\$32,000		Based on water cost of \$1.00 per 1000 gallons.
Increased bag and cage replacement	\$140,000		Based on bag and cage cost of \$135 per bag
<b>Total Variable O&amp;M Costs</b>	<b>\$8,590,000</b>		
<b>Fixed O&amp;M Costs</b>			
Additional Operators per shift	0		Assume no additional operators
Operating Labor	\$0		N/A
Supervisor Labor	\$0		N/A
Maintenance Materials	\$2,315,000		Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor	\$0		Included in cost for maintenance materials.
<b>Total Fixed O&amp;M Cost</b>	<b>\$2,315,000</b>		
<b>Indirect Operating Cost</b>			
Property Taxes	\$2,426,000		1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	\$2,426,000		1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	\$4,853,000		2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
<b>Total Indirect Operating Cost</b>	<b>\$9,705,000</b>		
<b>Total Annual Operating Cost</b>	<b>\$20,610,000</b>		
<b>TOTAL ANNUAL COST</b>			
Annualized Capital Cost	\$19,885,000		
Annual Operating Cost	\$20,610,000		
<b>Total Annual Cost</b>	<b>\$40,495,000</b>		

Coyote Station Unit 1  
SO<sub>2</sub> Control Cost Evaluation  
Wet FGD

SO <sub>2</sub> Control Option Description	Wet FGD
Baseline SO <sub>2</sub> Emissions, lb/MMBtu	0.85
Post Upgrade SO <sub>2</sub> Emissions, lb/MMBtu	0.06
Capacity Factor used of Cost Estimates (%)	72%

CAPITAL COSTS		Cost (2018\$)	Basis
<b>Direct Costs</b>			
<b>Purchased Equipment Costs (PEC)</b>			
Equipment and Materials	\$112,208,000		Based on Sargent & Lundy's conceptual cost estimating system. Costs include equipment and material.
Dry FGD Instrumentation	\$0		Included in equipment and materials cost
Sales Tax	\$5,610,000		5% of Equipment/Material Cost
Freight	\$5,610,000		5% of Equipment/Material Cost
<b>Total PEC</b>	<b>\$123,428,000</b>		
<b>Direct Installation Costs</b>			
Labor	\$76,285,000		Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding	\$1,907,000		2.5% of Labor
Mobilization / Demobilization	\$1,144,000		1.5% of Labor
Labor Cost Due To Overtime Inefficiency	\$3,814,000		5% of Labor
<b>Total Direct Installation Costs</b>	<b>\$83,150,000</b>		
<b>Total Direct Costs (PEC + Direct Installation Costs)</b>	<b>\$206,578,000</b>		
<b>Indirect Costs</b>			
Contractor's General and Administration Expense	\$20,658,000		10% of Total Direct Costs
Contractor's Profit	\$10,329,000		5% of Total Direct Costs
Dry FGD Engineering, Procurement, & Project Services	\$16,526,000		8% of Total Direct Costs
Construction Management/Field Engineering	\$8,263,000		4% of Total Direct Costs
S-U / Commissioning	\$3,099,000		1.5% of Total Direct Costs
Spare Parts	\$1,033,000		0.5% of Total Direct Costs
Owner's Cost	\$4,132,000		2% of Total Direct Costs
<b>Total Indirect Costs</b>	<b>\$64,040,000</b>		
<b>Contingency</b>	<b>\$54,124,000</b>		20% of Direct and Indirect Costs
<b>Total Capital Investment (TCI)</b>	<b>\$324,742,000</b>		sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$	0.0820		20 year life of equipment (years) @ 5.25% interest.
<b>Annualized Capital Costs (CRF x TCI)</b>	<b>\$26,613,000</b>		
<b>OPERATING COSTS</b>			
<b>Operating &amp; Maintenance Costs</b>			
<b>Variable O&amp;M Costs</b>			
Increased Waste Disposal Cost	\$1,895,000		Based on disposal rate of \$32.46 per ton.
Increased Lime Reagent Cost	\$3,057,000		Based on lime reagent cost of \$128 per ton.
Limestone Reagent Cost	\$4,042,000		Based on limestone reagent cost of \$70 per ton.
Increased Auxiliary Power Cost	\$949,000		Based on auxiliary power cost of \$23 per MWh
Increased Water Cost	\$66,000		Based on water cost of \$1.00 per 1000 gallons.
<b>Total Variable O&amp;M Costs</b>	<b>\$3,895,000</b>		
<b>Fixed O&amp;M Costs</b>			
Additional Operators per Shift	4		
Operating Labor	\$2,172,000		Assume \$62/hr for each additional operator
Supervisor Labor	\$326,000		15% of Operating Labor. EPA Cost Manual Section 1, Chapter 2, page 2-31.
Maintenance Materials	\$3,099,000		Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor	\$0		Included in cost for maintenance materials.
<b>Total Fixed O&amp;M Cost</b>	<b>\$5,597,000</b>		
<b>Indirect Operating Cost</b>			
Property Taxes	\$3,247,000		1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	\$3,247,000		1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	\$6,495,000		2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
<b>Total Indirect Operating Cost</b>	<b>\$12,989,000</b>		
<b>Total Annual Operating Cost</b>	<b>\$22,481,000</b>		
<b>TOTAL ANNUAL COST</b>			
Annualized Capital Cost	\$26,613,000		
Annual Operating Cost	\$22,481,000		
<b>Total Annual Cost</b>	<b>\$49,094,000</b>		



COYOTE STATION UNIT 1

**NORTH DAKOTA REGIONAL HAZE SECOND PLANNING PERIOD**

**FOUR-FACTOR ANALYSIS**

SL-014745

**FINAL REV 1**

Appendixes

## APPENDIX C

### NO<sub>x</sub> CONTROL COST EFFECTIVENESS ESTIMATES

Coyote Station Unit 1  
NO<sub>x</sub> Control Summary

Table 1. Coyote Unit 1 Operating Parameters

Parameter		Unit	Notes
Power Output	427	MW-net	Nominal
Annual Average Heat Input	32,301,802	MMBtu/yr	24-month annual average for period July 2016 to June 2018 (post-SOFA upgrades)
Average Capacity Factor	79%	%	Based on annual average MW-h during the baseline period.

Table 2. Control Effectiveness

Control Technology	Control Efficiency (%)	Expected Emissions (ton/year)	Emission Rate (lb/MMBtu)	Expected Emissions Reduction (ton/year)
SNCR + RRI	56.2%	3,226	0.20	4,137
SNCR	38.7%	4,516	0.28	2,847
Combustion Optimization	8.0%	6,775	0.42	589
Baseline (SOFA)		7,363	0.46	0

Table 3. Cost Effectiveness

Control Technology	Emissions (tpy)	Tons of NO <sub>x</sub> Removed (tpy)	Total Capital Requirement (\$)	Annualized Capital Cost (\$/year)	Annualized Outage Cost (\$/year)	Total Annual Operating Costs (\$/year)	Total Annual Costs (\$)	Average Cost Effectiveness (\$/ton)	Incremental Cost Effectiveness (\$/ton)
Baseline (SOFA)	7,363	0	--	--	--	--	--		
Combustion Optimization	6,775	589	\$0	\$0	\$0	\$0	\$0	\$0	
SNCR	4,516	2,847	\$19,840,000	\$1,626,000	\$0	\$3,128,000	\$4,754,000	\$1,670	\$2,105
SNCR + RRI	3,226	4,137	\$25,895,000	\$2,122,000	\$0	\$6,495,000	\$8,617,000	\$2,083	\$2,994



Coyote Station Unit 1  
NO<sub>x</sub> Control Cost Evaluation  
Combustion Optimization

NO <sub>x</sub> Control Option Description	Combustion Optimization
Baseline NO <sub>x</sub> Emissions, lb/MMBtu	0.46
Post Upgrade NO <sub>x</sub> Emissions, lb/MMBtu	0.42
Capacity Factor used of Cost Estimates (%)	79%

CAPITAL COSTS		Cost (2018\$)	Basis
<b>Direct Costs</b>			
Purchased Equipment Costs (PEC)			
Equipment and Materials	\$0		
Instrumentation	\$0		
Sales Tax	\$0		
Freight	\$0		
Total PEC	\$0		
Direct Installation Costs			
Labor	\$0		
Scaffolding	\$0		
Mobilization / Demobilization	\$0		
Labor Cost Due To Overtime Inefficiency	\$0		
Total Direct Installation Costs	\$0		
Total Direct Costs (PEC + Direct Installation Costs)	\$0		
<b>Indirect Costs</b>			
Contractor's General and Administration Expense	\$0		
Contractor's Profit	\$0		
Engineering, Procurement, & Project Services	\$0		
Construction Management/Field Engineering	\$0		
S-U / Commissioning	\$0		
Spare Parts	\$0		
Owner's Cost	\$0		
Total Indirect Costs	\$0		
Contingency	\$0		
Total Capital Investment (TCI)	\$0		
Capital Recovery Factor (CRF) = $(1 + i)^n / (1 + i)^n - 1$	0.0820		20 year life of equipment (years) @ 5.25% interest.
Annualized Capital Costs (CRF x TCI)	\$0		
<b>OPERATING COSTS</b>			
<b>Operating &amp; Maintenance Costs</b>			
<b>Variable O&amp;M Costs</b>			
Dry Urea Reagent Cost	\$0		Based on dry urea reagent cost of \$354 per ton.
Ammonia Reagent Cost	\$0		Based on ammonia reagent cost of \$700 per ton.
RO Water Cost	\$0		Based on water cost of \$1.00 per 1,000 gallons.
Steam Cost	\$0		Based on steam cost of \$1.06 per MMBtu.
Hydrated Lime Cost	\$0		Based on hydrated lime cost of \$187 per ton.
Catalyst Replacement Cost	\$0		Based on catalyst cost of \$8,000 per m3 and catalyst replacement cost of \$1,000 per m3.
Auxiliary Power Cost	\$0		Based on auxiliary power cost of \$23 per MWh
Total Variable O&M Costs	\$0		
<b>Fixed O&amp;M Costs</b>			
Additional Operators per shift	0		Assume no additional operators
Operating Labor	\$0		N/A
Supervisor Labor	\$0		N/A
Maintenance Materials	\$0		Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor	\$0		Included in cost for maintenance materials.
Total Fixed O&M Cost	\$0		
<b>Indirect Operating Cost</b>			
Property Taxes	\$0		1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	\$0		1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34
Administration	\$0		2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Total Indirect Operating Cost	\$0		
Total Annual Operating Cost	\$0		
<b>TOTAL ANNUAL COST</b>			
Annualized Capital Cost	\$0		
Annual Operating Cost	\$0		
Total Annual Cost	\$0		

Coyote Station Unit 1  
NO<sub>x</sub> Control Cost Evaluation  
SNCR

NO <sub>x</sub> Control Option Description	SNCR
Baseline NO <sub>x</sub> Emissions, lb/MMBtu	0.46
Post Upgrade NO <sub>x</sub> Emissions, lb/MMBtu	0.28
Capacity Factor used of Cost Estimates (%)	79%

CAPITAL COSTS		Cost (2018\$)	Basis
<b>Direct Costs</b>			
<b>Purchased Equipment Costs (PEC)</b>			
Equipment and Materials	\$8,718,000		Based on Sargent & Lundy's conceptual cost estimating system. Costs include equipment and material.
Instrumentation	\$0		Included in equipment and materials cost
Sales Tax	\$436,000		5% of Equipment/Material Cost
Freight	\$436,000		5% of Equipment/Material Cost
<b>Total PEC</b>	<b>\$9,590,000</b>		
<b>Direct Installation Costs</b>			
Labor	\$2,780,000		Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding	\$70,000		2.5% of Labor
Mobilization / Demobilization	\$42,000		1.5% of Labor
Labor Cost Due To Overtime Inefficiency	\$139,000		5% of Labor
<b>Total Direct Installation Costs</b>	<b>\$3,031,000</b>		
<b>Total Direct Costs (PEC + Direct Installation Costs)</b>	<b>\$12,621,000</b>		
<b>Indirect Costs</b>			
Contractor's General and Administration Expense	\$1,262,000		10% of Total Direct Costs
Contractor's Profit	\$631,000		5% of Total Direct Costs
Engineering, Procurement, & Project Services	\$1,010,000		8% of Total Direct Costs
Construction Management/Field Engineering	\$505,000		4% of Total Direct Costs
S-U / Commissioning	\$189,000		1.5% of Total Direct Costs
Spare Parts	\$63,000		0.5% of Total Direct Costs
Owner's Cost	\$252,000		2% of Total Direct Costs
<b>Total Indirect Costs</b>	<b>\$3,912,000</b>		
<b>Contingency</b>	<b>\$3,307,000</b>		20% of Direct and Indirect Costs
<b>Total Capital Investment (TCI)</b>	<b>\$19,840,000</b>		sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor (CRF) = $(1 + i)^n / (1 + i)^n - 1$	0.0820		20 year life of equipment (years) @ 5.25% interest.
<b>Annualized Capital Costs (CRF x TCI)</b>	<b>\$1,626,000</b>		
<b>OPERATING COSTS</b>			<b>Basis</b>
<b>Operating &amp; Maintenance Costs</b>			
<b>Variable O&amp;M Costs</b>			
Dry Urea Reagent Cost	\$1,401,000		Based on dry urea reagent cost of \$354 per ton.
Ammonia Reagent Cost	\$0		Based on ammonia reagent cost of \$700 per ton.
Water Cost	\$82,000		Based on water cost of \$1.00 per 1,000 gallons.
Steam Cost	\$32,000		Based on steam cost of \$1.06 per MMBtu.
Hydrated Lime Cost	\$0		Based on hydrated lime cost of \$187 per ton.
Catalyst Replacement Cost	\$0		Based on catalyst cost of \$8,000 per m3 and catalyst replacement cost of \$1,000 per m3.
Auxiliary Power Cost	\$7,000		Based on auxiliary power cost of \$23 per MWh
<b>Total Variable O&amp;M Costs</b>	<b>\$1,522,000</b>		
<b>Fixed O&amp;M Costs</b>			
Additional Operators per shift	1		Assume \$62/hr for each additional operator
Operating Labor	\$543,000		
Supervisor Labor	\$81,000		15% of Operating Labor. EPA Cost Manual Section 1, Chapter 2, page 2-31.
Maintenance Materials	\$189,000		Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor	\$0		Included in cost for maintenance materials.
<b>Total Fixed O&amp;M Cost</b>	<b>\$813,000</b>		
<b>Indirect Operating Cost</b>			
Property Taxes	\$198,000		1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	\$198,000		1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	\$397,000		2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
<b>Total Indirect Operating Cost</b>	<b>\$793,000</b>		
<b>Total Annual Operating Cost</b>	<b>\$3,128,000</b>		
<b>TOTAL ANNUAL COST</b>			
Annualized Capital Cost	\$1,626,000		
Annual Operating Cost	\$3,128,000		
<b>Total Annual Cost</b>	<b>\$4,754,000</b>		

Coyote Station Unit 1  
NO<sub>x</sub> Control Cost Evaluation  
SNCR + RRI

NO <sub>x</sub> Control Option Description	SNCR + RRI
Baseline NO <sub>x</sub> Emissions, lb/MMBtu	0.46
Post Upgrade NO <sub>x</sub> Emissions, lb/MMBtu	0.20
Capacity Factor used of Cost Estimates (%)	79%

CAPITAL COSTS		Cost (2018\$)	Basis
<b>Direct Costs</b>			
<b>Purchased Equipment Costs (PEC)</b>			
Equipment and Materials	\$11,179,000		Based on Sargent & Lundy's conceptual cost estimating system. Costs include equipment and material.
Instrumentation	\$0		Included in equipment and materials cost
Sales Tax	\$559,000		5% of Equipment/Material Cost
Freight	\$559,000		5% of Equipment/Material Cost
<b>Total PEC</b>	<b>\$12,297,000</b>		
<b>Direct Installation Costs</b>			
Labor	\$3,831,000		Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding	\$96,000		2.5% of Labor
Mobilization / Demobilization	\$57,000		1.5% of Labor
Labor Cost Due To Overtime Inefficiency	\$192,000		5% of Labor
<b>Total Direct Installation Costs</b>	<b>\$4,176,000</b>		
<b>Total Direct Costs (PEC + Direct Installation Costs)</b>	<b>\$16,473,000</b>		
<b>Indirect Costs</b>			
Contractor's General and Administration Expense	\$1,647,000		10% of Total Direct Costs
Contractor's Profit	\$824,000		5% of Total Direct Costs
Engineering, Procurement, & Project Services	\$1,318,000		8% of Total Direct Costs
Construction Management/Field Engineering	\$659,000		4% of Total Direct Costs
S-U / Commissioning	\$247,000		1.5% of Total Direct Costs
Spare Parts	\$82,000		0.5% of Total Direct Costs
Owner's Cost	\$329,000		2% of Total Direct Costs
<b>Total Indirect Costs</b>	<b>\$5,106,000</b>		
Contingency	\$4,316,000		20% of Direct and Indirect Costs
<b>Total Capital Investment (TCI)</b>	<b>\$25,895,000</b>		sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor (CRF) = $(1+i)^n / (1+i)^n - 1$	0.0820		20 year life of equipment (years) @ 5.25% interest.
<b>Annualized Capital Costs (CRF x TCI)</b>	<b>\$2,122,000</b>		
<b>OPERATING COSTS</b>			
<b>Operating &amp; Maintenance Costs</b>			
<b>Variable O&amp;M Costs</b>			
Dry Urea Reagent Cost	\$4,300,000		Based on dry urea reagent cost of \$354 per ton.
Ammonia Reagent Cost	\$0		Based on ammonia reagent cost of \$700 per ton.
RO Water Cost	\$179,000		Based on water cost of \$1.00 per 1,000 gallons.
Steam Cost	\$99,000		Based on steam cost of \$1.06 per MMBtu.
Hydrated Lime Cost	\$0		Based on hydrated lime cost of \$187 per ton.
Catalyst Replacement Cost	\$0		Based on catalyst cost of \$8,000 per m3 and catalyst replacement cost of \$1,000 per m3.
Auxiliary Power Cost	\$10,000		Based on auxiliary power cost of \$23 per MWh
<b>Total Variable O&amp;M Costs</b>	<b>\$4,588,000</b>		
<b>Fixed O&amp;M Costs</b>			
Additional Operators per shift	1		
Operating Labor	\$543,000		Assume \$62/hr for each additional operator
Supervisor Labor	\$81,000		15% of Operating Labor. EPA Cost Manual Section 1, Chapter 2, page 2-31.
Maintenance Materials	\$247,000		Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor	\$0		Included in cost for maintenance materials.
<b>Total Fixed O&amp;M Cost</b>	<b>\$871,000</b>		
<b>Indirect Operating Cost</b>			
Property Taxes	\$259,000		1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	\$259,000		1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	\$518,000		2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
<b>Total Indirect Operating Cost</b>	<b>\$1,036,000</b>		
<b>Total Annual Operating Cost</b>	<b>\$6,495,000</b>		
<b>TOTAL ANNUAL COST</b>			
Annualized Capital Cost	\$2,122,000		
Annual Operating Cost	\$6,495,000		
<b>Total Annual Cost</b>	<b>\$8,617,000</b>		

215 South Cascade Street  
PO Box 496  
Fergus Falls, Minnesota 56538-0496  
218 739-8200  
www.otpc.com



January 6, 2020

Mr. Jim Semerad  
Director, Division of Air Quality  
North Dakota Department of Health  
Gold Seal Center, 918 East Divide Ave  
Bismarck, ND 58501-1947

Dear Mr. Semerad:

Re: Updates to Regional Haze Four Factor Analysis - Coyote Station

The purpose of this submittal is to provide the North Dakota Department of Environmental Quality (DEQ) with updated information related to the NOx technology options presented in the Coyote Station Regional Haze reasonable progress report (Four-Factor Analysis).

As you recall, Revision 1 of the Four-Factor Analysis, dated May 8, 2019, determined that there were two technically feasible post-combustion NOx technologies applicable to Coyote Station: Selective non-catalytic reduction (SNCR) and Rich Reagent Injection (RRI). The Four-Factor Analysis presented the predicted emission reductions and costs associated with those technologies; however, in both cases the report noted that computational fluid dynamic (CFD) modeling would be needed to confirm that the incremental reduction in NOx emission is achievable without creating unacceptable operational issues.<sup>1</sup>

Subsequent to the Four-Factor Analysis, Otter Tail Power Company proceeded with the CFD modeling, and retained Sargent & Lundy, L.L.C. (S&L) to prepare the attached technical memorandum to summarize the modeling results and determine the associated impacts to the Four-Factor Analysis.

As described in the S&L memorandum, it has been determined that in order to achieve the level of NOx reductions with RRI originally predicted by the Four-Factor Analysis, Coyote Station would need to relocate both the existing furnace vent ports and separated overfire air ports. Therefore, the costs of the RRI option need to be revised upward to account for these port relocations.

We look forward to working with the DEQ throughout the second planning period. If you have any questions about this updated information, please contact me at (218) 739-8526.

Sincerely,

Mark Thoma  
Manager, Environmental Services

Enclosure

<sup>1</sup> See Pages 5-26 and 5-27 of the Coyote Station May 8, 2019 Four-Factor Analysis

TECHNICAL MEMORANDUM

**From:** Wayshalee Patel  
**Date:** January 6, 2020  
**Project No.:** A12715.011

**Client:** Otter Tail Power Company  
**Station:** Coyote Station Unit 1

**Subject:** Update to Four Factor Analysis

The purpose of this technical memorandum is to provide the North Dakota Department of Environmental Quality (NDDEQ) a summary of computational fluid dynamic (CFD) modeling recently completed by Otter Tail Power Company (OTP) since the submittal of the Coyote Station Unit 1 Four-Factor Analysis dated May 8, 2019. For nitrogen oxides (NO<sub>x</sub>), the CFD modeling was conducted for the selective non-catalytic reduction (SNCR) and rich reagent injection (RRI) technology options.

**NO<sub>x</sub> CFD Modeling Summary**

OTP engaged Reaction Engineering International (REI) to complete CFD modeling of OTP's Coyote Station Unit 1 to further evaluate and potentially refine the emission removal capabilities and equipment modifications necessary for SNCR and RRI for NO<sub>x</sub> emissions.

**NO<sub>x</sub> Emissions Modeling:**

REI developed a CFD model of the Coyote Unit 1 cyclone barrels and boiler furnace in order to evaluate the impact of various technologies on Unit 1 furnace NO<sub>x</sub> reduction. The modeling effort assessed performance of combustion modifications, SNCR, and RRI systems and generally evaluated the following:

- SNCR with sensitivity to injector locations, urea solution droplet sizes, and normalized stoichiometric ratio (NSR)
- RRI exploring injector locations and performance when combined with existing and alternative OFA and vent designs

The results of the NO<sub>x</sub> CFD modeling effort predict that the average NO<sub>x</sub> emission rate achievable with SNCR is 0.28 lb/MMBtu<sup>1</sup>, which is the value that was estimated in the Four-Factor Analysis. As such, the achievable emission reduction and associated costs and cost effectiveness for SNCR provided in the Four-Factor Analysis is reasonable and updates are not necessary. For the RRI option, the CFD modeling

---

<sup>1</sup> Modeling scenarios that resulted in a predicted ammonia slip of greater than 10 ppm were not included in determining this average in order to avoid formation of ammonia salts on the boiler tube banks.



indicated that the 12 existing furnace vents and the 14 existing separated overfire air (SOFA) vents would need to be relocated at an elevation higher in the furnace in order to create sub-stoichiometric oxygen concentrations in the lower furnace, thereby promoting NO<sub>x</sub> reduction. The Four-Factor Analysis did not include the costs associated with relocating these SOFA and vent ports which, based on the CFD modeling, is necessary to obtain the estimated NO<sub>x</sub> reductions indicated in the Four-Factor Analysis. As such, the cost effectiveness table provided in the Four-Factor Analysis has been updated and is provided in Table 1 below. In summary, the cost effectiveness for the option that included RRI increased from \$2,083/ton to \$3,067/ton. Detailed cost effectiveness tables are included in Appendix A of this memorandum.

**Table 1. NO<sub>x</sub> Emissions Control System Cost Effectiveness (\$2018)**

	<b>Total Annualized Cost</b>	<b>Expected Emission Reduction</b>	<b>Average Annual Cost Effectiveness (Note 1)</b>	<b>Incremental Annual Cost Effectiveness (Note 2)</b>
<b>NO<sub>x</sub> Control Option</b>	<b>\$/yr</b>	<b>tons NO<sub>x</sub>/yr</b>	<b>\$/ton NO<sub>x</sub> removed</b>	<b>\$/ton NO<sub>x</sub> removed</b>
Baseline (Existing SOFA)	---	---	---	---
Combustion Optimization	\$0	589	\$0	\$0
SNCR + Combustion Optimization	\$4,754,000	2,847	\$1,670	\$2,105
SNCR + RRI + Combustion Optimization + SOFA/Vent Port	\$12,690,000	4,137	\$3,067	\$6,150

Note 1. Average cost effectiveness for each control option is the total annual cost divided by the expected emission reduction.

Note 2. Incremental cost effectiveness represents the incremental increase in annual costs (\$/yr) divided by the incremental increase in annual emissions reductions (tpy) between a control option and the next most effective option.

**TECHNICAL MEMORANDUM**

**Appendix A**  
**Revised NO<sub>x</sub> Cost Effectiveness Tables**

Coyote Station Unit 1  
NO<sub>x</sub> Control Summary

Table 1. Coyote Unit 1 Operating Parameters

Parameter		Unit	Notes
Power Output	427	MW-net	Nominal
Annual Average Heat Input	32,301,802	MMBtu/yr	24-month annual average for period July 2016 to June 2018 (post-SOFA upgrades)
Average Capacity Factor	79%	%	Based on annual average MW-h during the baseline period.

Table 2. Control Effectiveness

Control Technology	Control Efficiency (%)	Expected Emissions (ton/year)	Emission Rate (lb/MMBtu)	Expected Emissions Reduction (ton/year)
SNCR + RRI	56.2%	3,226	0.20	4,137
SNCR	38.7%	4,516	0.28	2,847
Combustion Optimization	8.0%	6,775	0.42	589
Baseline (SOFA)		7,363	0.46	0

Table 3. Cost Effectiveness

Control Technology	Emissions (tpy)	Tons of NO <sub>x</sub> Removed (tpy)	Total Capital Requirement (\$)	Annualized Capital Cost (\$/year)	Annualized Outage Cost (\$/year)	Total Annual Operating Costs (\$/year)	Total Annual Costs (\$)	Average Cost Effectiveness (\$/ton)	Incremental Cost Effectiveness (\$/ton)
Baseline (SOFA)	7,363	0	--	--	--	--	--		
Combustion Optimization	6,775	589	\$0	\$0	\$0	\$0	\$0	\$0	
SNCR	4,516	2,847	\$19,840,000	\$1,626,000	\$0	\$3,128,000	\$4,754,000	\$1,670	\$2,105
SNCR + RRI	3,226	4,137	\$56,864,000	\$4,660,000	\$0	\$8,030,000	\$12,690,000	\$3,067	\$6,150

Coyote Station Unit 1  
NO<sub>x</sub> Control Cost Evaluation  
SNCR + RRI

NO <sub>x</sub> Control Option Description	SNCR + RRI
Baseline NO <sub>x</sub> Emissions, lb/MMBtu	0.46
Post Upgrade NO <sub>x</sub> Emissions, lb/MMBtu	0.20
Capacity Factor used of Cost Estimates (%)	79%

CAPITAL COSTS		Cost (2018\$)	Basis
<b>Direct Costs</b>			
<b>Purchased Equipment Costs (PEC)</b>			
Equipment and Materials		\$19,179,000	Based on Sargent & Lundy's conceptual cost estimating system. Costs include equipment and material.
Instrumentation		\$0	Included in equipment and materials cost
Sales Tax		\$959,000	5% of Equipment/Material Cost
Freight		\$959,000	5% of Equipment/Material Cost
<b>Total PEC</b>		<b>\$21,097,000</b>	
<b>Direct Installation Costs</b>			
Labor		\$13,831,000	Based on Sargent & Lundy's conceptual cost estimating system
Scaffolding		\$346,000	2.5% of Labor
Mobilization / Demobilization		\$207,000	1.5% of Labor
Labor Cost Due To Overtime Inefficiency		\$692,000	5% of Labor
<b>Total Direct Installation Costs</b>		<b>\$15,076,000</b>	
<b>Total Direct Costs (PEC + Direct Installation Costs)</b>		<b>\$36,173,000</b>	
<b>Indirect Costs</b>			
Contractor's General and Administration Expense		\$3,617,000	10% of Total Direct Costs
Contractor's Profit		\$1,809,000	5% of Total Direct Costs
Engineering, Procurement, & Project Services		\$2,894,000	8% of Total Direct Costs
Construction Management/Field Engineering		\$1,447,000	4% of Total Direct Costs
S-U / Commissioning		\$543,000	1.5% of Total Direct Costs
Spare Parts		\$181,000	0.5% of Total Direct Costs
Owner's Cost		\$723,000	2% of Total Direct Costs
<b>Total Indirect Costs</b>		<b>\$11,214,000</b>	
Contingency		\$9,477,000	20% of Direct and Indirect Costs
<b>Total Capital Investment (TCI)</b>		<b>\$56,864,000</b>	sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor (CRF) = $\frac{i(1+i)^n}{(1+i)^n - 1}$		0.0820	20 year life of equipment (years) @ 5.25% interest.
<b>Annualized Capital Costs (CRF x TCI)</b>		<b>\$4,660,000</b>	
<b>OPERATING COSTS</b>			
<b>Operating &amp; Maintenance Costs</b>			
<b>Variable O&amp;M Costs</b>			
Dry Urea Reagent Cost		\$4,300,000	Based on dry urea reagent cost of \$354 per ton
Ammonia Reagent Cost		\$0	Based on ammonia reagent cost of \$700 per ton.
RO Water Cost		\$179,000	Based on water cost of \$1.00 per 1,000 gallons.
Steam Cost		\$99,000	Based on steam cost of \$1.06 per MMBtu.
Hydrated Lime Cost		\$0	Based on hydrated lime cost of \$187 per ton
Catalyst Replacement Cost		\$0	Based on catalyst cost of \$8,000 per m3 and catalyst replacement cost of \$1,000 per m3.
Auxiliary Power Cost		\$10,000	Based on auxiliary power cost of \$23 per MWh.
<b>Total Variable O&amp;M Costs</b>		<b>\$4,588,000</b>	
<b>Fixed O&amp;M Costs</b>			
Additional Operators per shift		1	
Operating Labor		\$543,000	Assume \$62/hr for each additional operator
Supervisor Labor		\$81,000	15% of Operating Labor. EPA Cost Manual Section 1, Chapter 2, page 2-31
Maintenance Materials		\$543,000	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor		\$0	Included in cost for maintenance materials.
<b>Total Fixed O&amp;M Cost</b>		<b>\$1,167,000</b>	
<b>Indirect Operating Cost</b>			
Property Taxes		\$569,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance		\$569,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34
Administration		\$1,137,000	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34
<b>Total Indirect Operating Cost</b>		<b>\$2,275,000</b>	
<b>Total Annual Operating Cost</b>		<b>\$8,030,000</b>	
<b>TOTAL ANNUAL COST</b>			
Annualized Capital Cost		\$4,660,000	
Annual Operating Cost		\$8,030,000	
<b>Total Annual Cost</b>		<b>\$12,690,000</b>	

215 South Cascade Street  
PO Box 496  
Fergus Falls, Minnesota 56538-0496  
218 739-8200  
[www.otpc.com](http://www.otpc.com)



June 8, 2020

Mr. James L. Semerad  
Director, Division of Air Quality  
North Dakota Department of Health  
Gold Seal Center, 918 East Divide Ave  
Bismarck, ND 58501-1947

Dear Mr. Semerad:

Re: Update to Regional Haze Four Factor Analysis - Coyote Station

The purpose of this submittal is to provide the North Dakota Department of Environmental Quality (DEQ) with updated information related to the sulfur dioxide (SO<sub>2</sub>) technology options presented in the Coyote Station Regional Haze Four-Factor Analysis.

As you may recall, Revision 1 of the Four-Factor Analysis, dated May 8, 2019, determined that there were six technically feasible SO<sub>2</sub> technologies applicable to Coyote Station. One of these options involved retrofitting the existing dry flue gas desulfurization (DFGD) system with a new absorber module(s). This option was specifically limited to dismantling Coyote Station Unit 1's existing absorber modules and installing a new reactor absorber(s) in the same location. The same location was used for the retrofit absorbers as the existing DFGD because, at the time of the initial Four-Factor Analysis, it was predicted that redirecting flue gas to a different location would likely result in significant solids dropout and other operational issues.<sup>1</sup>

Subsequent to the Four-Factor Analysis, Otter Tail Power Company (OTP) became aware of a recent successful project by Babcock and Wilcox (B&W) that involved redirecting flue gas to a new SDA module located adjacent to an existing fabric filter. Therefore, OTP engaged B&W and Sargent & Lundy, L.L.C. (S&L) to perform a supplemental evaluation of this option for Coyote Station Unit 1. The attached technical memorandum from S&L summarizes the results of that evaluation and associated impacts to the Four-Factor Analysis.

We look forward to working with the DEQ throughout the second planning period. If you have any questions about this updated information, please contact me at (218) 739-8526.

Sincerely,

A handwritten signature in black ink that reads "Mark Thoma".

Mark Thoma  
Manager, Environmental Services

Enclosure

---

<sup>1</sup> See *Coyote Station Unit 1: North Dakota Regional Haze Second Planning Period Four-Factor Analysis* pg. 5-10. May 8, 2019.





## TECHNICAL MEMORANDUM

**From:** Wayshalee Patel  
**Date:** June 4, 2020  
**Project No.:** A12715.011

**Client:** Otter Tail Power Company  
**Station:** Coyote Station Unit 1

**Subject:** Update to Four Factor Analysis

The purpose of this technical memorandum is to provide the North Dakota Department of Environmental Quality (NDDEQ) a summary of an additional evaluation regarding replacement of the existing spray dry absorber (SDA) modules with new absorber module(s) on the Otter Tail Power Company (OTP) Coyote Station Unit 1.

### **SDA Module Replacement Option**

One of the technically feasible sulfur dioxide control technologies presented to the NDDEQ in the initial Four-Factor Analysis for Coyote Station Unit 1 involved retrofitting the existing dry flue gas desulfurization (DFGD) system with a new absorber modules.<sup>1</sup> This option was specifically limited to dismantling Coyote Station Unit 1's existing absorber modules and installing new reactor absorbers in the same location. The same location was used for the retrofit absorbers as the existing DFGD because, at the time of the initial Four-Factor Analysis, it was predicted that redirecting flue gas to a different location would likely result in significant solids dropout and other operational issues.

Since submittal of the Four-Factor Analysis, OTP became aware of a recent successful project by Babcock and Wilcox (B&W) that involved redirecting flue gas to a new SDA module located adjacent to an existing fabric filter.<sup>2</sup> Therefore, OTP engaged B&W and Sargent & Lundy to perform a supplemental evaluation of this option for Coyote Station Unit 1.

B&W evaluated single module and two-module equipment arrangements for Coyote Station Unit 1. Given B&W's extensive project experience and Coyote Station's operating conditions, B&W's evaluation focused on the two-module design in order to confidently treat 100% of the Coyote Station Unit 1 flue gas. B&W's evaluation determined that Coyote Station's flue gas could in fact be re-directed through two new 62 ft. diameter modules<sup>3</sup> located adjacent to the existing Coyote Station Unit 1 DFGD, and then following the new SDA modules, the flue gas could be routed back to the existing Reverse Air Fabric Filter (RAFF). The

---

<sup>1</sup> See *Coyote Station Unit 1: North Dakota Regional Haze Second Planning Period Four-Factor Analysis*. May 8, 2019.

<sup>2</sup> In 2017, B&W installed a new SDA adjacent to an existing fabric filter at the Colorado Springs Utilities Nixon Plant.

<sup>3</sup> These exact modules have been installed by B&W at several sites, and most recently at Alliant Columbia Power Station (start-up 2015).

expected performance of this arrangement is an average controlled SO<sub>2</sub> emission rate of approximately 0.09 lb/MMBtu at Coyote Station Unit 1.

### **Balance of Plant Impacts**

The following balance of plant systems were evaluated by Sargent & Lundy to determine what other modifications to the existing systems would be required as part of the overall retrofit cost for the B&W two absorber module option.

#### **Pebble Lime Reagent Preparation & Fresh Lime Slurry System:**

- The storage duration of the existing lime silo (63,000 ft<sup>3</sup> or 1,733 tons) will be reduced from over 15.75 days of storage to 5.89 days assuming the unit is operated at full load, 100% capacity. This would result in an increased number of pebble lime deliveries; however no modifications will be required for the storage silos.
- The existing detention slakers and the rest of the slaking equipment will be reused; no modifications required. However, a new slaker water flow control valve (FCV) will be added to increase the controllable flow up to 375 gpm.
- The existing reagent mix tank reagent feed pumps (150 gpm) are undersized and will be replaced with new 2 x 100% lime slurry transfer pumps (500 gpm).
- The two (2) existing atomizer feed tanks (11,800 gal) will be repurposed as the lime slurry feed tanks, new 2 x 100% lime slurry feed pumps will transfer slurry to new 2 x 50% atomizer head tanks located in the new SDA penthouse. The lime slurry will be fed to the atomizer head tank in a continuous loop returning to the lime slurry storage tank. Flow from the continuous loop will be metered into the atomizer head tank based on unit load, inlet SO<sub>2</sub>, the SO<sub>2</sub> emission setpoint and trimmed by the SO<sub>2</sub> feedback measured at the stack.

#### **Recycle Slurry System:**

- Solids from the existing RAFF are collected and transported (via the ash handling system) to the existing recycle silo (38,000 ft<sup>3</sup>). No modifications required.
- A new rotary feeder will be added at the outlet of the recycle silo to meter recycle solids into the recycle mixer where water will be added to achieve an increased recycle slurry solids content of 45% solids.
- New 2 x 100% fly ash slurry transfer pumps will forward slurry to the existing reagent storage tanks that will be repurposed as recycle slurry storage tanks.
- The recycle mix chamber agitator, recycle fly ash wetting tank agitator and the repurposed recycle slurry tank agitators will be upgraded and/or replaced to handle the increase in torque caused by the higher recycle slurry solids content.
- The existing 2 x 100% recycle slurry feed pumps will be upgraded to be capable of transferring the new slurry demand. Similar to the new lime slurry feed pumps, the recycle slurry will be fed in a continuous loop to the new atomizer head tanks to maintain a tank level setpoint.

#### Byproduct/Waste Ash Conveying System:

- Sargent & Lundy evaluated the original design of the existing waste ash conveying system and determined that the existing system is sufficiently sized to operate with the higher byproduct generation.

#### Waste Ash Silo:

- When operating to achieve an outlet SO<sub>2</sub> emission of 0.09 lb/MMBtu, the produced waste ash will have a higher concentration of FGD byproducts and unreacted lime, and therefore a decreased concentration of fly ash which will decrease volumetric density of the waste ash.
  - Based on the original waste ash silo design information available, Sargent & Lundy estimated approximately six days (147 hours) of storage, assuming the unit is operated at full load, 100% capacity.
  - With the higher concentration of FGD byproducts and unreacted lime, the waste ash density was estimated to be reduced to approximately 34 lb/ft<sup>3</sup> (reduced fly ash concentration ~29%), reducing the storage duration to a little over three days (85 hours), assuming the unit is operated at full load, 100% capacity.
  - As 3 days of storage is typically recommended as the minimum storage time to cover operation over long weekends without silo unloading activities, it is assumed that the plant should still be able to manage loadout activities accordingly, and therefore no modifications or new equipment is required.
- The unloader from the silo is sufficiently rated and should not require any modifications.
- The waste ash is conditioned with water in pug mills for truck unloading. The plant has made recent upgrades to the water spray headers to the pug mills and have adequate water to condition the increased amount of waste ash loadout activities.
- To help facilitate the increased activity at the waste ash silo, costs have been included to enclose the three (3) open sides of the silo skirt.

#### Reverse Air Fabric Filter (RAFF):

- The existing Wheelabrator baghouse has 38 compartments, but at any given time, the baghouse normally has 36 compartments operating with 2 compartments offline for cleaning. The existing cleaning system can clean all 38 compartments in 30 minutes (i.e. can complete two cleaning cycles per hour).
- The existing Wheelabrator baghouse was designed for 1,582,000 ACFM at 185°F. Each compartment has 204 bags (12 rows of 17), for a total of 7,752 bags. The total cloth area of 709,308 ft<sup>2</sup> results in an air to cloth (A/C) ratio of 2.33:1 when normally operating 36 compartments.
- The new outlet conditions from the 2 SDA modules are estimated to be approximately 2,011,000 ACFM at 174°F. B&W confirmed that the new resulting A/C ratio (approximate 2.8:1) is within their recommended RAFF guidelines and continued operation should not require modifications. However, since the proposed outlet temperature of the 2 SDA modules will be closer to the water saturation temperature, it will be important to prevent moisture from condensing in the baghouse that may potentially cause corrosion.

- The solids loading to the baghouse will be increasing by approximately 70%. Assuming the current pressure drop across the baghouse will be maintained in the new configuration by increased the frequency of cleaning cycles will cause an increased wear on the bags, shortening the bag life to approximately 3-4 years from the current 6 years.

ID Fans:

- The two (2) variable pitch, axial flow induced draft (ID) fans are each rated for 1,279,000 ACFM, 46.71 in. w.c. and 210°F. The incremental increase in pressure for the new configuration is within the capacity of the existing fans. As the fans and motors are in good condition, no modifications are required.

Based on this additional evaluation by Sargent & Lundy and B&W, re-directing Coyote Station's Unit 1 flue gas to two new absorber modules adjacent to the existing fabric filter is considered a technically feasible option.

**Revised SO<sub>2</sub> Cost Effectiveness Summary**

Budgetary costs estimates were prepared by B&W and reviewed by Sargent & Lundy for the design, procurement, supply, and installation of the new SDA modules and associated balance of plant equipment.

The Four-Factor Analysis cost effectiveness table has been updated to include the associated costs and cost effectiveness for the replacement of the existing DFGD with two new SDA modules and is provided in Table 1 below. Note that since this new option is similar in annualized costs and achieves greater emissions reductions as compared to the prior Four-Factor Analysis option for an in-place absorber, the prior option was removed from the cost effectiveness table. Similarly, since the new two SDA module option is substantially lower in annualized costs and achieves the same emissions reductions as compared to the prior Four-Factor Analysis option for a new Dry FGD, the new Dry FGD option was removed from the cost effectiveness table.

Detailed cost effectiveness tables are included in Appendix A of this memorandum.

**Table 1. SO<sub>2</sub> Emissions Control System Cost Effectiveness (\$2018)**

SO <sub>2</sub> Control Option	Total Annualized Cost <sup>(Note 1)</sup> \$/yr	Expected Emission Reduction tons SO <sub>2</sub> /yr	Average Annual Cost Effectiveness <sup>(Note 2)</sup> \$/ton SO <sub>2</sub> removed	Incremental Annual Cost Effectiveness <sup>(Note 3)</sup> \$/ton SO <sub>2</sub> removed
Baseline (existing DFGD/FF)	---	---	---	---
DSI + Existing FGD	\$12,371,000	4,131	\$2,994	
FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio	\$2,082,000	5,354	\$389	
DSI + FGD Operational Improvements	\$14,453,000	7,952	\$1,818	\$4,762
FGD Upgrades - Replace Existing Absorbers with New Absorber (In-Place)	(Removed from Four Factor Analysis)			
FGD Upgrades – Replace Existing Absorbers with Two (2) New Absorbers (Adjacent to Existing FF + Increased Lime Injection)	\$21,122,000	11,619	\$1,818	\$1,819
Dry FGD (CDS) + FF	(Removed from Four Factor Analysis)			
Wet FGD	\$49,035,000	12,078	\$4,060	\$60,813

Note 1. Total annualized costs for all options presented reflect more recent Coyote Station water consumption pricing.

Note 2. Average cost effectiveness for each control option is the total annual cost divided by the expected emission reduction.

Note 3. Incremental cost effectiveness represents the incremental increase in annual costs (\$/yr) divided by the incremental increase in annual emissions reductions (tpy) between a control option and the next most effective option.





**TECHNICAL MEMORANDUM**

**Appendix A**  
**Revised SO<sub>2</sub> Cost Effectiveness Tables**

**Coyote Station Unit 1  
SO<sub>2</sub> Control Summary**

**Table 1. Coyote Unit 1 Operating Parameters**

Parameter		Unit	Notes
Power Output	427	MW-net	Nominal
Annual Heat Input	30,562,287	MMBtu/yr	24-month annual average for period July 2016 to June 2018.
Average Capacity Factor	72%	%	Based on annual average MW-h during the baseline period.

**Table 2. Control Effectiveness**

Control Technology	Control Efficiency (%)	Expected Emissions (ton/year)	Emission Rate (lb/MMBtu)	Expected Emissions Reduction (ton/year)
Wet FGD	92.9%	917	0.06	12,078
Dry FGD (CDS) + FF	(Removed from Four Factor Analysis)			
FGD Upgrades - Replace Existing Absorbers with 2 New Absorbers (Adjacent to Existing FF + Increased Lime Injection)	89.4%	1,375	0.09	11,619
FGD Upgrades - Replace Existing Absorbers with New Absorber (In-Place)	(Removed from Four Factor Analysis)			
DSI + FGD Operational Improvements	61.2%	5,043	0.33	7,952
FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio	41.2%	7,641	0.50	5,354
DSI + Existing FGD	31.8%	8,863	0.58	4,131
Baseline (DFGD/FF)		<b>12,994</b>	0.85	0

**Table 3. Cost Effectiveness**

Control Technology	Emissions (tpy)	Tons of SO <sub>2</sub> Removed (tpy)	Total Capital Requirement (\$)	Annualized Capital Cost (\$/year)	Annualized Outage Cost (\$/year)	Total Annual Operating Costs (\$/year)	Total Annual Costs (\$)	Average Cost Effectiveness (\$/ton)	Incremental Cost Effectiveness (\$/ton)
Baseline (DFGD/FF)	12,994	0	--	--		--	--		
DSI + Existing FGD	8,863	4,131	\$23,765,000	\$1,948,000	\$0	\$10,423,000	\$12,371,000	<b>\$2,994</b>	
FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio	7,641	5,354	\$526,000	\$43,000	\$0	\$2,039,000	\$2,082,000	<b>\$389</b>	
DSI + FGD Operational Improvements	5,043	7,952	\$24,292,000	\$1,991,000	\$0	\$12,462,000	\$14,453,000	<b>\$1,818</b>	\$4,762
FGD Upgrades - Replace Existing Absorbers with New Absorber (In-Place)	(Removed from Four Factor Analysis)								
FGD Upgrades - Replace Existing Absorbers with 2 New Absorbers (Adjacent to Existing FF + Increased Lime Injection)	1,375	11,619	\$110,120,000	\$9,025,000	\$0	\$12,097,000	\$21,122,000	<b>\$1,818</b>	\$1,819
Dry FGD (CDS) + FF	(Removed from Four Factor Analysis)								
Wet FGD	917	12,078	\$324,742,000	\$26,613,000	\$0	\$22,422,000	\$49,035,000	<b>\$4,060</b>	\$60,813

**Coyote Station Unit 1**  
**SO<sub>2</sub> Control Cost Evaluation**  
**FGD Upgrades - Replace Existing Absorbers with 2 New Absorbers (Adjacent to Existing FF + Increased Lime Injection)**

SO <sub>2</sub> Control Option Description	FGD Upgrades - Replace Existing Absorbers with 2 New Absorbers (Adjacent to Existing FF + Increased Lime Injection)
Baseline SO <sub>2</sub> Emissions, lb/MMBtu	0.85
Post Upgrade SO <sub>2</sub> Emissions, lb/MMBtu	0.09
Capacity Factor used of Cost Estimates (%)	72%

CAPITAL COSTS		Cost (2018\$)	Basis
<b>Direct Costs</b>			
<b>Purchased Equipment Costs (PEC)</b>			
Equipment and Materials	\$47,564,000		Based on budgetary quote received from B&W and Sargent & Lundy's conceptual cost estimating system. Costs include equipment and material.
Instrumentation	\$0		Included in equipment and materials cost
Sales Tax	\$2,378,000		5% of Equipment/Material Cost
Freight	\$2,378,000		5% of Equipment/Material Cost
<b>Total PEC</b>	<b>\$52,320,000</b>		
<b>Direct Installation Costs</b>			
Labor	\$35,917,000		Based on budgetary quote received from B&W and Sargent & Lundy's conceptual cost estimating system.
Scaffolding	included		
Mobilization / Demobilization	included		
Labor Cost Due To Overtime Inefficiency	included		
<b>Total Direct Installation Costs</b>	<b>\$35,917,000</b>		
<b>Total Direct Costs (PEC + Direct Installation Costs)</b>	<b>\$88,237,000</b>		
<b>Indirect Costs</b>			
Contractor's General and Administration Expense	included		
Contractor's Profit	included		
Engineering, Procurement, & Project Services	included		
Construction Management/Field Engineering	included		
S-U / Commissioning	\$1,324,000		1.5% of Total Direct Costs
Spare Parts	\$441,000		0.5% of Total Direct Costs
Owner's Cost	\$1,765,000		2% of Total Direct Costs
<b>Total Indirect Costs</b>	<b>\$3,530,000</b>		
<b>Contingency</b>	<b>\$18,353,000</b>		20% of Direct and Indirect Costs
<b>Total Capital Investment (TCI)</b>	<b>\$110,120,000</b>		sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$	0.0820		20 year life of equipment (years) @ 5.25% interest.
<b>Annualized Capital Costs (CRF x TCI)</b>	<b>\$9,025,000</b>		
<b>OPERATING COSTS</b>			
<b>Operating &amp; Maintenance Costs</b>			
<b>Variable O&amp;M Costs</b>			
Increased Waste Disposal Cost	\$2,564,000		Based on disposal rate of \$32.46 per ton.
Increased Lime Reagent Cost	\$3,573,000		Based on lime reagent cost of \$128 per ton.
Increased Auxiliary Power Cost	\$229,000		Based on auxiliary power cost of \$23 per MWh
Increased Water Cost	\$3,000		Based on water cost of \$0.11 per 1000 gallons.
Increased bag and cage replacement	\$52,000		Based on bag cost of \$135 per bag
<b>Total Variable O&amp;M Costs</b>	<b>\$6,369,000</b>		
<b>Fixed O&amp;M Costs</b>			
Additional Operators per shift	0		Assume no additional operators
Operating Labor	\$0		N/A
Supervisor Labor	\$0		N/A
Maintenance Materials	\$1,324,000		Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor	\$0		Included in cost for maintenance materials.
<b>Total Fixed O&amp;M Cost</b>	<b>\$1,324,000</b>		
<b>Indirect Operating Cost</b>			
Property Taxes	\$1,101,000		1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	\$1,101,000		1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	\$2,202,000		2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
<b>Total Indirect Operating Cost</b>	<b>\$4,404,000</b>		
<b>Total Annual Operating Cost</b>	<b>\$12,097,000</b>		
<b>TOTAL ANNUAL COST</b>			
Annualized Capital Cost	\$9,025,000		
Annual Operating Cost	\$12,097,000		
<b>Total Annual Cost</b>	<b>\$21,122,000</b>		

## B.1.c – Communications



March 20, 2019

**FILE**

Mr. Mark Thoma  
Manager, Environmental Services  
OtterTail Power Cooperative  
P.O. Box 496  
Fergus Falls, MN 56538-0496

Re: Four Factors Analysis - Coyote Station

Dear Mr. Thoma:

We have reviewed the Four-Factors Analysis for the Coyote Station and have only a few significant comments.

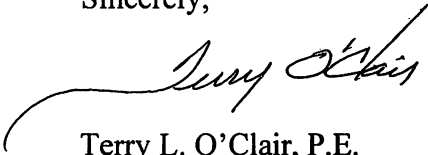
- 1) The baseline emission rates should represent a realistic depiction of anticipated (future) annual emissions for a source (BART Guideline, 4. Step 4). Table 2-1 indicates an expected sulfur content of the lignite combusted in the range of 0.82 – 1.06%. Footnote 1 to Table 5-4 indicates that the inlet SO<sub>2</sub> rate of 3.12 lb/MMBtu to the various scrubbing options is based on a future sulfur content. Normally, a look back at past emissions would be acceptable for determining the baseline emissions. However, since you are anticipating a higher sulfur content in the future lignite combusted, past emissions do not represent a realistic estimate of anticipated emissions. We believe the baseline SO<sub>2</sub> emission rate (12,994 tons/yr) is underestimated in the analysis. The North Dakota Department of Health (Department) has calculated the average SO<sub>2</sub> removal efficiency of the current FGD system from 2013, 2014, 2016, 2017 and 2018 using the AP-42 emission factor of 30(S). Using this average FGD removal efficiency (49%), an average sulfur content of 0.94% (average of 0.82% and 1.06%), and the average coal consumption for the same period (2,204,420 tons/yr), we calculate a baseline emission rate of 15,852 tons/yr. This rate compares very favorably to the 2018 actual emissions (14,913 tons) when adjusting the 2018 sulfur content of 0.89% to 0.94%. The Annual Emissions Inventory Reports for 2016, 2017 and 2018 indicate an increasing sulfur content. The SO<sub>2</sub> analysis should be edited using a more appropriate baseline emission rate.
- 2) We also believe the inlet SO<sub>2</sub> rate to possible control options (3.12 lb/MMBtu) is high. Using the AP-42 emission factor, we calculate an inlet emission rate of approximately 2.3 lb/MMBtu for 1.06% sulfur in the lignite. We believe this will affect the Total Annual Cost and cost effectiveness of the various control options. The analysis should be changed based on a more realistic inlet SO<sub>2</sub> rate.



- 3) The Department included tail-end selective catalytic reduction (SCR) as a technically feasible option in the first Regional Haze planning period. However, as you noted in your analysis, the Department ultimately determined that high dust, low dust and tail-end SCR are not technically feasible for cyclone boilers combusting North Dakota lignite (see *United States of America and the State of North Dakota versus Minnkota Power Cooperative and Square Butte Power Cooperative*). Table 5-10 lists tail-end SCR as a technically infeasible option. Since tail-end SCR is not a technically feasible option, we suggest that it be removed from Tables 5-11, 6-3 and 6-4.
- 4) Many cost estimates throughout the analysis are based on Sargent & Lundy's (S&L) conceptual cost estimating system with major equipment costs based on recently developed projects. When cost estimates are not based on EPA's Control Cost Manual, more documentation is required to substantiate the costs. Please provide the documentation to support costs that are not based on the Control Cost Manual.

If you have any questions, please feel free to 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

## B.2 – Basin AVS

### B.2.a – Department Request



May 2, 2018

**FILE**

Mr. Mike Paul  
Basin Electric Power Coop.  
1717 E Interstate Avenue  
Bismarck, ND 58503-0564

Re: Regional Haze  
Second Planning Period

Dear Mr. Paul:

The Department of Health (Department) has begun work on the second planning period (Round 2) State Implementation Plan (SIP) for regional haze. In Round 1 of the regional planning process, the emphasis was on Best Available Retrofit Technology (BART) and making reasonable progress towards the national visibility goal. In Round 2, there are no BART requirements; therefore, we will focus on making reasonable progress. The reasonable progress analysis will be made using the four factors in Section 169A(g)(1) of the Clean Air Act:

The four factors are:

1. The cost of compliance
2. The time necessary to achieve compliance
3. The energy and non-air quality environmental impact of compliance; and
4. The remaining useful life of any existing source subject to such requirements

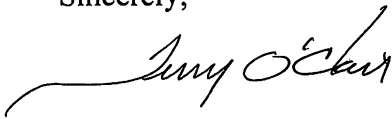
Guidance provided by the U.S. Environmental Protection Agency (Draft Guidance on Progress Tracking Metrics, Long Term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period at [https://www.epa.gov/sites/production/files/2016-07/documents/draft\\_regional\\_haze\\_guidance\\_july\\_2016.pdf](https://www.epa.gov/sites/production/files/2016-07/documents/draft_regional_haze_guidance_july_2016.pdf)) indicates the Department must address 80% of the visibility impairment caused by in-state sources. Data from the IMPROVE monitoring sites at Theodore Roosevelt National Park (TRNP) and Lostwood Wilderness Area (LWA) indicate that sulfates and nitrates continue to be the largest contributors to visibility impairment in these areas. The primary precursors of sulfates and nitrates are emissions of sulfur dioxide (SO<sub>2</sub>) and nitrogen oxides (NO<sub>x</sub>).

Coal-fired electrical generating units have been identified as one of the largest source of sulfur dioxide and nitrogen oxides in North Dakota. Therefore, the Department requests that you prepare a "four factors" analysis for your coal-fired electrical generating units. The analysis should be prepared using the draft EPA guidance noted above. The Department will identify other sources in North Dakota that will be required to submit a four factors analysis.

The Department will be working with the Western Regional Air Partnership (WRAP) to prepare the Round 2 SIP. WRAP will be conducting air quality modeling of regional emissions reductions in early 2019. The Department asks that your "four factors" analysis be submitted by January 31, 2019.

If you have any questions, please contact David Stroh of my staff at (701)328-5188.

Sincerely,



Terry L. O'Clair  
Director  
Division of Air Quality

TLO/TB:saj

xc: Cris Miller, Basin Electric Power Coop.

## B.2.b – Facility Response





January 31, 2019

Mr. Terry O'Clair  
North Dakota Department of Health  
918 East Divide Avenue, Second Floor  
Bismarck, ND 58501-1947

Dear Mr. O'Clair:

RE: Four Factor Analysis Submittal for Antelope Valley Station and Leland Olds Station

Enclosed, you will find one CD and three hard copies of Basin Electric Power Cooperative's (**Basin Electric**) Round II Regional Haze Determination Four Factor Analysis for the Antelope Valley and Leland Olds Stations. This analysis was performed as outlined in the North Dakota Department of Health's (**NDDH**) May 2, 2018, request. Basin Electric is aware that the four factor analysis is one component contributing to the NDDH's Round II Regional Haze State Implementation Plan's Determination for each of these emission sources.

North Dakota is relying on the Western Regional Air Partnership (**WRAP**) to develop the visibility modeling platform needed to evaluate visibility at the Class I areas and subsequently for the individual states to develop and assess compliance strategies that will be formalized within the Round II Regional Haze State Implementation Plan.

Basin Electric requests that the NDDH withhold its Round II Regional Haze Determination until a comparative evaluation of visibility from the various control alternatives have been performed. The timing of the visibility analysis is subject to model availability. Basin Electric will continue to monitor WRAP's model development and will coordinate closely with the NDDH prior to initiating visibility impact analysis.

Should you have any questions concerning this submittal, please do not hesitate to contact Erin Dukart, Environmental Compliance Administrator at [edukart@bepc.com](mailto:edukart@bepc.com) or 701.557.5557.

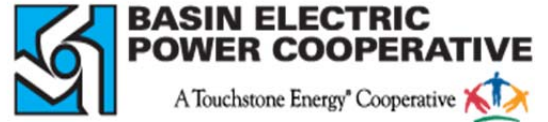
Sincerely,

Mike Paul  
Chief Technical Advisor

/efd/sw

Enclosures

cc: Erin Fox Dukart  
Keri Schiferl  
Casey Mutzenberger



# NORTH DAKOTA ROUND II REGIONAL HAZE STATE IMPLEMENTATION PLAN DETERMINATION'S FOUR-FACTOR ANALYSIS FOR ANTELOPE VALLEY STATION UNITS 1 AND 2

SL-014754

Final

January 30, 2019

Project No. 13772-001



55 East Monroe Street • Chicago, IL 60603-5780 USA • 312-269-2000  
[www.sargentlundy.com](http://www.sargentlundy.com)

## CONTENTS

<b>EXECUTIVE SUMMARY .....</b>	<b>1</b>
<b>1. INTRODUCTION .....</b>	<b>1-1</b>
<b>2. FACILITY DESCRIPTION.....</b>	<b>2-1</b>
<b>3. FOUR-FACTOR ANALYSIS REQUIREMENTS .....</b>	<b>3-1</b>
<b>3.1 REGIONAL HAZE RULE BACKGROUND .....</b>	<b>3-1</b>
3.1.1 First Implementation Period.....	3-3
3.1.2 Round II Regional Haze SIP Determination .....	3-8
<b>3.2 DESCRIPTIONS OF THE FOUR STATUTORY FACTORS.....</b>	<b>3-10</b>
3.2.1 Costs of Compliance .....	3-10
3.2.2 Time Necessary for Compliance .....	3-12
3.2.3 Energy and Non-Air Quality Environmental Impacts.....	3-12
3.2.4 Remaining Useful Life.....	3-13
3.2.5 Approach for Evaluating Control Measures.....	3-14
<b>4. SO<sub>2</sub> CONTROL EVALUATION .....</b>	<b>4-1</b>
<b>4.1 BASELINE SO<sub>2</sub> EMISSIONS .....</b>	<b>4-1</b>
<b>4.2 COAL SULFUR CONTENT.....</b>	<b>4-3</b>
<b>4.3 SO<sub>2</sub> EMISSIONS CONTROLS .....</b>	<b>4-4</b>
4.3.1 Identify Available SO <sub>2</sub> Control Options .....	4-4
4.3.2 Technical Feasibility of Available SO <sub>2</sub> Control Options .....	4-4
4.3.3 Evaluate Technically Feasible SO <sub>2</sub> Control Options for Effectiveness .....	4-21
<b>4.4 SO<sub>2</sub> COST OF COMPLIANCE (STATUTORY FACTOR ONE) .....</b>	<b>4-23</b>
4.4.1 SO <sub>2</sub> Average Annual Economic Evaluation.....	4-25
4.4.2 SO <sub>2</sub> Projected Future Maximum Annual Economic Evaluation .....	4-28

<b>5. NO<sub>x</sub> CONTROL EVALUATION.....</b>	<b>5-1</b>
<b>5.1 BASELINE NO<sub>x</sub> EMISSIONS .....</b>	<b>5-1</b>
<b>5.2 NO<sub>x</sub> EMISSIONS CONTROLS .....</b>	<b>5-3</b>
5.2.1 Identify Available NO <sub>x</sub> Control Options .....	5-3
5.2.2 Technical Feasibility of Available NO <sub>x</sub> Control Options .....	5-3
5.2.3 Evaluate Technically Feasible NO <sub>x</sub> Control Options for Effectiveness .....	5-18
<b>5.3 NO<sub>x</sub> COST OF COMPLIANCE (STATUTORY FACTOR ONE) .....</b>	<b>5-20</b>
5.3.1 NO <sub>x</sub> Average Annual Economic Evaluation .....	5-22
5.3.2 NO <sub>x</sub> Projected Future Maximum Economic Evaluation.....	5-24
<b>6. TIME NECESSARY FOR COMPLIANCE (STATUTORY FACTOR TWO) .....</b>	<b>6-1</b>
<b>7. ENERGY AND NON-AIR QUALITY ENVIRONMENTAL IMPACTS (STATUTORY FACTOR THREE) .....</b>	<b>7-1</b>
<b>7.1 ENVIRONMENTAL IMPACTS .....</b>	<b>7-1</b>
<b>7.2 ENERGY IMPACTS .....</b>	<b>7-2</b>
<b>7.3 ENVIRONMENTAL / ENERGY IMPACTS SUMMARY .....</b>	<b>7-3</b>
<b>8. REMAINING USEFUL LIFE (STATUTORY FACTOR FOUR) .....</b>	<b>8-5</b>
<b>9. CONCLUSIONS .....</b>	<b>9-1</b>

**FIGURES/TABLES**

Figure 3-1. Federal Class I Areas .....	3-1
Figure 3-2. Regional Planning Organization Map.....	3-2
Table ES-1. Technically Feasible SO <sub>2</sub> Control Options for AVS Units 1 and 2.....	2
Table ES-2. Technically Feasible NO <sub>x</sub> Control Options for AVS Units 1 and 2.....	3
Table ES-3. Proposed Round II Determination's SO <sub>2</sub> Emission Rate.....	5
Table 2-1. Four Factor Analysis Design Basis Parameters .....	2-1
Table 3-1. Initial Planning Period SIP Summary .....	3-7
Table 3-2. Key Steps in Developing the Round II Determination.....	3-9
Table 4-1. Representative Baseline Periods for SO <sub>2</sub> Emissions .....	4-1
Table 4-2. Baseline Actual SO <sub>2</sub> Emissions .....	4-2

NORTH DAKOTA ROUND II REGIONAL HAZE SIP  
DETERMINATION'S FOUR-FACTOR ANALYSIS FOR ANTELOPE  
VALLEY STATION UNITS 1 AND 2

iv

Table 4-3. Projected Future Maximum SO <sub>2</sub> Emissions.....	4-2
Table 4-4. Baseline AVS Coal Quality (Annual).....	4-3
Table 4-5. Future AVS Coal Quality (Annual).....	4-3
Table 4-6. Design Basis for Future Projected AVS Coal Quality (Annual).....	4-4
Table 4-7. Available SO <sub>2</sub> Control Options.....	4-4
Table 4-8. FGD Operational Improvements and Equipment Upgrades .....	4-6
Table 4-9. Increased SO <sub>2</sub> Emissions on AVS Unit 1 (June 2015-June 2018) .....	4-7
Table 4-10. Increased SO <sub>2</sub> Emissions on AVS Unit 2 (June 2015-June 2018) .....	4-7
Table 4-11. Technically Feasible SO <sub>2</sub> Control Options .....	4-20
Table 4-12. Evaluate Technically Feasible SO <sub>2</sub> Control Options by Effectiveness for AVS Unit 1.....	4-21
Table 4-13. Evaluate Technically Feasible SO <sub>2</sub> Control Options by Effectiveness for AVS Unit 2.....	4-22
Table 4-14. Evaluate Technically Feasible SO <sub>2</sub> Control Options by Effectiveness – AVS Unit 1 or 2 .....	4-23
Table 4-15. SO <sub>2</sub> Control Cost Summary (Average Annual) .....	4-26
Table 4-16. SO <sub>2</sub> Emissions Control System Cost Effectiveness (Average Annual).....	4-27
Table 4-17. SO <sub>2</sub> Control Cost Summary (Projected Future Maximum).....	4-29
Table 4-18. SO <sub>2</sub> Emissions Control System Cost Effectiveness (Projected Future Maximum).....	4-30
Table 5-1. Representative Baseline Periods for NO <sub>x</sub> Emissions.....	5-1
Table 5-2. Baseline Actual NO <sub>x</sub> Emissions .....	5-2
Table 5-3. Baseline Projected Future Maximum NO <sub>x</sub> Emissions.....	5-2
Table 5-4. Available NO <sub>x</sub> Control Options.....	5-3
Table 5-5. Technically Feasible NO <sub>x</sub> Control Options .....	5-17
Table 5-6. Evaluate Technically Feasible NO <sub>x</sub> Control Options by Effectiveness for AVS Unit 1 .....	5-19
Table 5-7. Evaluate Technically Feasible NO <sub>x</sub> Control Options by Effectiveness for AVS Unit 2 .....	5-19
Table 5-8. Evaluate Technically Feasible NO <sub>x</sub> Control Options by Effectiveness – AVS Unit 1 or 2.....	5-20
Table 5-9. NO <sub>x</sub> Control Cost Summary (Average Annual) .....	5-22
Table 5-10. NO <sub>x</sub> Emissions Control System Cost Effectiveness (Average Annual) .....	5-23
Table 5-11. NO <sub>x</sub> Control Cost Summary (Projected Future Maximum) .....	5-24
Table 5-12. NO <sub>x</sub> Emissions Control System Cost Effectiveness (Based on Projected Future Maximum Emissions).....	5-25
Table 6-1. SO <sub>2</sub> Emissions Control System Implementation Schedule .....	6-1
Table 6-2. NO <sub>x</sub> Emissions Control System Implementation Schedule.....	6-2
Table 7-1. Summary of Energy and Non-Air Quality Environmental Impacts .....	7-4
Table ES-1. Proposed Round II Determination's SO <sub>2</sub> Emission Rate.....	9-3



NORTH DAKOTA ROUND II REGIONAL HAZE SIP  
DETERMINATION'S FOUR-FACTOR ANALYSIS FOR ANTELOPE  
VALLEY STATION UNITS 1 AND 2

---

**v****APPENDICES**

- A. North Dakota Department of Health Letter
- B. Antelope Valley Station Units 1 and 2 Baseline Emissions
- C. SO<sub>2</sub> Control Cost Effectiveness Estimates
- D. NO<sub>x</sub> Control Cost Effectiveness Estimates

## ABBREVIATIONS/ACRONYMS

Abbreviation/Acronym	Explanation
ASOFA	advanced separated overfire air
AVS	Antelope Valley Station
B&W	Babcock & Wilcox
BACT	Best Available Control Technology
BART	Best Available Retrofit Technology
Basin Electric	Basin Electric Power Cooperative
Ca	calcium
CAA	Clean Air Act
CATC	Clean Air Technology Center
CEMS	continuous emissions monitoring system
CFR	Code of Federal Regulations
CRF	capital recovery factor
DFGD	dry lime flue gas desulfurization
DSI	dry DSI
dv	deciview
ESP	electrostatic precipitator
EPA	Environmental Protection Agency
EGU	electric generating unit
FGD	flue gas desulfurization
FIP	Federal Implementation Plan
G&A	general and administrative
GHG	greenhouse gas
GPSP	Great Plains Synfuels Plant
HHV	Higher Heating Value
H <sub>2</sub> O	water
H <sub>2</sub> SO <sub>4</sub>	sulfuric acid
K	potassium
LNB	Low-NO <sub>x</sub> burner
LTS	long-term strategy
Mg	magnesium

NORTH DAKOTA ROUND II REGIONAL HAZE SIP  
DETERMINATION'S FOUR-FACTOR ANALYSIS FOR ANTELOPE  
VALLEY STATION UNITS 1 AND 2

vii

MMBtu	million British thermal units
MNL	multi-nozzle lance
MRYs	Milton R. Young Station
MW	megawatt
MWg	megawatt gross
N <sub>2</sub>	nitrogen
Na	sodium
ND	North Dakota
NDDH	North Dakota Department of Health
NH <sub>3</sub>	ammonia
NO	nitric oxide
NO <sub>2</sub>	nitrogen dioxide
NO <sub>x</sub>	nitrogen oxides
NSR	New Source Review
OEM	original equipment manufacturer
OFA	overfire air
O&M	operations and maintenance
PC	pulverized coal
PM	particulate matter
PRB	Powder River Basin
RBLC	RACT/BACT/LAER Clearinghouse
Round II Determination	Round II Regional Haze Sate Implementation Plan Determination
RPG	Reasonable Progress Goals
RPO	Regional Planning Organization
RRI	rich reagent injection
S	sulfur
S&L	Sargent & Lundy, L.L.C.
SACR	selective autocatalytic reduction
SCR	selective catalytic reduction
SIP	State Implementation Plan
SNCR	selective non-catalytic reduction
SO <sub>2</sub>	sulfur dioxide
SO <sub>3</sub>	sulfur trioxide

NORTH DAKOTA ROUND II REGIONAL HAZE SIP  
DETERMINATION'S FOUR-FACTOR ANALYSIS FOR ANTELOPE  
VALLEY STATION UNITS 1 AND 2

**viii**

---

SOFA	separated overfire air
TAC	total annual cost
TCI	total capital investment
TE-SCR	tail-end SCR
URP	uniform rate of progress
WRAP	Western Region Air Partnership

---

## EXECUTIVE SUMMARY

The Antelope Valley Station (AVS), located near Beulah, North Dakota, has two generating units (Units 1 and 2) each rated at 470 megawatts gross (MWg). AVS Unit 1 went on line in 1984 and Unit 2 went on line in 1986. AVS Units 1 and 2 are Combustion Engineering (CE) pulverized coal (PC), tangential fired units firing North Dakota lignite. Each unit is equipped with an over-fire air (OFA) system, low-NO<sub>x</sub> concentric firing system (LNCFS), and Omnivise Combustion Optimizer for NO<sub>x</sub> control, a dry lime flue gas desulfurization (DFGD) system, and fabric filter baghouse (FF) control system for SO<sub>2</sub> and particulate matter (PM) control. AVS receives a majority of its lignite fuel from the fine coal rejected by the adjacent Great Plains Syngas Plant (GPSP) coal screening process, with the balance of fuel requirements being delivered directly to AVS from the Freedom Mine, which is located adjacent to the AVS/GPSP Complex.

On July 1, 1999, the U.S. EPA published regulations implementing Section 169A of the Clean Air Act (CAA), establishing a comprehensive visibility protection program for Federal Class I areas (the Regional Haze Rule).<sup>1</sup> The Regional Haze Rule requires each state to develop, and submit for approval by EPA, a state implementation plan (SIP) detailing the state's plan to protect visibility in Class I areas. The Regional Haze Rule established a schedule setting forth deadlines by which the states must submit their initial regional haze SIPs and subsequent revisions to the SIPs. Regional Haze SIPs for the initial planning period were due in 2007, with subsequent SIP updates due in 2018 and every 10 years thereafter.<sup>2</sup>

During the initial planning period, North Dakota Department of Health's (NDDH) reasonable progress determination found that no NO<sub>x</sub> or SO<sub>2</sub> controls were warranted for Basin Electric Power Cooperative's (Basin Electric) AVS Units 1 & 2. U.S. EPA disapproved NDDH's determination for AVS Units 1 & 2, and promulgated a Federal Implementation Plan (FIP) that included a reasonable progress determination that low NO<sub>x</sub> burners and separated overfire air (LNB+SOFA) and a NO<sub>x</sub> emission limit of 0.17 lb/MMBtu (30-day rolling average) was required for NO<sub>x</sub> control for AVS Units 1 and 2. The FIP required Basin Electric to install the NO<sub>x</sub> control technologies on AVS Units 1 & 2 by July 31, 2018. In accordance with the FIP requirements, Basin Electric

---

<sup>1</sup> 64 FR 35713

<sup>2</sup> On January 10, 2017, EPA made a one-time adjustment to the due date for the second implementation period (2018 – 2028) by extending the deadline from July 31, 2018 to July 31, 2021 (82 FR 3078).



installed a low-NO<sub>x</sub> concentric firing system (LNCFS) on AVS Units 1 and 2 in 2014 and 2016, respectively, coinciding with the scheduled tri-annual maintenance outages.

As part of the Round II Regional Haze State Implementation Plan (Round II Determination), NDDH requested that Basin Electric prepare a four-factor analysis of sulfur dioxide (SO<sub>2</sub>) and nitrogen oxide (NO<sub>x</sub>) emissions control options for AVS Units 1 and 2. The analysis evaluates technically feasible SO<sub>2</sub> and NO<sub>x</sub> emission reduction measures for the following four statutory factors:

- Factor 1: The cost of compliance
- Factor 2: The time necessary to achieve compliance
- Factor 3: The energy and non-air quality environmental impact of compliance
- Factor 4: The remaining useful life of any existing source subject to such requirements

Sargent & Lundy LLC (S&L) and Basin Electric evaluated potentially available SO<sub>2</sub> and NO<sub>x</sub> emissions reduction options for AVS Units 1 and 2 to identify technically feasible control options for inclusion in the four factor analysis. The SO<sub>2</sub> and NO<sub>x</sub> control options included in this four factor analysis are identified in Table ES-1 and Table ES-2.

**Table ES-1. Technically Feasible SO<sub>2</sub> Control Options for AVS Units 1 and 2**

Alt. No.	SO <sub>2</sub> Control Technology
E	New Retrofit WFGD
D	New Retrofit DFGD (CDS/FF)
C	New Retrofit DFGD (SDA/FF)
B	FGD Operational Improvements – Increase Ca:S Stoichiometric Ratio
A	FGD Operational Improvements – Station Work Practice
--	Baseline (existing DFGD/FF)

**Table ES-2. Technically Feasible NO<sub>x</sub> Control Options for AVS Units 1 and 2**

Alt. No.	NO <sub>x</sub> Control Technology
B	SCR – tail-end configuration <sup>(Note 1)</sup>
A	SNCR
--	Baseline (existing OFA/LNCFS)

Note 1. Tail-end SCR has not been installed on a North Dakota lignite-fired unit, and extended trials would be needed to better understand the design and operation of tail-end SCR on AVS Unit 1. Nevertheless, during the initial planning period, NDDH concluded that tail-end SCR was a technically feasible NO<sub>x</sub> control technology for a North Dakota lignite-fired boiler, and evaluated the costs and cost-effectiveness of the control system. For consistency with NDDH's conclusion from the first planning period, tail-end SCR will be carried forward to the four factor analysis

The cost of compliance evaluation (Statutory Factor 1) prepared for SO<sub>2</sub> controls indicates that, from baseline emission rates, the average annual cost effectiveness of the technically feasible SO<sub>2</sub> control options for Unit 1 ranges from \$340 per ton (Alternative A) to \$6,992 per ton SO<sub>2</sub> removed (Alternative E), and for Unit 2 ranges from \$284 per ton (Alternative A) to \$6,861 per ton SO<sub>2</sub> removed (Alternative E). When evaluating projected future maximum emissions reductions, the average annual cost effectiveness of the technically feasible SO<sub>2</sub> control options for Unit 1 ranges from \$623 per ton (Alternative A) to \$6,677 per ton SO<sub>2</sub> removed (Alternative D), and for Unit 2 ranges from \$526 per ton (Alternative A) to \$6,584 per ton SO<sub>2</sub> removed (Alternative D).

The cost of compliance evaluation prepared for NO<sub>x</sub> controls indicates that, from baseline emission rates, the average annual cost effectiveness of the technically feasible NO<sub>x</sub> control options for Unit 1 ranges from \$19,893 per ton (Alternative A) to \$39,035 per ton NO<sub>x</sub> removed (Alternative B), and for Unit 2 ranges from \$18,179 per ton (Alternative A) to \$36,792 per ton NO<sub>x</sub> removed (Alternative B). When evaluating projected future maximum emissions reductions, the average annual cost effectiveness of the technically feasible NO<sub>x</sub> control options for Unit 1 ranges from \$16,667 per ton (Alternative A) to \$31,977 per ton NO<sub>x</sub> removed (Alternative B), and for Unit 2 ranges from \$15,910 per ton (Alternative A) to \$31,589 per ton NO<sub>x</sub> removed (Alternative B).

The time necessary for compliance (Statutory Factor 2) for the SO<sub>2</sub> control options ranges from 3 months (Alternative A) to 60 months (Alternative E). For NO<sub>x</sub> control options, the time necessary for compliance ranges from 22 months (Alternative A) to 52 months (Alternative B).

An evaluation of energy impacts and non-air environmental impacts (Statutory Factor 3) indicates that certain control options will increase auxiliary power requirements due to increased pressure drop, which would adversely impact net plant heat rate. Consequently, heat input to the boiler would need to increase to compensate for the

increased auxiliary power requirements while achieving the same net plant output, or net output from the unit would decrease. Collateral environmental impacts include increases in water consumption, FGD wastewater treatment and discharge, solid waste generation, and sulfuric acid mist and ammonia emissions.

Regarding remaining useful life (Statutory Factor 4), under the current Basin Electric resource plan, the remaining useful life of AVS Units 1 and 2 are considered to be greater than 20 years. Therefore, the remaining useful life has no impact on the annualized cost of control under the current regulatory framework.

Based on the results of the four factor analysis prepared for AVS, Basin Electric is aware that reducing SO<sub>2</sub> emissions by implementing FGD Operational Improvements (Alternative B) on Units 1 and 2 may be determined to be cost effective by the NDDH.

Within the Round II Determination process, the NDDH will evaluate visibility improvements relying on Western Region Area Partnership's (WRAP) cumulative modeling of the North Dakota based facilities for the various control options being evaluated. Basin Electric requests that the NDDH withhold their Round II Regional Haze SIP Determination for the AVS until the cumulative modeling platform is made available to the public and visibility improvement assessments can be conducted. Basin Electric will then perform a comparative visibility improvement analysis and submit the results to the NDDH for consideration. This effort will be coordinated with the NDDH for consistency of modeling protocols and model inputs.

In addition, Basin Electric requests, that in the event that SO<sub>2</sub> reductions will be required, any future 30-day rolling average permit limit will be based on an equivalent mass based combined plant (lb SO<sub>2</sub>/hr) 30-day rolling average basis. Since AVS began operation, the current combined plant total permit limit of 3,845 lb SO<sub>2</sub>/hr, 3-hour average, has been the benchmark for all operations guidance and procedures and is imbedded in the DFGD process control logic. To alter the basis of the operational control to a mass emission rate (lb SO<sub>2</sub>/MMBtu) will be extremely disruptive from an operational perspective when consideration is given to the complexity and variability of DFGD operations.

The four factor analysis prepared for AVS NO<sub>x</sub> reductions indicates that SNCR and tail-end SCR control options are cost prohibitive. The control cost evaluation indicates that the average cost effectiveness levels exceed \$15,000 per ton NO<sub>x</sub> removed. Basin Electric is proposing that the existing OFA / LNCFS systems on Units 1 and 2 represent appropriate controls for the Round II Determination, therefore no change to the current Title V Operating Permit is proposed for NO<sub>x</sub> emissions at AVS. Table ES-3 includes a summary of the proposed Round II

NORTH DAKOTA ROUND II REGIONAL HAZE SIP  
DETERMINATION'S FOUR-FACTOR ANALYSIS FOR ANTELOPE  
VALLEY STATION UNITS 1 AND 2

**ES-5**

Determination's control strategy for SO<sub>2</sub>, assessed SO<sub>2</sub> emissions on a 30-day rolling average basis and a proposed combined plant average emission rate for AVS. The proposed emissions include compliance margin to account for items such as variability in fuel heating value and sulfur content, and operating load profile.

**Table ES-3. Proposed Round II Determination's SO<sub>2</sub> Emission Rate**

<b>AVS Unit No.</b>	<b>Pollutant</b>	<b>Proposed Round II Determination's Emission Rate lb/MMBtu (30-day rolling average)</b>	<b>Proposed Round II Determination's Combined Plant Emission Rate (Note 1) (lb/hr)</b>	<b>Control Technology</b>
Unit 1	SO <sub>2</sub>	0.30	2,958	FGD Operational Improvements
Unit 2	SO <sub>2</sub>	0.30	2,958	FGD Operational Improvements

Note 1. The proposed Round II Determination's combined plant emission rate is a 23% reduction from the current combined plant permit limit of 3,845 lb SO<sub>2</sub>/hr, 3-hour avg.

## 1. INTRODUCTION

Sargent & Lundy, L.L.C. (S&L) was retained by Basin Electric Power Cooperative (Basin Electric) to prepare a Round II Regional Haze State Implementation Plan Determination's (Round II Determination) four-factor analysis for the control of sulfur dioxide (SO<sub>2</sub>) and nitrogen oxide (NO<sub>x</sub>) emissions from Basin Electric's Antelope Valley Station (AVS) Units 1 and 2. The evaluation is in response to the North Dakota Department of Health's formal letter dated May 2, 2018, attached in Appendix A. The evaluation includes an assessment of potentially available emission reduction measures for the four statutory factors listed in 40 CFR 51.308(f)(2), and takes into consideration U.S. Environmental Protection Agency's (EPA's) *Draft Guidance on Progress Tracking Metrics, Long Term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period* (the "Draft EPA Guidance").<sup>3</sup> Technically feasible SO<sub>2</sub> and NO<sub>x</sub> emission reduction measures are evaluated for the following four statutory factors:

- Factor 1: The cost of compliance
- Factor 2: The time necessary to achieve compliance
- Factor 3: The energy and non-air quality environmental impact of compliance
- Factor 4: The remaining useful life of any existing source subject to such requirements

The Round II Determination's four factor analysis for AVS Units 1 and 2 is presented in the following sections:

- Section 2: Facility Description** contains information describing the facility, site location, and existing equipment.
- Section 3: Four-Factor Analysis Requirements** provides a brief description of the Regional Haze Program requirements set forth in 40 CFR 51.308.
- Section 4: SO<sub>2</sub> Control Evaluation** establishes representative baseline SO<sub>2</sub> emissions, identifies potentially available emission control technologies, evaluates each control option for technical feasibility and evaluates cost effectiveness of technically feasible control options.
- Section 5: NO<sub>x</sub> Control Evaluation** establishes representative baseline NO<sub>x</sub> emissions, identifies potentially available emission control technologies, evaluates each control option for

<sup>3</sup> On September 11, 2018, EPA released a "*Regional Haze Reform Roadmap*" announcing its plan to "release a series of implementation tools and guidance documents that will help focus states' efforts and reduce and streamline the time and resources needed to meet the statutory and regulatory requirements for reducing regional haze in National Parks, wildlife refuges, and wilderness areas." EPA stated that it plans to issue a new guidance document on Regional Haze SIP Development by Spring, 2019. Basin Electric reserves the right to update and modify this four-factor analysis, as needed, to be consistent with any new guidance issued by the agency.



technical feasibility and evaluates cost effectiveness of technically feasible control options.

**Section 6: Time Necessary for Compliance** provides typical timelines required to design, engineer, procure and install the technically feasible control options.

**Section 7: Energy and Non-Air Quality Environmental Impacts** identifies the energy and non-air quality environmental impacts associated with each technically feasible control option.

**Section 8: Remaining Useful Life** includes a discussion of the planned remaining useful life of AVS Units 1 and 2, including an evaluation of how remaining useful life affects the cost-effectiveness of each technically feasible control option.

**Section 9: Summary and Conclusions**

**Appendix A: North Dakota Department of Health Letter**

**Appendix B: Antelope Valley Station Units 1 and 2 Baseline Emissions**

**Appendix C: SO<sub>2</sub> Control Cost Effectiveness Estimates**

**Appendix D: NO<sub>x</sub> Control Cost Effectiveness Estimates**

## 2. FACILITY DESCRIPTION

The Antelope Valley Station (AVS), located near Beulah, North Dakota, has two generating units (Units 1 and 2) each rated at 470 megawatts gross (MWg). AVS Unit 1 went on line in 1984 and Unit 2 went on line in 1986. AVS Units 1 and 2 are Combustion Engineering (CE) pulverized coal (PC), tangential fired units firing North Dakota lignite. Each unit is equipped with an over-fire air (OFA), low-NO<sub>x</sub> concentric firing system (LNCFS), and Omnivise Combustion Optimizer for NO<sub>x</sub> control, a dry lime flue gas desulfurization (DFGD) system, and fabric filter baghouse (FF) control system for SO<sub>2</sub> and PM control. AVS receives a majority of its lignite fuel from the fine coal rejected by the adjacent Great Plains Syngas Plant (GPSP) coal screening process, with the balance of fuel requirements being delivered directly to AVS from the Freedom Mine, which is located adjacent to the AVS/GPSP Complex.

Table 2-1 provides a summary of the design parameters used for the AVS Units 1 and 2 four factor analysis. The four factor analysis design parameters listed in Table 2-1 were developed from information provided by Basin Electric. The parameters are for each AVS unit.

**Table 2-1. Four Factor Analysis Design Basis Parameters**

Parameter	AVS Unit 1	AVS Unit 2
Boiler type	PC tangential fired	PC tangential fired
Boiler manufacturer	Combustion Engineering	Combustion Engineering
Generating Capacity (MWg)	470	470
Design Heat Input (MBtu/hr)	4,930	4,930
Average Hourly Heat Input for Baseline SO <sub>2</sub> period (MBtu/hr)	4,459	4,499
Capacity Factor for Baseline SO <sub>2</sub> period (%)	86	87
Average Hourly Heat Input for Baseline NO <sub>x</sub> period (MBtu/hr)	4,126	4,480
Capacity Factor for Baseline NO <sub>x</sub> period (%)	81	85

NORTH DAKOTA ROUND II REGIONAL HAZE SIP  
 DETERMINATION'S FOUR-FACTOR ANALYSIS FOR ANTELOPE  
 VALLEY STATION UNITS 1 AND 2

**2-2**

Parameter	AVS Unit 1	AVS Unit 2
DFGD Design Parameters		
SO <sub>2</sub> Content lb/MMBtu	3.56	3.56
Design Removal Efficiency (%)	89	89
Baseline Fuel Parameters <sup>(1)</sup>		
Higher Heating Value (Btu/lb)	6,755	6,755
Fuel sulfur content (%)	0.98	0.98
SO <sub>2</sub> content (lb/MMBtu)	2.90	2.90
Projected Future Fuel Parameters <sup>(2)</sup>		
Higher Heating Value (Btu/lb)	6,434	6,434
Fuel sulfur content (%)	1.09	1.09
SO <sub>2</sub> content (lb/MMBtu)	3.39	3.39

Note 1. Baseline fuel parameters are based on the actual annual average fuel sulfur content from 2013-2018 provided by Basin Electric.

Note 2. Projected future fuel parameters are based on anticipated annual average coal projections provided by Basin Electric from 2019-2045. Projected future sulfur and SO<sub>2</sub> content includes margin based on the actual deviation in annual average sulfur content from current coal data. Additional detail on coal sulfur provided in Section 4.2.

### 3. FOUR-FACTOR ANALYSIS REQUIREMENTS

### 3.1 REGIONAL HAZE RULE BACKGROUND

Section 169A of the 1977 Amendments to the Clean Air Act (CAA) sets forth a program for protecting visibility in Federal Class I areas which calls for “ the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory Federal Class I areas which impairment results from manmade air pollution.” Federal Class I areas include national parks, memorial parks, and wilderness areas over a certain size. Figure 3-1 shows the locations of the 156 federally mandated Class I areas. Federal Class I areas located within ND include the Theodore Roosevelt National Park and the Lostwood National Wildlife Refuge.

### Figure 3-1. Federal Class I Areas



On July 1, 1999, the U.S. EPA published regulations implementing Section 169A of the CAA, establishing a comprehensive visibility protection program for Federal Class I areas (the Regional Haze Rule).<sup>4</sup> The Regional Haze Rule requires each state to develop, and submit for approval by EPA, a state implementation plan (SIP) detailing the state's plan to protect visibility in Class I areas. Regional Haze SIPs must contain such emission limits, schedules of compliance, and other measures as may be necessary to make reasonable progress toward meeting the national visibility goal of achieving visibility in Class 1 areas which reflects natural conditions by 2064.

To address the combined visibility effects of various pollution sources over a wide geographic region, EPA designated five Regional Planning Organizations (RPOs) to assist with the coordination and cooperation needed to address the visibility issue. The five RPOs are shown in Figure 3-2. North Dakota is a member of the Western Regional Air Partnership (WRAP), which serves as the RPO for visibility protection at 118 Class I areas in 15 western states.

**Figure 3-2. Regional Planning Organization Map**



<sup>4</sup> 64 FR 35713



### **3.1.1 First Implementation Period**

The Regional Haze Rule established a schedule setting forth deadlines by which the states must submit their initial regional haze SIPs and subsequent revisions to the SIPs. Regional Haze SIPs for the initial planning period were due in 2007, with subsequent SIP updates due in 2018 and every 10 years thereafter.<sup>5</sup>

Regional Haze SIP requirements for the first planning period required that states incorporate into their plans the core program requirements in 40 CFR 51.308(d), including: (1) establishing reasonable progress goals (RPGs) for each Class I area within the state that provide for measurable progress towards achieving natural visibility conditions; (2) developing a long-term strategy (LTS) including enforceable emissions limitations and compliance schedules to achieve the RPGs; and (3) developing plans to monitor and assess the effectiveness of the LTS to achieve the RPGs over the prior implementation period and affirmation of or revision to the RPGs.

The Regional Haze Rule requires that states determine the consistent rate of progress over time needed to attain natural visibility conditions on the 20 percent most impaired days by the year 2064. This “glidepath” is referred to as the uniform rate of progress (URP) line. States must consider the URP, and the emission reduction measures needed to achieve this level of improvement, when developing their RPGs and LTS. Regulations at 40 CFR 51.308(g) require each state to submit progress reports, in the form of SIP revisions, every 5 years following the submission of the initial SIP. These progress reports must evaluate the progress made towards the RPGs for Class I areas located within the state as well as those Class I areas located outside the state that may be affected by emissions from within the state.

#### **3.1.1.1 Best Available Retrofit Technology**

As a one-time requirement during the first implementation period, potential best available retrofit technology (BART) controls had to be evaluated for certain large stationary sources. States were required to conduct BART determinations for “BART-eligible” sources anticipated to cause or contribute to any visibility impairment in one or more Class I area. BART-eligible sources included coal-fired electric generating units (EGUs) that were in existence on August 7, 1977, but not in operation prior to August 7, 1962. In its determination of BART, states were required to take into consideration the costs of compliance, the energy and non-air quality environmental impacts of compliance, any existing pollution control technology in use at the source, the remaining useful life of

---

<sup>5</sup> On January 10, 2017, EPA made a one-time adjustment to the due date for the second implementation period (2018 – 2028) by extending the deadline from July 31, 2018 to July 31, 2021 (82 FR 3078).

the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.<sup>6</sup> As an alternative to requiring source-specific BART controls, states also had the flexibility to adopt an emissions trading program or other alternative program as long as the alternative provided greater reasonable progress towards improving visibility than BART.

### **3.1.1.2 North Dakota's Initial Planning Period SIP Summary**

The State of North Dakota submitted its regional haze SIP addressing the requirements of 40 CFR 51.308 to EPA for review on March 3, 2010 (the "Regional Haze SIP").<sup>7</sup> The Regional Haze SIP was prepared by the North Dakota Department of Health, Air Quality Division (NDDH). The SIP included BART determinations for seven steam EGU's identified as being subject to the BART requirements of 40 CFR 51.208(e) and a reasonable progress evaluation for six additional non-BART sources identified as having the potential to affect visibility in a Class I area.

Basin Electric's Leland Olds Station (LOS) Units 1 & 2 were evaluated by NDDH as subject-to-BART sources.<sup>8</sup> Based on its evaluation of available control technologies, NDDH concluded that BART for both LOS units included new wet flue gas desulfurization (WFGD) for SO<sub>2</sub> control and separated overfire air (SOFA) with selective non-catalytic reduction (SNCR) for NO<sub>x</sub> control. NDDH determined that selective catalytic reduction (SCR), a higher performing NO<sub>x</sub> control option, was not an available, and thus not a technically feasible, NO<sub>x</sub> control option.<sup>9</sup>

Basin Electric's AVS Units 1 & 2 were evaluated by NDDH under the further reasonable progress requirements. Based on an evaluation of the four reasonable progress statutory factors (i.e., costs of compliance, time necessary

---

<sup>6</sup> CAA Section 169A(g)(2).

<sup>7</sup> North Dakota State Implementation Plan for Regional Haze – 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, February 24, 2010. In addition to the initial SIP submittal, the State submitted a SIP Supplement No. 1 on July 27, 2010, and a SIP Amendment No. 1 on July 28, 2011 (collectively the "Regional Haze SIP").

<sup>8</sup> In addition to LOS Units 1 & 2, NDDH evaluated Great River Energy's Coal Creek Station Units 1 & 2; Great River Energy's Stanton Station Unit 1; and Minnkota Power Cooperative's Milton R. Young Station Units 1 & 2 as subject-to-BART sources.

<sup>9</sup> Regional Haze SIP, pg. 73. The State's evaluation of SCR for North Dakota lignite was included as Appendix B.5 to the Regional Haze SIP (Best Available Retrofit Technology – Selective Catalytic Reduction Technical Feasibility Analysis for North Dakota Lignite, July 2009). NDDH eliminated SCR from consideration as BART based on a finding that SCR was not technically feasible to control emissions from North Dakota lignite coal. In particular, NDDH noted that no SCR has ever been employed on an electric generating unit (EGU) burning North Dakota lignite, that North Dakota lignite has unique properties that have the potential to quickly degrade the SCR catalyst, and that no catalyst vendor would provide a guarantee of catalyst life without first conducting slipstream or pilot testing.

for compliance, energy and non-air quality environmental impacts of compliance, and the remaining useful life of the units) plus an evaluation of incremental visibility improvement, NDDH concluded that requiring additional controls (beyond those required for the BART-eligible sources) would not substantially improve visibility in the Class I areas, and that for all reasonable progress sources evaluated individually and cumulatively, control technology costs (evaluated on a dollar per deciview improvement (\$/dv) basis) was excessive. Therefore, the initial Regional Haze SIP did not include additional control for AVS Units 1 & 2.<sup>10</sup>

On September 21, 2011, EPA published a Proposed Rule proposing to partially approve and partially disapprove specific aspects the Regional Haze SIP.<sup>11</sup> Among other things, EPA proposed to disapprove the State's determination of BART for LOS Unit 2 as well as the reasonable progress determination for AVS Units 1 & 2. EPA proposed to approve the remaining aspects of North Dakota's Regional Haze SIP, including that State's BART determination for SO<sub>2</sub> control at LOS (i.e., new WFGD) and the NO<sub>x</sub> BART determination for LOS Unit 1 (i.e., SOFA+SNCR).<sup>12</sup> Along with the proposed partial disapproval of North Dakota's SIP, EPA proposed the promulgation of a Federal Implementation Plan (FIP). The proposed FIP included, among other items: (1) a NO<sub>x</sub> BART determination and emission limits for LOS Unit 2; and (2) a reasonable progress determination and NO<sub>x</sub> emission limits for AVS Units 1 & 2. EPA proposed advanced SOFA (ASOFA) plus SCR and an emission rate of 0.07 lb/MMBtu (30-day rolling average) as BART for NO<sub>x</sub> control on LOS Unit 2. EPA also proposed low-NO<sub>x</sub> burners (LNB) plus SOFA and an emission limit of 0.17 lb/MMBtu (30-day rolling average) as representing reasonable progress NO<sub>x</sub> control on AVS Units 1 & 2.<sup>13</sup>

---

<sup>10</sup> *Id.* at pg. 188.

<sup>11</sup> 76 Fed. Reg. 58570, September 21, 2011 (the "Proposed FIP"). In addition to the proposed disapproval of the State's BART determination for Leland Olds Station Unit 2, EPA proposed disapproving the BART determinations for the Coal Creek Station and Milton R. Young Station (MRYS) Units 1 & 2.

<sup>12</sup> *Id.* at pg. 58619. Note that for LOS Unit 1 EPA stated that it did not agree with the State's cost analysis for SCR, but nonetheless found the elimination of SCR for LOS Unit 1 to be acceptable because LOS Unit 1 is relatively small (216 MW) compared to LOS Unit 2 (440 MW) and MRYS Units 1 & 2, and LOS Unit 1 had lower baseline NO<sub>x</sub> emission. (76 FR 58596, Table 22).

<sup>13</sup> *Id.* at pg. 58632. EPA eliminated higher performing NO<sub>x</sub> control options for AVS Units 1 & 2, including LNB + SNCR; SCR; and LNB + SCR, because their cost effectiveness values were significantly higher and/or the emission reductions were not that much higher than LNB. Considering the statutory factors, EPA found that it was not reasonable to insist on these higher control levels in the first; however, EPA noted that expected North Dakota to consider such controls in the next planning period.

Following the public notice and comment period EPA issued its Final Rule on April 6, 2012.<sup>14</sup> The Final Rule differed from the Proposed Rule in that EPA reversed its position regarding the technical feasibility of SCR on LOS Unit 2 and decided to approve the State's BART determination for NO<sub>x</sub> control on LOS Unit 2.<sup>15</sup> Conversely, EPA finalized its determination that LNB+SOFA was required by reasonable progress for AVS Units 1 & 2.

EPA's decision to accept the BART determinations for LOS Unit 2 (and Milton R. Young Station (MRYS) Units 1 & 2) was based primarily on the decision in United States v. Minnkota Power Cooperative, Inc.<sup>16</sup> which concluded that the State's best available control technology (BACT) analysis for NO<sub>x</sub> control on MRYS Units 1 & 2 was not unreasonable, a conclusion that was contrary to EPA's position at the time of the Proposed FIP.<sup>17</sup> In explaining its decision to reverse its position that SCR was a technically feasible NO<sub>x</sub> control option for LOS Unit 2, EPA noted that the technical feasibility determination under the BACT and BART analyses was substantially the same, and that the BART Guidelines permit a state to rely upon a BACT determination for purposes of selecting BART unless new technologies have become available or best control levels for recent retrofits have become more stringent.<sup>18</sup> Noting that the District Court upheld North Dakota's BACT determination for MRYS Units 1 & 2, EPA concluded that it would be inappropriate to proceed with its proposed disapproval of SNCR as BART, and approved the State's determination that ASOFA+SNCR and an emission rate of 0.35 lb/MMBtu (30-day rolling average) was BART for NO<sub>x</sub> control on LOS Unit 2.

With respect to NO<sub>x</sub> control on AVS Units 1 & 2, EPA finalized its proposed determination that LNB+SOFA and a NO<sub>x</sub> emission rate of 0.17 lb/MMBtu (30-day rolling average) was required for reasonable progress. North Dakota challenged EPA's disapproval of its reasonable progress determination for AVS Units 1 & 2, and EPA's subsequent promulgation of the FIP. The District Court found that EPA's determination on this matter was entitled to judicial

---

<sup>14</sup> 77 Fed. Reg. 20894.

<sup>15</sup> *Id.* at pg. 20897-98. EPA also reversed its position and decided to approve the State's BART determination for NO<sub>x</sub> control on MRYS Units 1 & 2.

<sup>16</sup> United States v. Minnkota Power Cooperative, Inc., 831 F. Supp. 2d 1109, 1127-30 (D.N.D. 2011).

<sup>17</sup> Contemporaneous with the Regional Haze SIP/FIP process, NDDH was also determining BACT for MRYS Units 1 & 2 pursuant to a Consent Decree entered into between the owner of the station (Minnkota), the State, and EPA under the CAA's Prevention of Significant Deterioration program. In its BACT analysis, NDDH concluded that SCR was technically infeasible on a lignite-fired cyclone boiler, and selected SNCR as BACT. EPA challenged the State's BACT determination in district court, contending that SCR was a technically feasible emission control option and should have been selected as BACT. On December 21, 2011, the District Court issued its decision on EPA's challenge of the State's BACT determination, finding that the State's conclusion that SCR was not technically feasible was not unreasonable. See, *U.S. v. Minnkota*, 831 F. Supp. 2d at 1127-30.

<sup>18</sup> 77 Fed. Reg. 20897.

deference, and could not conclude that EPA acted in a manner that was arbitrary or capricious; therefore, the State's petition for review was denied and EPA's reasonable progress determination for AVS Units 1 & 2 was upheld.

Emission controls required by the Regional Haze SIP for the Basin Electric's LOS and AVS stations are summarized in Table 3-1.

**Table 3-1. Initial Planning Period SIP Summary**

Source & Unit	Pollutant	Control Device / Emission Limit
LOS Unit 1 (BART)	NO <sub>x</sub>	Basic SOFA + SNCR with an emission limit of 0.19 lb/MMBtu (30-day rolling average)
	SO <sub>2</sub>	New wet FGD operating at 95% efficiency or below an emission limit of 0.15 lb/MMBtu (30-day rolling average)
LOS Unit 2 (BART)	NO <sub>x</sub>	Advanced SOFA + SNCR with an emission limit of 0.35 lb/MMBtu (30-day rolling average)
	SO <sub>2</sub>	New wet FGD operating at 95% efficiency or below an emission limit of 0.15 lb/MMBtu (30-day rolling average)
AVS Unit 1 (reasonable progress)	NO <sub>x</sub>	LNB+SOFA with an emission limit of 0.17 lb/MMBtu (30-day rolling average)
	SO <sub>2</sub>	No additional control beyond the existing dry FGD / baghouse
AVS Unit 2 (reasonable progress)	NO <sub>x</sub>	LNB+SOFA with an emission limit of 0.17 lb/MMBtu (30-day rolling average)
	SO <sub>2</sub>	No additional control beyond the existing dry FGD / baghouse

### 3.1.1.3 Reasonable Progress Control Requirements for AVS Units 1 and 2 during First Planning Period

AVS Units 1 & 2 were not subject to the Regional Haze BART requirements of 40 CFR 51.208(e). Nevertheless, during the initial planning period NDDH evaluated emissions reductions from AVS as a reasonable progress source. Based on an evaluation of control technology costs and the resulting incremental improvement in visibility, NDDH found that no additional NO<sub>x</sub> controls were warranted during the initial planning period. As discussed in Section 3.1.1.2, EPA disapproved the State's reasonable progress determination for AVS Units 1 & 2, and promulgated a FIP that included a reasonable progress determination that LNB+SOFA and a NO<sub>x</sub> emission limit of 0.17 lb/MMBtu (30-day rolling average) was required for NO<sub>x</sub> control for AVS Units 1 and 2. The FIP required Basin Electric to install the NO<sub>x</sub> control technologies on AVS Units 1 & 2 by July 31, 2018. In accordance with the FIP requirements, Basin Electric installed a low-NO<sub>x</sub> concentric firing system (LNCFS) on AVS Units 1 and 2 in 2014 and 2016, respectively, coinciding with the scheduled tri-annual maintenance outages.

### **3.1.2 Round II Regional Haze SIP Determination**

The Round II Determination must be submitted to EPA for review by July 31, 2021. Among other requirements, the Round II Determination is required to include an assessment of the state's RPGs and LTS. To support states in their efforts to develop the Round II Determination, in July 2016 EPA released a draft guidance document titled *"Draft Guidance on Progress Tracking Metrics, Long-term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period"* ("Draft EPA Guidance").<sup>19</sup> The Draft EPA Guidance document describes key steps states should implement when developing their RPGs and LTS for the Round II Determination. Key steps identified in the Draft EPA Guidance are listed in Table 3-2.

---

<sup>19</sup> See, EPA-457/P-16-001. On September 11, 2018, EPA released a *"Regional Haze Reform Roadmap"* announcing its plan to "release a series of implementation tools and guidance documents that will help focus states' efforts and reduce and streamline the time and resources needed to meet the statutory and regulatory requirements for reducing regional haze in National Parks, wildlife refuges, and wilderness areas." EPA stated that it plans to issue a new guidance document on Regional Haze SIP Development by Spring, 2019. Basin Electric reserves the right to update and modify this four-factor analysis, as needed, to be consistent with any new guidance issued by the agency.



**Table 3-2. Key Steps in Developing the Round II Determination**

1. *Ambient data analysis* – Quantify baseline, current and natural conditions and the uniform rate of progress that would achieve natural conditions by 2064 (40 CFR 51.308(f)(1))
2. *Screening of sources* – Identify the pollutants and emission sources for which a full reasonable progress analysis will be completed and explain why it is appropriate to limit the full analysis to only these sources (40 CFR 51.308(f)(2))
3. *Source and emission control measure analysis* – Identify potential emission control measures for sources selected in the screening step and develop data on the four statutory factors and visibility benefits if they will be considered (40 CFR 51.308(f)(2))
4. *Decisions on the content of the LTS* – Consider applicable factors and decide on new emission controls for incorporation into the LTS (40 CFR 51.308(f)(2))
5. *Regional scale modeling* – Model the emissions reductions that will result from implementation of the LTS and other enforceable measures that will reduce visibility impairment to set the RPGs for 2028 (40 CFR 51.308(f)(3))
6. *Progress, degradation and glidepath checks* – Demonstrate that there will be an improvement on the 20 percent most impaired days. Demonstrate that there is no degradation on the 20 percent clearest days. Compare the 2028 RPG for the 20 percent most impaired days to the 2028 point on the URP line (the glidepath) and, if required, provide additional justification for the reasonableness of the RPG. Revise the LTS if additional measures are identified as necessary to make reasonable progress. (40 CFR 51.308(f)(3))
7. *Additional requirements for SIPs* – Provide additional information necessary to ensure that other requirements of the Regional Haze rule are met.

The Draft EPA Guidance recommends that states evaluate all technically feasible emission control options for stationary sources and source categories identified as having the greatest potential to impact visibility at one or more Class I area. The Draft EPA Guidance recommends several options for states to consider when evaluating potential emission reductions, including work practices, replacement and retrofit controls, existing control upgrades, fuel switching, year-round operation of controls, and operating restrictions.<sup>20</sup>

Emission control evaluations must consider the four statutory factors identified in 40 CFR 51.308(f)(2)(i) (discussed in Section 3.2). In addition, the Draft EPA Guidance notes that control technology assessment recommendations presented in the BART Guidelines continue to be relevant as recommendations for how a state should evaluate and select emission control measures for stationary sources.<sup>21</sup> Recommendations in the BART

<sup>20</sup> See, Draft EPA Guidance, pgs. 85-86.

<sup>21</sup> Draft EPA Guidance, pg. 85. The BART Guidelines are published at 40 CFR Part 51 Appendix Y.

Guidelines that continue to be relevant to the Round II Determination's four factor analysis are listed in the Appendix of the Draft EPA Guidance, and include, in general, the recommended approach for evaluating the technical feasibility, effectiveness, costs, and cost-effectiveness of available emission control measures.<sup>22</sup>

### **3.2 DESCRIPTIONS OF THE FOUR STATUTORY FACTORS**

Under 40 CFR 51.308(f)(2)(i), states must consider four statutory factors when evaluating and determining emissions reduction measures from stationary sources, or groups of sources, that are necessary to make reasonable progress towards achieving natural visibility conditions. The four statutory factors are:

1. The costs of compliance;
2. The time necessary for compliance;
3. The energy and non-air quality environmental impacts of compliance; and
4. The remaining useful life of any potentially affected anthropogenic source of visibility impairment.

A brief description of each of the four statutory factors, and EPA's recommendations for evaluating each of the four factors (from the Draft EPA Guidance) is provided below.

#### **3.2.1 Costs of Compliance**

Cost estimates should be developed for each technically feasible control option. Costs include the total capital costs to engineer, design, procure, and install the control technology, and annual operating and maintenance (O&M) costs. O&M costs include both fixed and variable O&M. Fixed O&M includes costs that are independent of control system operation and would be incurred even if the control system were shut down. Fixed O&M includes categories such as operating and maintenance labor, administrative charges, property taxes, and insurance. Variable O&M includes the cost of consumables, including reagent (e.g., lime or limestone, ammonia, urea, etc.), by-product management, water consumption, and auxiliary power requirements associated with operating the control system. For existing facilities, O&M cost estimates should represent the control option's incremental increase over current O&M costs.

Capital costs include all costs required to engineer, design, procure, and install equipment needed for the control system. The Draft EPA Guideline recommends that states adhere to the accounting principles described in Chapter

---

<sup>22</sup> Draft EPA Guidance, Appendix D, pgs. 186-196.

2 Section 1 of EPA's Air Pollution Control Cost Manual (the "Control Cost Manual") when calculating control system costs for a four factor analysis.<sup>23</sup>

Section 2.3 of the Control Cost Manual (Section 1, Chapter 2) describes the cost categories generally used to calculate the total capital cost of a retrofit control technology. Cost categories include total capital investment (TCI), which is defined to "include all costs required to purchase equipment needed for the control systems (purchased equipment costs), the costs of labor and materials for installing that equipment (direct installation costs), costs for site preparation and buildings, and certain other costs (indirect installation costs). TCI also includes costs for land, working capital, and off-site facilities." Direct installation costs include costs for foundations and supports, erecting and handling the equipment, electrical work, piping, insulation, and painting. Indirect installation costs include costs such as engineering costs; construction and field expenses (i.e., cost for construction supervisory personnel, office personnel, rental of temporary offices, etc.); contractor fees (for construction and engineering firms involved in the project); start-up and performance test costs (to get the control system running and to verify that it meets performance guarantees); and contingencies.<sup>24</sup>

The total annual cost (TAC) of a control option includes the annualized capital recovery cost plus the total annual O&M costs. The Control Cost Manual recommends using an equivalent uniform annual cash flow method to annualize the total capital investment by multiplying the total capital investment by a capital recovery factor (CRF).<sup>25</sup> The product of the total capital investment and CRF gives a uniform end-of-year payment necessary to repay the initial capital investment in "n" years at an interest rate of "i". The CRF is calculated using the following equation:

$$CRF = \frac{i * (1 + i)^n}{(1 + i)^n - 1}$$

Where:

i = interest rate; and

n = economic life of the emission control system

The Draft EPA Guidance suggests that states may use generic cost estimates or estimating algorithms for estimating control system costs; however, source specific estimates prepared by knowledgeable engineering professionals

<sup>23</sup> EPA Air Pollution Control Cost Manual, Sixth Edition, EPA/452/B-02-001, January 2002.

<sup>24</sup> EPA Air Pollution Control Cost Manual, Sixth Edition, EPA/452/B-02-001, January 2002, pg. 2-5.

<sup>25</sup> Id., at pg 2-21.

provide more reliable information than generic cost estimates.<sup>26</sup> Source-specific cost estimate should be well documented for purposes of public comment and EPA review.<sup>27</sup>

The total annual cost of each control option (\$/yr) is divided by the total annual emissions reduction (tpy) to determine the control option's average cost-effectiveness on a \$/ton basis. Emissions reductions are calculated based on the difference between baseline annual emissions and post-control annual emissions. The Draft EPA Guidance generally recommends calculating baseline emissions based on projected 2028 emissions assuming source compliance with emission limits that have been adopted and are enforceable. As an alternative, baseline emissions may be based on representative past actual emissions, assuming there is no evident basis for using a different emissions rate.

### **3.2.2 Time Necessary for Compliance**

For stationary sources, the provisions of the BART Guidelines regarding the time necessary for compliance are relevant to the Round II Determination's analyses. EPA recommends that prior experiences with the planning and installation of new emission controls is the best guide to how much time a particular source will reasonably need for compliance. However, source-specific factors should be considered when evaluating the time necessary to engineer, procure, and install an available and technically feasible control option. Source-specific factors that affect the time necessary to install new emission controls should be identified and documented in the four factor analysis.

### **3.2.3 Energy and Non-Air Quality Environmental Impacts**

For stationary sources, the provisions of the BART Guidelines regarding energy impacts are relevant to the Round II Determination's analyses. Energy impacts of an emission control measure are a matter of engineering design and control system operation; thus, EPA recommends that prior experience at similar sources will be informative. Energy impacts may be considered in terms of kilowatt-hours or fuels used to operate the control system. The energy impact analysis should focus on direct energy consumption at the source rather than indirect energy inputs needed to produce raw materials for the construction and operation of control equipment.

---

<sup>26</sup> Draft EPA Guidance, pg. 91.

<sup>27</sup> *Id.*

For stationary sources, the provisions of the BART Guidelines regarding non-air quality environmental impacts are relevant to the Round II Determination's analyses. Non-air quality impacts include solid or hazardous waste generation, increased water consumption, wastewater discharge, land use impacts, and impacts to threatened and endangered species or their natural habitat. Characterizing the non-air quality environmental impacts should be done on a source-specific basis. Other guidance intended for use in assessments under the National Environmental Policy Act may be relevant to this evaluation.

Even though states are not required to consider GHG emission impacts, the Draft EPA Guidance encourages states to consider GHG impacts when developing their LTS.<sup>28</sup> As an example, some measures that would reduce emissions that contribute to visibility impairment will also reduce GHG emissions, such as measures that reduce the use of energy produced from combusting fossil fuels with relatively high GHG emissions. Conversely, control measures that require significant energy to capture visibility impairing emissions could result in increased GHG emission. Where a measure necessary to make reasonable progress towards natural visibility conditions would increase GHG emissions, Draft EPA Guidance encourages states to work to harmonize visibility and climate change objectives.<sup>29</sup>

### **3.2.4 Remaining Useful Life**

For stationary sources, the provisions of the BART Guidelines regarding remaining useful life are relevant to the Round II Determination's analyses. In general, the remaining useful life of the source itself will be longer than the useful life of the emission control measure under consideration unless there is an enforceable requirement for the source to cease operation sooner. Thus, the useful life of the control measure will normally be used in the four factor analysis to calculate emission reductions, amortized costs, and cost-effectiveness. However, if there is an enforceable requirement for the source to cease operation by a date before the end of what would otherwise be the useful life of the control measure under consideration, then the enforceable shutdown date should be used to calculate remaining useful life and evaluate control technology cost-effectiveness.

---

<sup>28</sup> Draft EPA Guidance, pg. 92.

<sup>29</sup> *Id.*

### **3.2.5 Approach for Evaluating Control Measures**

S&L used a top-down approach to identify and evaluate the technical feasibility and effectiveness of potentially available SO<sub>2</sub> and NO<sub>x</sub> control measures. S&L followed Steps 1 thru 3 of the top-down approach described in the BART Guidelines to identify all available retrofit emission control measures, eliminate technically infeasible options, and evaluate the effectiveness of the technically feasible options.<sup>30</sup> A brief description of each step is provided below.

#### ***Step 1 - Identify All Available Control Options***

Available control options are those air pollution control technologies with a practical potential for application to the emission unit and the regulated pollutant under evaluation. Air pollution control technologies can include a wide variety of available methods, systems, and techniques for control of the affected pollutant, and include not only existing controls for the source category but also take into account technology transfer of controls that have been applied to similar source categories and gas streams. Technologies which have not been applied to (or permitted for) full scale operations need not be considered as available.<sup>31</sup>

In an effort to identify all potentially available emission control technologies, S&L searched a broad range of information sources including, but not necessarily limited to:

- EPA's RACT/BACT/LAER Clearinghouse (RBLC);
- EPA's New Source Review (NSR) and Clean Air Technology Center (CATC) Web sites;
- BART evaluations prepared during the initial Regional Haze planning period;
- Information from control technology vendors and engineering/environmental consultants;
- Federal and State NSR permits and BACT determinations for similar sources; and
- Technical journals, reports, newsletters and air pollution control seminars.

#### ***Step 2 - Eliminate Technically Infeasible Control Options***

In Step 2, S&L evaluated the technical feasibility of the control options identified in Step 1 with respect to source-specific and unit-specific factors. Control technologies are technically feasible if either: (1) they have been installed and operated successfully for the type of source under review under similar conditions; or (2) the technology could be applied to the source under review. In order for a control option to be technically feasible, it

<sup>30</sup> See, 40 CFR Part 51 Appendix Y, Section IV.D.

<sup>31</sup> *Id.*, at IV.D.1.



must be “available” and “applicable” to the source under consideration. A technology is considered “available” if the source owner may obtain it through commercial channels. An available technology is “applicable” if it can reasonably be installed and operated on the source type under consideration.<sup>32</sup>

Control technologies that are technically infeasible (i.e., not available or not applicable to the source under consideration) are eliminated for further evaluation. A demonstration of technical infeasibility must be based on physical, chemical and engineering principals, and must show that technical difficulties would preclude the successful use of the control option on the emission unit under consideration. The economics of an option are not considered in the determination of technical feasibility/infeasibility.

### ***Step 3 - Evaluate Technically Feasible Control Technologies for Effectiveness***

Step 3 involves evaluating the control effectiveness of all the technically feasible control alternatives identified in Step 2 for the pollutant and emissions unit under review. Control effectiveness should be expressed using a metric that ensures an “apples-to-apples” comparison of emissions performance levels among options, and is generally expressed as the rate that a pollutant is emitted after installation of the control measure. Control technology evaluations for existing sources should consider ways to improve the performance of existing control devices. Special circumstances pertinent to the specific source under review should be identified and taken into consideration when assessing the capability of the control alternative and determining control effectiveness.

For this evaluation, S&L assessed the technically feasible SO<sub>2</sub> and NO<sub>x</sub> control options for effectiveness on AVS Units 1 and 2. As discussed above, AVS Units 1 and 2 are PC tangential-fired boilers designed to fire North Dakota lignite. The units are equipped with SOFA, LNCFS and an Omnivise Combustion Optimizer for NO<sub>x</sub> control, DFGD and FF for SO<sub>2</sub> and PM control.

---

<sup>32</sup> A more detailed description of control technology “availability” and “applicability” is provided in 40 CFR Part 51 Appendix Y, Section IV.D.2.  
SL-014754\_AVIS\_Four-Factor Analysis\_Final.docx  
Project 13772-001

## 4. SO<sub>2</sub> CONTROL EVALUATION

### 4.1 BASELINE SO<sub>2</sub> EMISSIONS

The first step in developing the four factor analysis is to establish AVS Units 1 and 2 baseline SO<sub>2</sub> emissions. To establish representative baseline emissions, S&L evaluated AVS Units 1 and 2 operating data for the five year period January 1, 2013 to June 30, 2018 to identify periods of normal operation (i.e., periods of operation when the boiler was not limited by infrequent or extraordinary operating restrictions). Based on review of fuels consumed, heat input to the boiler, boiler heat rates, power generation, and capacity factors, as well as input from Basin Electric, it was determined that the operating periods of January 1, 2013 to June 30, 2018 were representative of normal boiler operation for SO<sub>2</sub> emissions. The representative baseline periods for the AVS Units are shown in Table 4-1.

**Table 4-1. Representative Baseline Periods for SO<sub>2</sub> Emissions**

Pollutant	Representative Baseline Periods	
	AVS Unit 1	AVS Unit 2
SO <sub>2</sub> Emissions	1/1/2013 to 6/30/2018	1/1/2013 to 6/30/2018

Baseline annual SO<sub>2</sub> emissions were determined based on data obtained from the Units 1 and 2 continuous emissions monitoring system (CEMS) that was reported to EPA's Clean Air Markets. The maximum 24-consecutive month annual average emission rate during the representative time period was used to establish baseline annual emissions (in terms of tons per year). Representative baseline emission factors (in terms of pounds per million British Thermal Units (lb/MMBtu)) were developed using baseline annual emissions and the respective annual heat inputs. Table 4-2 provides a summary of the AVS Units 1 and 2 SO<sub>2</sub> representative baseline emissions; additional details are included in Appendix B. Table 4-3 provides a summary of the AVS Units 1 and 2 SO<sub>2</sub> projected future maximum emissions based on the future projected coal sulfur content, boiler design heat input and 100% capacity factor.

NORTH DAKOTA ROUND II REGIONAL HAZE SIP  
 DETERMINATION'S FOUR-FACTOR ANALYSIS FOR ANTELOPE  
 VALLEY STATION UNITS 1 AND 2

**4-2**
**Table 4-2. Baseline Actual SO<sub>2</sub> Emissions**

AVS Unit	Baseline Controls	SO <sub>2</sub> Emission <sup>(Notes 1 and 2)</sup>			Capacity Factor During Baseline Period	Current SO <sub>2</sub> Control Percentage <sup>(Note 3)</sup>	Current Permit Limits (3-hr rolling average)
		lb/hr	lb/MMBtu	tons/yr			
Unit 1	DFGD/FF	1,656	0.37	6,921	86%	86-88	1.2 lb/MMBtu 3,845 lb/hr (plant total)
Unit 2	DFGD/FF	1,685	0.37	7,016	87%	86-88	1.2 lb/MMBtu 3,845 lb/hr (plant total)

Note 1. Unit 1 SO<sub>2</sub> emissions based on 24-month annual average for period September 2014 to August 2016.

Note 2. Unit 2 SO<sub>2</sub> emissions based on 24-month annual average for period July 2016 to June 2018.

Note 3. Control percentage calculated based on the range of baseline annual coal SO<sub>2</sub> content (2.72 – 3.15 lb/MMBtu) between 2013-2018.

**Table 4-3. Projected Future Maximum SO<sub>2</sub> Emissions**

AVS Unit	Baseline Controls	SO <sub>2</sub> Emission <sup>(Note 1)</sup>			Capacity Factor for Future Maximum Emissions	Assumed SO <sub>2</sub> Control Percentage <sup>(Note 2)</sup>	Current Permit Limits (3-hr rolling average)
		lb/hr	lb/MMBtu	tons/yr			
Unit 1	DFGD/FF	1,831	0.37	8,018	100%	89.1	1.2 lb/MMBtu 3,845 lb/hr (plant total)
Unit 2	DFGD/FF	1,847	0.37	8,089	100%	89.1	1.2 lb/MMBtu 3,845 lb/hr (plant total)

Note 1. Projected future maximum SO<sub>2</sub> emissions based on forecast future maximum coal SO<sub>2</sub> content of 3.39 lb/MMBtu, boiler design heat input of 4,930 MBtu/hr and assumes 100% capacity factor.

Note 2. Control percentage calculated based on the baseline SO<sub>2</sub> emission rate of 0.37 lb/MMBtu and the baseline average uncontrolled emission rate of 3.39 lb/MMBtu.

## 4.2 COAL SULFUR CONTENT

The generation of SO<sub>2</sub> is directly related to the sulfur content and heating value (HHV) of the fuel burned. AVS currently burns North Dakota Lignite fuel from the Freedom Mine. North Dakota lignite is characterized by a low heating value and relatively low sulfur content. Typical HHV and coal sulfur content provided by Basin Electric are listed in Table 4-4. The coal quality is based on actual annual fuel data provided by the facility between 2013 and 2018, which is the same time period as the baseline emission rates.

**Table 4-4. Baseline AVS Coal Quality (Annual)**

Parameter	Minimum	Average	Maximum
HHV (Btu/lb)	6556	6755	7169
As-Received Sulfur (%)	0.89	0.98	1.13
Uncontrolled SO <sub>2</sub> (lb/MMBtu)	2.72	2.90	3.15

As shown in Table 4-4, the deviation between the average coal sulfur content and the maximum coal sulfur content is 0.15%.

In addition, Basin Electric provided anticipated future annual average coal quality projections for the facility between 2019 and 2045. The future range in coal quality is provided in Table 4-5.

**Table 4-5. Future AVS Coal Quality (Annual)**

Parameter	Minimum	Average	Maximum
HHV (Btu/lb)	6,434	6,506	6,587
As-Received Sulfur (%)	0.72	0.84	0.94

The future projected coal quality listed in Table 4-5 are based on an annual average values and do not take into account potential deviations in the coal quality that could be seen on a short term basis. As such, S&L and Basin Electric applied the actual coal sulfur content deviation (0.15%) from the baseline coal quality, stated above, to the maximum annual sulfur coal in Table 4-5. The results are shown in Table 4-6.

**Table 4-6. Design Basis for Future Projected AVS Coal Quality (Annual)**

Parameter	Value
HHV (Btu/lb)	6,434
As-Received Sulfur (%)	1.09
Uncontrolled SO <sub>2</sub> (lb/MMBtu)	3.39
Uncontrolled SO <sub>2</sub> per Unit(lb/hr) <sup>(Note 1)</sup>	16,704
Uncontrolled SO <sub>2</sub> per Unit (ton/yr) <sup>(Note 1)</sup>	73,164

Note 1. Uncontrolled SO<sub>2</sub> emissions calculated at the design heat input (4,930 MBtu/hr) of each Unit.

Based on the evaluation above, S&L and Basin Electric have concluded that using a 3.39 lb SO<sub>2</sub>/MMBtu as the design basis for evaluating the SO<sub>2</sub> control technologies presented in this report is reasonable.

## 4.3 SO<sub>2</sub> EMISSIONS CONTROLS

### 4.3.1 Identify Available SO<sub>2</sub> Control Options

Based on a review of available SO<sub>2</sub> control technologies, as well as operational practices and equipment upgrades implemented on existing control systems, potentially available options to control SO<sub>2</sub> emissions from AVS Units 1 and 2 are listed in Table 4-7.

**Table 4-7. Available SO<sub>2</sub> Control Options**

SO <sub>2</sub> Control Technologies
Fuel Switching
Existing DFGD Operational Improvements
Existing DFGD Upgrades
Existing DFGD + Dry DSI (DSI)
Retrofit New Dry FGD
Retrofit New Wet FGD

### 4.3.2 Technical Feasibility of Available SO<sub>2</sub> Control Options

Potentially available SO<sub>2</sub> control options identified in Table 4-7 are those control technologies and operational improvements with a practical potential for application to AVS Units 1 and 2. The technologies were evaluated for

technical feasibility (i.e. availability and applicability to AVS Units 1 and 2) based on a review of physical, chemical, and engineering principals, and an assessment of commercial availability. Options determined to be technically infeasible, or options that have no practical application to AVS, were eliminated from further review. S&L evaluated the effectiveness of the control options determined to be technically feasible, and established an emissions performance level (i.e., control emissions rate) for each.

#### **4.3.2.1 Fuel Switching**

One potential strategy for reducing SO<sub>2</sub> emissions is to reduce the sulfur content of the coal. Limiting the amount of sulfur in the coal directly limits the amount released during the combustion process, and would reduce SO<sub>2</sub> loading to the dry scrubber.

AVS is a mine mouth generation facility. AVS was designed and developed to burn North Dakota lignite coal received from the adjacent Freedom Mine for the purpose of generating electricity. Previous regulatory and court decisions have concluded that requiring a mine mouth facility to evaluate low sulfur coal would require the facility to redefine its fundamental purpose and design; therefore, fuel switching can be rejected as an available control option.<sup>33</sup> Because the use of North Dakota lignite from the adjacent Freedom Mine is an inherent aspect of AVS operation, fuel switching will not be evaluated.

#### **4.3.2.2 Existing FGD Operational Improvements and Equipment Upgrades**

Operational and other design changes/upgrades to the existing dry scrubber may provide an opportunity for additional SO<sub>2</sub> removal and allow the units to achieve lower controlled SO<sub>2</sub> emissions. S&L, working with Basin Electric personnel, identified a number of potentially feasible operational changes that may be available to increase SO<sub>2</sub> removal efficiency with the existing equipment. Potentially available operational and design changes to the existing control system are summarized in Table 4-8. A detailed discussion of each of these options is provided in the following sections.

---

<sup>33</sup> In re: Prairie State Generating Company, PSD Appeal No. 05-05, Slip. Op. at 36 (2006)  
SL-014754\_AVS\_Four-Factor Analysis\_Final.docx  
Project 13772-001



**Table 4-8. FGD Operational Improvements and Equipment Upgrades**

Existing FGD Operational Improvements
Station Work Practices
Lime Quality
Ca:S Stoichiometric Ratio
Lower Approach to Saturation Temperature
Existing FGD Design Changes and Equipment Upgrades
Atomizer Replacement
Slaker Replacement
Adding an Absorber Module
Replacing Existing Absorbers with New Absorber Modules

#### Station Work Practices

AVS Units 1 and 2 have a 3-hour SO<sub>2</sub> plantwide applicability limit (PAL) of 3,845 lb/hr in their Title V Air Permit that allows the station to adjust operation of each unit's FGD system as long as they achieve the overall plantwide limit. Historically, when one unit would be in extended major outage the station would adjust operation (i.e., decrease SO<sub>2</sub> removal) on the other Unit to be in compliance with the PAL. AVS schedules major maintenance outages on a tri-annual(three-year) basis. As such, the opportunity for additional reductions is available one out of every 3 years on each unit. S&L reviewed the operating practices of the two units over the period June 2015–June 2018 to determine the increase in SO<sub>2</sub> emissions for the unit that was not in outage.

Table 4-9 and Table 4-10 below show the increase in SO<sub>2</sub> emissions for both Units 1 and 2.

**Table 4-9. Increased SO<sub>2</sub> Emissions on AVS Unit 1 (June 2015-June 2018)**

Parameter	AVS Unit 1	AVS Unit 2
Average annual hours in outage on Unit 2	--	981
Average SO <sub>2</sub> emissions on Unit 1 during Unit 2 outage (lb/hr)	2,394	--
Average SO <sub>2</sub> emissions on Unit 1 during normal operation (lb/hr)	1,432	--
Average excess SO <sub>2</sub> emissions on Unit 1 during Unit 2 outage (lb/hr)	962	--
<b>Average excess SO<sub>2</sub> emissions on Unit 1 during Unit 2 outage (ton/yr)</b>	<b>472</b>	<b>--</b>

**Table 4-10. Increased SO<sub>2</sub> Emissions on AVS Unit 2 (June 2015-June 2018)**

Parameter	AVS Unit 1	AVS Unit 2
Average annual hours in outage on Unit 1	769	--
Average SO <sub>2</sub> emissions on Unit 2 during Unit 1 outage (lb/hr)	--	2,573
Average SO <sub>2</sub> emissions on Unit 2 during normal operation (lb/hr)	--	1,542
Average excess SO <sub>2</sub> emissions on Unit 2 during Unit 1 outage (lb/hr)	--	1,031
<b>Average excess SO<sub>2</sub> emissions on Unit 2 during Unit 1 outage (ton/yr)</b>	<b>--</b>	<b>396</b>

As shown in the tables above, the excess emission on Units 1 and 2 were 472 tons and 396 tons, respectively on an annual basis. Using the annual baseline SO<sub>2</sub> emissions and annual average heat input, provided in Section 4, eliminating these emissions would reduce the outlet SO<sub>2</sub> emission rate from 0.37 lb/MMBtu to a controlled emission rate of 0.35 lb/MMBtu on each Unit. However, it should be noted that under the current outage schedule, the emission reductions shown above would only be achieved every 3<sup>rd</sup> year for a single unit since outages occur on a tri-annual basis. Based on this analysis, a change to the current station work practice is considered a technically feasible SO<sub>2</sub> control option for AVS Units 1 and 2.

### Lime Quality

The quantity of lime (CaO) available in a dry scrubbing system compared to the amount of SO<sub>2</sub> entering the system is called the stoichiometric ratio (generally referenced as the Ca:S stoichiometric ratio). Reagent quality directly affects the Ca:S stoichiometric ratio in DFGD control systems. Using a high quality lime increases the availability of hydrated lime to support process chemistry, and reduces the lime slurry injection rate needed for SO<sub>2</sub> removal.

Lime quality is measured both by the CaO content and reactivity of the lime product. In a dry scrubber system, CaO is combined with water in a slaker to form hydrated lime or calcium hydroxide (Ca(OH)<sub>2</sub>), which provides the calcium that is needed to react with SO<sub>2</sub> in the flue gas. With a higher quality lime, more calcium hydroxide is available to react with SO<sub>2</sub>. Lime products with a CaO content of 90% or greater are generally considered high quality lime. Reactivity of the lime is measured by the temperature rise when the lime is slaked (i.e. water addition). In general, porous lime products have higher reactivity which is demonstrated by achieving a temperature rise 40°C within three minutes of adding water.

Based on a review of lime analyses and a review of operating data from the existing lime slaking system, AVS currently procures a high quality lime for use in the dry scrubbers. The typical CaO content of the lime used at AVS is 90% or greater, and the slaking process achieves a 40°C temperature rise within three minutes of adding water. For these reasons, changing the lime quality is not considered a technically feasible operational change available to control SO<sub>2</sub> emissions from AVS, and will not be evaluated further.

### Ca:S Stoichiometric Ratio

Other operational changes that may be available to increase the Ca:S stoichiometry in the existing dry scrubber include: (1) increasing the byproduct recycle ash rate; and/or (2) increasing the quantity of fresh hydrated lime introduced to the system. Due to the cost savings that may be realized with the first option, some facilities with existing DFGD controls have opted to increase solids recycle rates to as high as 40-50% solids to achieve an incremental increase in SO<sub>2</sub> reduction, if capacity was available in the byproducts handling system. If capacity is not available, increasing fresh lime addition to the system may also be a viable option to increase the Ca:S stoichiometric ratio.

Within each AVS DFGD, there are two parallel slurry preparation trains that prepare and supply the lime slurry feed to each of the five scrubber modules. The slurry preparation trains consist of recycle ash silos, ash mix tanks, slurry feed tanks and associated slurry and atomizer feed pumps, piping and controls and instrumentation. Solids

from a dry scrubber consist of fly ash, reaction byproduct, and residual unreacted hydrated lime. On AVS Units 1 and 2, solids collected in the fabric filter hoppers are conveyed to either a dry storage silo for disposal or to a recycle ash silo where it is used as reactant slurry. The recycle system is designed to utilize a portion of the unreacted lime in the solids rather than disposing of all of the solids. Recycle solids are combined with the fresh lime addition to provide the makeup lime needed for SO<sub>2</sub> reduction. Increasing the recycle rate can increase the amount of available Ca added to the system (i.e., stoichiometric ratio) without increasing the quantity of fresh lime added to the system.

The DFGD systems on the AVS Units currently operate the recycle system at approximately 45% solids. The AVS recycle system is operating within the original design conditions and system capacity which is in line with industry practice. The plant has tested higher recycle rates, but at these higher rates plant personnel reported significant problems with recycle slurry pumping and pluggage of the recycle tanks and negative impacts to the FF due to the increase in ash loading. Based on the adverse operational impacts observed during these tests, increasing the recycle percent solids is not considered a technically feasible SO<sub>2</sub> control option for the AVS Units, and will not be evaluated further.

As an alternative to increasing the recycle rate, the Ca:S stoichiometric ratio in the system may be increased by increasing the quantity of fresh lime introduced to the system. Basin Electric contracted with B&W, the original equipment manufacturer (OEM) of the AVS DFGD system, to determine if additional SO<sub>2</sub> removal could be achieved by increasing the amount of fresh lime added to the system while maintaining approximate 40-45% solids slurry to the atomizer. B&W ran their proprietary software which estimates the AVS DFGD performance. The results of the model indicated that AVS could potentially achieve 93% SO<sub>2</sub> removal of normal DFGD operation at 1% sulfur coal by increasing the fresh lime to the DFGD. Due to the uncertainties with the model, additional analysis is required to fully understand plant operational and performance impacts associated with an increased Ca:S stoichiometric ratio. There would be percent solids capacity limitation with the existing recycle slurry system and risks of increased scaling and build-up within tanks and piping with the increased lime solids. As such, this system will require modifications including new mix tanks, pumps and piping to minimize slurry preparation train outages. When a slurry preparation train fails, it requires the standby slurry preparation train to come on-line that could result in an increase in short term emissions until the slurry preparation train is placed into service. The 93% removal represents an average percent control that each AVS unit would be expected to achieve on an on-going long-term basis under normal operating conditions with the equipment upgrades installed. The emission rate should

not be construed to represent proposed permit limits. Corresponding permit limits must be evaluated on a control system-specific basis.

### Approach to Saturation Temperature

The reaction of  $\text{SO}_2$  with  $\text{Ca}(\text{OH})_2$  in a dry scrubber is driven by the absorber temperature. Water surrounding the lime slurry droplet allows  $\text{SO}_2$  to dissolve into the liquid and facilitates the reaction between lime and  $\text{SO}_2$ . The temperature differential between the inlet and the outlet of the DFGD is used as a driving force for  $\text{SO}_2$  removal; however, outlet temperatures must be maintained above the saturation temperature to ensure byproducts exiting the absorber module are dry and remain dry as they pass through the FF, ductwork and stack. Residence time within the absorber vessel, drying time, and exit temperature are all important design parameters for a dry scrubbing system.

Inlet temperature to the dry scrubbing module is relatively constant; however there can be short term temperature swings of  $\pm 10^\circ\text{F}$  that occur due to coal quality, boiler sootblowing, convection pass and air heater cleanliness; therefore, temperature differential across the module is a function of the outlet temperature. As a general rule-of-thumb, the closer the outlet temperature is to the adiabatic saturation temperature, the higher the  $\text{SO}_2$  removal efficiency.

Operating a dry scrubbing system at outlet temperatures significantly above the adiabatic saturation temperature accelerates water evaporation from the reactant slurry, limits  $\text{SO}_2$  absorption into the droplet, and limits the reaction between the lime and  $\text{SO}_2$ . Reducing the temperature in the absorber closer to the saturation point can provide additional  $\text{SO}_2$  removal. On the other hand, the absorber module may not have sufficient residence time to dry all slurry droplets if the system is operated too close to adiabatic saturation, which would result in deposits in the absorber module, corrosion, and severe operational problems. Therefore, maintaining an absorber outlet temperature close to the point of saturation, while staying above it, is vital for optimal reaction kinetics.

The AVS dry scrubbers currently operate with at an outlet temperature near  $165\text{--}170^\circ\text{F}$ , which is approximately  $30^\circ\text{F}$  above the adiabatic saturation temperature and within the OEM design. This is in line with new spray dryer absorbers which are typically designed to operate at  $30^\circ\text{F}$  approach to saturation. Therefore, the current approach to saturation temperature achieved on the AVS scrubbers are aligned with standard industry practices. Lowering the outlet temperature further has significant potential to cause detrimental corrosion of the vessel or downstream

equipment and other significant operating issues. Therefore, further reducing the absorber module outlet temperature is not considered a technically feasible SO<sub>2</sub> control option for AVS, and will not be evaluated further.

### Atomizer Replacement

Spray droplet size is an important parameter in the design and operation of a dry scrubber, and can improve lime utilization and SO<sub>2</sub> removal. Finer spray will increase the surface area of the slurry droplets exposed to the flue gas. Greater surface area increases the potential for SO<sub>2</sub> to absorb into the moisture of the slurry droplets. Droplet fineness also plays a role in particle drying time. Larger droplets can have a negative effect on the slurry drying time which can lead to moisture carryover to downstream equipment causing buildup and corrosion.

AVS Units 1 and 2 dry scrubbers were provided by B&W's predecessor Joy Niro, and were designed with five absorber modules each with a single rotary atomizer with a 12 nozzle wheel to achieve a fine slurry spray. The design of the atomizer and speed at which the wheel rotates are controlling factors for the size and form of the droplets in the spray. Each atomizer wheel in AVS Unit 1 absorber module is powered by a 700 hp motor and Unit 2 absorber modules are designed with a 800 hp motor. In addition, the design of the atomizers is highly dependent on the spray pattern needed to mix with the hot flue gas in the scrubber module for optimum absorption of SO<sub>2</sub> while also preventing wetting of the absorber walls. Based on S&L's analysis and input from the station, there has not been any significant moisture carry-over into the baghouse or wetting of the absorber walls that would indicate that the atomizers are not achieving an optimum droplet size or spray pattern. In addition, both AVS dry scrubbers are operating at a consistent 30°F approach to saturation temperature, in-line with industry practice, concluding that the droplets are drying efficiently. Therefore, replacing the atomizer motor or atomizer wheel is not considered a technically feasible SO<sub>2</sub> control option for the AVS scrubbers, and will not be evaluated further.

### Slaker Replacement

Lime slurry, the reagent used for SO<sub>2</sub> removal in a dry scrubber, is produced by mixing pebble lime with heated water in a slaker; this process is referred to as "slaking". The slaker is operated at an optimum water-to-lime ratio (typically between 3:1 and 6:1) to produce lime slurry by metering the amount of water and the amount of lime added to the slaker. Slakers are typically designed to produce a lime slurry between 15-20% solids. The lime slurry is added to the recycle slurry in a mix tank and then sent to the atomizer where it is sprayed into the scrubber for SO<sub>2</sub> removal.



In 2011, additional slaking capacity was installed at a cost of approximately \$15 million, in the form of two Vert-Mill lime slakers, lime storage and conveying systems in preparation of higher sulfur fuel deliveries. The slakers operate at a 5:1 water to lime ratio and approximately 18% solids which is in line with the design as well as industry practice. Therefore, replacing the already upgraded slaking systems is not considered a technically feasible SO<sub>2</sub> control option for the AVS scrubbers, and will not be evaluated further.

### *Adding an Absorber Module*

Another option for extending the residence time within the reactor modules and increasing Ca:S contact would be to add an additional reactor module to each AVS unit. The existing system is designed with five absorber modules per unit. The system was originally designed to operate with four modules carrying full load gas flow with a standby spare available for routine maintenance. Subsequently, operation was changed so that all five modules are operated for full load gas flow. This change increased flue gas residence time in the reaction vessels from 5.0 seconds (at full load) to 6.5 seconds. More recent dry scrubbing systems have been designed with reaction vessel residence times of 10 seconds or more.

One potential option available to AVS to further increase reaction vessel residence time would be to add an additional absorber module to the existing dry scrubbing system on each unit. The number of absorber modules used in a DFGD system is dependent on multiple operating parameters, including the flue gas flow rate and SO<sub>2</sub> concentrations. DFGD modules are typically specified with minimum and maximum flue gas flow rates. If the absorber modules are oversized, flue gas velocities through the module can be too low, causing solids dropout inside the vessel. If the absorber modules are undersized, flue gas velocities can be too high, causing residence time to fall below recommended levels.

Dry scrubbing units that are operating at flue gas volumes significantly above the design flow rate can benefit from adding an extra module to the system. The module would be placed in parallel with the existing modules to achieve a similar pressure drop through each vessel and to ensure equal flue gas distribution to the modules. In 2006, Basin Electric hired B&W's Allen-Sherman Hoff to develop a computer model of the existing five scrubber modules to determine the impact of adding a 6<sup>th</sup> absorber module to each of the AVS units in response to potentially higher-sulfur fuels in the future. The modeling showed the five existing absorbers have adequate residence time for the expected higher sulfur in the coal and operate at an approach to saturation of 30°F which is consistent with industry practice. Installation of a sixth absorber would not provide any significant improvement towards removing additional sulfur. The primary benefit of a sixth SDA chamber would be to provide redundancy. While this would

be beneficial towards maintaining unit loads without having to restrict generating capacity for chamber maintenance items, inspections and chamber cleaning, it would not provide any additional improvement to reducing SO<sub>2</sub>. Therefore, incorporating an additional absorber module into the existing system is not a technically feasible SO<sub>2</sub> control strategy for AVS, and will not be evaluated further.

#### *Replacing Existing Absorbers with New Absorber Modules*

Replacing the existing modules with new absorber modules would require significant engineering and facility modifications. Based on a preliminary review of the control system layout, the only practical location for this option would be to construct the new vessels in the same location as the existing modules. Locating the DFGD modules adjacent to the existing dry scrubber would require flue gas to be redirected from the air heater outlet to the new absorbers and back to the existing fabric filter, which would likely result in significant solids dropout and other operational issues. Therefore, locating the new absorber modules adjacent to the existing absorber modules is not considered a technically feasible option.

DFGD control systems use a hydrated lime slurry to remove SO<sub>2</sub> from the combustion gases. Various operating parameters will affect the efficiency of the DFGD process including the residence time and how close the system operates to saturation. These are the same operating parameters that affect the efficiency of the existing AVS Units 1 and 2 dry scrubbers. The AVS Units 1 and 2 dry scrubbers already operate at an approach to saturation temperature of 30°F which is consistent with industry practice as well as have adequate residence time. Therefore, replacing the existing absorber modules with new absorber modules would not provide any additional benefit and will not be evaluated further.

#### **4.3.2.3 Existing FGD + Dry DSI**

Alkali based DSI is a proven technology for the removal of sulfur trioxide (SO<sub>3</sub>) and other acid gases from coal-fired power plant flue gas, and can be used to provide SO<sub>2</sub> control. Sorbent is injected into the ductwork after the furnace and prior to the particulate collection device, where it reacts with SO<sub>2</sub> and other acid gases. DSI systems are relatively simple systems consisting of material storage, feeding mechanism, blower or transfer line, and an injection device. For SO<sub>2</sub> control on AVS Units 1 and 2, sorbent would be injected upstream of the dry scrubber to provide an incremental reduction in the concentration of SO<sub>2</sub> in the flue gas at the inlet to the dry scrubber.

Sorbents react with SO<sub>2</sub>, and other acid gases, in the flue gas when injected at an appropriate rate and within the proper temperature range for that sorbent. The resulting particulate matter is removed from the flue gas by the

particulate control system. The process works through neutralization of the acid gases with the alkaline sorbent. The neutralization reaction occurs as long as the sorbent remains in contact with the gas in the flue gas duct work within the required temperature range.

Dry sorbents that have been used for SO<sub>2</sub> control on coal-fired boilers include:

- Hydrated Lime (Ca(OH)<sub>2</sub>)
- Trona or Sodium Bicarbonate (SBC)

The following wet sorbents have also been used for acid gas control at coal-fired power generating stations:

- Sodium Bisulfite (SBS)
- Soda Ash

Dry sorbents, including hydrated lime, Trona, and SBC would be injected pneumatically as a dry powder into the flue gas ductwork upstream of the AVS Units 1 and 2 DFGD. Trona and SBC are both sodium-based sorbents, which react with SO<sub>2</sub> to form sodium salts. Hydrated lime would react with SO<sub>2</sub> to form calcium sulfate salts. The hydrated lime reactions are the same reactions that are taking place in the existing dry scrubber.

Hydrated lime is less reactive than the sodium based dry sorbents; thus, higher injection rates and longer residence time would be required to achieve the same removal efficiency. However, hydrated lime has a lower unit cost compared to other sorbent options, offsetting the higher injection rates. It is also important to note that the hydrated lime chemistry involves the same reactions, and forms the same calcium salts, as those currently taking place in the dry scrubber reaction vessels. Therefore, using hydrated lime as the sorbent would not introduce any new constituents into the dry scrubbing system, and could potentially increase the Ca:S stoichiometry in the dry scrubber.

Because of the higher reactivity of sodium based sorbents, less reactant may be required to achieve the same removal efficiency; however, injecting a sodium-based sorbent into the flue gas upstream of the AVS Units 1 and 2 DFGD would introduce new chemical constituents into the scrubber and into the fly ash/scrubber byproduct material. This could prove problematic as sodium compounds are water soluble, and introducing sodium into the system could adversely affect the characteristics of the byproduct solids generated by the system and introduce additional corrosion related issues within the SDA and FF systems. Detailed studies and demonstration tests would be needed to ensure that introducing relatively large amounts of sodium would not adversely affect scrubber operation or result in solids disposal issues.

SBS and soda ash ( $\text{Na}_2\text{CO}_3$ ) injection are wet injection technologies typically used for  $\text{SO}_3$  mitigation. SBS and soda ash can be injected into the flue gas upstream or downstream of the air heater as a 10% solution (by weight) using dual fluid atomizers. Both products will react with  $\text{SO}_2$  and  $\text{SO}_3$  to form sodium salts, which can be collected in the downstream particulate collection device. URS/Codan Associates own the patent for this SBS control process. Based on conversations with URS, their SBS technology is generally more economical using soda ash, and all recent projects have used soda ash. However, as with the dry sodium-based injection systems, these systems would introduce sodium into the AVS Units 1 and 2 DFGD control system.

DSI upstream of the existing dry scrubber is a technically feasible and commercially available  $\text{SO}_2$  control option for AVS Units 1 and 2. Taking into consideration the fact that AVS is currently equipped with a calcium-based dry scrubbing system, hydrated lime dry DSI would be the most practical, and potentially the most effective, DSI control option. Sodium-based systems would require extensive testing to determine the potential impacts associated with introducing significant quantities of sodium into the existing system, and are not considered practical control options for AVS Units 1 and 2. However, although DSI is a technically feasible control option, it should be noted that DSI upstream of the existing DFGD control system at AVS would not provide any additional  $\text{SO}_2$  removal than what could already be achieved by increasing the fresh lime or calcium content through the existing upgraded lime slaking system as discussed in Section 4.3.2.2 Ca:S Stoichiometric Ratio. The existing upgraded lime slaking system at AVS has sufficient capacity to provide the increase in calcium content. Therefore, DSI will not be evaluated further.

#### **4.3.2.4 Retrofit New Dry FGD System**

Replacing the existing dry scrubber/FF with new control systems would require significant engineering and modifications to the facility. Based on a preliminary review of the facility layout, the new control systems could be located south of Unit 1 and north of the Unit 2 existing dry scrubber/FF. The new DFGD/FF and all auxiliary equipment could be constructed while the units remain on line. The control systems could be tied-in to the existing systems during a scheduled major outage.

Various DFGD systems have been designed for use with pulverized coal-fired boilers; including the SDA and circulating dry scrubber (CDS). Both systems are evaluated in more detail below.

### *Spray Dryer Absorber / Fabric Filter*

SDA systems have been used in large coal-fired utility applications, and have demonstrated the ability to effectively reduce uncontrolled SO<sub>2</sub> emissions from pulverized coal units. Like other dry scrubbing systems, SDA control systems use a slurry of lime and water injected into the reaction modules to remove SO<sub>2</sub> from the combustion gases. The reaction modules are designed to provide adequate contact and residence time between the exhaust gas and the slurry to produce a dry by-product. Process equipment associated with an SDA control system includes an alkaline storage tank, mixing and feed tanks, atomizer assembly, spray chamber module, integrated fabric filter, and solids recycle system. The recycle system collects solid reaction byproducts and recycles them back to the spray dryer feed system to maximize reactant utilization.

Various process parameters affect the efficiency of the SDA process including: the type and quality of the additive used for the reactant, reactant-to-sulfur stoichiometric ratio, how close the SDA is operated to saturation conditions, and the amount of solids product recycled to the atomizer. SDA systems are typically designed to operate within approximately 30 °F adiabatic approach to saturation temperature. Operating closer to the adiabatic saturation temperature may allow for higher SO<sub>2</sub> control efficiencies; however, outlet temperatures too close to the saturation temperature will result in severe operating problems including reactant build-up in the absorber modules, blinding of the fabric filter bags, and corrosion in the fabric filter and ductwork.

SO<sub>2</sub> removal efficiencies in a SDA are also dependent upon good gas-to-liquid contact. Reactant spray nozzle designs are vendor-specific, and include both dual-fluid nozzles and rotary atomizers. The atomizing nozzle assembly is typically located in the SDA penthouse and flange mounted to the roof of the absorber vessel.

Replacing the existing dry scrubber/FF with a new SDA/FF control systems is a technically feasible and commercially available control option on the AVS Units. SDA/FF control systems are generally limited to an SO<sub>2</sub> removal of approximately 95%. This removal represents what the control system vendor would be willing to guarantee upon initial operation of the control system.

### *Circulating Dry Scrubber / Fabric Filter*

A second type of dry scrubbing system is the circulating dry scrubber (CDS). Similar to other DFGD systems, the CDS system would be located after the air preheater, and byproducts from the system collected in an integrated fabric filter. Unlike the SDA systems, CDS systems use a circulating fluidized bed of hydrated lime reagent to

remove SO<sub>2</sub> rather than an atomized lime slurry; however, similar chemical reaction kinetics are used in the SO<sub>2</sub> removal process.

In a CDS, flue gas is treated in an absorber vessel where the flue gas stream flows through a fluidized bed of hydrated lime and recycled byproduct. Water is injected into the absorber through a venturi located at the base of the absorber for temperature control. Flue gas velocity through the vessel is maintained to keep the fluidized bed of particles suspended in the absorber. Water sprayed into the absorber cools the flue gas from approximately 300 °F at the inlet to the scrubber to approximately 160 °F at the outlet of the fabric filter. The hydrated lime absorbs SO<sub>2</sub> from the gas and forms calcium sulfite and calcium sulfate solids. Desulfurized flue gas passes out of the absorber, along with the particulate matter (reaction products, unreacted hydrated lime, calcium carbonate, and the fly ash) to the fabric filter.

As with the SDA/FF option, replacing the existing DFGD with a new CDS/FF control system would require significant engineering and modifications to the existing facility. For this evaluation it was assumed that the CDS/FF control systems could be located adjacent to the existing dry scrubber/FF, and that the control systems could be tied-in to the existing system during a scheduled major outage.

Replacing the existing dry scrubber and FF with a new CDS/FF control system is a technically feasible and commercially available control option for the AVS units. Based on engineering judgment, it is anticipated that the retrofit CDS/FF control option would achieve controlled SO<sub>2</sub> emission rates higher than those achieved with a SDA/FF due to the increased Ca:S in the fluidized bed absorber vessel. Based on recent CDS retrofit projects, and taking into consideration expected future design coal characteristics, it is anticipated that the retrofit CDS/FF control system could achieve SO<sub>2</sub> removal efficiencies of approximately 97%. This removal efficiency represents what the control system vendor would be willing to guarantee upon initial operation of the system and on an on-going long-term basis under normal operating conditions.

#### **4.3.2.5 Retrofit New Wet FGD System**

Another option available to AVS would be to replace the existing dry scrubbing system with a new wet FGD control system located downstream of the existing FF.

Wet FGD technology is an established SO<sub>2</sub> control technology. Wet scrubbing systems have been designed to utilize various alkaline scrubbing solutions including lime, limestone, and magnesium-enhanced lime. Wet



scrubbing systems have also been designed with spray tower reactors and with reaction vessels (e.g., jet bubbling reactor). Although the flue gas/reactant contact systems may vary, the chemistry involved in all wet scrubbing systems is essentially identical. All wet scrubbing systems use an alkaline slurry that reacts with  $\text{SO}_2$  in the flue gas to form insoluble calcium sulfite ( $\text{CaSO}_3$ ) and calcium sulfate ( $\text{CaSO}_4$ ) salts.

A large majority of the wet FGD systems designed to remove  $\text{SO}_2$  from existing high-sulfur utility boilers have been designed as wet limestone scrubbers with spray towers and forced oxidation systems. Therefore, for this evaluation, it was assumed that the WFGD control system would be designed as a limestone spray tower scrubber with forced oxidation. Other potentially available wet scrubber designs are not included in this evaluation because the chemistry involved in all wet scrubbing systems are essentially identical, alternative designs would not provide any additional  $\text{SO}_2$  control, and control system costs would be similar.

### Wet Limestone Scrubbing

In a wet limestone scrubbing system, limestone ( $\text{CaCO}_3$ ) is mixed with water to formulate the alkali scrubber slurry. Flue gas enters the absorber vessel and contacts the absorbent slurry in a countercurrent spray tower.  $\text{SO}_2$  in the flue gas reacts with the limestone slurry to form insoluble calcium sulfite ( $\text{CaSO}_3$ ) and calcium sulfate ( $\text{CaSO}_4$ ) which is removed as a solid waste by-product. Spent absorbent is returned to the reaction tank where dissolved sulfur compounds are precipitated as calcium salts. Fresh limestone slurry is added to regenerate the spent absorbent.

The reaction tank is sized to provide sufficient time for precipitation of the sulfur compounds. From the reaction tank, regenerated absorbent slurry is recycled to the absorber. The slurry typically contains from 5 to 15% suspended solids consisting of fresh additive, absorption reaction products, and lesser amounts of fly ash. To regulate the accumulation of solids, a bleed stream from the reaction is routed to the solid/liquid separation equipment.

Forced oxidation of the scrubber slurry may be used with limestone WFGD systems to produce calcium sulfate solids (gypsum) instead of the calcium sulfite by-product. Air blown into the reaction tank provides oxygen to convert most of the calcium sulfite ( $\text{CaSO}_3$ ) to relatively pure gypsum. Forced oxidation of the scrubber slurry provides a more stable by-product and reduces the potential for scaling in the spray tower. The gypsum by-product from this process must be dewatered, and may be salable if a local market for gypsum is available, reducing the quantity of solid waste that needs to be landfilled.

For this evaluation it was assumed that the existing AVS dry scrubber reactor vessel would remain in place, and that the WFGD control system would be located downstream of the existing FFs and ID fans most likely south of Unit 1 and north of the Unit 2 existing dry scrubber/FF. Dry scrubber reactor vessel internals would ultimately be removed to reduce pressure drop through the system. A single absorber tower for each Unit would be sufficient for the flue gas flow. In addition to the absorber tower and reaction vessel, the WFGD control system would require a limestone handling and preparation system and by-product dewatering systems. Because of the saturated nature of the flue gas exiting the WFGD and the velocity requirements with wet stack operation, a new stack with a liner capable of wet flue gas operation would be required. New booster ID fans would also be required to account for the additional pressure drop through the WFGD control system.

Wet FGD technology is an established SO<sub>2</sub> control technology. Wet scrubbing systems have been installed on units that fire medium to high sulfur coals, and would be a technically feasible SO<sub>2</sub> control option for AVS Units 1 and 2. Based on engineering judgment and information from control system vendors, it is anticipated that a retrofit WFGD control system on a North Dakota lignite-fired unit would be designed to achieve and SO<sub>2</sub> removal efficiency of approximately 98%. This removal efficiency represents what the control system vendor would be willing to guarantee upon initial operation of the system and on an on-going long-term basis under normal operating conditions.

#### **4.3.2.6 Technical Feasibility Summary**

Table 4-11 summarizes the results of the feasibility evaluation of available control options for AVS Units 1 and 2.

**Table 4-11. Technically Feasible SO<sub>2</sub> Control Options**

SO <sub>2</sub> Control Option	Technically Feasible (Yes/No)	Control Percentage (Note 1)	Technical Feasibility Summary
Fuel Switching	No	0%	Fuel switching is not considered an available SO <sub>2</sub> control option for AVS Units 1 and 2 since the units are mine mouth to the existing source of lignite coal.
Existing DFGD Operational Improvements:			
Station Work Practice	Yes	5%	Adjusting operation on the non-outage unit to maintain the same SO <sub>2</sub> removal efficiency achieved prior to the other Unit taking an outage is considered a technically feasible option for AVS Units 1 and 2. However, the opportunity to achieve these reductions is one out of every three years on each unit
Lime Quality	No	0%	Changing lime quality in the existing DFGD control system is not a technically feasible operational change for AVS Units 1 and 2.
Ca:S Stoichiometric Ratio	Yes	93%	Increasing the Ca:S stoichiometric ratio by increase the quantity of fresh lime to the system is considered a technically feasible option for AVS Units 1 and 2.
Approach to Saturation Temperature	No	0%	Further reducing the absorber module outlet temperature on the existing DFGD control system is not a technically feasible option for AVS Units 1 and 2.
Existing DFGD Equipment Upgrades:			
Atomizer Replacement	No	0%	Replacing the existing atomizers is not a technically feasible option for AVS Units 1 and 2.
Slaker Replacement	No	0%	Slaker replacement would not be expected to provide additional SO <sub>2</sub> control, and is not a technically feasible equipment upgrade for AVS Units 1 and 2.
Adding an Absorber Module	No	0%	Adding an absorber module to AVS Units 1 and 2 is not a technically feasible SO <sub>2</sub> control option.
Replace Existing Absorbers with New Absorber Modules	No	0%	Replacing the exiting absorber modules with new absorber modules is not a feasible SO <sub>2</sub> control system upgrade for AVS Units 1 and 2 since it would require at least a 12-month outage and replacement power, existing today, is not available.
Existing DFGD + DSI	Yes	0%	Hydrated lime DSI upstream of the existing AVS Units 1 and 2 absorber modules is a technically feasible SO <sub>2</sub> control option, however would not be expected to provide any additional SO <sub>2</sub> control beyond what could be achieved with increasing the Ca:S stoichiometric ratio through the existing lime slaking system.
New Retrofit DFGD (CDS/FF)	Yes	97%	Replacing the existing DFGD control system with a new retrofit DFGD (i.e., CDS/FF) is a technically feasible SO <sub>2</sub> control option for AVS Units 1 and 2.

SO <sub>2</sub> Control Option	Technically Feasible (Yes/No)	Control Percentage (Note 1)	Technical Feasibility Summary
New Retrofit WFGD	Yes	98%	Replacing the existing DFGD control system with a new retrofit WFGD is a technically feasible SO <sub>2</sub> control option for AVS Units 1 and 2.

Note 1. Control percentage calculated using the baseline SO<sub>2</sub> coal quality of 2.90 lb/MBtu and the achievable SO<sub>2</sub> emission rate for each technically feasible control option.

### 4.3.3 Evaluate Technically Feasible SO<sub>2</sub> Control Options for Effectiveness

The technically feasible SO<sub>2</sub> control technologies for Units 1 and 2 are listed in Table 4-12 and Table 4-13 in increasing order of control efficiency. Table 4-12 and Table 4-13 also provide control option-specific SO<sub>2</sub> emission rates in terms of lb/MMBtu. Emission rates shown represent baseline average emission rates that the control options would be expected to achieve during normal operations.

**Table 4-12. Evaluate Technically Feasible SO<sub>2</sub> Control Options by Effectiveness for AVS Unit 1 (Baseline Average Emissions)**

Alt. No.	Control Technology	SO <sub>2</sub> Emission Rate (Note 1) lb/MMBtu	% Reduction from Baseline SO <sub>2</sub> Coal Quality (Note 2)	SO <sub>2</sub> Emission Rate (Note 1) lb/hr	SO <sub>2</sub> Emission Rate (Note 1) tons/yr
E	New Retrofit WFGD	0.07	98%	312	1,305
D	New Retrofit DFGD (CDS/FF)	0.09	97%	401	1,678
C	New Retrofit DFGD (SDA/FF)	0.15	95%	669	2,796
B	FGD Operational Improvements – Increase Ca:S Stoichiometric Ratio	0.20	93%	892	3,728
A	FGD Operational Improvements – Station Work Practice (Note 3)	0.35	88%	1,561	6,524
--	Baseline (existing DFGD/FF)	0.37	87%	1,656	6,921
--	Permit Limit (assumes 50/50 split for each unit)	1.2 (3-hour)		1,923 (3-hour)	

Note 1: Emission rates shown represent average emission rates that the control options would be expected to achieve on an on-going long-term basis under normal operating conditions for AVS Unit 1. Emission rates are provided for comparative purposes, and should not be construed to represent proposed permit limits. Corresponding permit limits must be evaluated on a control system-specific basis.

Note 2: Baseline SO<sub>2</sub> coal quality is 2.90 lb/MMBtu. See Section 4.2 for additional details on coal sulfur.

Note 3: Emission reductions achievable, under the current outage schedule, would only be achieved once every three years on each Unit.

**Table 4-13. Evaluate Technically Feasible SO<sub>2</sub> Control Options by Effectiveness for AVS Unit 2  
(Baseline Average Emissions)**

Alt. No.	Control Technology	SO <sub>2</sub> Emission Rate <sup>(Note 1)</sup> lb/MMBtu	% Reduction from Baseline SO <sub>2</sub> Coal Quality <sup>(Note 2)</sup>	SO <sub>2</sub> Emission Rate <sup>(Note 1)</sup> lb/hr	SO <sub>2</sub> Emission Rate <sup>(Note 1)</sup> tons/yr
E	New Retrofit WFGD	0.07	98%	315	1,311
D	New Retrofit DFGD (CDS/FF)	0.09	97%	405	1,686
C	New Retrofit DFGD (SDA/FF)	0.15	95%	675	2,810
B	FGD Operational Improvements – Increase Ca:S Stoichiometric Ratio	0.20	93%	900	3,746
A	FGD Operational Improvements – Station Work Practice <sup>(Note 3)</sup>	0.35	88%	1,575	6,555
--	Baseline (existing DFGD/FF)	0.37	87%	1,685	7,016
--	Permit Limit (assumes 50/50 split for each unit)	1.2 (3-hour)		1,923 (3-hour)	

Note 1: Emission rates shown represent average emission rates that the control options would be expected to achieve on an on-going long-term basis under normal operating conditions for AVS Unit 2. Emission rates are provided for comparative purposes, and should not be construed to represent proposed permit limits. Corresponding permit limits must be evaluated on a control system-specific basis.

Note 2: Baseline SO<sub>2</sub> coal quality is 2.90 lb/MMBtu. See Section 4.2 for additional details on coal sulfur.

Note 3: Emission reductions achievable, under the current outage schedule, would only be achieved once every three years on each Unit.

Table 4-14 provides control option-specific SO<sub>2</sub> emission rates in terms of lb/MMBtu based on the projected future maximum emission rates. Emission rates shown represent the projected future maximum emission rates that the control options would be expected to achieve during normal operations.

**Table 4-14. Evaluate Technically Feasible SO<sub>2</sub> Control Options by Effectiveness – AVS Unit 1 or 2  
(Projected Future Maximum Emissions)**

Alt. No.	Control Technology	SO <sub>2</sub> Emission Rate (Note 4) lb/MMBtu	% Reduction from Future SO <sub>2</sub> Coal Quality (Note 1)	SO <sub>2</sub> Emission Rate (Note 1) lb/hr	SO <sub>2</sub> Emission Rate (Note 2) tons/yr
E	New Retrofit WFGD	0.07	98%	334	1,463
D	New Retrofit DFGD (CDS/FF)	0.10	97%	501	2,195
C	New Retrofit DFGD (SDA/FF)	0.17	95%	838	3,671
B	FGD Operational Improvements – Increase Ca:S Stoichiometric Ratio	0.24	93%	1,169	5,121
A	FGD Operational Improvements – Station Work Practice (Note 3)	0.34	90%	1,670	7,316
--	Baseline Unit 1 (existing DFGD/FF)	0.37	89%	1,831	8,018
--	Baseline Unit 2 (existing DFGD/FF)	0.37	89%	1,847	8,089
--	Permit Limit (assumes 50/50 split for each unit)	1.2 (3-hour)		1,923 (3-hour)	

Note 1. Future SO<sub>2</sub> coal quality is 3.39 lb/MMBtu. See Section 4.2 for additional details on coal sulfur.

Note 2. Annual SO<sub>2</sub> emissions based on 8,760 hours per year operation.

Note 3: Emission reductions achievable, under the current outage schedule, would only be achieved once every three years on each Unit.

Note 4. Emission rates are provided for comparative purposes, and should not be construed to represent proposed emission limits. Corresponding permit limits must be evaluated on a control system-specific basis.

## 4.4 SO<sub>2</sub> COST OF COMPLIANCE (STATUTORY FACTOR ONE)

The economic analysis performed as part of the four factor analysis examines the cost-effectiveness of each technically feasible control technology, on a dollar per ton of pollutant removed basis. Annual emissions, calculated for a particular control device, are subtracted from baseline annual emissions to calculate tons of pollutant controlled per year. For units with existing controls, the base case represents existing baseline actual emissions. Annual costs for each control option are calculated relative to the base case by adding annual O&M costs to the annualized cost of capital and, if applicable, lost revenue due to extended outage required for installation of control equipment. Capital costs and lost revenues were annualized using a capital recovery factor based on an annual interest rate of 5.25% and equipment life of 20 years.<sup>34</sup> Cost effectiveness (\$/ton) of a particular

<sup>34</sup> The assumed 20-year equipment life is consistent with the control system equipment life used by NDDH in its evaluation of NO<sub>x</sub> and SO<sub>2</sub> control technologies for BART-eligible sources. (see, e.g., ND Regional Haze Final SIP, Appendix C.1, "BART Determination Study for Leland Olds Station Units 1 & 2, Basin Electric Power Cooperative, August 2006, pgs. 64 (NO<sub>x</sub> controls) and 158 (SO<sub>2</sub> controls). See also, ND



control option is simply the annual cost (\$/yr) divided by the annual reduction in annual emissions (ton/yr). In addition to cost-effectiveness relative to the base case, the incremental cost-effectiveness to go from one level of control to the next, more stringent, level of control may also be calculated to evaluate the incremental cost effectiveness of the more stringent control.

Capital and O&M cost estimates were developed for each of the technically feasible SO<sub>2</sub> control options. The AVS Units 1 and 2 cost estimates are conceptual in nature; thus, S&L did not procure equipment quotes specifically for the Units 1 and 2 control system upgrades. Rather, equipment costs are based on conceptual designs developed for the retrofit control systems, preliminary equipment sizing developed for the major pieces of equipment (based on AVS-specific design parameters, including typical fuel characteristics, full load heat input, and flue gas temperatures and flow rates), and recent pricing for similar equipment. S&L would characterize the cost estimates for the AVS Units 1 and 2 retrofit technologies as “concept screening” cost estimates generally based on parametric models, judgment, or analogy.

Control technology equipment costs for the retrofit options were developed by scaling cost estimates prepared by S&L for other similar projects. Major equipment costs were developed based on equipment costs recently developed for similar projects, and include the equipment, material, labor, and all other direct costs needed to retrofit the units with the control technology. Sub-accounts for the capital cost estimates (e.g., mobilization and demobilization, consumables, Contractor G&A expense, freight on materials, etc.) were developed by applying ratios from detailed cost estimates that were prepared for projects with similar scopes.

Fixed O&M costs include operating labor, maintenance labor, maintenance material, and administrative labor. Variable O&M costs include the cost of consumables, including reagent, water consumption, and auxiliary power requirements. Auxiliary power requirements reflect the additional power requirements associated with the operation of the new control technology (compared to the existing technology). All O&M costs reflect the incremental increase in O&M costs compared to the costs incurred to operate the existing dry scrubber and FF control systems.

In addition to the cost effectiveness relative to the base case, the incremental cost-effectiveness to go from one level of control to the next more stringent level of control will also be calculated to evaluate the cost effectiveness of the more stringent control.

#### **4.4.1 SO<sub>2</sub> Average Annual Economic Evaluation**

Table 4-15 presents the capital costs and annual operating costs associated with installing and operating each technically feasible SO<sub>2</sub> control system for AVS Units 1 and 2.

Table 4-16 shows the average annual and incremental cost effectiveness for each control system. Additional cost details are provided in Appendix C.

Cost estimates were not prepared for the SDA/FF option since the capital and operating costs for the SDA/FF option would be similar to the costs for the CDS/FF option, and the CDS/FF option would likely provide the opportunity to achieve somewhat lower controlled SO<sub>2</sub> emissions (compared to SDA/FF). Therefore, of the two new DFGD system options, only the CDS/FF option was evaluated.

**Table 4-15. SO<sub>2</sub> Control Cost Summary (Average Annual)**

AVS Unit No.	Alt. No.	SO <sub>2</sub> Control Option	Total Capital Investment \$	Annual Capital Recovery Cost \$/yr	Annual Operating Cost \$/yr (Note 1)	Total Annual Cost \$/yr
Unit 1	E	Retrofit New Wet FGD	\$272,384,000	\$22,322,000	\$16,945,000	\$39,267,000
	D	Retrofit New Dry FGD (CDS + FF)	\$230,447,000	\$18,886,000	\$16,718,000	\$35,604,000
	B	Existing FGD Operational Improvements – Increase Ca:S Stoichiometric Ratio	\$9,698,000	\$795,000	\$1,144,000	\$1,939,000
	A	Existing FGD Operational Improvements – Station Work Practice	\$0	\$0	\$135,000	\$135,000
Unit 2	E	Retrofit New Wet FGD	\$272,384,000	\$22,322,000	\$16,819,000	\$39,141,000
	D	Retrofit New Dry FGD (CDS + FF)	\$230,447,000	\$18,886,000	\$16,678,000	\$35,564,000
	B	Existing FGD Operational Improvements – Increase Ca:S Stoichiometric Ratio	\$9,698,000	\$795,000	\$1,142,000	\$1,937,000
	A	Existing FGD Operational Improvements – Station Work Practice	\$0	\$0	\$131,000	\$131,000

Note 1. Annual operating costs based on baseline SO<sub>2</sub> coal quality (2.90 lb/MBtu) and capacity factor during baseline SO<sub>2</sub> period for each AVS Unit.

**Table 4-16. SO<sub>2</sub> Emissions Control System Cost Effectiveness (Average Annual)**

AVS Unit No.	Alt. No.	SO <sub>2</sub> Control Option	Total Annual Cost \$	Expected Emission Reduction (Note 2) tons SO <sub>2</sub> /yr	Average Annual Cost-Effectiveness (Note 2) \$/ton SO <sub>2</sub> removed	Incremental Annual Cost-Effectiveness (Note 1) \$/ton SO <sub>2</sub> removed
Unit 1	E	Retrofit New Wet FGD	\$39,267,000	5,616	\$6,992	\$9,826
	D	Retrofit New Dry FGD (CDS + FF)	\$35,604,000	5,243	\$6,790	\$16,420
	B	Existing FGD Operational Improvements – Increase Ca:S Stoichiometric Ratio	\$1,939,000	3,193	\$607	\$645
	A	Existing FGD Operational Improvements – Station Work Practice	\$135,000	397	\$340	--
Unit 2	E	Retrofit New Wet FGD	\$39,141,000	5,705	\$6,861	\$9,549
	D	Retrofit New Dry FGD (CDS + FF)	\$35,564,000	5,330	\$6,672	\$16,322
	B	Existing FGD Operational Improvements – Increase Ca:S Stoichiometric Ratio	\$1,937,000	3,270	\$592	\$643
	A	Existing FGD Operational Improvements – Station Work Practice	\$131,000	461	\$284	--

Note 1. Incremental cost-effectiveness represents the incremental increase in annual costs (\$/yr) divided by the incremental increase in annual SO<sub>2</sub> emissions reductions (tpy) between a control option and the next most effective option. For the option "Existing FGD operational improvements – Increase Ca:S Stoichiometric Ratio," incremental cost compares to the option "Existing FGD operational improvements – Station Work Practice."

Note 2. Expected emission reductions and average annual cost-effectiveness based on baseline SO<sub>2</sub> coal quality (2.90 lb/MBtu) and capacity factor during baseline SO<sub>2</sub> period for each AVS Unit.

Table 4-16 indicates that the average annual cost effectiveness of the technically feasible SO<sub>2</sub> control options for Unit 1 range from \$340 per ton (Existing FGD Operational Improvements – Station Work Practice) to \$6,992 per

ton (Retrofit New Wet FGD) SO<sub>2</sub> removed; and for Unit 2 ranges from \$284 per ton to \$6,861 per ton SO<sub>2</sub> removed.

The “Existing FGD operational improvements – Station Work Practice” control option is expected to achieve approximately 5% reduction from the current baseline SO<sub>2</sub> emissions. This option can be implemented without additional capital costs and with minimal increases in operating costs associated with increased lime use during outage periods only. The cost effectiveness of “Existing FGD Operational Improvements – Station Work Practice” control option is approximately \$300 per ton, respectively.

The “Existing FGD Operational Improvements – Increase Ca:S Stoichiometric Ratio” option would require relatively low capital investment for new tanks, pumps and piping in the slurry preparation systems since the lime slaking system had been recently upgraded, and an increase in operating costs primarily due to increased reagent usage. This option will achieve approximately 93% SO<sub>2</sub> reduction, resulting in a cost effectiveness of approximately \$600 per ton. It should be noted that the recent slaking upgrade project incurred a cost of \$15 million which allows the increased Ca:S stoichiometric ratio option to be viable in this analysis. Without the slaking upgrade project, the Ca:S stoichiometric ratio option would have to bear this additional cost.

The installation of new Dry FGD (CDS) or new Wet FGD systems are high capital and annual operating cost options. The cost effectiveness for these options is approximately \$6,700 per ton (Dry FGD) and \$6,900 per ton (Wet FGD). The incremental cost of installing a Dry FGD system, compared to “Existing FGD Operational Improvements – Increase Ca:S Stoichiometric Ratio,” is approximately \$16,000 per ton. The incremental cost of installing a Wet FGD system, compared to a Dry FGD system, is approximately \$10,000 per ton.

#### **4.4.2 SO<sub>2</sub> Projected Future Maximum Annual Economic Evaluation**

Table 4-17 presents the capital costs and annual operating costs associated with building and operating each control system; annual operating costs are based on the unit's operating at 100% capacity factor and projected future coal quality considering potential variability.

**Table 4-17. SO<sub>2</sub> Control Cost Summary (Projected Future Maximum)**

AVS Unit No.	Alt. No.	SO <sub>2</sub> Control Option	Total Capital Investment \$	Annual Capital Recovery Cost \$/yr	Annual Operating Cost <sup>(Note 1)</sup> \$/yr	Total Annual Cost \$/yr
Unit 1	E	Retrofit New Wet FGD	\$272,384,000	\$22,322,000	\$18,361,000	\$40,683,000
	D	Retrofit New Dry FGD (CDS + FF)	\$230,447,000	\$18,886,000	\$19,993,000	\$38,879,000
	B	Existing FGD Operational Improvements – Increase Ca:S Stoichiometric Ratio	\$9,698,000	\$795,000	\$2,937,000	\$3,732,000
	A	Existing FGD Operational Improvements – Station Work Practice	\$0	\$0	\$437,000	\$437,000
Unit 2	E	Retrofit New Wet FGD	\$272,384,000	\$22,322,000	\$18,210,000	\$40,532,000
	D	Retrofit New Dry FGD (CDS + FF)	\$230,447,000	\$18,886,000	\$19,919,000	\$38,805,000
	B	Existing FGD Operational Improvements – Increase Ca:S Stoichiometric Ratio	\$9,698,000	\$795,000	\$2,932,000	\$3,727,000
	A	Existing FGD Operational Improvements – Station Work Practice	\$0	\$0	\$406,000	\$406,000

Note 1. Annual operating costs based on projected future maximum SO<sub>2</sub> coal quality (3.39 lb/MBtu) and 100% capacity factor for each AVS Unit.

Table 4-18 shows the average annual and incremental cost effectiveness for each control system with emissions reductions and cost effectiveness values based on 100% capacity factors and projected future maximum emission rates. Additional cost details are provided in Appendix C.



**Table 4-18. SO<sub>2</sub> Emissions Control System Cost Effectiveness (Projected Future Maximum)**

AVS Unit No.	Alt. No.	SO <sub>2</sub> Control Option	Total Annual Cost \$	Expected Emission Reduction (Note 2) tons SO <sub>2</sub> /yr	Average Annual Cost-Effectiveness (Note 2) \$/ton SO <sub>2</sub> removed	Incremental Annual Cost-Effectiveness (Note 1) \$/ton SO <sub>2</sub> removed
Unit 1	E	Retrofit New Wet FGD	\$40,683,000	6,555	\$6,207	\$2,466
	D	Retrofit New Dry FGD (CDS + FF)	\$38,879,000	5,823	\$6,677	\$12,010
	B	Existing FGD Operational Improvements – Increase Ca:S Stoichiometric Ratio	\$3,732,000	2,896	\$1,288	\$1,501
	A	Existing FGD Operational Improvements – Station Work Practice	\$437,000	702	\$623	--
Unit 2	E	Retrofit New Wet FGD	\$40,532,000	6,625	\$6,118	\$2,360
	D	Retrofit New Dry FGD (CDS + FF)	\$38,805,000	5,894	\$6,584	\$11,986
	B	Existing FGD Operational Improvements – Increase Ca:S Stoichiometric Ratio	\$3,727,000	2,967	\$1,256	\$1,513
	A	Existing FGD Operational Improvements – Station Work Practice	\$406,000	772	\$526	--

Note 1. Incremental cost-effectiveness represents the incremental increase in annual costs (\$/yr) divided by the incremental increase in annual SO<sub>2</sub> emissions reductions (tpy) between a control option and the next most effective option. For the option "Existing FGD operational improvements – Increase Ca:S Stoichiometric Ratio," incremental cost compares to the option "Existing FGD operational improvements – Station Work Practice."

Note 2. Expected emission reductions and average annual cost-effectiveness based on baseline SO<sub>2</sub> coal quality (3.39 lb/MBtu) and 100% capacity factor for each AVS Unit.

Table 4-18 indicates that the average annual cost effectiveness of the technically feasible SO<sub>2</sub> control options for Unit 1 range from \$623 per ton (Existing FGD operational improvements – Station Work Practice) to \$6,677 per ton (Retrofit New Dry FGD) SO<sub>2</sub> removed; and for Unit 2 ranges from \$526 per ton to \$6,584 per ton SO<sub>2</sub> removed.

The “Existing FGD Operational Improvements – Station Work Practice” control option is expected to achieve approximately 5% reduction from the current baseline SO<sub>2</sub> emissions once every three years on each Unit based on the current maintenance schedule. This option can be implemented without additional capital costs and with minimal increases in operating costs associated with increased lime use. The cost effectiveness of “Existing FGD operational improvements – Station Work Practice” control option is approximately \$600 per ton.

The “Existing FGD Operational Improvements – Increase Ca:S Stoichiometric Ratio” option would require the relatively low capital investment for new tanks, pumps and piping, in the slurry preparation systems since the lime slaking system had been recently upgraded, and an increase in operating costs primarily due to increased reagent usage. This option will achieve approximately 93% SO<sub>2</sub> removal from the projected future maximum levels, resulting in a cost effectiveness of approximately \$1,200 per ton. It should be noted that the slaking upgrade project incurred a cost of \$15 million which allows the increased Ca:S stoichiometric ratio option to be viable in this analysis. Without the slaking upgrade, the Ca:S stoichiometric ratio option would have to bear this additional cost.

The installation of new Dry FGD (CDS) or new Wet FGD systems are high capital and annual operating cost options. The cost effectiveness for these options is approximately \$6,600 per ton (Dry FGD) and \$6,200 per ton (Wet FGD). The incremental cost of installing a Dry FGD system, compared to “Existing FGD Operational Improvements – Increase Ca:S Stoichiometric Ratio,” is approximately \$12,000 per ton. The incremental cost of installing a Wet FGD system, compared to a Dry FGD system, is approximately \$2,400 per ton.

## 5. NO<sub>x</sub> CONTROL EVALUATION

### 5.1 BASELINE NO<sub>x</sub> EMISSIONS

The first step in developing the four factor analysis is to establish AVS Units 1 and 2 baseline NO<sub>x</sub> emissions. To establish representative baseline emissions, S&L evaluated Units 1 and 2 operating data for the period January 1, 2013 to June 30, 2018 to identify periods of normal operation (i.e., periods of operation when the boiler was not limited by infrequent or extraordinary operating restrictions). Based on review of fuels consumed, heat input to the boiler, boiler heat rates, power generation, and capacity factors, as well as input from Basin Electric, it was determined that the operating periods of January 1, 2013 to June 30, 2018 were representative of normal plant operation. However, during the baseline period, the OFA and LNB on Units 1 and 2 were upgraded in order to comply with the First Regional Haze Planning Period. The upgraded NO<sub>x</sub> control systems were in service and additional optimization was achieved on June 2017 (Unit 1) and July 2017 (Unit 2), by installing an Omnivise Combustion Optimizer. Thus, representative baseline periods for the AVS Units are shown in Table 5-1.

**Table 5-1. Representative Baseline Periods for NO<sub>x</sub> Emissions**

Pollutant	Representative Baseline Periods	
	AVS Unit 1	AVS Unit 2
NO <sub>x</sub> Emissions	6/1/2017 to 6/30/2018	7/1/2017 to 6/30/2018

Baseline annual NO<sub>x</sub> emissions were determined based on data obtained from the Units 1 and 2 continuous emissions monitoring system (CEMS) that was reported to EPA's Clean Air Markets. The maximum 12-month annual average emission rates were used to establish the baseline NO<sub>x</sub> emissions. Representative baseline emission factors (in terms of lb/MMBtu) were developed using baseline annual emissions and the respective annual heat inputs. Table 5-2 provides a summary of the AVS Units 1 and 2 NO<sub>x</sub> representative baseline emissions; additional details are included in Appendix B. Table 5-3 provides a summary of the AVS Units 1 and 2 NO<sub>x</sub> projected future maximum emissions based on the boiler design heat input and 100% capacity factor.

NORTH DAKOTA ROUND II REGIONAL HAZE SIP  
 DETERMINATION'S FOUR-FACTOR ANALYSIS FOR ANTELOPE  
 VALLEY STATION UNITS 1 AND 2

5-2

**Table 5-2. Baseline Actual NO<sub>x</sub> Emissions**

AVS Unit	Baseline Controls	NO <sub>x</sub> Emission <sup>(Note 1)</sup>			Capacity Factor During Baseline Period	Current Permit Limits
		lb/hr	lb/MMBtu	tons/yr		
Unit 1	OFA / LNCFS	427	0.10	1,802	81%	0.17 lb/MMBtu (30-day average) 4,930 lb/hr (3-hr average, plant total) 0.50 lb/MMBtu (3-hr average)
Unit 2	OFA / LNCFS	466	0.10	1,904	85%	0.17 lb/MMBtu (30-day average) 4,930 lb/hr (3-hr average, plant total) 0.50 lb/MMBtu (3-hr average)

 Note 1. Units 1 and 2 NO<sub>x</sub> emissions based on annual average for period July 2017 to June 2018.

**Table 5-3. Baseline Projected Future Maximum NO<sub>x</sub> Emissions**

AVS Unit	Baseline Controls	NO <sub>x</sub> Emission <sup>(Note 1)</sup>			Capacity Factor During Baseline Period	Current Permit Limits
		lb/hr	lb/MMBtu	tons/yr		
Unit 1	OFA / LNCFS	510	0.10	2,235	100%	0.17 lb/MMBtu (30-day average) 4,930 lb/hr (3-hr average, plant total) 0.50 lb/MMBtu (3-hr average)
Unit 2	OFA / LNCFS	512	0.10	2,244	100%	0.17 lb/MMBtu (30-day average) 4,930 lb/hr (3-hr average, plant total) 0.50 lb/MMBtu (3-hr average)

 Note 1. Projected future maximum NO<sub>x</sub> emissions based on the boiler design heat input of 4,930 MBtu/hr and assumes 100% capacity factor.

## 5.2 NO<sub>x</sub> EMISSIONS CONTROLS

### 5.2.1 Identify Available NO<sub>x</sub> Control Options

Based on a review of available NO<sub>x</sub> control technologies installed on existing tangential-fired pulverized coal boilers designed to fire lignite coal, NO<sub>x</sub> control techniques can be divided into pre-combustion strategies and post-combustion controls. NO<sub>x</sub> control options identified for potential application to AVS Units 1 and 2 are listed in Table 5-4.

**Table 5-4. Available NO<sub>x</sub> Control Options**

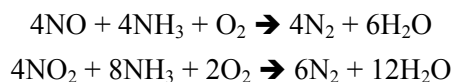
NO <sub>x</sub> Control Technologies
Selective Catalytic Reduction - High Dust, Low Dust or Tail End Configuration (TE-SCR)
Selective Non-Catalytic Reduction (SNCR)
Gas Reburn
Innovative Technologies (i.e. NO <sub>x</sub> Star, Water Injection, LoTOX, PerNO <sub>x</sub> ide, Water Injection)

### 5.2.2 Technical Feasibility of Available NO<sub>x</sub> Control Options

Potentially available NO<sub>x</sub> control options identified in Table 5-4 were evaluated for technical feasibility (i.e. availability and applicability to AVS Units 1 and 2) based on a review of physical, chemical, and engineering principals, and an assessment of commercial availability. Options deemed to be technically infeasible, or options that have no practical application to AVS Units 1 and 2, were eliminated from further review. S&L evaluated the effectiveness of the control options determined to be technically feasible, and established an emission performance level (i.e., controlled emission rate) for each.

#### 5.2.2.1 Selective Catalytic Reduction

SCR is a process by which ammonia (NH<sub>3</sub>) reacts with nitric oxide (NO) and nitrogen dioxide (NO<sub>2</sub>), collectively NO<sub>x</sub>, in the presence of a catalyst to reduce the NO<sub>x</sub> to nitrogen (N<sub>2</sub>) and water (H<sub>2</sub>O). SCR technology has been applied to NO<sub>x</sub>-bearing flue gases generated from power generating facilities burning various types of coal, including bituminous, subbituminous, and Texas lignite). The principal reactions resulting in NO<sub>x</sub> reduction are:



Because these reactions proceed slowly at typical boiler exit gas temperatures of a coal-fired steam electric generating unit, a catalyst is used to increase the reaction rate between  $\text{NO}_x$  and  $\text{NH}_3$ . Depending on the specific constituents in the flue gas, a typical temperature range of 550°F to 780°F is necessary to achieve normal performance of the catalyst. For the typical coal-fired boiler, optimal performance will be in the range of approximately 650°F to 750°F.

In general, there are three candidate SCR configurations that can be employed on coal-fired steam electric generating units. The SCR configuration designations generally describe the location of the SCR reaction vessel in relation to other post-combustion air quality control systems. Candidate SCR configurations include:

- High-dust configuration
- Low-dust configuration
- Tail-end configuration

Each of these configurations is described below as they may be applied at AVS Units 1 and 2.

#### High-Dust Configuration

In a high-dust configuration, the SCR reactor is located in the flue gas stream between the economizer outlet and the air heater inlet. This configuration locates the SCR within the inherently optimal temperature range environment for  $\text{NO}_x$  reduction (i.e., 650°F to 750°F); however, flue gas characteristics at the economizer outlet can also have detrimental effects on the SCR catalyst. As an example, the high-dust SCR configuration exposes the SCR catalyst to high levels of fly ash loading. High levels of fly ash can result in significant erosion of the catalyst, resulting in more frequent cleaning cycles and catalyst replacement. A second major concern with the high-dust configuration at AVS Units 1 and 2 is the presence of high levels of sodium (both in the vapor-phase and as submicron aerosols) in the North Dakota lignite-derived flue gas. Sodium is a known SCR catalyst poison, and also affects the adhesive and cohesive characteristics of the fly ash, which in turn, would have an adverse effect on the SCR catalyst and reactor vessel.

SCR catalyst deactivation occurs through two primary mechanisms: physical deactivation and chemical poisoning. Physical deactivation is caused by either exposure of the catalyst to excessive temperatures (thermal deactivation) or masking of the catalyst due to entrainment of particulate from the flue gas stream (fouling). Chemical



deactivation is caused by either an irreversible reaction of the catalyst with a contaminant in the gas stream (poisoning) or a reversible absorption of a contaminant on the surface of the catalyst (inhibition). Loss of catalyst activity through thermal degradation or poisoning is permanent, and reactivity can only be restored by replacing the catalyst.

In a North Dakota lignite application, SCR catalyst poisoning is expected to result from the presence of trace elements and strong alkaline substances in flue gas, including sodium (Na), potassium (K), and calcium (Ca). Alkaline metals can chemically attach to active catalyst pore sites and cause deactivation. Sodium and potassium are of prime concern especially in their water-soluble forms, which are more mobile and can penetrate into the catalyst pores. Earth metals, especially calcium, can react with SO<sub>3</sub> absorbed within the catalyst to form CaSO<sub>4</sub> and blind the catalyst.

North Dakota lignite contains relatively high levels of organically associated alkali and alkaline-earth elements, including Na, Ca, K, and Mg. Sodium levels in North Dakota lignite are typically 5 to 20 times higher than sodium levels in bituminous and subbituminous coals, and sodium compounds can represent between 5% and 11% of the ash generated from firing North Dakota lignite. These sodium levels, occurring in both the vapor phase and particulate phase, along with relatively high levels of potassium and calcium, significantly increase the potential for catalyst deactivation, plugging, and erosion. Based on the ash chemistry, a conventional high dust SCR arrangement would likely experience unacceptable catalyst deactivation rates.

As noted in section 3.1.1.2, during the first Regional Haze planning period, NDDH prepared a comprehensive technical feasibility assessment of high dust SCR on lignite-fired boilers (North Dakota Regional Haze SIP, Appendix B-5).<sup>35</sup> The NDDH concluded, based on the unique characteristics of North Dakota lignite-derived flue gas, that the high-dust SCR configuration was not a technically feasible or commercially available NO<sub>x</sub> control option for North Dakota lignite-fired boilers such as AVS Units 1 and 2.<sup>36</sup> This determination was consistent with the NDDH's NO<sub>x</sub> BACT determination for MRYS Units 1 & 2.<sup>37</sup> Reasons upon which NDDH based its

---

<sup>35</sup> See, North Dakota State Implementation Plan for Regional Haze, February 24, 2010, Appendix B.5, Best Available Retrofit Technology – Selective Catalytic Reduction Technical Feasibility Analysis for North Dakota Lignite, July 2009.

<sup>36</sup> *Id.* at pg. 19.

<sup>37</sup> As noted in section 3.1.1.2, contemporaneous with the Regional Haze SIP/FIP process, NDDH also prepared a BACT analysis for MRYS Units 1 & 2. In its BACT analysis, NDDH concluded that SCR was technically infeasible on a lignite-fired cyclone boiler, and selected SNCR as BACT. On December 21, 2011, the District Court issued a decision finding that the State's conclusion that SCR was not technically feasible was not unreasonable. See, U.S. v. Minnkota, 831 F. Supp. 2d at 1127-30

conclusion that high-dust SCR was not a technically feasible option for North Dakota lignite-fired boilers included, but were not limit to:<sup>38</sup>

- 1) North Dakota lignite<sup>39</sup> has a higher organic matter content and contains a higher proportion of alkali metal constituents, especially sodium, than subbituminous coal. Approximately 75% of the total sodium in lignite is associated with the organic fraction of the lignite. During combustion, organic and water-soluble sodium vaporizes; consequently, combustion of the coal leads to higher flue-gas concentrations of alkali metals in vapor form.
- 2) The unburned or partially burned organic fraction of North Dakota lignite contains more sodium than other coals. Sodium can react with silicate particles causing a “stickiness” quality to the flue gas ash, resulting in increased ash deposition on heat transfer surfaces. Larger particles can fracture from heat-transfer surfaces (a.k.a. popcorn ash) and enter the flue gas stream. Consequently, deposition on surfaces of catalytic reactors occurs and rates of deposition are higher.
- 3) NO<sub>x</sub> reduction occurs on the flat surfaces of a catalyst and in pores within the flat surfaces. The pores are open to the flue gas passing through the catalyst reactor. Condensed vapors, alkali sulfates and alkaline-earth oxides and silicates are minute particles (less than 1 microns), which enter pores of the catalyst (a.k.a. plugging) and prevent catalytic reaction with NO<sub>x</sub>. Residual alkali vapors (Na, K, and Ca) displace hydrogen on fresh catalyst, which prevents catalytic reaction with NO<sub>x</sub> (a.k.a poisoning) and reacts with sulfate to cause blinding of catalyst surfaces. Pore condensation of sodium also causes catalyst deactivation, which is a major deactivation mechanism. The rate of catalyst deactivation depends on the concentration and form of alkali in the flue gas; higher Na and K accelerate catalyst poisoning, blinding and plugging.
- 4) During the development of the initial planning period SIP, NDDH found that there were no SCR systems planned, constructed, or operating in the flue gas stream of boilers fired with North Dakota lignite. North Dakota lignite has certain coal characteristics that are uniquely different than Texas or Gulf Coast lignites, such as the larger proportion of organic matter and association of alkali, sodium specifically, with that organic matter.
- 5) Slipstream SCR reactors of the same design were installed at three power plants to test SCR for NO<sub>x</sub> emissions control. One of the plants was cyclone fired with North Dakota lignite and the others with subbituminous coal. Deposition on the reactor surface after two months using the lignite was significantly greater; the deposits were rich in sodium, calcium, and sulfur. The tests confirmed catalyst blinding and plugging, but did not provide rates for catalyst deactivation. Tests also indicated that the deposits causing blinding and plugging of pores contained more sodium compared to Powder River Basin (PRB) coal.

Based on these findings, NDDH concluded that additional pilot scale testing would be required to assess issues specifically associated with the North Dakota lignite-generated flue gas characteristics, including potential impacts associated with:

<sup>38</sup> Findings and conclusions are summarized from the North Dakota Regional Haze SIP, Appendix B.5, pgs. 15-19.

<sup>39</sup> Although the BART determination specifically references Fort Union lignite, the findings would apply to all North Dakota lignites.

- the high level of soluble alkali in North Dakota lignite;
- the potential abrasive qualities of North Dakota lignite ash; and
- particle size and sticky nature of high alkaline North Dakota lignite ash.

The NDDH concluded that without pilot scale testing the long term NO<sub>x</sub> reduction efficiency, the volume of the reactor, the catalyst pitch and life of catalyst, could not be predicted with a high degree of confidence. Noting that the BART Guidelines do not require source owners/operators to conduct extended trials to learn how to apply a technology on a totally new and dissimilar source type, and that technologies in the pilot scale testing stages of development are not considered as “available” for purposes of BART, NDDH determined that high dust SCR was not available, and thus, not technically feasible for units combusting North Dakota lignite.<sup>40</sup>

Although the first planning period BART determinations, focused on North Dakota lignite-fired cyclone boilers (i.e., LOS Unit 2 and MRYS Units 1 & 2), technical issues regarding the high level of soluble alkali in North Dakota lignite, the particle size and sticky nature of high alkaline fly ash, and the potential abrasive qualities of North Dakota lignite ash would apply equally to wall-fired and tangentially fired boilers. Technical issues identified by NDDH during the first planning period would also apply to AVS Units 1 & 2; therefore, findings and conclusions from the first planning period BART determinations (Regional Haze SIP, Appendix B.5) and the MRYS Units 1 & 2 BACT analysis, are incorporated by reference into this reasonable progress four-factor analysis.

Based on a review of SCR installations on coal-fired boilers and a review of reported advances in SCR catalysts since the first planning period, deactivation rates due to soluble alkali compounds in the flue gas (including soluble sodium and potassium compounds) and the adhesive/cohesive characteristics and potential abrasive qualities of the North Dakota lignite-derived fly ash still remain a concern for North Dakota lignite-fired boilers. SCR has not been installed and successfully operated on a North Dakota lignite-fired boiler, and the bench scale and pilot-scale studies needed to better understand ash behavior and catalyst blinding/erosion with North Dakota lignite-derived fly ash, and to better understand catalyst deactivation mechanisms associated with high soluble alkali compound

---

<sup>40</sup> *Id.* at pg. 19. NDDH reached a similar conclusion in its BACT determination for NO<sub>x</sub> control on MRYS Units 1 & 2, finding that high-dust SCR had not been deployed on the same or a similar source, and that the flue gas characteristics of North Dakota lignite are significantly different from other sources that have applied high-dust SCR. The NDDH found that these unique characteristics present significant challenges to the successful application of high-dust SCR for NO<sub>x</sub> control, and that pilot testing would be needed to evaluate applicability of the control technology. Thus, NDDH concluded that because high-dust SCR is neither “available” nor “applicable” to the MRYS units, the control technology was technically infeasible and excluded from consideration as BACT. (See, Best Available Control Technology Determination for Control of Nitrogen Oxides for M.R. Young Station Units 1 and 2, April 2010).

concentrations in the flue gas have not been required or completed. Pilot-scale studies are needed to evaluate these issues to inform the development of advanced catalyst formulations, and to support the engineering and design studies needed to mitigate for potential deactivation routes (e.g., removing soluble alkali compounds from the flue gas and SCR design considerations such as catalyst formulation, catalyst pitch, reactor velocity, and catalyst surface and volume). Pilot-scale tests and engineering/design studies have not advanced since the first planning period's exhaustive analysis. These issues have not been resolved since the first planning period and still remain a significant barrier to the design and successful operation of high dust SCR on North Dakota lignite-fired boilers.

The BART Guidelines state that “[a] control technique is considered available...if it has reached the stage of licensing and commercial availability.”<sup>41</sup> Commercial availability follows bench scale and laboratory testing and pilot scale testing. Consequently, the guidelines state that “you would not consider technologies in the pilot scale testing stages of development as ‘available’ for purposes of BART review.”<sup>42</sup> Furthermore, source owners/operators are not expected to conduct extended trials to learn how to apply a technique on a dissimilar source type.<sup>43</sup> These BART guidelines also apply as a recommendation for the development of the LTS in the second planning period and the four factor analysis.<sup>44</sup> Because there are still unresolved issues associated with catalyst poisoning, catalyst blinding and plugging, and catalyst erosion; and engineering solutions have not yet been determined or demonstrated and the high dust configuration has not moved beyond pilot scale testing, high dust SCR is still not available, and thus, not a technically feasible NO<sub>x</sub> control technology for AVS Units 1 and 2.

### Low-Dust Configuration

In the low-dust configuration, the SCR reactor vessel is located in the flue gas stream after the particulate collection device (i.e. ESP or FF). Employing this configuration would represent a relatively low level of exposure to fly ash (with the exception of submicron ash particles), but a potentially high level of vapor-phase alkalis, such as sodium. This configuration can be used on units equipped with particulate control only or units equipped with particulate control followed by a WFGD control system. The existing dry FGD/FF control configuration at AVS Units 1 and 2 for SO<sub>2</sub> and particulate control would preclude the application of a low-dust SCR configuration since, by definition, the SCR would have to be located downstream of both the dry FGD and FF. At that location the SCR would be more appropriately defined as a tail-end SCR configuration, which is described in more detail in the following

---

<sup>41</sup> 40 CFR Part 51 Appendix Y, Section D.2.1.

<sup>42</sup> *Id.*

<sup>43</sup> *Id.*

<sup>44</sup> See, Draft EPA Guidelines, pg. 183.

section. Because AVS Units 1 and 2 are equipped with existing dry FGD/FF controls, low-dust SCR has no practical application on these units, and low-dust SCR is not considered a technically feasible NO<sub>x</sub> control option for AVS Units 1 and 2.

### Tail-End Configuration

In the tail-end configuration, the SCR reaction vessel is located in the flue gas stream after the particulate and FGD control systems. The potential advantage of a tail-end SCR configuration at AVS is that the flue gas will have passed through the dry FGD/FF system prior to the SCR catalyst. As such, there is the possibility that the mass transfer mechanism that results in the capture of SO<sub>2</sub> will also capture some of the vapor-phase sodium and the sodium-enriched submicron particles, reducing the risk of catalyst poisoning and/or deactivation.

Successful operation of the tail-end configuration would also require a capital and operating cost-intensive gas-to-gas heat exchanger to reheat the flue gas from approximately 170 °F downstream of the existing FF to approximately 550°F to support the SCR NO<sub>x</sub> reactions. After the flue gas passes through the SCR (at approximately 550°F), it would pass through the hot side of the gas-to-gas heat exchanger to cool the flue gas to 150°F prior to the exhaust stack. Although this stack gas temperature would be lower than the current stack temperature (165-170°F), it is still higher than the adiabatic saturation temperature of the flue gas (i.e., approximately 135°F). As such, it is likely that the existing stack could be reused with minor modifications.

During the first planning period, NDDH initially concluded, based on preliminary information provided by SCR catalyst vendors, that the tail-end SCR configuration would be a technically feasible option for units firing North Dakota lignite.<sup>45</sup> However, as part of the MRYS NO<sub>x</sub> BACT determination process, detailed information describing the expected ash characteristics and flue gas characteristics was provided to two SCR catalyst vendors (CERAM Environmental, Inc. (CERAM) and Haldor Topsoe, Inc.). Based on their review of the data, both vendors concluded that they would not be able to provide a catalyst life guarantee for either low-dust or tail-end SCR without pilot-scale testing.<sup>46</sup>

During the BACT review process, both companies made statements bringing into question the technical feasibility of either low-dust or tail-end SCR. For example, CERAM stated that the high levels of sodium oxide (Na<sub>2</sub>O) in the ash for North Dakota lignite are not commonly found in subbituminous and bituminous coals which are fired in

<sup>45</sup> See, North Dakota Regional Haze SIP, Appendix B.5, pg. 25.

<sup>46</sup> See, *United States v. Minnkota*, 831 F. Supp. 2d, at 1117.

boilers equipped with SCR systems, and that it was unaware of any SCR application experience in the industry with the level and form of sodium in the North Dakota lignite-derived ash. CERAM stated further that small aerosol particles can penetrate and neutralize active catalyst sites even in dry conditions, and that catalyst installed even in low dust and tail-end locations can be poisoned from exposure to the high levels of phosphorous, sodium, and potassium found in the mineral analyses provided for the MRYS BACT analysis.<sup>47</sup> Similarly, Haldor Topsoe stated that the potential exists that physical deactivation due to catalyst blinding and plugging could be severe enough to make SCR a non-viable option for controlling NO<sub>x</sub> emissions.

Based on information provided by SCR design engineering firms and SCR catalyst vendors, NDDH made the following findings and conclusions with respect to the technical feasibility of low-dust and tail-end SCR on a North Dakota lignite-fired boiler:<sup>48</sup>

- 1) There has never been a full scale SCR of any type installed on a facility that burns North Dakota lignite.
- 2) To determine technical feasibility of tail-end SCR, one must compare the flue gas characteristics generated from firing North Dakota lignite to the flue gas characteristics of other source types to which these control technologies have been applied previously.
- 3) Flue gas characteristics of boilers firing North Dakota lignite are significantly different from other boilers where SCR has been applied.
- 4) North Dakota lignite contains high quantities of soluble sodium and potassium which can cause catalyst reaction site poisoning, blinding, and plugging of catalyst pores and channels, and that the soluble sodium and potassium can also form sulfates that can blind and plug the catalyst pores and plug the catalyst channels.
- 5) Both CERAM and Haldor Topsoe indicated that they would not provide a guarantee for the catalyst life without successful pilot scale testing being done.

Technologies in the pilot scale testing phase of development need not be considered as available control technologies. Based on the fact that SCR had not been installed nor effectively operated on an North Dakota lignite-fired unit, the lack of a commercially viable vendor guarantee, and the need to conduct pilot-scale testing to evaluate potentially significant operational and design issues, NDDH concluded that the use of SCR technology, including low-dust and tail-end SCR, on the lignite-fired MRYS boilers would be technically infeasible.<sup>49</sup>

---

<sup>47</sup> *Id.*

<sup>48</sup> Findings and conclusions are summarized from United States v. Minnkota, pgs 1115-1116.

<sup>49</sup> Best Available Control Technology Determination for Control of Nitrogen Oxides for M.R. Young Station Units 1 and 2, April, 2010, pg. 21.



Although the MRYS BACT determination, and the initial planning period BART determinations, focused on North Dakota lignite-fired cyclone boilers (i.e., LOS Unit 2 and MRYS Units 1 & 2), technical issues regarding the high level of soluble alkali in North Dakota lignite-derived flue gas would also apply to AVS Units 1 & 2. Therefore, findings and conclusions included in the MRYS Units 1 & 2 BACT analysis and the initial planning period BART determinations (Regional Haze SIP, Appendix B.5) are incorporated by reference into this four-factor analysis.

Based on a current review of SCR installations on coal-fired boilers, and a review of reported advances in SCR catalysts since the first planning period, deactivation rates due to soluble alkali compounds in the flue gas (including soluble sodium and potassium compounds) still remain a concern for North Dakota lignite-fired boilers. Tail-end SCR has not been demonstrated on a North Dakota lignite-fired boiler, and there are still significant technical concerns associated with the availability of existing SCR catalysts on a lignite-fired unit. Catalyst in a tail-end SCR will still be vulnerable to alkali poisoning, pore pluggage, and premature catalyst deactivation, and it is not known whether the comparatively high levels of soluble sodium and potassium in North Dakota lignite will be effectively removed by the upstream dry FGD/FF. Furthermore, the potential exists for fine particulate remaining in the flue gas to get into the catalyst pores reducing catalyst activity. Pilot-scale studies are needed to better understand catalyst deactivation mechanisms associated with high soluble alkali compound concentrations in the flue gas have not been completed.

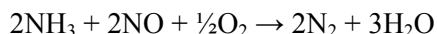
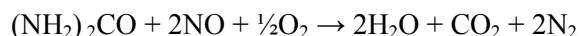
In order to understand the effect of North Dakota lignite-derived flue gas on tail-end SCR catalyst, identify potential design solutions, and evaluate the technical feasibility and effectiveness of tail-end SCR at AVS Units 1 and 2 with any degree of certainty, pilot scale testing of the control configuration would be needed. Because there are still unresolved issues associated with catalyst poisoning, it's very unlikely that Basin Electric could obtain a viable commercial offering for tail-end SCR on AVS Units 1 and 2 without extended pilot-scale tests.

During the first planning period NDDH determined that tail-end SCR was not available, and thus, not a technically feasible NO<sub>x</sub> control option for North Dakota lignite-fired boilers. Although the NDDH's control technology evaluation during the first planning period specifically focused on North Dakota lignite-fired cyclone boilers, technical issues regarding catalyst deactivation mechanisms associated with the high level of soluble alkali in North Dakota lignite would apply equally to wall-fired and tangentially-fired boilers. The administrative record developed during the first planning period, including the BART determinations and MRYS BACT analysis, supports the conclusion that tail-end SCR is not an available NO<sub>x</sub> control option for AVS Units 1 & 2. An evaluation of SCR installations and reported advances in SCR catalysts since the first planning period, coupled with

the fact that tail-end SCR has not been demonstrated on a North Dakota lignite-fired boiler, and the likelihood that Basin Electric could not obtain a viable commercial offering for tail-end SCR without extended pilot-scale testing, continues to support the conclusion that tail-end SCR is not an available NO<sub>x</sub> control technology. Nevertheless, because the first planning period BART analysis (and the MRYs BACT analysis) focused on cyclone boilers, Basin Electric has elected to include tail-end SCR as a potentially feasible control option and carry it forward to the cost impact evaluation (Section 5.2.2.1). Based on controlled NO<sub>x</sub> emissions achieved in practice at existing bituminous- and subbituminous-fired units, S&L assumed that the tail-end SCR control option could achieve an average controlled NO<sub>x</sub> emission rate of 0.05 lb/MMBtu.

#### **5.2.2.2 Selective Non-Catalytic Reduction**

Selective non-catalytic reduction (SNCR) involves the direct injection of ammonia or urea (CO(NH<sub>2</sub>)<sub>2</sub>) at high flue gas temperatures (approximately 1,600°F – 2,100°F) in an oxidizing environment. The ammonia or urea reacts with NO<sub>x</sub> in the flue gas to produce N<sub>2</sub> and water as shown below.



Flue gas temperature at the point of reagent injection can greatly affect NO<sub>x</sub> removal efficiencies and the quantity of NH<sub>3</sub> or urea that will pass through the SNCR unreacted (referred to as NH<sub>3</sub> slip). In general, SNCR reactions are effective in the range of 1,600°F – 2,100°F. At temperatures below the desired operating range, the NO<sub>x</sub> reduction reactions diminish and unreacted NH<sub>3</sub> emissions increase. Above the desired temperature range, NH<sub>3</sub> is oxidized to NO<sub>x</sub> resulting in low NO<sub>x</sub> reduction efficiencies.

Mixing of the reactant and flue gas within the reaction zone is an important factor to SNCR performance. In large boilers, the physical distance over which reagent must be dispersed increases, and the surface area/volume ratio of the convective pass decreases. Furnace geometry, urea spray coverage, and droplet size must be considered when developing good mixing of reagent and flue gas, delivery of reagent in the proper temperature window, and sufficient residence time of the reagent and flue gas in that temperature window. As the boiler cycles in load, the optimum injection region may change. Thus most facilities require multiple injection zones which are placed in and out of service as the unit ramps in load. This can include modifying the zones of injectors that are operating and different loads and temperatures.

Retractable multinozzle lances (MNLs) are sometimes used to improve SNCR performance, especially if the furnace exit flue gas temperatures are too high. The retractable lances allow injection into the appropriate temperature zone more so than wall injectors, depending on the unit load and temperatures. The MNLs also help improve performance by refining the spray pattern for quicker vaporization of the conveying water. MNLs are often used in conjunction with wall injection to provide optimized coverage while reducing reagent cost.

In addition to temperature and mixing, several other factors influence the performance of an SNCR system, including residence time, reagent-to-NO<sub>x</sub> ratio, and fuel sulfur content. Increasing the normalized stoichiometric ratio can improve NO<sub>x</sub> removal. This is completed by increasing urea solution flow through the injectors or changing the concentration of urea in the solution. However, too high of reagent injection rates will increase the ammonia slip beyond the recommended 10 ppmvd limit. Above this concentration, there are expected to be major impacts to the formation of ammonia salts on the boiler tube banks, reducing heat transfer efficiency, and air heater baskets, causing corrosion.

SNCR can be applied on pulverized coal boiler due to having reasonable temperature windows and residence time, however the potential NO<sub>x</sub> reduction is boiler-specific. SNCR has been used as a retrofit NO<sub>x</sub> control system on pulverized coal, fluidized bed boilers, and cyclone boilers. Furthermore, SNCR can be implemented on boilers equipped with LNB, overfire air, or SOFA systems. Based on the boiler residence time, temperature profile, and stoichiometry, as well as input from SNCR OEMs, it is estimated that an SNCR system could achieve an average controlled NO<sub>x</sub> emission rate of approximately 0.09 lb/MMBtu (approximately 10% below the baseline emission rate of 0.10 lb/MMBtu) while limiting ammonia slip to 10 ppmvd. It should be noted that computational fluid dynamic modeling and temperature mapping of the boiler would be needed to confirm that the incremental reduction in NO<sub>x</sub> emission is achievable without creating unacceptable operational issues.

#### **5.2.2.3 Rich Reagent Injection**

Similar to SNCR, the concept of rich reagent injection (RRI) is to use a nitrogen-containing additive (urea) injected into a reducing environment to promote peak NO<sub>x</sub> reduction efficiency. RRI is a commercial technology for cyclone boilers only. Since the AVS units are pulverized coal boilers, this technology is not considered a technically feasible NO<sub>x</sub> control technology at AVS.

#### **5.2.2.4 Gas Reburn**

Gas reburn is a retrofit technique that has been used to control  $\text{NO}_x$  emissions from coal- and oil-fired boilers. Gas reburn involves combustion in three distinct zones within the boiler: (1) a primary combustion zone, where the primary fuel is fired using conventional burners; (2) a reburn zone, where secondary fuel, typically natural gas, is introduced into the boiler; and (3) an OFA burnout zone.

In the primary zone of coal-fired boilers, coal is fired through LNCFS, at a rate corresponding to approximately 80% to 90% of the total heat input. Natural gas reburn fuel is then injected above the primary combustion zone under fuel-rich conditions at a rate corresponding to approximately 10% to 20% of the total heat input (on a Btu/hour basis). The fuel-rich reburn zone creates a reducing (sub-stoichiometric) region within the boiler where the natural gas, principally methane ( $\text{CH}_4$ ), breaks down to produce hydrocarbon radicals ( $\text{CH}$  and  $\text{CH}_2$ ). The hydrocarbon radicals react with  $\text{NO}_x$  produced in the primary combustion zone to form nitrogen ( $\text{N}_2$ ) and water vapor. Because the natural gas is not completely combusted in the reburn zone, gases exiting the reburn zone will contain considerable CO and unburned hydrocarbons; therefore, additional OFA is introduced above the reburn zone to complete the combustion process.

Critical design parameters that affect the feasibility and performance of a gas reburn retrofit system include: (1) baseline  $\text{NO}_x$  concentration; (2) reburn zone temperature, residence time, and stoichiometry; (3) OFA burnout zone temperature and residence time; and (4) mixing of the reburn fuel and overfire air with the bulk flue gas.

Gas reburn can have a positive impact on emissions of  $\text{NO}_x$ ; however, in order to make a meaningful prediction of the  $\text{NO}_x$  removal capabilities at AVS, extensive testing at each unit would be required because the performance is significantly dependent upon boiler operating characteristics. As such, gas reburn is not considered a technically feasible  $\text{NO}_x$  control technology at AVS.

#### **5.2.2.5 Innovative Technologies**

##### *$\text{NO}_x\text{Star}^{\text{TM}}$*

The  $\text{NO}_x\text{Star}^{\text{TM}}$  process, also known as selective autocatalytic reduction (SACR), uses a continuous controlled amount of ammonia-based reagent with relatively small amounts of hydrocarbon to reduce  $\text{NO}_x$  emissions. The hydrocarbon is introduced into the flue gas at the convective pass of the boiler, with elevated temperatures. At the elevated temperatures, the hydrocarbon auto-ignites to form a plasma of free radicals that auto catalyzes the reaction of  $\text{NH}_3$  and  $\text{NO}_x$  to form  $\text{N}_2$  and  $\text{H}_2\text{O}$ . The hydrocarbon and ammonia are added through banks of nozzles

in the superheat or reheat sections of the boiler. The injection location is determined by the location of the temperature windows for the "plasma creation zone" as well as the reaction zone for the ammonia.

To date, only one full-scale demonstration has been conducted to evaluate the technology on utility-sized boilers similar to AVS. The process is an emerging NO<sub>x</sub> control, and there is limited information available to evaluate its technical feasibility and long-term effectiveness on a large lignite-fired boiler. Potential NO<sub>x</sub> removal efficiencies would be a function of NH<sub>3</sub>-NO<sub>x</sub> mixing, flue gas temperature, flue gas composition, and residence time downstream of the injection lances.

Because this is an emerging technology, long-term full-scale demonstration testing is required to demonstrate its effectiveness at AVS. It is likely that extensive design engineering and testing would be required to evaluate the technical feasibility and long-term effectiveness of the control system. Detailed design of the lances, mixing, optimization of the reagent supply across the boiler convective pass, flue gas temperatures, and flow distribution would have to be studied. Interference with the tube pendants in the convective pass may also make this more difficult to install. Installing a hydrocarbon distribution grid may present a problem with large boilers because of the span needed to uniformly distribute the reagent, interference with the tube pendants in the convective pass, and an additional booster fan may be needed. As such, NO<sub>x</sub>Star™ is not considered a technically feasible NO<sub>x</sub> control technology at AVS.

#### *PerNO<sub>x</sub>ide*

PerNO<sub>x</sub>ide utilizes hydrogen peroxide (H<sub>2</sub>O<sub>2</sub>) to reduce NO<sub>x</sub> emissions. Hydrogen peroxide is injected into the ducts ahead of the air preheater and oxidizes the NO to NO<sub>2</sub>, which is then captured in a downstream FGD system. To date, the technology has only been tested on a pilot-scale, and it has not been demonstrated on any coal-fired boilers. It is likely that extensive design engineering and testing would be required to evaluate the scale-up potential and long-term effectiveness of the system on AVS. As such, PerNO<sub>x</sub>ide is not considered a technically feasible NO<sub>x</sub> control technology at AVS.

#### LoTOX®

The LoTOX system is a gas-phase, low-temperature oxidation system, wherein ozone is injected into the flue gas stream to oxidize NO and NO<sub>2</sub> to N<sub>2</sub>O<sub>5</sub> before being removed in a wet scrubber. This highly oxidized species of NO<sub>x</sub> is water-soluble and rapidly reacts with water to form nitric acid. The conversion of NO<sub>x</sub> to nitric acid occurs as the N<sub>2</sub>O<sub>5</sub> contacts liquid sprays in the scrubber. The nitric acid would react with the alkali compounds in

the scrubber and would be eliminated via the scrubber waste and byproduct streams. The LoTO<sub>x</sub> system requires on demand ozone generation from a liquid oxygen supply.

The LoTO<sub>x</sub> system has been successfully applied in refinery applications however; there are no full-scale installations on coal-fired boilers. According to vendors, one coal-fired boiler demonstration on a 25-MW boiler was performed which showed 90% NO<sub>x</sub> removal. It is likely that extensive design engineering and testing would be required to evaluate the scale-up potential and long-term effectiveness of the system at AVS. As such, LoTO<sub>x</sub> is not considered a technically feasible NO<sub>x</sub> control technology at AVS.

### Water Injection

The principle behind this technology is to inject an atomized water spray into the high-NO<sub>x</sub> production zones of a cyclone burner or in the core of the flame for other furnaces. The water spray reduces the temperature and results in lower NO<sub>x</sub> production within this zone. Developers claim that water injection through burners used in tangential-fired and wall-fired units will also lower the flame temperature and, hence, lower NO<sub>x</sub> production. However, only laboratory results are available to demonstrate this technology's effectiveness in coal-fired applications.

Water injection is well demonstrated for combustion turbine applications for NO<sub>x</sub> reduction. However, there is insufficient experience and demonstration data in coal-fired applications. As such, water injection is not considered a technically feasible NO<sub>x</sub> control technology at AVS.

### **5.2.2.6 Technical Feasibility Summary**

Table 5-5 summarizes the results of the feasibility evaluation of available NO<sub>x</sub> control options for AVS Units 1 and 2.



**Table 5-5. Technically Feasible NO<sub>x</sub> Control Options**

NO <sub>x</sub> Control Option	Technically Feasible (Yes/No)	Control Percentage (Note 1)	Technical Feasibility Summary
Selective Non-Catalytic Reduction (SNCR)	Yes	10%	SNCR is considered an available and technically feasible NO <sub>x</sub> control technology for AVS Units 1 and 2. Computational fluid dynamic modeling and temperature mapping of the boiler would be needed to confirm that the incremental reduction in NO <sub>x</sub> emissions is achievable without creating unacceptable operational issues.
Rich Reagent Injection	No	0%	RRI is not considered an available or technically feasible NO <sub>x</sub> control option at AVS.
Gas Reburn	No	0%	Gas reburn is not considered an available or technically feasible NO <sub>x</sub> control technology at AVS Units 1 and 2.
Innovative Technologies: NO <sub>x</sub> Star™ PerNO <sub>x</sub> ide LoTO <sub>x</sub> Water Injection	No	0%	Innovative NO <sub>x</sub> control technologies are evaluated in Section 5.2.2.5. In all cases, the technologies have not been demonstrated on a large North Dakota lignite-fired boiler. Extensive testing and design engineering would be required to evaluate the technical feasibility and long-term effectiveness of each innovative control system on AVS Units 1 and 2. Therefore, the innovative NO <sub>x</sub> control technologies are not considered available control options and are not technically feasible NO <sub>x</sub> control options for AVS Units 1 and 2.
Selective Catalytic Reduction:			
High-dust configuration	No	0%	Due to significant unresolved issues associated with catalyst poisoning, catalyst blinding and plugging, and catalyst erosion; and based on the finding that engineering solutions have not been determined or demonstrated and the high dust configuration has not moved beyond pilot scale testing, high dust SCR is not an available or technically feasible NO <sub>x</sub> control technology for AVS Units 1 and 2.
Low-dust configuration	No	0%	Because AVS Units 1 and 2 is equipped with existing dry FGD/FF control systems, low-dust SCR has no practical application on the unit, and low-dust SCR is not considered an available or technically feasible NO <sub>x</sub> control option for AVS Units 1 and 2.

NO <sub>x</sub> Control Option	Technically Feasible (Yes/No)	Control Percentage (Note 1)	Technical Feasibility Summary
Tail-end configuration	Yes	50%	Tail-end SCR has not been installed on a North Dakota lignite-fired unit, and extended trials would be needed to better understand the design and operation of tail-end SCR on AVS Units 1 and 2. Because there are unresolved issues associated with catalyst poisoning, it's unlikely that Basin Electric could obtain a viable commercial offering for tail-end SCR on AVS Units 1 and 2. Nevertheless, during the initial planning period, NDDH concluded that tail-end SCR was a technically feasible NO <sub>x</sub> control technology for a North Dakota lignite-fired boiler, and evaluated the costs and cost-effectiveness of the control system. Based on the approach NDDH used during the initial planning period (i.e., assuming technical feasibility and evaluating the control system for costs and cost-effectiveness), tail-end SCR will be carried forward to the four factor analysis.

Note 1. Control percentage calculated using the baseline NO<sub>x</sub> emission rate and the achievable NO<sub>x</sub> emission rate for each technically feasible control option.

### 5.2.3 Evaluate Technically Feasible NO<sub>x</sub> Control Options for Effectiveness

The technically feasible NO<sub>x</sub> control technologies for Units 1 and 2 are listed in Table 5-6 and Table 5-7 in descending order of control efficiency. Table 5-6 and Table 5-7 also provide control option-specific NO<sub>x</sub> emission rates in terms of lb/MMBtu. Emission rates shown represent average emission rates that the control options would be expected to achieve during normal operations.

**Table 5-6. Evaluate Technically Feasible NO<sub>x</sub> Control Options by Effectiveness for AVS Unit 1  
(Baseline Average Emissions)**

Alt. No.	Control Technology	NO <sub>x</sub> Emission Rate <sup>(Note 1)</sup> lb/MMBtu	% Reduction from Baseline <sup>(Note 2)</sup>	NO <sub>x</sub> Emission Rate <sup>(Note 1)</sup> lb/hr	NO <sub>x</sub> Emission Rate <sup>(Note 1)</sup> tons/yr
B	SCR – tail-end configuration <sup>(Note 2)</sup>	0.05	52%	206	870
A	SNCR	0.09	10%	388	1,636
--	Baseline (existing OFA/LNCFS)	0.10		427	1,802
--	Permit Limit (assume 50/50 split for each unit)	0.17 (30-day) 0.50 (3-hour)	--	2,465 lb/hr (3-hr average)	

Note 1. Emission rates shown represent average emission rates that the control options would be expected to achieve on an on-going long-term basis under normal operating conditions for AVS Unit 1. Emission rates are provided for comparative purposes, and should not be construed to represent proposed emission limits. Corresponding permit limits must be evaluated on a control system-specific basis.

Note 2. Tail-end SCR has not been installed on a North Dakota lignite-fired unit, and extended trials would be needed to better understand the design and operation of tail-end SCR on AVS Unit 1. Nevertheless, during the initial planning period, NDDH concluded that tail-end SCR was a technically feasible NO<sub>x</sub> control technology for a North Dakota lignite-fired boiler, and evaluated the costs and cost-effectiveness of the control system. For consistency with NDDH's conclusion from the first planning period, tail-end SCR will be carried forward to the four factor analysis.

**Table 5-7. Evaluate Technically Feasible NO<sub>x</sub> Control Options by Effectiveness for AVS Unit 2  
(Baseline Average Emissions)**

Alt. No.	Control Technology	NO <sub>x</sub> Emission Rate <sup>(Note 1)</sup> lb/MMBtu	% Reduction from Baseline	NO <sub>x</sub> Emission Rate <sup>(Note 1)</sup> lb/hr	NO <sub>x</sub> Emission Rate <sup>(Note 1)</sup> tons/yr
B	SCR – tail-end configuration <sup>(Note 2)</sup>	0.05	52%	224	916
A	SNCR	0.09	10%	421	1,722
--	Baseline (existing OFA/LNCFS)	0.10		466	1,904
--	Permit Limit (assume 50/50 split for each unit)	0.17 (30-day) 0.50 (3-hour)	--	2,465 lb/hr (3-hr average)	

Note 1. Emission rates shown represent average emission rates that the control options would be expected to achieve on an on-going long-term basis under normal operating conditions for AVS Unit 2. Emission rates are provided for comparative purposes, and should not be construed to represent proposed emission limits. Corresponding permit limits must be evaluated on a control system-specific basis.

Note 2. Tail-end SCR has not been installed on a North Dakota lignite-fired unit, and extended trials would be needed to better understand the design and operation of tail-end SCR on AVS Unit 2. Nevertheless, during the initial planning period, NDDH concluded that tail-end SCR was a technically feasible NO<sub>x</sub> control technology for a North Dakota lignite-fired boiler, and evaluated the costs and cost-effectiveness of the control system. For consistency with NDDH's conclusion from the first planning period, tail-end SCR will be carried forward to the four factor analysis.

Table 5-8 provides control option-specific NO<sub>x</sub> emission rates in terms of lb/MMBtu based on the projected future maximum emission rates. Emission rates shown represent the projected future maximum emission rates that the control options would be expected to achieve during normal operations.

**Table 5-8. Evaluate Technically Feasible NO<sub>x</sub> Control Options by Effectiveness – AVS Unit 1 or 2 (Projected Future Maximum Emissions)**

Alt. No.	Control Technology	NO <sub>x</sub> Emission Rate <sup>(Note 1)</sup> lb/MMBtu	% Reduction from Baseline	NO <sub>x</sub> Emission Rate <sup>(Note 1)</sup> lb/hr	NO <sub>x</sub> Emission Rate <sup>(Note 1)</sup> tons/yr
B	SCR – tail-end configuration <sup>(Note 2)</sup>	0.05	52%	247	1,080
A	SNCR	0.09	10%	463	2,030
--	Baseline Unit 1 (existing OFA/LNCFS)	0.10	--	510	2,235
--	Baseline Unit 2 (existing OFA/LNCFS)	0.10	--	512	2,244
--	Permit Limit (assume 50/50 split for each unit)	0.17 (30-day) 0.50 (3-hour)	--	2,465 lb/hr (3-hr average)	

Note 1. Emission rates shown represent projected future maximum emission rates that the control options would be expected to achieve on an on-going long-term basis under 100% capacity factor operation for AVS Unit 1 or 2. Emission rates are provided for comparative purposes, and should not be construed to represent proposed emission limits. Corresponding permit limits must be evaluated on a control system-specific basis.

Note 2. Tail-end SCR has not been installed on a North Dakota lignite-fired unit, and extended trials would be needed to better understand the design and operation of tail-end SCR on AVS Units 1 and 2. Nevertheless, during the initial planning period, NDDH concluded that tail-end SCR was a technically feasible NO<sub>x</sub> control technology for a North Dakota lignite-fired boiler, and evaluated the costs and cost-effectiveness of the control system. For consistency with NDDH's conclusion from the first planning period, tail-end SCR will be carried forward to the four factor analysis.

### 5.3 NO<sub>x</sub> COST OF COMPLIANCE (STATUTORY FACTOR ONE)

The economic analysis performed as part of the four factor analysis examines the cost-effectiveness of each technically feasible control technology, on a dollar per ton of pollutant removed basis. Annual emissions, calculated for a particular control device, are subtracted from baseline annual emissions to calculate tons of pollutant controlled per year. For units with existing controls, the base case represents existing baseline actual emissions. Annual costs for each control option are calculated relative to the base case by adding annual O&M costs to the annualized cost of capital and, if applicable, lost revenue due to extended outage required for installation of control equipment. Capital costs and lost revenues were annualized using a capital recovery factor

based on an annual interest rate of 5.25% and equipment life of 20 years.<sup>50</sup> Cost effectiveness (\$/ton) of a particular control option is simply the annual cost (\$/yr) divided by the annual reduction in annual emissions (ton/yr). In addition to cost-effectiveness relative to the base case, the incremental cost-effectiveness to go from one level of control to the next, more stringent, level of control may also be calculated to evaluate the incremental cost effectiveness of the more stringent control.

Capital and O&M cost estimates were developed for each of the technically feasible NO<sub>x</sub> control options. The AVS Units 1 and 2 cost estimates are conceptual in nature; thus, S&L did not procure equipment quotes specifically for the Units 1 and 2 control system upgrades. Rather, equipment costs are based on conceptual designs developed for the retrofit control systems, preliminary equipment sizing developed for the major pieces of equipment (based on AVS-specific design parameters, including typical fuel characteristics, full load heat input, and flue gas temperatures and flow rates), and recent pricing for similar equipment. S&L would characterize the cost estimates for the AVS Units 1 and 2 retrofit technologies as “concept screening” cost estimates generally based on parametric models, judgment, or analogy.

Control technology equipment costs for the retrofit options were developed by scaling cost estimates prepared by S&L for other similar projects. Major equipment costs were developed based on equipment costs recently developed for similar projects, and include the equipment, material, labor, and all other direct costs needed to retrofit the units with the control technology. Sub-accounts for the capital cost estimates (e.g., mobilization and demobilization, consumables, Contractor G&A expense, freight on materials, etc.) were developed by applying ratios from detailed cost estimates that were prepared for projects with similar scopes.

Fixed O&M costs include operating labor, maintenance labor, maintenance material, and administrative labor. Variable O&M costs include the cost of consumables, including reagent, water consumption, and auxiliary power requirements. Auxiliary power requirements reflect the additional power requirements associated with the operation of the new control technology (compared to the existing technology). All O&M costs reflect the incremental increase in O&M costs compared to the costs incurred to operate the existing control systems.

---

<sup>50</sup> The assumed 20-year equipment life is consistent with the control system equipment life used by NDDH in its evaluation of NO<sub>x</sub> and SO<sub>2</sub> control technologies for BART-eligible sources. (see, e.g., ND Regional Haze Final SIP, Appendix C.1, “BART Determination Study for Leland Olds Station Units 1 & 2, Basin Electric Power Cooperative, August 2006, pgs. 64 (NO<sub>x</sub> controls) and 158 (SO<sub>2</sub> controls). See also, ND Regional Haze Final SIP, Appendix C4, “NO<sub>x</sub> Best Available Control Technology Study for Milton R. Young Station Unit 1, Minnkota Power Cooperative, Inc., October 2006, pg. 3-22).

In addition to the cost effectiveness relative to the base case, the incremental cost-effectiveness to go from one level of control to the next more stringent level of control will also be calculated to evaluate the cost effectiveness of the more stringent control.

### 5.3.1 NO<sub>x</sub> Average Annual Economic Evaluation

Table 5-9 presents the capital costs and annual operating costs associated with building and operating each control system. Table 5-9 shows the average annual and incremental cost effectiveness for each control system. Additional cost details are provided in Appendix D.

**Table 5-9. NO<sub>x</sub> Control Cost Summary (Average Annual)**

AVS Unit No.	Alt. No.	NO <sub>x</sub> Control Option	Total Capital Investment \$	Annual Capital Recovery Cost \$/yr	Annual Operating Cost \$/yr	Total Annual Cost \$/yr
Unit 1	B	SCR – tail-end configuration	\$221,396,000	\$18,144,000	\$18,201,000	\$36,345,000
	A	SNCR	\$16,356,000	\$1,340,000	\$1,945,000	\$3,285,000
Unit 2	B	SCR – tail-end configuration	\$221,396,000	\$18,144,000	\$18,207,000	\$36,351,000
	A	SNCR	\$16,356,000	\$1,340,000	\$1,970,000	\$3,310,000



**Table 5-10. NO<sub>x</sub> Emissions Control System Cost Effectiveness (Average Annual)**

AVS Unit No.	Alt. No.	NO <sub>x</sub> Control Option	Total Annual Cost \$	Expected Emission Reduction (Note 2) tons NO <sub>x</sub> /yr	Average Annual Cost- Effectiveness (Note 2) \$/ton NO <sub>x</sub> removed	Incremental Annual Cost- Effectiveness (Note 1) \$/ton NO <sub>x</sub> removed
Unit 1	B	SCR – tail-end configuration	\$36,345,000	931	\$39,035	\$43,161
	A	SNCR	\$3,285,000	165	\$19,893	
Unit 2	B	SCR – tail-end configuration	\$36,351,000	988	\$36,792	\$40,997
	A	SNCR	\$3,310,000	182	\$18,179	

Note 1. Incremental cost-effectiveness represents the incremental increase in annual costs (\$/yr) divided by the incremental increase in annual NO<sub>x</sub> emissions reductions (tpy) between a control option and the next most effective option. For the option “SCR,” incremental cost compares to the option “SNCR.”

Note 2. Expected emission reductions and average annual cost-effectiveness based on baseline NO<sub>x</sub> emission rate and capacity factor during baseline NO<sub>x</sub> period for each AVS Unit.

Table 5-10 indicates that the average annual cost effectiveness of the technically feasible NO<sub>x</sub> control options for Unit 1 range from \$19,893 per ton (SNCR) to \$39,035 per ton (SCR – Tail end configuration) NO<sub>x</sub> removed; and for Unit 2 ranges from \$18,179 per ton to \$36,792 per ton NO<sub>x</sub> removed.

Installation of an SNCR system is expected to achieve approximately 10% NO<sub>x</sub> reduction. The cost effectiveness of this option is approximately \$19,000 per ton.

Tail-end SCR system costs have been included to remain consistent with the approach used by NDDH during the initial planning period. Based on preliminary cost estimates, the cost effectiveness of a tail-end SCR system is approximately \$39,000 per ton. Compared to the SNCR control option, the incremental cost effectiveness is approximately \$43,000 per ton.

### 5.3.2 NO<sub>x</sub> Projected Future Maximum Economic Evaluation

Table 5-11 presents the capital costs and annual operating costs associated with building and operating each control system; annual operating costs are based on the units operating at 100% capacity factor. Table 5-12 shows the average annual and incremental cost effectiveness for each control system with emissions reductions and cost effectiveness values based on 100% capacity factors and projected future maximum emission rates. Additional cost details are provided in Appendix D.

**Table 5-11. NO<sub>x</sub> Control Cost Summary (Projected Future Maximum)**

AVS Unit No.	Alt. No.	NO <sub>x</sub> Control Option	Total Capital Investment \$	Annual Capital Recovery Cost \$/yr	Annual Operating Cost \$/yr	Total Annual Cost \$/yr
Unit 1	B	SCR – tail-end configuration	\$221,396,000	\$18,144,000	\$18,788,000	\$36,932,000
	A	SNCR	\$16,356,000	\$1,340,000	\$2,074,000	\$3,414,000
Unit 2	B	SCR – tail-end configuration	\$221,396,000	\$18,144,000	\$18,649,000	\$36,793,000
	A	SNCR	\$16,356,000	\$1,340,000	\$2,075,000	\$3,415,000

Note 1. Annual operating costs based on baseline NO<sub>x</sub> emissions and 100% capacity factor for each AVS

**Table 5-12. NO<sub>x</sub> Emissions Control System Cost Effectiveness (Based on Projected Future Maximum Emissions)**

AVS Unit No.	Alt. No.	NO <sub>x</sub> Control Option	Total Annual Cost \$	Expected Emission Reduction tons NO <sub>x</sub> /yr	Average Annual Cost-Effectiveness \$/ton NO <sub>x</sub> removed	Incremental Annual Cost-Effectiveness (Note 1) \$/ton NO <sub>x</sub> removed
Unit 1	B	SCR – tail-end configuration	\$36,932,000	1,155	\$31,977	\$35,278
	A	SNCR	\$3,414,000	205	\$16,667	
Unit 2	B	SCR – tail-end configuration	\$36,793,000	1,165	\$31,589	\$35,131
	A	SNCR	\$3,415,000	215	\$15,910	

Note 1. Incremental cost-effectiveness represents the incremental increase in annual costs (\$/yr) divided by the incremental increase in annual NO<sub>x</sub> emissions reductions (tpy) between a control option and the next most effective option. For the option “SCR,” incremental cost compares to the option “SNCR.”

Note 2. Expected emission reductions and average annual cost-effectiveness based on baseline NO<sub>x</sub> emissions and 100% capacity factor for each AVS Unit.

Table 5-12 indicates that the average annual cost effectiveness based on projected future maximum of the technically feasible NO<sub>x</sub> control options for Unit 1 from \$16,667 per ton (SNCR) to \$31,977 per ton (SCR – Tail end configuration) NO<sub>x</sub> removed; and for Unit 2 ranges from \$15,910 per ton to \$31,589 per ton NO<sub>x</sub> removed.

Installation of an SNCR system is expected to achieve approximately 10% NO<sub>x</sub> reduction from the projected future maximum emissions. The cost effectiveness of this option is approximately \$16,000 per ton.

Tail-end SCR system costs have been included to remain consistent with the approach used by NDDH during the initial planning period. Based on preliminary cost estimates, the cost effectiveness of a tail-end SCR system is approximately \$31,000 per ton. Compared to the SNCR control option, the incremental cost effectiveness is approximately \$35,000 per ton.

## 6. TIME NECESSARY FOR COMPLIANCE (STATUTORY FACTOR TWO)

The time necessary for compliance is generally defined as the time needed for full implementation of the technically feasible control options. This includes the time needed to develop and implement the regulations, as well as the time needed to install the selected control equipment. The time needed to install the control equipment includes time for equipment procurement, design, fabrication, and installation. Therefore, compliance deadlines must consider the time necessary for compliance by setting a compliance deadline that provides a reasonable amount of time for the source to implement the control measure.

Table 6-1 and Table 6-2 include estimated timeframes needed to implement each of the technically feasible control. The estimated timeframes do not account for time needed for North Dakota to develop and implement the regulations; therefore, the scheduled activities identified below commence immediately after SIP approval and are subject to the maintenance outage schedules of the individual unit.

**Table 6-1. SO<sub>2</sub> Emissions Control System Implementation Schedule**

SO <sub>2</sub> Control Option	Alt. No.	Design / Specification / Procurement (months)	Detail Design / Fabrication (months)	Construction / Commissioning / Startup / Tuning (months)	Compliance Date (months after SIP approval)
FGD operational improvements – Station Work Practice (Note 1)	A	0	0	3	3
FGD operational improvements – Increase Ca:S Stoichiometric Ratio	B	12	15	24 <sup>(Note 2)</sup>	No later than 60 months
Dry FGD (CDS) + Existing FF	D	12	20	24	No later than 60 months
Wet FGD	E	12	22	26	No later than 60 months

Note 1. Although this option would not require design/fabrication and construction months, Basin Electric would need 2-3 months to update O&M manuals and personnel training for the change to the work practice of the existing DFGD systems.

Note 2. Requires coordination with normal tri-annual outage schedules.

NORTH DAKOTA ROUND II REGIONAL HAZE SIP  
DETERMINATION'S FOUR-FACTOR ANALYSIS FOR ANTELOPE  
VALLEY STATION UNITS 1 AND 2

**6-2****Table 6-2. NO<sub>x</sub> Emissions Control System Implementation Schedule**

<b>NO<sub>x</sub> Control Option</b>	<b>Alt. No.</b>	<b>Design / Specification / Procurement (months)</b>	<b>Detail Design / Fabrication (months)</b>	<b>Construction / Commissioning / Startup (months)</b>	<b>Compliance Date (months after SIP approval)</b>
SNCR	A	10	6	6	No later than 60 months
SCR – Tail-End Configuration	B	10	18	24	No later than 60 months

## **7. ENERGY AND NON-AIR QUALITY ENVIRONMENTAL IMPACTS (STATUTORY FACTOR THREE)**

The primary purpose of the environmental impact analysis is to assess collateral environmental impacts due to control of the regulated pollutant in question. Environmental impacts may include solid or hazardous waste generation, discharges of polluted water from a control device, visibility impacts, increased emissions of other criteria or non-criteria pollutants, increased water consumption, and land use impacts from waste disposal.

### **7.1 ENVIRONMENTAL IMPACTS**

AVS Units 1 and 2 are currently equipped with LNCFS/OFA for NO<sub>x</sub> control and dry scrubber technology for SO<sub>2</sub> control. The hydrated lime reactant used in a dry scrubbing system reacts with SO<sub>2</sub> in the flue gas to form calcium sulfate and calcium sulfite solids. The solids are captured in the existing FF particulate control system and either returned to the system for reuse or removed from the system as nonhazardous solid waste. The existing dry scrubbing system also requires water to hydrate the lime prior to injection into the reaction modules. Based on the design of the control system, the DFGD at AVS currently use approximately 690 gpm of water. Collateral environmental impacts associated with the existing Units 1 and 2 control systems include water consumption and increased solid waste generation. There were no collateral impacts associated with the LNCFS/OFA system.

Based on a review of potential non-air quality environmental impacts, no significant collateral environmental impacts were identified for any of the SO<sub>2</sub> and NO<sub>x</sub> control options included in this evaluation, with the exception, potentially, of the WFGD, TE-SCR and SNCR options. No significant non-air quality environmental impacts were identified for the options that include replacing the existing scrubber modules with new scrubber modules or FGD operational improvements/upgrades.

There are a number of potential non-air quality environmental impacts associated with the WFGD control option. Unlike dry scrubbing systems that generate a dry FGD byproduct, WFGD systems generate a liquid calcium sulfate by-product that must be dewatered prior to disposal. WFGD control systems can be designed with forced oxidation that results in a gypsum-grade by-product that can be sold into the local gypsum market. If an adequate gypsum market is not available, the gypsum by-product will require disposal. WFGD control systems also generate a wastewater stream that must be treated prior to discharge. WFGD wastewaters typically consist of a saturated solution of calcium sulfate, calcium sulfite, and sodium chloride, with trace amounts of fly ash and unreacted



limestone. Traces of metal ions may also be present due to fly ash carryover from the flue gas to the WFGD scrubber liquor. WFGD wastewater treatment systems typically require calcium sulfate/sulfite desaturation, heavy metals precipitation, coagulation/precipitation, and sludge dewatering. Treated wastewater is typically discharged to surface water pursuant to a National Pollutant Discharge Elimination System (NPDES) discharge permit, and solids are typically disposed of in a landfill. However, AVS is a zero discharge facility where only non-contact stormwater is currently discharged. With the implementation of a WFGD, the facility would need to remain a zero discharge facility.

WFGD systems also require significantly more water than the dry systems. Based on design criteria for wet and dry FGD control systems, WFGD systems typically require approximately 25-30% more water than a similarly sized DFGD control system. This would increase water consumption at each AVS Unit on average approximately 115 gpm. Water consumption is an important factor when assessing potential non-air quality environmental impacts at facilities located in North Dakota, and could represent a significant non-air quality collateral environmental impact.

In addition, the TE-SCR and SNCR control options have a number of collateral impacts. The TE-SCR catalyst oxidizes some of the  $\text{SO}_2$  to  $\text{SO}_3$  in addition to catalyzing the reaction between  $\text{NO}_x$  and ammonia. There could be the potential for increased  $\text{SO}_3$  emissions with the use of a TE-SCR. The  $\text{SO}_3$  will react with the moisture in the stack to form  $\text{H}_2\text{SO}_4$  emissions. In addition both the TE-SCR and SNCR options utilize ammonia as the reagent for the reactions with  $\text{NO}_x$  to occur. There will be some ammonia slip emission from a TE-SCR in the range of 2 ppm. However the ammonia slip emission from a SNCR control technology will be significantly higher at 10 ppm. Ammonia slip emissions from the SNCR option will likely end up in the dry FGD solids, however there is no means to capture the ammonia slip emissions from the TE-SCR since it is installed prior to the stack. The ammoniated dry FGD solids would create a more difficult work environment for the AVS staff that would be performing maintenance on the ash handling system and performing waste disposal activities.

## **7.2 ENERGY IMPACTS**

Options that include replacing the existing Unit 1 dry scrubbing system with a CDS/FF or WFGD system or adding a TE-SCR will increase pressure drop through the control systems, increase auxiliary power requirements, and

adversely affect the unit's net plant heat rate (Btu heat input per MW<sub>Net</sub> output).<sup>51</sup> Consequently, heat input to the boiler would need to increase to compensate for the increased auxiliary power requirements while achieving the same net plant output, or net output from the unit would decrease.

Although several of the control options have energy impacts, none of the impacts are considered significant enough as to disqualify any of the options from consideration in the four factor analysis. In order to account for potential energy impacts associated with each option, the auxiliary power cost associated with operating the control systems have been included as an annual operating cost in the economic impact assessment.

### **7.3 ENVIRONMENTAL / ENERGY IMPACTS SUMMARY**

A summary of the Statutory Factor 3 environmental and energy impact analysis is provided in Table 7-1.

---

<sup>51</sup> Heat rate represents the amount of heat input to the boiler (Btu) required to generate one megawatt (MW) net electric output and is reported as Btu/MW<sub>Net</sub>.

**Table 7-1. Summary of Energy and Non-Air Quality Environmental Impacts**

Control Option	Collateral Environmental & Energy Impacts
<b>Baseline</b>	<ul style="list-style-type: none"> <li>➤ AVS Units 1 and 2 are currently equipped with dry scrubbing / FF control systems. Existing collateral environmental and energy impacts include:</li> <li>➤ Solid FGD by-product management and disposal</li> <li>➤ Increased water consumption</li> <li>➤ Increased auxiliary power requirements and heat rate penalty</li> </ul>
<b><u>SO<sub>2</sub> Control Options</u></b>	
Replace existing DFGD with New WFGD control system	<ul style="list-style-type: none"> <li>➤ Increased water consumption</li> <li>➤ Wet by-product that requires dewatering prior to disposal</li> <li>➤ FGD wastewater treatment &amp; discharge</li> <li>➤ Increased auxiliary power requirements and heat rate penalty</li> </ul>
Replace existing DFGD with New CDS/FF Control System	<ul style="list-style-type: none"> <li>➤ Increased auxiliary power requirements and heat rate penalty</li> <li>➤ Increased solid FGD by-product management and disposal</li> </ul>
<b><u>NO<sub>x</sub> Control Options</u></b>	
Selective Catalytic Reduction (SCR) - Tail End Configuration	<ul style="list-style-type: none"> <li>➤ Increased auxiliary power requirements and heat rate penalty</li> <li>➤ Increased ammonia slip emissions</li> <li>➤ Potential increase in SO<sub>3</sub> emissions</li> </ul>
<b>SNCR</b>	<ul style="list-style-type: none"> <li>➤ Increased ammonia slip emissions</li> <li>➤ Increased auxiliary power requirements and heat rate penalty</li> <li>➤ Increased water consumption</li> <li>➤ Increased health and safety precautions required with ammoniated dry FGD solids O&amp;M activities.</li> </ul>

## **8. REMAINING USEFUL LIFE (STATUTORY FACTOR FOUR)**

The evaluation of technically feasible NO<sub>x</sub> and SO<sub>2</sub> controls options should consider the source's "remaining useful life" in determining the costs of compliance. The remaining useful life is the difference between the date that controls would be put in place and the date that the facility permanently ceases operation. If the remaining useful life of the unit is shorter than the useful life of a particular control option, the remaining useful life should be used annualizing costs. If the remaining useful life exceeds the useful life of the control options, the remaining use life has no effect on the cost evaluation.

Under the current Basin Electric resource plan, the remaining useful life of AVS Units 1 and 2 are considered to be greater than 20 years. Therefore, the remaining useful life has no impact on the annualized cost of control under the current regulatory framework.

## 9. CONCLUSIONS

At the request of NDDH, a four factor analysis was prepared for AVS Units 1 and 2 for use in their Round II Determination. The analysis identified technically feasible SO<sub>2</sub> and NO<sub>x</sub> control options for the units, and evaluated each of the control measures for the following four statutory factors:

1. The costs of compliance;
2. The time necessary for compliance;
3. The energy and non-air quality environmental impacts of compliance; and
4. The remaining useful life of any potentially affected anthropogenic source of visibility impairment.

The cost of compliance evaluation (Statutory Factor 1) prepared for SO<sub>2</sub> controls indicates that, from baseline emission rates, the average annual cost effectiveness of the technically feasible SO<sub>2</sub> control options for Unit 1 ranges from \$340 per ton (Alternative A) to \$6,992 per ton SO<sub>2</sub> removed (Alternative E), and for Unit 2 ranges from \$284 per ton (Alternative A) to \$6,861 per ton SO<sub>2</sub> removed (Alternative E). When evaluating projected future maximum emissions reductions, the average annual cost effectiveness of the technically feasible SO<sub>2</sub> control options for Unit 1 ranges from \$623 per ton (Alternative A) to \$6,677 per ton SO<sub>2</sub> removed (Alternative D), and for Unit 2 ranges from \$526 per ton (Alternative A) to \$6,584 per ton SO<sub>2</sub> removed (Alternative D).

The cost of compliance evaluation prepared for NO<sub>x</sub> controls indicates that, from baseline emission rates, the average annual cost effectiveness of the technically feasible NO<sub>x</sub> control options for Unit 1 ranges from \$19,893 per ton (Alternative A) to \$39,035 per ton NO<sub>x</sub> removed (Alternative B), and for Unit 2 ranges from \$18,179 per ton (Alternative A) to \$36,792 per ton NO<sub>x</sub> removed (Alternative B) from historical baselines. When evaluating projected future maximum emissions reductions, the average annual cost effectiveness of the technically feasible NO<sub>x</sub> control options for Unit 1 ranges from \$16,667 per ton (Alternative A) to \$31,977 per ton NO<sub>x</sub> removed (Alternative B), and for Unit 2 ranges from \$15,910 per ton (Alternative A) to \$31,589 per ton NO<sub>x</sub> removed (Alternative B).

The time necessary for compliance (Statutory Factor 2) for the SO<sub>2</sub> control options ranges from 3 months (Alternative A) to 60 months (Alternative E). For NO<sub>x</sub> control options, the time necessary for compliance ranges from 22 months (Alternative A) to 52 months (Alternative B).

An evaluation of energy impacts and non-air environmental impacts (Statutory Factor 3) indicates that certain control options will increase auxiliary power requirements due to increased pressure drop, which would adversely impact net plant heat rate. Consequently, heat input to the boiler would need to increase to compensate for the increased auxiliary power requirements while achieving the same net plant output, or net output from the unit would decrease. Collateral environmental impacts include increases in water consumption, FGD wastewater treatment and discharge, and solid waste generation.

Regarding remaining useful life (Statutory Factor 4), under the current Basin Electric resource plan, the remaining useful life of AVS Units 1 and 2 are considered to be greater than 20 years. Therefore, the remaining useful life has no impact on the annualized cost of control under the current regulatory framework.

Based on the results of the four factor analysis prepared for AVS, Basin Electric is aware that reducing SO<sub>2</sub> emissions by implementing FGD Operational Improvements (Alternative B) on Units 1 and 2 may be determined to be cost effective by the NDDH.

Within the Round II Determination process, the NDDH will evaluate visibility improvements relying on Western Region Area Partnership's (WRAP) cumulative modeling of the North Dakota based facilities for the various control options being evaluated. Basin Electric requests that the NDDH withhold their Round II Regional Haze SIP Determination for the AVS until the cumulative modeling platform is made available to the public and visibility improvement assessments can be conducted. Basin Electric will then perform a comparative visibility improvement analysis and submit the results to the NDDH for consideration. This effort will be coordinated with the NDDH for consistency of modeling protocols and model inputs.

In addition, Basin Electric requests, that in the event that SO<sub>2</sub> reductions will be required, any future 30-day rolling average permit limit will be based on an equivalent mass based combined plant (lb SO<sub>2</sub>/hr) 30-day rolling average basis. Since AVS began operation, the current combined plant total permit limit of 3,845 lb SO<sub>2</sub>/hr, 3-hour average, has been the benchmark for all operations guidance and procedures and is imbedded in the DFGD process control logic. To alter the basis of the operational control to a mass emission rate (lb SO<sub>2</sub>/MMBtu) will be extremely disruptive from an operational perspective when consideration is given to the complexity and variability of DFGD operations.

The four factor analysis prepared for AVS NO<sub>x</sub> reductions indicates that SNCR and tail-end SCR control options are cost prohibitive. The control cost evaluation indicates that the average cost effectiveness levels exceed \$15,000



per ton NO<sub>x</sub> removed. Basin Electric is proposing that the existing OFA / LNCFS systems on Units 1 and 2 represent appropriate controls for the Round II Determination, therefore no change to the current Title V Operating Permit is proposed for NO<sub>x</sub> emissions at AVS. Table ES-3 includes a summary of the proposed Round II Determination's control strategy for SO<sub>2</sub>, assessed SO<sub>2</sub> emissions on a 30-day rolling average basis and a proposed combined plant average emission rate for AVS. The proposed emissions include compliance margin to account for items such as variability in fuel heating value and sulfur content, and operating load profile.

**Table ES-1. Proposed Round II Determination's SO<sub>2</sub> Emission Rate**

<b>AVS Unit No.</b>	<b>Pollutant</b>	<b>Proposed Round II Determination's Emission Rate lb/MMBtu (30-day rolling average)</b>	<b>Proposed Round II Determination's Combined Plant Emission Rate (Note 1) (lb/hr)</b>	<b>Control Technology</b>
Unit 1	SO <sub>2</sub>	0.30	2,958	FGD Operational Improvements
Unit 2	SO <sub>2</sub>	0.30	2,958	FGD Operational Improvements

Note 1. The proposed Round II Determination's combined plant emission rate is a 23% reduction from the current combined plant permit limit of 3,845 lb SO<sub>2</sub>/hr, 3-hour avg.

## APPENDIX A

### NORTH DAKOTA DEPARTMENT OF HEALTH LETTER



May 2, 2018

**RECEIVED MAY 04 2018**

Mr. Mike Paul  
Basin Electric Power Coop.  
1717 E Interstate Avenue  
Bismarck, ND 58503-0564

Re: Regional Haze  
Second Planning Period

Dear Mr. Paul:

The Department of Health (Department) has begun work on the second planning period (Round 2) State Implementation Plan (SIP) for regional haze. In Round 1 of the regional planning process, the emphasis was on Best Available Retrofit Technology (BART) and making reasonable progress towards the national visibility goal. In Round 2, there are no BART requirements; therefore, we will focus on making reasonable progress. The reasonable progress analysis will be made using the four factors in Section 169A(g)(1) of the Clean Air Act:

The four factors are:

1. The cost of compliance
2. The time necessary to achieve compliance
3. The energy and non-air quality environmental impact of compliance; and
4. The remaining useful life of any existing source subject to such requirements

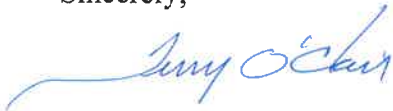
Guidance provided by the U.S. Environmental Protection Agency (Draft Guidance on Progress Tracking Metrics, Long Term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period at [https://www.epa.gov/sites/production/files/2016-07/documents/draft\\_regional\\_haze\\_guidance\\_july\\_2016.pdf](https://www.epa.gov/sites/production/files/2016-07/documents/draft_regional_haze_guidance_july_2016.pdf)) indicates the Department must address 80% of the visibility impairment caused by in-state sources. Data from the IMPROVE monitoring sites at Theodore Roosevelt National Park (TRNP) and Lostwood Wilderness Area (LWA) indicate that sulfates and nitrates continue to be the largest contributors to visibility impairment in these areas. The primary precursors of sulfates and nitrates are emissions of sulfur dioxide (SO<sub>2</sub>) and nitrogen oxides (NO<sub>x</sub>).

Coal-fired electrical generating units have been identified as one of the largest source of sulfur dioxide and nitrogen oxides in North Dakota. Therefore, the Department requests that you prepare a "four factors" analysis for your coal-fired electrical generating units. The analysis should be prepared using the draft EPA guidance noted above. The Department will identify other sources in North Dakota that will be required to submit a four factors analysis.

The Department will be working with the Western Regional Air Partnership (WRAP) to prepare the Round 2 SIP. WRAP will be conducting air quality modeling of regional emissions reductions in early 2019. The Department asks that your "four factors" analysis be submitted by January 31, 2019.

If you have any questions, please contact David Stroh of my staff at (701)328-5188.

Sincerely,

A handwritten signature in blue ink, appearing to read "Terry O'Clair", with a long horizontal flourish extending to the left.

Terry L. O'Clair  
Director  
Division of Air Quality

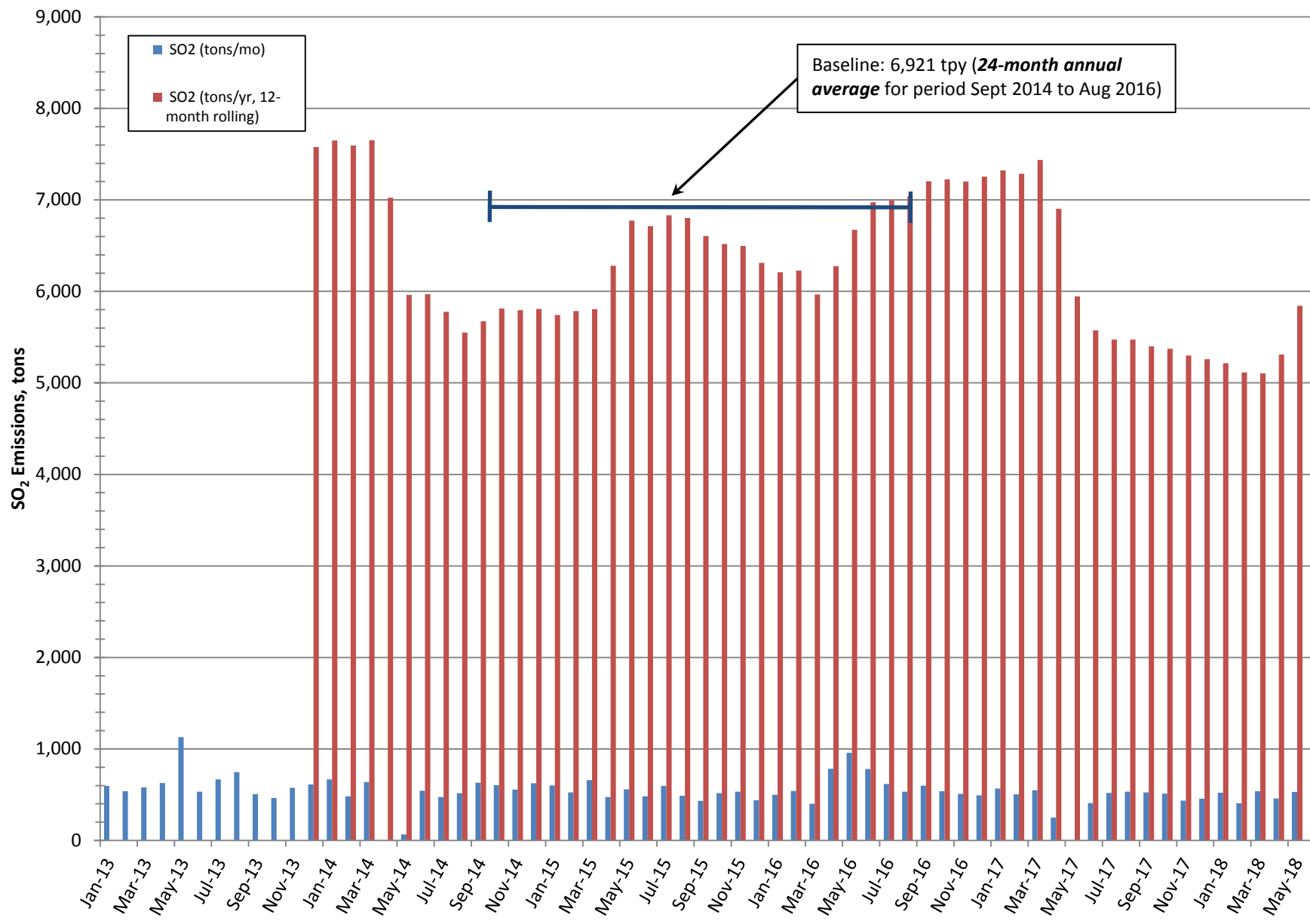
TLO/TB:saj

xc: Cris Miller, Basin Electric Power Coop.

## APPENDIX B

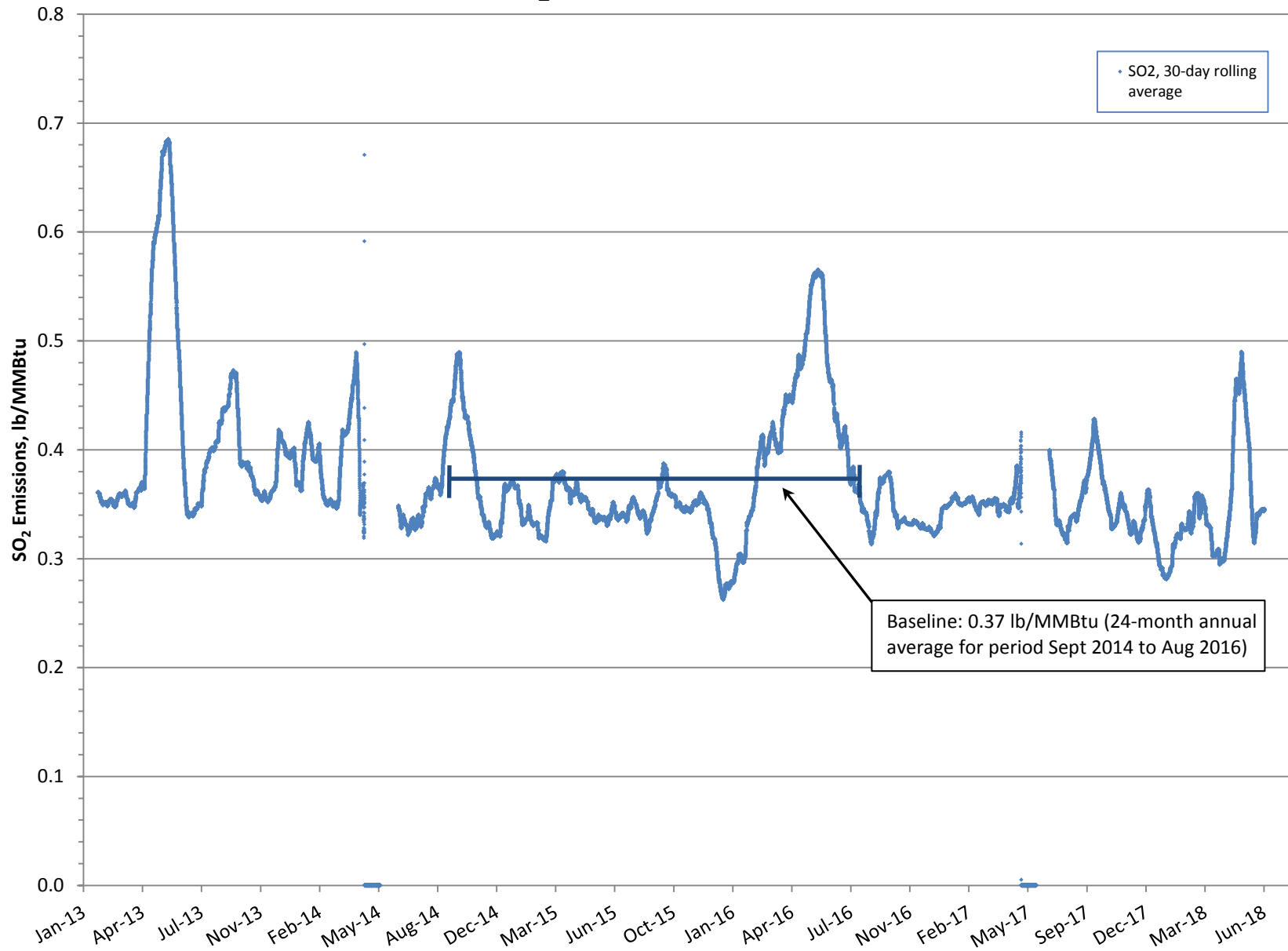
### ANTELOPE VALLEY UNITS 1 AND 2 BASELINE EMISSIONS

## AVS Unit 1 - Baseline SO<sub>2</sub> Emissions (tons) [1/2013 to 6/2018]

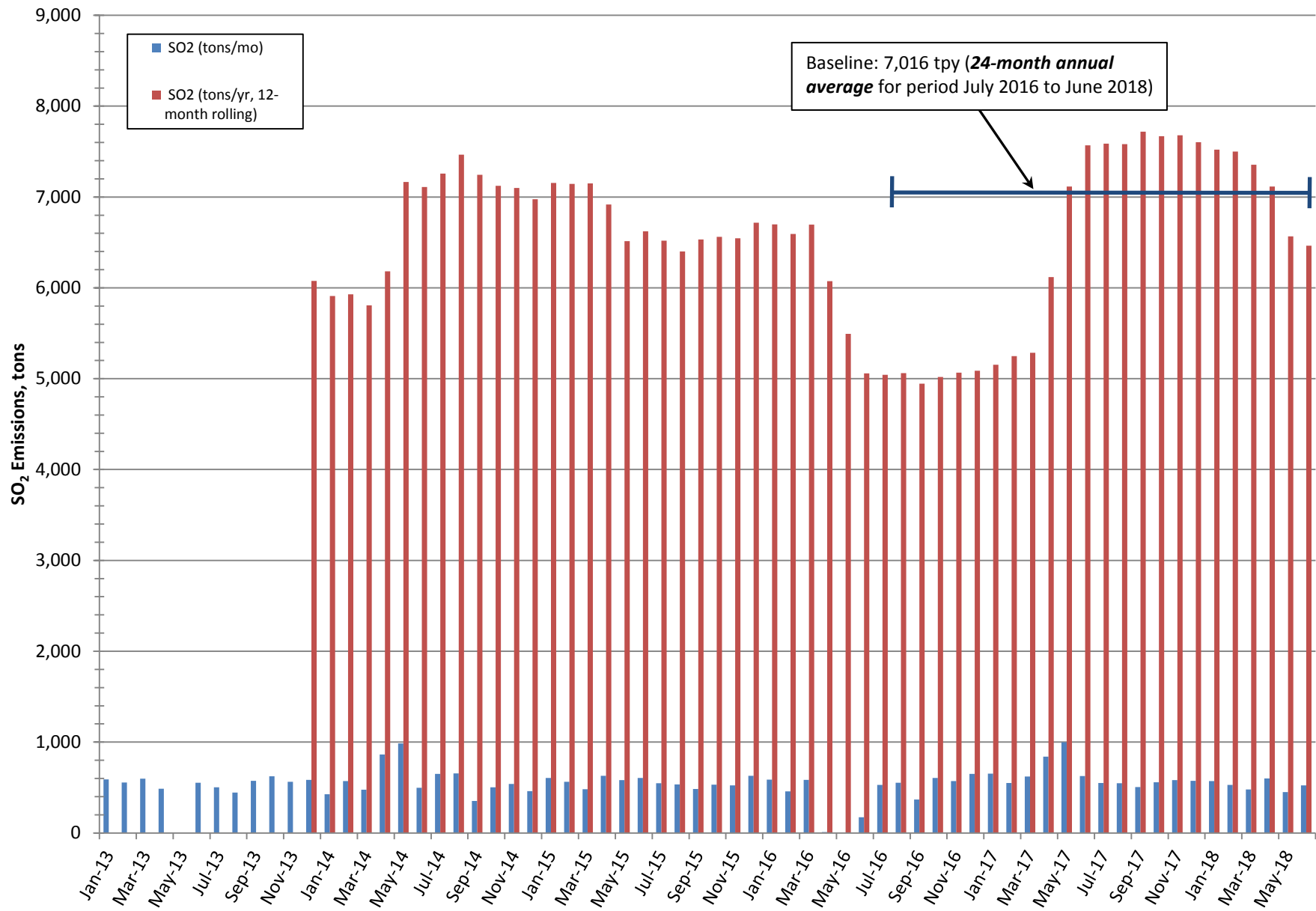




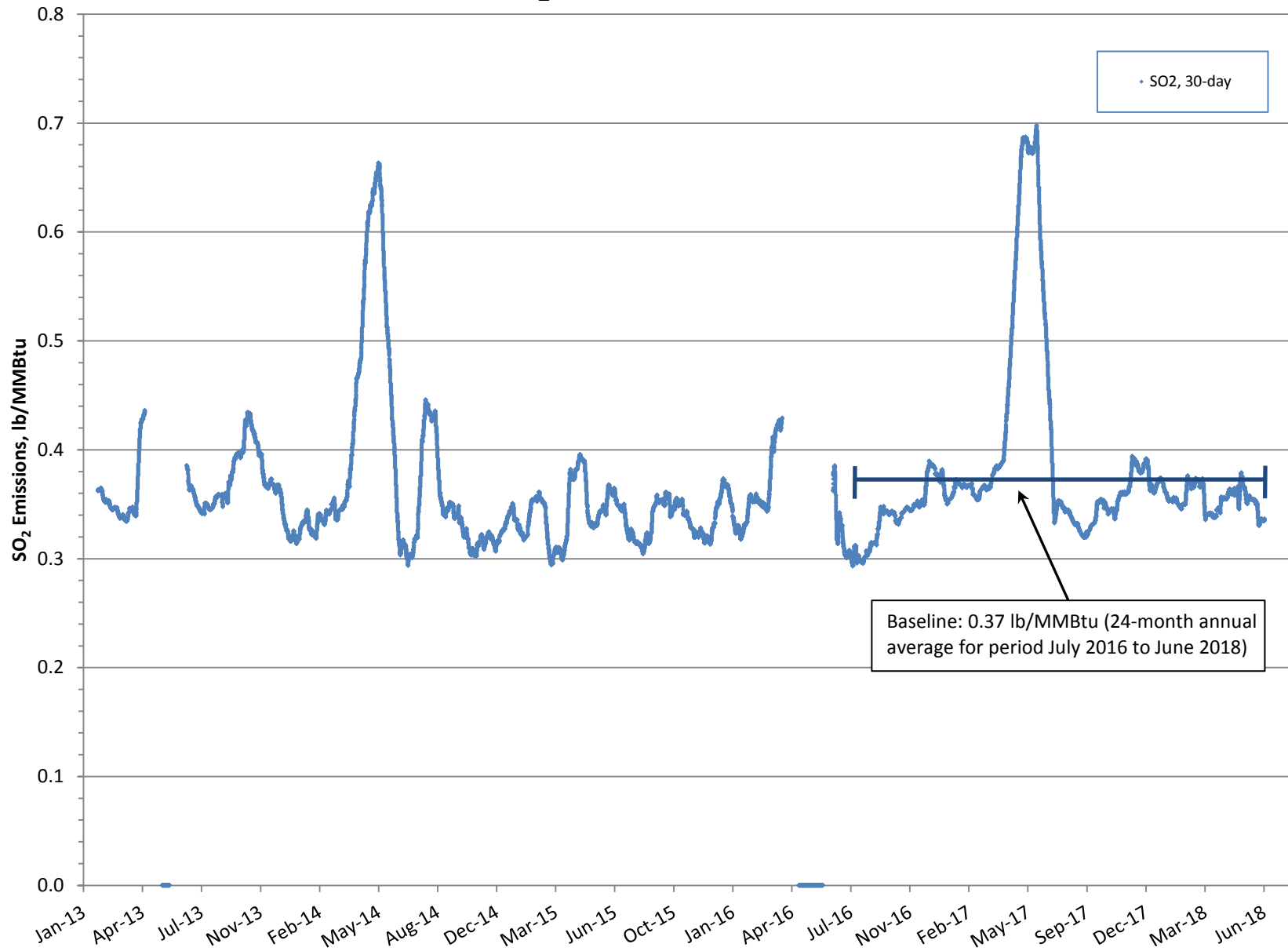
## AVS Unit 1 - Baseline SO<sub>2</sub> Emissions (lb/MMBtu) [1/2013 - 6/2018]



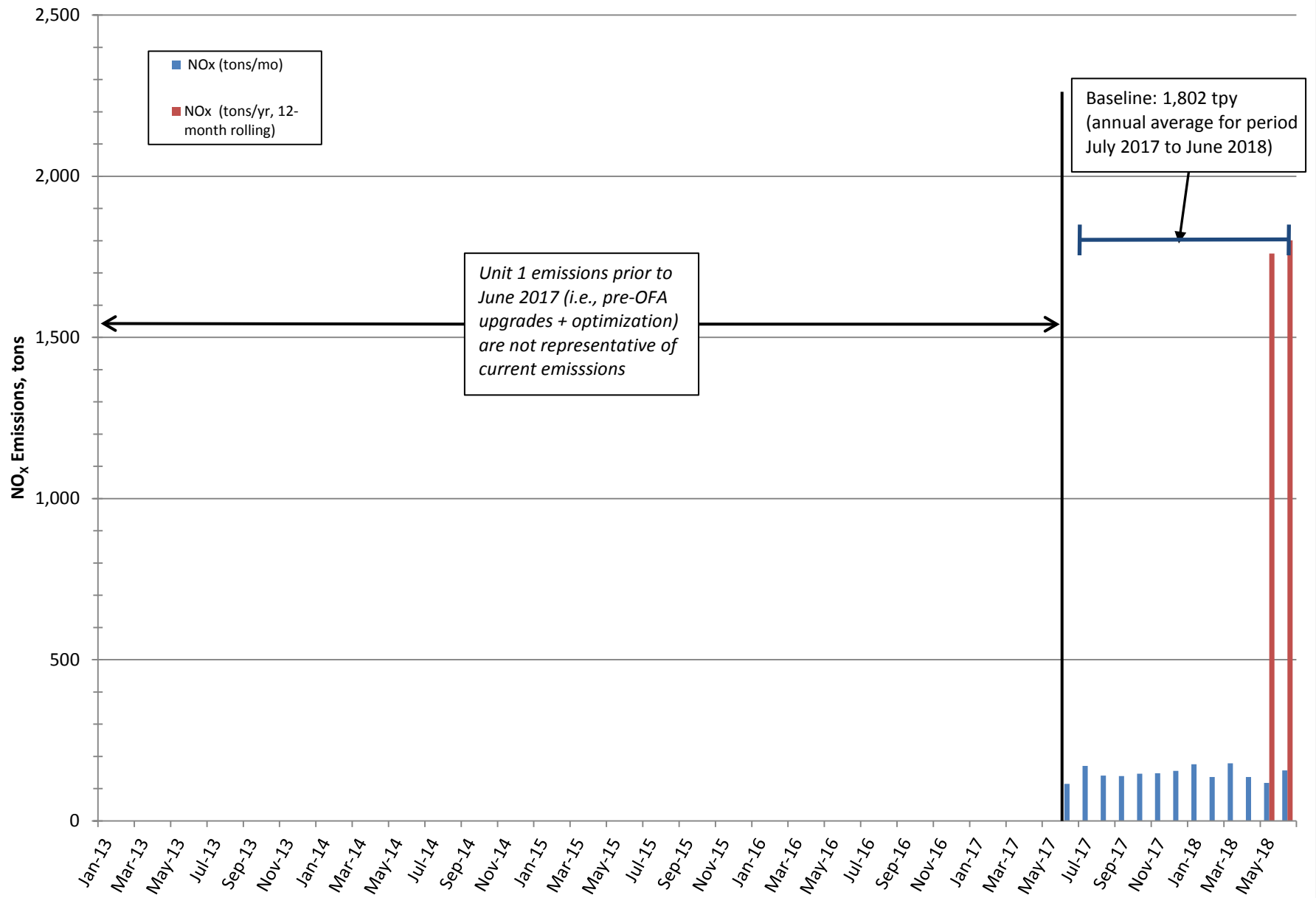
## AVS Unit 2 - Baseline SO<sub>2</sub> Emissions (tons) [1/2013 to 6/2018]



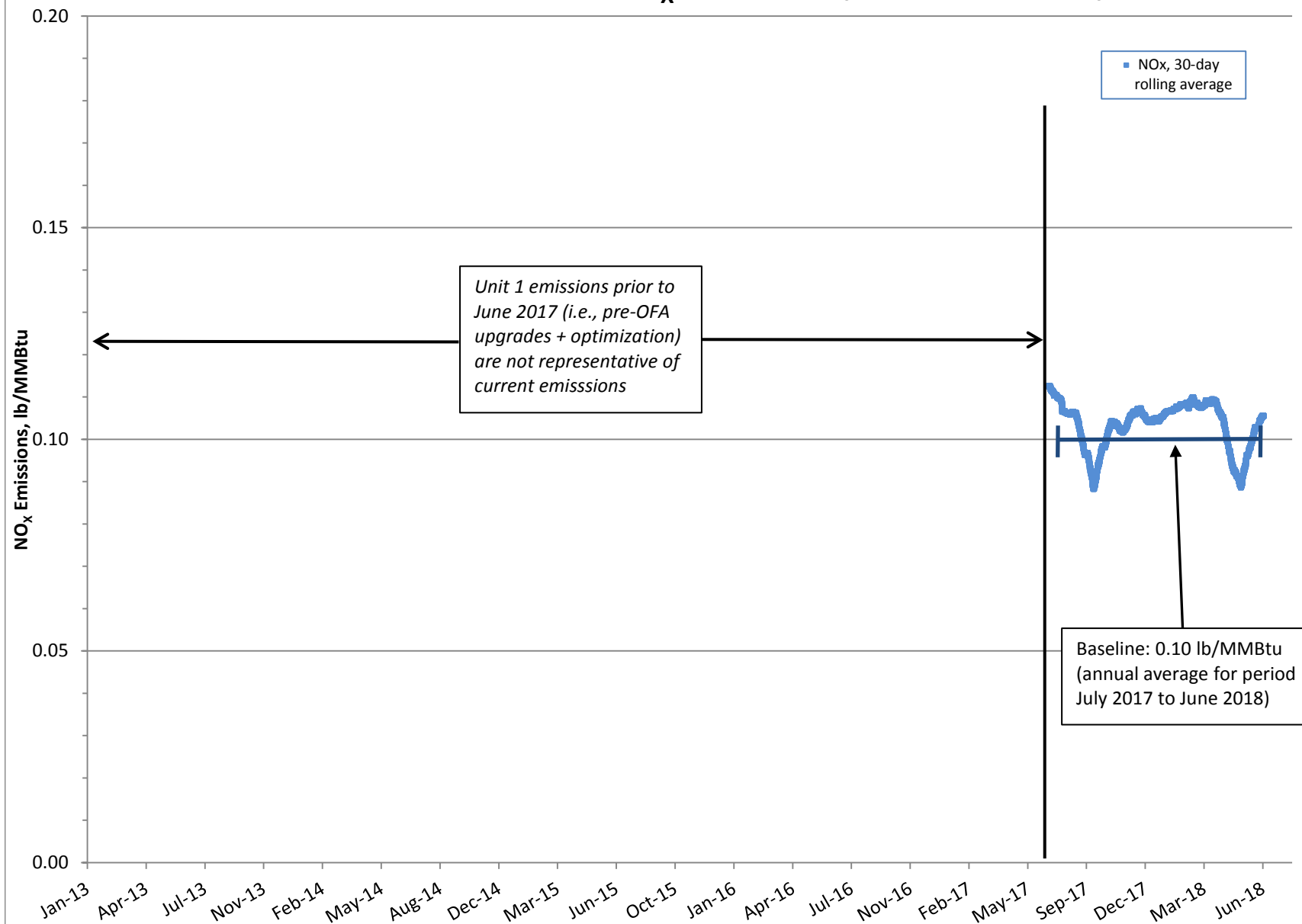
## AVS Unit 2 - Baseline SO<sub>2</sub> Emissions (lb/MMBtu) [1/2013 - 6/2018]



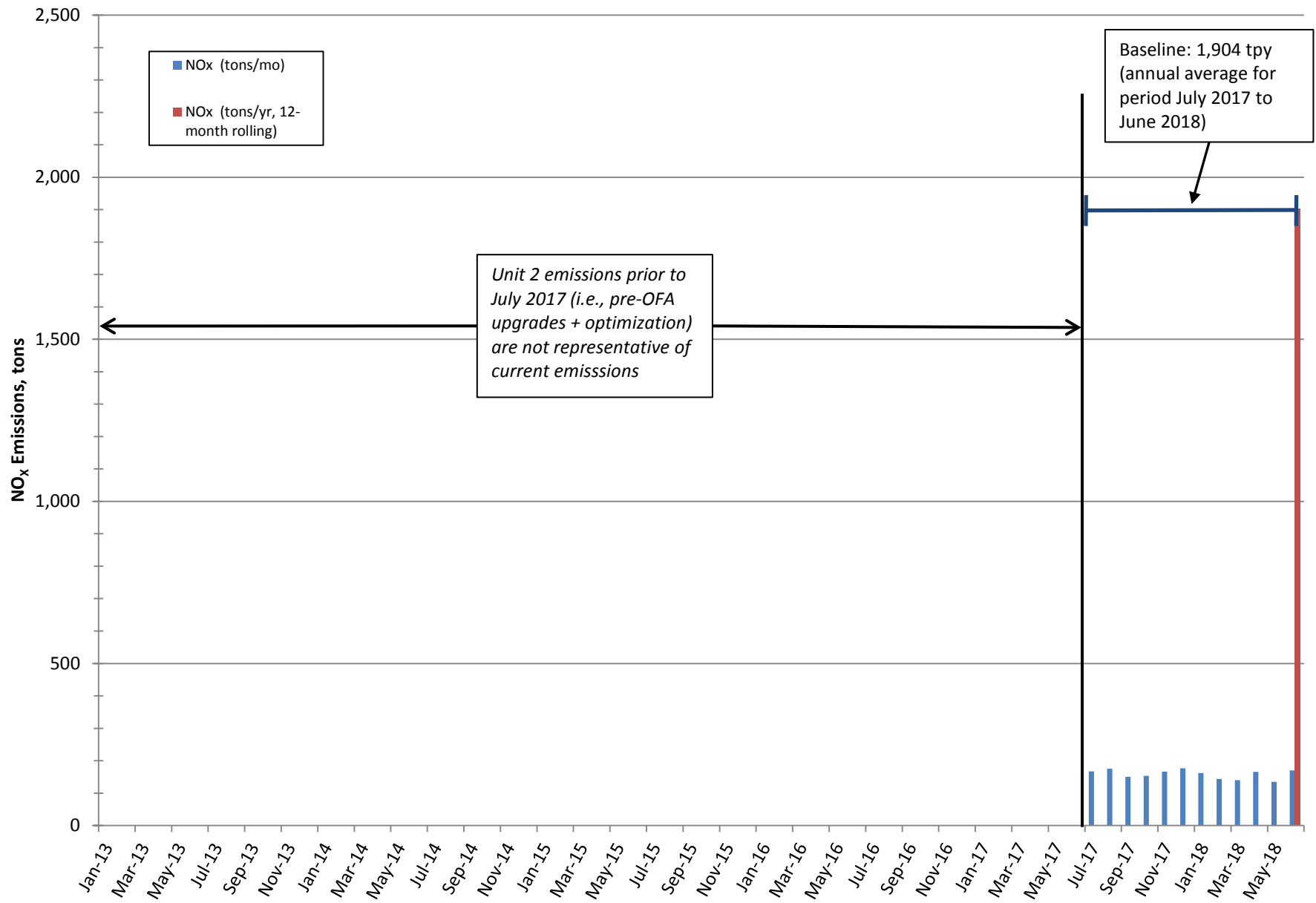
## AVS Unit 1 - Baseline NO<sub>x</sub> Emissions (tons) [1/2013 to 6/2018]



## AVS Unit 1 - Baseline NO<sub>x</sub> Emissions (1/2013 - 6/2018)

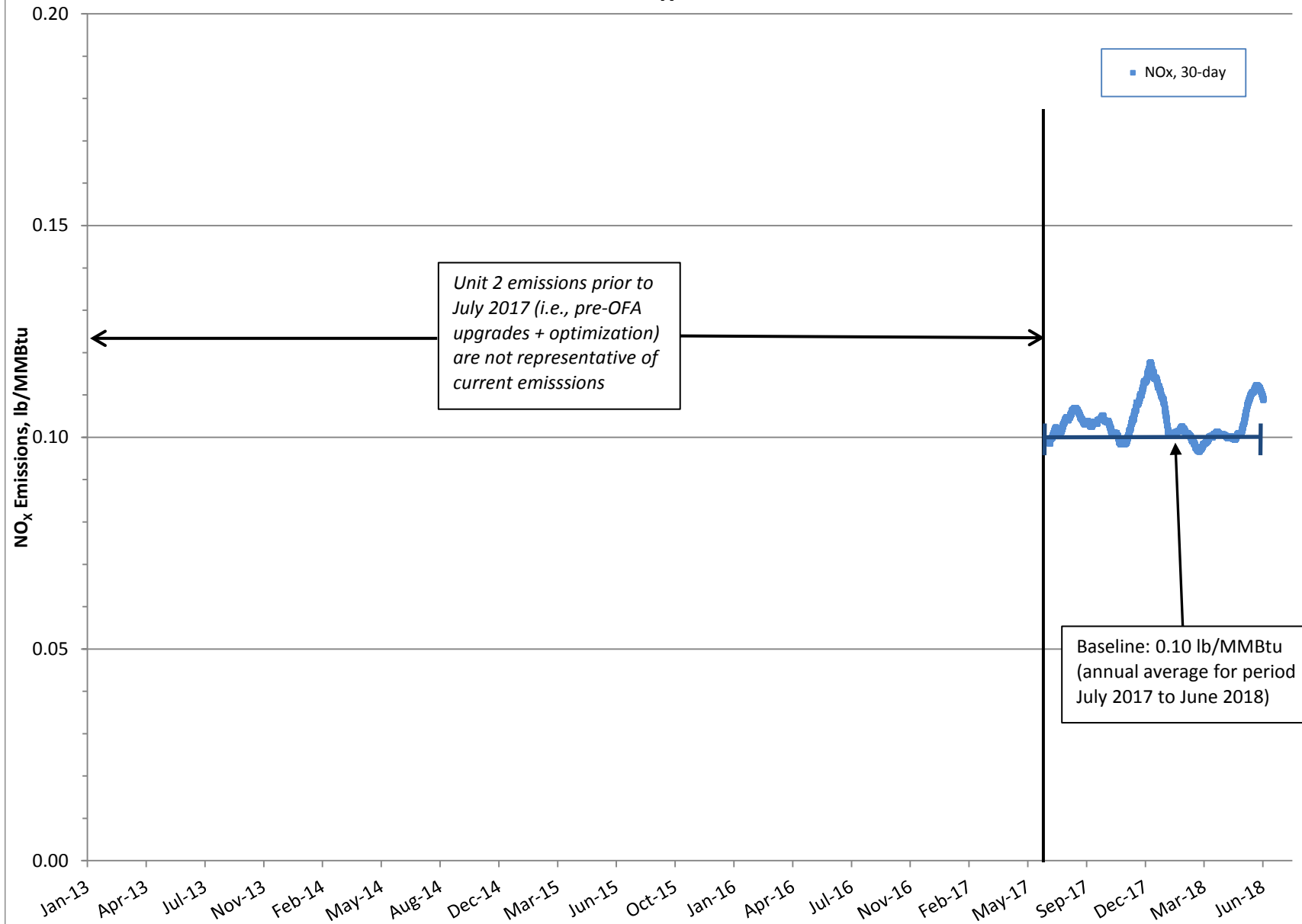


## AVS Unit 2 - Baseline NO<sub>x</sub> Emissions (tons) [1/2013 to 6/2018]





## AVS Unit 2 - Baseline NO<sub>x</sub> Emissions (1/2013 - 6/2018)



## APPENDIX C

### SO<sub>2</sub> CONTROL COST EFFECTIVENESS ESTIMATES

## SO<sub>2</sub> CONTROL COST EFFECTIVENESS ESTIMATES

### *BASILINE CAPACITY FACTORS/EMISSIONS AND PROJECTED ACTUAL EMISSION RATES*

**Antelope Valley Station Units 1 & 2  
SO<sub>2</sub> Control Summary**

**Table 1. AVS Units 1 & 2 Operating Parameters**

Parameter	Units	Unit 1	Unit 2	Notes
Nominal Power Output	MW gross	470	470	
Annual Heat Input	MMBtu/yr	37,278,202	37,459,113	24-month annual average for periods Sept 2014 to Aug 2016 (Unit 1) and July 2016 to June 2018 (Unit 2).
Annual Capacity Factor	%	86%	87%	Capacity factor based on Design Hourly Heat Input (MBtu/hr) and Annual Baseline Heat Input (MBtu/yr)
Average Baseline Hourly Heat Input	MMBtu/hr	4,459	4,499	Average hourly heat input for periods Sept 2014 to Aug 2016 (Unit 1) and July 2016 to June 2018 (Unit 2). Emission rates in lb/hr based on Average baseline hourly heat input.
Design Hourly Heat Input	MMBtu/hr	4,930	4,930	AVS Boiler Design Data Sheet @ 100% MCR

**Table 2. SO<sub>2</sub> Control Effectiveness**

Control Technology	Unit 1					Unit 2				
	Control Efficiency	Expected Emissions	Emission Rate	Emission Rate	Expected Emissions Reduction	Control Efficiency	Expected Emissions	Emission Rate	Emission Rate	Expected Emissions Reduction
	(%)	(ton/year)	(lb/hr)	(lb/MMBtu)	(ton/year)	(%)	(ton/year)	(lb/hr)	(lb/MMBtu)	(ton/year)
Wet FGD	98%	1,305	312	0.07	5,616	98%	1,311	315	0.07	5,705
Dry FGD (CDS + FF)	97%	1,678	401	0.09	5,243	97%	1,686	405	0.09	5,330
FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio	93%	3,728	892	0.20	3,193	93%	3,746	900	0.20	3,270
FGD Operational Improvements - Station Work Practice	88%	6,524	1,561	0.35	397	88%	6,555	1,575	0.35	461
Baseline (DFGD/FF)	87%	6,921	1,656	0.37		87%	7,016	1,685	0.37	
Uncontrolled SO <sub>2</sub>		54,082	12,939	2.90			54,345	13,053	2.90	

**Table 3. SO<sub>2</sub> Control Cost Effectiveness - Unit 1**

Control Technology	Emissions	Tons of SO <sub>2</sub> Removed	Total Capital Requirement	Annualized Capital Cost	Annualized Outage Cost	Total Annual Operating Costs	Total Annual Costs	Average Cost Effectiveness	Incremental Cost Effectiveness
	(tpy)	(tpy)	(\$)	(\$/year)	(\$/year)	(\$/year)	(\$)	(\$/ton)	(\$/ton)
Wet FGD	1,305	5,616	\$272,384,000	\$22,322,000		\$16,945,000	\$39,267,000	<b>\$6,992</b>	\$9,826
Dry FGD (CDS + FF)	1,678	5,243	\$230,447,000	\$18,886,000		\$16,718,000	\$35,604,000	<b>\$6,790</b>	\$16,420
FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio	3,728	3,193	\$9,698,000	\$795,000		\$1,144,000	\$1,939,000	<b>\$607</b>	\$645
FGD Operational Improvements - Station Work Practice	6,524	397	\$0	\$0		\$135,000	\$135,000	<b>\$340</b>	
Baseline (DFGD/FF)	6,921								

**Table 4. SO<sub>2</sub> Control Cost Effectiveness - Unit 2**

Control Technology	Emissions	Tons of SO <sub>2</sub> Removed	Total Capital Requirement	Annualized Capital Cost	Annualized Outage Cost	Total Annual Operating Costs	Total Annual Costs	Average Cost Effectiveness	Incremental Cost Effectiveness
	(tpy)	(tpy)	(\$)	(\$/year)	(\$/year)	(\$/year)	(\$)	(\$/ton)	(\$/ton)
Wet FGD	1,311	5,705	\$272,384,000	\$22,322,000		\$16,819,000	\$39,141,000	<b>\$6,861</b>	\$9,549
Dry FGD (CDS + FF)	1,686	5,330	\$230,447,000	\$18,886,000		\$16,678,000	\$35,564,000	<b>\$6,672</b>	\$16,322
FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio	3,746	3,270	\$9,698,000	\$795,000		\$1,142,000	\$1,937,000	<b>\$592</b>	\$643
FGD Operational Improvements - Station Work Practice	6,555	461	\$0	\$0		\$131,000	\$131,000	<b>\$284</b>	
Baseline (DFGD/FF)	7,016								

AVS Units 1 and 2  
SO<sub>2</sub> Control Cost Evaluation  
FGD Operational Improvements - Station Work Practice

SO <sub>2</sub> Control Option Description	FGD Operational Improvements - Station Work Practice	
	Unit 1	Unit 2
Baseline SO <sub>2</sub> Emissions, lb/MMBtu	0.37	0.37
Post Upgrade SO <sub>2</sub> Emissions, lb/MMBtu	0.35	0.35
Capacity Factor used of Cost Estimates (%)	86%	87%

CAPITAL COSTS		Cost (2018\$)		Basis
		Unit 1	Unit 2	
Direct Costs				
Purchased Equipment Costs (PEC)				
Equipment and Materials	\$0	\$0	Based on Sargent & Lundy's conceptual cost estimating system. Includes costs for equipment, material and installation.  Included in equipment and materials cost 5% of Equipment/Material Cost 5% of Equipment/Material Cost	
Instrumentation	\$0	\$0		
Sales Tax	\$0	\$0		
Freight	\$0	\$0		
Total PEC	\$0	\$0		
Direct Installation Costs				
Labor	\$0	\$0	Based on Sargent & Lundy's conceptual cost estimating system.  2.5% of Labor 1.5% of Labor 5% of Labor	
Scaffolding	\$0	\$0		
Mobilization / Demobilization	\$0	\$0		
Labor Cost Due To Overtime Inefficiency	\$0	\$0		
Total Direct Installation Costs	\$0	\$0		
Total Direct Costs (PEC + Direct Installation Costs)	\$0	\$0		
Indirect Costs				
Contractor's General and Administration Expense	\$0	\$0	10% of Total Direct Costs	
Contractor's Profit	\$0	\$0	5% of Total Direct Costs	
Engineering, Procurement, & Project Services	\$0	\$0	8% of Total Direct Costs	
Construction Management/Field Engineering	\$0	\$0	4% of Total Direct Costs	
S-U / Commissioning	\$0	\$0	1% of Total Direct Costs	
Spare Parts	\$0	\$0	0.5% of Total Direct Costs	
Owner's Cost	\$0	\$0	2% of Total Direct Costs	
Total Indirect Costs	\$0	\$0		
Contingency	\$0	\$0	20% of Direct and Indirect Costs	
Total Capital Investment (TCI)	\$0	\$0	sum of direct costs, indirect costs, and contingency	
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$	0.0820	0.0820	20 year life of equipment (years) @ 5.25% interest.	
Annualized Capital Costs (CRF x TCI)	\$0	\$0		
OPERATING COSTS				
Operating & Maintenance Costs				
Variable O&M Costs				
Increased Waste Disposal Cost	\$69,000	\$75,000	Based on disposal rate of \$6.53 per ton.	
Increased Lime Reagent Cost	\$61,000	\$51,000	Based on lime reagent cost of \$97 per ton.	
Hydrated Lime Reagent Cost	\$0	\$0	Based on hydrated lime cost of \$189 per ton.	
Limestone Reagent Cost	\$0	\$0	Based on limestone reagent cost of \$57 per ton.	
Increased Auxiliary Power Cost	\$0	\$0	Based on auxiliary power cost of \$38.07 per MWh (Unit 1) and \$35.72 (Unit 2).	
Increased Water Cost	\$5,000	\$5,000	Based on water cost of \$0.60 per 1,000 gallons.	
Increased bag and cage replacement	\$0	\$0	Based on bag and cage cost of \$141 per bag	
Total Variable O&M Costs	\$135,000	\$131,000		
Fixed O&M Costs				
Additional Operators per shift	0	0	Assume no additional operators	
Operating Labor	\$0	\$0	N/A	
Supervisor Labor	\$0	\$0	N/A	
Maintenance Materials	\$0	\$0	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs	
Maintenance Labor	\$0	\$0	Included in cost for maintenance materials.	
Total Fixed O&M Cost	\$0	\$0		
Indirect Operating Cost				
Property Taxes	\$0	\$0	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.	
Insurance	\$0	\$0	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.	
Administration	\$0	\$0	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.	
Total Indirect Operating Cost	\$0	\$0		
Total Annual Operating Cost	\$135,000	\$131,000		
TOTAL ANNUAL COST				
Annualized Capital Cost	\$0	\$0		
Annual Operating Cost	\$135,000	\$131,000		
Total Annual Cost	\$135,000	\$131,000		

AVS Units 1 and 2  
SO<sub>2</sub> Control Cost Evaluation  
FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio

SO <sub>2</sub> Control Option Description	FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio	
	Unit 1	Unit 2
Baseline SO <sub>2</sub> Emissions, lb/MMBtu	0.37	0.37
Post Upgrade SO <sub>2</sub> Emissions, lb/MMBtu	0.20	0.20
Capacity Factor used of Cost Estimates (%)	86%	87%

CAPITAL COSTS		Cost (2018\$)		Basis
	Unit 1	Unit 2		
<b>Direct Costs</b>				
<b>Purchased Equipment Costs (PEC)</b>				
Equipment and Materials	\$4,016,000	\$4,016,000	Based on Sargent & Lundy's conceptual cost estimating system. Includes costs for equipment, material and installation.	
Instrumentation	\$0	\$0	Included in equipment and materials cost	
Sales Tax	\$201,000	\$201,000	5% of Equipment/Material Cost	
Freight	\$201,000	\$201,000	5% of Equipment/Material Cost	
Total PEC	\$4,418,000	\$4,418,000		
<b>Direct Installation Costs</b>				
Labor	\$1,607,000	\$1,607,000	Based on Sargent & Lundy's conceptual cost estimating system.	
Scaffolding	\$40,000	\$40,000	2.5% of Labor	
Mobilization / Demobilization	\$24,000	\$24,000	1.5% of Labor	
Labor Cost Due To Overtime Inefficiency	\$80,000	\$80,000	5% of Labor	
Total Direct Installation Costs	\$1,751,000	\$1,751,000		
Total Direct Costs (PEC + Direct Installation Costs)	\$6,169,000	\$6,169,000		
<b>Indirect Costs</b>				
Contractor's General and Administration Expense	\$617,000	\$617,000	10% of Total Direct Costs	
Contractor's Profit	\$308,000	\$308,000	5% of Total Direct Costs	
Engineering, Procurement, & Project Services	\$494,000	\$494,000	8% of Total Direct Costs	
Construction Management/Field Engineering	\$247,000	\$247,000	4% of Total Direct Costs	
S-U / Commissioning	\$93,000	\$93,000	1% of Total Direct Costs	
Spare Parts	\$31,000	\$31,000	0.5% of Total Direct Costs	
Owner's Cost	\$123,000	\$123,000	2% of Total Direct Costs	
Total Indirect Costs	\$1,913,000	\$1,913,000		
Contingency	\$1,616,000	\$1,616,000	20% of Direct and Indirect Costs	
Total Capital Investment (TCI)	\$9,698,000	\$9,698,000	sum of direct costs, indirect costs, and contingency	
Capital Recovery Factor (CRF) = $i(1 + i)^n / (1 + i)^n - 1$	0.0820	0.0820	20 year life of equipment (years) @ 5.25% interest.	
Annualized Capital Costs (CRF x TCI)	\$795,000	\$795,000		
<b>OPERATING COSTS</b>				
<b>Operating &amp; Maintenance Costs</b>				
<b>Variable O&amp;M Costs</b>				
Increased Waste Disposal Cost	\$76,000	\$76,000	Based on disposal rate of \$6.53 per ton.	
Increased Lime Reagent Cost	\$510,000	\$512,000	Based on lime reagent cost of \$97 per ton.	
Hydrated Lime Reagent Cost	\$0	\$0	Based on hydrated lime cost of \$189 per ton.	
Limestone Reagent Cost	\$0	\$0	Based on limestone reagent cost of \$57 per ton.	
Increased Auxiliary Power Cost	\$72,000	\$68,000	Based on auxiliary power cost of \$38.07 per MWh (Unit 1) and \$35.72 (Unit 2).	
Increased Water Cost	\$5,000	\$5,000	Based on water cost of \$0.60 per 1,000 gallons.	
Increased bag and cage replacement	\$0	\$0	Based on bag and cage cost of \$141 per bag	
Total Variable O&M Costs	\$663,000	\$661,000		
<b>Fixed O&amp;M Costs</b>				
Additional Operators per shift	0	0	Assume no additional operators	
Operating Labor	\$0	\$0	N/A	
Supervisor Labor	\$0	\$0	N/A	
Maintenance Materials	\$93,000	\$93,000	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs	
Maintenance Labor	\$0	\$0	Included in cost for maintenance materials.	
Total Fixed O&M Cost	\$93,000	\$93,000		
<b>Indirect Operating Cost</b>				
Property Taxes	\$97,000	\$97,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.	
Insurance	\$97,000	\$97,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.	
Administration	\$194,000	\$194,000	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.	
Total Indirect Operating Cost	\$388,000	\$388,000		
Total Annual Operating Cost	\$1,144,000	\$1,142,000		
<b>TOTAL ANNUAL COST</b>				
Annualized Capital Cost	\$795,000	\$795,000		
Annual Operating Cost	\$1,144,000	\$1,142,000		
Total Annual Cost	\$1,939,000	\$1,937,000		



AVS Units 1 and 2  
SO<sub>2</sub> Control Cost Evaluation  
Dry FGD (CDS + FF)

SO <sub>2</sub> Control Option Description	Dry FGD (CDS + FF)	
	Unit 1	Unit 2
Baseline SO <sub>2</sub> Emissions, lb/MMBtu	0.37	0.37
Post Upgrade SO <sub>2</sub> Emissions, lb/MMBtu	0.09	0.09
Capacity Factor used of Cost Estimates (%)	86%	87%

CAPITAL COSTS		Cost (2018\$)		Basis	
		Unit 1	Unit 2		
Direct Costs					
Purchased Equipment Costs (PEC)					
Equipment and Materials	\$66,686,000	\$66,686,000		Based on Sargent & Lundy's conceptual cost estimating system. Includes costs for equipment, material and installation. Included in equipment and materials cost 5% of Equipment/Material Cost 5% of Equipment/Material Cost	
Instrumentation	\$0	\$0			
Sales Tax	\$3,334,000	\$3,334,000			
Freight	\$3,334,000	\$3,334,000			
Total PEC	\$73,354,000	\$73,354,000			
Direct Installation Costs					
Labor	\$67,192,000	\$67,192,000		Based on Sargent & Lundy's conceptual cost estimating system. 2.5% of Labor 1.5% of Labor 5% of Labor	
Scaffolding	\$1,680,000	\$1,680,000			
Mobilization / Demobilization	\$1,008,000	\$1,008,000			
Labor Cost Due To Overtime Inefficiency	\$3,360,000	\$3,360,000			
Total Direct Installation Costs	\$73,240,000	\$73,240,000			
Total Direct Costs (PEC + Direct Installation Costs)	\$146,594,000	\$146,594,000			
Indirect Costs					
Contractor's General and Administration Expense	\$14,659,000	\$14,659,000		10% of Total Direct Costs	
Contractor's Profit	\$7,330,000	\$7,330,000		5% of Total Direct Costs	
Engineering, Procurement, & Project Services	\$11,728,000	\$11,728,000		8% of Total Direct Costs	
Construction Management/Field Engineering	\$5,864,000	\$5,864,000		4% of Total Direct Costs	
S-U / Commissioning	\$2,199,000	\$2,199,000		1.5% of Total Direct Costs	
Spare Parts	\$733,000	\$733,000		0.5% of Total Direct Costs	
Owner's Cost	\$2,932,000	\$2,932,000		2% of Total Direct Costs	
Total Indirect Costs	\$45,445,000	\$45,445,000			
Contingency	\$38,408,000	\$38,408,000		20% of Direct and Indirect Costs	
Total Capital Investment (TCI)	\$230,447,000	\$230,447,000		sum of direct capital costs, indirect capital costs, and contingency	
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$	0.0820	0.0820		20 year life of equipment (years) @ 5.25% interest.	
Annualized Capital Costs (CRF x TCI)	\$18,886,000	\$18,886,000			
OPERATING COSTS					
Operating & Maintenance Costs					
Variable O&M Costs					
Increased Waste Disposal Cost	\$393,000	\$395,000		Based on disposal rate of \$6.53 per ton.	
Increased Lime Reagent Cost	\$3,711,000	\$3,728,000		Based on lime reagent cost of \$97 per ton.	
Hydrated Lime Reagent Cost	\$0	\$0		Based on hydrated lime cost of \$189 per ton.	
Limestone Reagent Cost	\$0	\$0		Based on limestone reagent cost of \$57 per ton.	
Increased Auxiliary Power Cost	\$1,033,000	\$974,000		Based on auxiliary power cost of \$38.07 per MWh (Unit 1) and \$35.72 (Unit 2).	
Increased Water Cost	\$13,000	\$13,000		Based on water cost of \$0.60 per 1,000 gallons.	
Increased bag and cage replacement	\$152,000	\$152,000		Based on bag and cage cost of \$141 per bag	
Total Variable O&M Costs	\$5,302,000	\$5,262,000			
Fixed O&M Costs					
Additional Operators per shift	0	0		Assume no additional operators	
Operating Labor	\$0	\$0		N/A	
Supervisor Labor	\$0	\$0		N/A	
Maintenance Materials	\$2,199,000	\$2,199,000		Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs	
Maintenance Labor	\$0	\$0		Included in cost for maintenance materials.	
Total Fixed O&M Cost	\$2,199,000	\$2,199,000			
Indirect Operating Cost					
Property Taxes	\$2,304,000	\$2,304,000		1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.	
Insurance	\$2,304,000	\$2,304,000		1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.	
Administration	\$4,609,000	\$4,609,000		2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.	
Total Indirect Operating Cost	\$9,217,000	\$9,217,000			
Total Annual Operating Cost	\$16,718,000	\$16,678,000			
TOTAL ANNUAL COST					
Annualized Capital Cost	\$18,886,000	\$18,886,000			
Annualized Lost Revenue due to Outage	\$0	\$0			
Annual Operating Cost	\$16,718,000	\$16,678,000			
Total Annual Cost	\$35,604,000	\$35,564,000			

AVS Units 1 and 2  
SO<sub>2</sub> Control Cost Evaluation  
Wet FGD

SO <sub>2</sub> Control Option Description	Wet FGD	
	Unit 1	Unit 2
Baseline SO <sub>2</sub> Emissions, lb/MMBtu	0.37	0.37
Post Upgrade SO <sub>2</sub> Emissions, lb/MMBtu	0.07	0.07
Capacity Factor used of Cost Estimates (%)	86%	87%

CAPITAL COSTS		Cost (2018\$)		Basis
	Unit 1	Unit 2		
Direct Costs				
Purchased Equipment Costs (PEC)				
Equipment and Materials	\$97,161,000	\$97,161,000	Based on Sargent & Lundy's conceptual cost estimating system. Includes costs for equipment, material and installation.  Included in equipment and materials cost 5% of Equipment/Material Cost 5% of Equipment/Material Cost	
Instrumentation	\$0	\$0		
Sales Tax	\$4,858,000	\$4,858,000		
Freight	\$4,858,000	\$4,858,000		
Total PEC	\$106,877,000	\$106,877,000		
Direct Installation Costs				
Labor	\$60,913,000	\$60,913,000	Based on Sargent & Lundy's conceptual cost estimating system.  2.5% of Labor 1.5% of Labor 5% of Labor	
Scaffolding	\$1,523,000	\$1,523,000		
Mobilization / Demobilization	\$914,000	\$914,000		
Labor Cost Due To Overtime Inefficiency	\$3,046,000	\$3,046,000		
Total Direct Installation Costs	\$66,396,000	\$66,396,000		
Total Direct Costs (PEC + Direct Installation Costs)	\$173,273,000	\$173,273,000		
Indirect Costs				
Contractor's General and Administration Expense	\$17,327,000	\$17,327,000	10% of Total Direct Costs	
Contractor's Profit	\$8,664,000	\$8,664,000	5% of Total Direct Costs	
Engineering, Procurement, & Project Services	\$13,862,000	\$13,862,000	8% of Total Direct Costs	
Construction Management/Field Engineering	\$6,931,000	\$6,931,000	4% of Total Direct Costs	
S-U / Commissioning	\$2,599,000	\$2,599,000	1.5% of Total Direct Costs	
Spare Parts	\$866,000	\$866,000	0.5% of Total Direct Costs	
Owner's Cost	\$3,465,000	\$3,465,000	2% of Total Direct Costs	
Total Indirect Costs	\$53,714,000	\$53,714,000		
Contingency	\$45,397,000	\$45,397,000	20% of Direct and Indirect Costs	
Total Capital Investment (TCI)	\$272,384,000	\$272,384,000	sum of direct capital costs, indirect capital costs, and contingency	
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$	0.0820	0.0820	20 year life of equipment (years) @ 5.25% interest.	
Annualized Capital Costs (CRF x TCI)	\$22,322,000	\$22,322,000		
OPERATING COSTS				
Operating & Maintenance Costs				
Variable O&M Costs				
Increased Waste Disposal Cost	\$121,000	\$122,000	Based on disposal rate of \$6.53 per ton. Based on lime reagent cost of \$97 per ton. Based on hydrated lime cost of \$189 per ton.	
Increased Lime Reagent Cost	\$-6,629,000	\$-6,660,000		
Hydrated Lime Reagent Cost	\$0	\$0		
Limestone Reagent Cost	\$5,408,000	\$5,433,000	Based on limestone reagent cost of \$57 per ton.	
Increased Auxiliary Power Cost	\$2,116,000	\$1,995,000	Based on auxiliary power cost of \$38.07 per MWh (Unit 1) and \$35.72 (Unit 2).	
Increased Water Cost	\$17,000	\$17,000	Based on water cost of \$0.60 per 1,000 gallons.	
Increased bag and cage replacement	\$0	\$0	Based on bag and cage cost of \$141 per bag	
Total Variable O&M Costs	\$1,033,000	\$907,000		
Fixed O&M Costs				
Additional Operators per Shift	4	4	Assume \$60/hr for each additional operator 15% of Operating Labor. EPA Cost Manual Section 1, Chapter 2, page 2-31.	
Operating Labor	\$2,102,000	\$2,102,000		
Supervisor Labor	\$315,000	\$315,000		
Maintenance Materials	\$2,599,000	\$2,599,000	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs	
Maintenance Labor	\$0	\$0	Included in cost for maintenance materials.	
Total Fixed O&M Cost	\$5,016,000	\$5,016,000		
Indirect Operating Cost				
Property Taxes	\$2,724,000	\$2,724,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.	
Insurance	\$2,724,000	\$2,724,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.	
Administration	\$5,448,000	\$5,448,000	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.	
Total Indirect Operating Cost	\$10,896,000	\$10,896,000		
Total Annual Operating Cost	\$16,945,000	\$16,819,000		
TOTAL ANNUAL COST				
Annualized Capital Cost	\$22,322,000	\$22,322,000		
Annual Operating Cost	\$16,945,000	\$16,819,000		
Total Annual Cost	\$39,267,000	\$39,141,000		

## SO<sub>2</sub> CONTROL COST EFFECTIVENESS ESTIMATES

### *100% CAPACITY FACTOR AND PROJECTED FUTURE MAXIMUM EMISSION RATES*

**Antelope Valley Station Units 1 & 2**  
**SO<sub>2</sub> Control Summary**

**Table 1. AVS Units 1 & 2 Operating Parameters**

Parameter	Units	Unit 1	Unit 2	Notes
Nominal Power Output	MW gross	470	470	
Annual Heat Input	MMBtu/yr	43,186,800	43,186,800	Based on hourly heat input (per Permit No. T5-F86003) and 100% capacity factor
Annual Capacity Factor	%	100%	100%	
Hourly Heat Input	MMBtu/hr	4,930	4,930	AVS Boiler Design Data Sheet @ 100% MCR

**Table 2. SO<sub>2</sub> Control Effectiveness**

Control Technology	Unit 1					Unit 2				
	Control Efficiency	Expected Emissions	Emission Rate	Emission Rate	Expected Emissions Reduction	Control Efficiency	Expected Emissions	Emission Rate	Emission Rate	Expected Emissions Reduction
	(%)	(ton/year)	(lb/hr)	(lb/MMBtu)	(ton/year)	(%)	(ton/year)	(lb/hr)	(lb/MMBtu)	(ton/year)
Wet FGD	98%	1,463	334	0.07	6,555	98%	1,463	334	0.07	6,625
Dry FGD (CDS + FF)	97%	2,195	501	0.10	5,823	97%	2,195	501	0.10	5,894
FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio	93%	5,121	1,169	0.24	2,896	93%	5,121	1,169	0.24	2,967
FGD Operational Improvements - Station Work Practice	90%	7,316	1,670	0.34	702	90%	7,316	1,670	0.34	772
Baseline (DFGD/FF)	89%	<b>8,018</b>	1,831	0.37		89%	<b>8,089</b>	1,847	0.37	
Uncontrolled SO <sub>2</sub>		73,164	16,704	3.39			73,164	16,704	3.39	

**Table 3. SO<sub>2</sub> Control Cost Effectiveness - Unit 1**

Control Technology	Emissions (tpy)	Tons of SO <sub>2</sub> Removed (tpy)	Total Capital Requirement (\$)	Annualized Capital Cost (\$/year)	Annualized Outage Cost (\$/year)	Total Annual Operating Costs (\$/year)	Total Annual Costs (\$)	Average Cost Effectiveness (\$/ton)	Incremental Cost Effectiveness (\$/ton)
Wet FGD	1,463	6,555	\$272,384,000	\$22,322,000		\$18,361,000	\$40,683,000	<b>\$6,207</b>	\$2,466
Dry FGD (CDS + FF)	2,195	5,823	\$230,447,000	\$18,886,000		\$19,993,000	\$38,879,000	<b>\$6,677</b>	\$12,010
FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio	5,121	2,896	\$9,698,000	\$795,000		\$2,937,000	\$3,732,000	<b>\$1,288</b>	\$1,501
FGD Operational Improvements - Station Work Practice	7,316	702	\$0	\$0		\$437,000	\$437,000	<b>\$623</b>	
Baseline (DFGD/FF)	8,018								

**Table 4. SO<sub>2</sub> Control Cost Effectiveness - Unit 2**

Control Technology	Emissions (tpy)	Tons of SO <sub>2</sub> Removed (tpy)	Total Capital Requirement (\$)	Annualized Capital Cost (\$/year)	Annualized Outage Cost (\$/year)	Total Annual Operating Costs (\$/year)	Total Annual Costs (\$)	Average Cost Effectiveness (\$/ton)	Incremental Cost Effectiveness (\$/ton)
Wet FGD	1,463	6,625	\$272,384,000	\$22,322,000		\$18,210,000	\$40,532,000	<b>\$6,118</b>	\$2,360
Dry FGD (CDS + FF)	2,195	5,894	\$230,447,000	\$18,886,000		\$19,919,000	\$38,805,000	<b>\$6,584</b>	\$11,986
FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio	5,121	2,967	\$9,698,000	\$795,000		\$2,932,000	\$3,727,000	<b>\$1,256</b>	\$1,513
FGD Operational Improvements - Station Work Practice	7,316	772	\$0	\$0		\$406,000	\$406,000	<b>\$526</b>	
Baseline (DFGD/FF)	8,089								

AVS Units 1 and 2  
SO<sub>2</sub> Control Cost Evaluation  
FGD Operational Improvements - Station Work Practice

SO <sub>2</sub> Control Option Description	FGD Operational Improvements - Station Work Practice	
	Unit 1	Unit 2
Baseline SO <sub>2</sub> Emissions, lb/MMBtu	0.37	0.37
Post Upgrade SO <sub>2</sub> Emissions, lb/MMBtu	0.34	0.34
Capacity Factor used of Cost Estimates (%)	100%	100%

CAPITAL COSTS		Cost (2018\$)		Basis
	Unit 1	Unit 2		
<b>Direct Costs</b>				
<b>Purchased Equipment Costs (PEC)</b>				
Equipment and Materials	\$0	\$0	Based on Sargent & Lundy's conceptual cost estimating system.	
Instrumentation	\$0	\$0	Included in equipment and materials cost	
Sales Tax	\$0	\$0	5% of Equipment/Material Cost	
Freight	\$0	\$0	5% of Equipment/Material Cost	
Total PEC	\$0	\$0		
<b>Direct Installation Costs</b>				
Labor	\$0	\$0	Based on Sargent & Lundy's conceptual cost estimating system.	
Scaffolding	\$0	\$0	2.5% of Labor	
Mobilization / Demobilization	\$0	\$0	1.5% of Labor	
Labor Cost Due To Overtime Inefficiency	\$0	\$0	5% of Labor	
Total Direct Installation Costs	\$0	\$0		
Total Direct Costs (PEC + Direct Installation Costs)	\$0	\$0		
<b>Indirect Costs</b>				
Contractor's General and Administration Expense	\$0	\$0	10% of Total Direct Costs	
Contractor's Profit	\$0	\$0	5% of Total Direct Costs	
Engineering, Procurement, & Project Services	\$0	\$0	8% of Total Direct Costs	
Construction Management/Field Engineering	\$0	\$0	4% of Total Direct Costs	
S-U / Commissioning	\$0	\$0	1% of Total Direct Costs	
Spare Parts	\$0	\$0	0.5% of Total Direct Costs	
Owner's Cost	\$0	\$0	2% of Total Direct Costs	
Total Indirect Costs	\$0	\$0		
Contingency	\$0	\$0	20% of Direct and Indirect Costs	
Total Capital Investment (TCI)	\$0	\$0	sum of direct costs, indirect costs, and contingency	
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$	0.0820	0.0820	20 year life of equipment (years) @ 5.25% interest.	
Annualized Capital Costs (CRF x TCI)	\$0	\$0		
<b>OPERATING COSTS</b>				
<b>Operating &amp; Maintenance Costs</b>				
<b>Variable O&amp;M Costs</b>				
Increased Waste Disposal Cost	\$280,000	\$280,000	Based on disposal rate of \$6.53 per ton.	
Increased Lime Reagent Cost	\$144,000	\$113,000	Based on lime reagent cost of \$97 per ton.	
Hydrated Lime Reagent Cost	\$0	\$0	Based on hydrated lime cost of \$189 per ton.	
Limestone Reagent Cost	\$0	\$0	Based on limestone reagent cost of \$57 per ton.	
Increased Auxiliary Power Cost	\$0	\$0	Based on auxiliary power cost of \$38.07 per MWh (Unit 1) and \$35.72 (Unit 2).	
Increased Water Cost	\$13,000	\$13,000	Based on water cost of \$0.60 per 1,000 gallons.	
Increased bag and cage replacement	\$0	\$0	Based on bag and cage cost of \$141 per bag	
Total Variable O&M Costs	\$437,000	\$406,000		
<b>Fixed O&amp;M Costs</b>				
Additional Operators per shift	0	0	Assume no additional operators	
Operating Labor	\$0	\$0	N/A	
Supervisor Labor	\$0	\$0	N/A	
Maintenance Materials	\$0	\$0	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs	
Maintenance Labor	\$0	\$0	Included in cost for maintenance materials.	
Total Fixed O&M Cost	\$0	\$0		
<b>Indirect Operating Cost</b>				
Property Taxes	\$0	\$0	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.	
Insurance	\$0	\$0	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.	
Administration	\$0	\$0	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.	
Total Indirect Operating Cost	\$0	\$0		
Total Annual Operating Cost	\$437,000	\$406,000		
<b>TOTAL ANNUAL COST</b>				
Annualized Capital Cost	\$0	\$0		
Annual Operating Cost	\$437,000	\$406,000		
Total Annual Cost	\$437,000	\$406,000		

AVS Units 1 and 2  
SO<sub>2</sub> Control Cost Evaluation  
FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio

SO <sub>2</sub> Control Option Description	FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio	
	Unit 1	Unit 2
Baseline SO <sub>2</sub> Emissions, lb/MMBtu	0.37	0.37
Post Upgrade SO <sub>2</sub> Emissions, lb/MMBtu	0.24	0.24
Capacity Factor used of Cost Estimates (%)	100%	100%

CAPITAL COSTS		Cost (2018\$)		Basis
	Unit 1	Unit 2		
Direct Costs				
Purchased Equipment Costs (PEC)				
Equipment and Materials	\$4,016,000	\$4,016,000	Based on Sargent & Lundy's conceptual cost estimating system.	
Instrumentation	\$0	\$0	Included in equipment and materials cost	
Sales Tax	\$201,000	\$201,000	5% of Equipment/Material Cost	
Freight	\$201,000	\$201,000	5% of Equipment/Material Cost	
Total PEC	\$4,418,000	\$4,418,000		
Direct Installation Costs				
Labor	\$1,607,000	\$1,607,000	Based on Sargent & Lundy's conceptual cost estimating system.	
Scaffolding	\$40,000	\$40,000	2.5% of Labor	
Mobilization / Demobilization	\$24,000	\$24,000	1.5% of Labor	
Labor Cost Due To Overtime Inefficiency	\$80,000	\$80,000	5% of Labor	
Total Direct Installation Costs	\$1,751,000	\$1,751,000		
Total Direct Costs (PEC + Direct Installation Costs)	\$6,169,000	\$6,169,000		
Indirect Costs				
Contractor's General and Administration Expense	\$617,000	\$617,000	10% of Total Direct Costs	
Contractor's Profit	\$308,000	\$308,000	5% of Total Direct Costs	
Engineering, Procurement, & Project Services	\$494,000	\$494,000	8% of Total Direct Costs	
Construction Management/Field Engineering	\$247,000	\$247,000	4% of Total Direct Costs	
S-U / Commissioning	\$93,000	\$93,000	1% of Total Direct Costs	
Spare Parts	\$31,000	\$31,000	0.5% of Total Direct Costs	
Owner's Cost	\$123,000	\$123,000	2% of Total Direct Costs	
Total Indirect Costs	\$1,913,000	\$1,913,000		
Contingency	\$1,616,000	\$1,616,000	20% of Direct and Indirect Costs	
Total Capital Investment (TCI)	\$9,698,000	\$9,698,000	sum of direct costs, indirect costs, and contingency	
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$	0.0820	0.0820	20 year life of equipment (years) @ 5.25% interest.	
Annualized Capital Costs (CRF x TCI)	\$795,000	\$795,000		
OPERATING COSTS				
Operating & Maintenance Costs				
Variable O&M Costs				
Increased Waste Disposal Cost	\$382,000	\$382,000	Based on disposal rate of \$6.53 per ton.	
Increased Lime Reagent Cost	\$1,978,000	\$1,978,000	Based on lime reagent cost of \$97 per ton.	
Hydrated Lime Reagent Cost	\$0	\$0	Based on hydrated lime cost of \$189 per ton.	
Limestone Reagent Cost	\$0	\$0	Based on limestone reagent cost of \$57 per ton.	
Increased Auxiliary Power Cost	\$83,000	\$78,000	Based on auxiliary power cost of \$38.07 per MWh (Unit 1) and \$35.72 (Unit 2).	
Increased Water Cost	\$13,000	\$13,000	Based on water cost of \$0.60 per 1,000 gallons.	
Increased bag and cage replacement	\$0	\$0	Based on bag and cage cost of \$141 per bag	
Total Variable O&M Costs	\$2,456,000	\$2,451,000		
Fixed O&M Costs				
Additional Operators per shift	0	0	Assume no additional operators	
Operating Labor	\$0	\$0	N/A	
Supervisor Labor	\$0	\$0	N/A	
Maintenance Materials	\$93,000	\$93,000	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs	
Maintenance Labor	\$0	\$0	Included in cost for maintenance materials.	
Total Fixed O&M Cost	\$93,000	\$93,000		
Indirect Operating Cost				
Property Taxes	\$97,000	\$97,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.	
Insurance	\$97,000	\$97,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.	
Administration	\$194,000	\$194,000	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.	
Total Indirect Operating Cost	\$388,000	\$388,000		
Total Annual Operating Cost	\$2,937,000	\$2,932,000		
TOTAL ANNUAL COST				
Annualized Capital Cost	\$795,000	\$795,000		
Annual Operating Cost	\$2,937,000	\$2,932,000		
Total Annual Cost	\$3,732,000	\$3,727,000		



AVS Units 1 and 2  
SO<sub>2</sub> Control Cost Evaluation  
Dry FGD (CDS + FF)

SO <sub>2</sub> Control Option Description	Dry FGD (CDS + FF)	
	Unit 1	Unit 2
Baseline SO <sub>2</sub> Emissions, lb/MMBtu	0.37	0.37
Post Upgrade SO <sub>2</sub> Emissions, lb/MMBtu	0.10	0.10
Capacity Factor used of Cost Estimates (%)	100%	100%

CAPITAL COSTS		Cost (2018\$)		Basis
		Unit 1	Unit 2	
<b>Direct Costs</b>				
<b>Purchased Equipment Costs (PEC)</b>				
Equipment and Materials	\$66,686,000	\$66,686,000	Based on Sargent & Lundy's conceptual cost estimating system.	
Instrumentation	\$0	\$0	Included in equipment and materials cost	
Sales Tax	\$3,334,000	\$3,334,000	5% of Equipment/Material Cost	
Freight	\$3,334,000	\$3,334,000	5% of Equipment/Material Cost	
<b>Total PEC</b>	<b>\$73,354,000</b>	<b>\$73,354,000</b>		
<b>Direct Installation Costs</b>				
Labor	\$67,192,000	\$67,192,000	Based on Sargent & Lundy's conceptual cost estimating system.	
Scaffolding	\$1,680,000	\$1,680,000	2.5% of Labor	
Mobilization / Demobilization	\$1,008,000	\$1,008,000	1.5% of Labor	
Labor Cost Due To Overtime Inefficiency	\$3,360,000	\$3,360,000	5% of Labor	
<b>Total Direct Installation Costs</b>	<b>\$73,240,000</b>	<b>\$73,240,000</b>		
<b>Total Direct Costs (PEC + Direct Installation Costs)</b>	<b>\$146,594,000</b>	<b>\$146,594,000</b>		
<b>Indirect Costs</b>				
Contractor's General and Administration Expense	\$14,659,000	\$14,659,000	10% of Total Direct Costs	
Contractor's Profit	\$7,330,000	\$7,330,000	5% of Total Direct Costs	
Engineering, Procurement, & Project Services	\$11,728,000	\$11,728,000	8% of Total Direct Costs	
Construction Management/Field Engineering	\$5,864,000	\$5,864,000	4% of Total Direct Costs	
S-U / Commissioning	\$2,199,000	\$2,199,000	1.5% of Total Direct Costs	
Spare Parts	\$733,000	\$733,000	0.5% of Total Direct Costs	
Owner's Cost	\$2,932,000	\$2,932,000	2% of Total Direct Costs	
<b>Total Indirect Costs</b>	<b>\$45,445,000</b>	<b>\$45,445,000</b>		
<b>Contingency</b>	<b>\$38,408,000</b>	<b>\$38,408,000</b>	20% of Direct and Indirect Costs	
<b>Total Capital Investment (TCI)</b>	<b>\$230,447,000</b>	<b>\$230,447,000</b>	sum of direct capital costs, indirect capital costs, and contingency	
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$	0.0820	0.0820	20 year life of equipment (years) @ 5.25% interest.	
<b>Annualized Capital Costs (CRF x TCI)</b>	<b>\$18,886,000</b>	<b>\$18,886,000</b>		
<b>OPERATING COSTS</b>				
<b>Operating &amp; Maintenance Costs</b>				
<b>Variable O&amp;M Costs</b>				
Increased Waste Disposal Cost	\$917,000	\$917,000	Based on disposal rate of \$6.53 per ton.	
Increased Lime Reagent Cost	\$6,282,000	\$6,282,000	Based on lime reagent cost of \$97 per ton.	
Hydrated Lime Reagent Cost	\$0	\$0	Based on hydrated lime cost of \$189 per ton.	
Limestone Reagent Cost	\$0	\$0	Based on limestone reagent cost of \$57 per ton.	
Increased Auxiliary Power Cost	\$1,197,000	\$1,123,000	Based on auxiliary power cost of \$38.07 per MWh (Unit 1) and \$35.72 (Unit 2).	
Increased Water Cost	\$29,000	\$29,000	Based on water cost of \$0.60 per 1,000 gallons.	
Increased bag and cage replacement	\$152,000	\$152,000	Based on bag and cage cost of \$141 per bag	
<b>Total Variable O&amp;M Costs</b>	<b>\$8,577,000</b>	<b>\$8,503,000</b>		
<b>Fixed O&amp;M Costs</b>				
Additional Operators per shift	0	0	Assume no additional operators	
Operating Labor	\$0	\$0	N/A	
Supervisor Labor	\$0	\$0	N/A	
Maintenance Materials	\$2,199,000	\$2,199,000	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs	
Maintenance Labor	\$0	\$0	Included in cost for maintenance materials.	
<b>Total Fixed O&amp;M Cost</b>	<b>\$2,199,000</b>	<b>\$2,199,000</b>		
<b>Indirect Operating Cost</b>				
Property Taxes	\$2,304,000	\$2,304,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.	
Insurance	\$2,304,000	\$2,304,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.	
Administration	\$4,609,000	\$4,609,000	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.	
<b>Total Indirect Operating Cost</b>	<b>\$9,217,000</b>	<b>\$9,217,000</b>		
<b>Total Annual Operating Cost</b>	<b>\$19,993,000</b>	<b>\$19,919,000</b>		
<b>TOTAL ANNUAL COST</b>				
Annualized Capital Cost	\$18,886,000	\$18,886,000		
Annualized Lost Revenue due to Outage	\$0	\$0		
Annual Operating Cost	\$19,993,000	\$19,919,000		
<b>Total Annual Cost</b>	<b>\$38,879,000</b>	<b>\$38,805,000</b>		

AVS Units 1 and 2  
SO<sub>2</sub> Control Cost Evaluation  
Wet FGD

SO <sub>2</sub> Control Option Description	Wet FGD	
	Unit 1	Unit 2
Baseline SO <sub>2</sub> Emissions, lb/MMBtu	0.37	0.37
Post Upgrade SO <sub>2</sub> Emissions, lb/MMBtu	0.07	0.07
Capacity Factor used of Cost Estimates (%)	100%	100%

CAPITAL COSTS		Cost (2018\$)		Basis
		Unit 1	Unit 2	
<b>Direct Costs</b>				
<b>Purchased Equipment Costs (PEC)</b>				
Equipment and Materials	\$97,161,000	\$97,161,000	Based on Sargent & Lundy's conceptual cost estimating system.	
Instrumentation	\$0	\$0	Included in equipment and materials cost	
Sales Tax	\$4,858,000	\$4,858,000	5% of Equipment/Material Cost	
Freight	\$4,858,000	\$4,858,000	5% of Equipment/Material Cost	
<b>Total PEC</b>	<b>\$106,877,000</b>	<b>\$106,877,000</b>		
<b>Direct Installation Costs</b>				
Labor	\$60,913,000	\$60,913,000	Based on Sargent & Lundy's conceptual cost estimating system.	
Scaffolding	\$1,523,000	\$1,523,000	2.5% of Labor	
Mobilization / Demobilization	\$914,000	\$914,000	1.5% of Labor	
Labor Cost Due To Overtime Inefficiency	\$3,046,000	\$3,046,000	5% of Labor	
<b>Total Direct Installation Costs</b>	<b>\$66,396,000</b>	<b>\$66,396,000</b>		
<b>Total Direct Costs (PEC + Direct Installation Costs)</b>	<b>\$173,273,000</b>	<b>\$173,273,000</b>		
<b>Indirect Costs</b>				
Contractor's General and Administration Expense	\$17,327,000	\$17,327,000	10% of Total Direct Costs	
Contractor's Profit	\$8,664,000	\$8,664,000	5% of Total Direct Costs	
Engineering, Procurement, & Project Services	\$13,862,000	\$13,862,000	8% of Total Direct Costs	
Construction Management/Field Engineering	\$6,931,000	\$6,931,000	4% of Total Direct Costs	
S-U / Commissioning	\$2,599,000	\$2,599,000	1.5% of Total Direct Costs	
Spare Parts	\$866,000	\$866,000	0.5% of Total Direct Costs	
Owner's Cost	\$3,465,000	\$3,465,000	2% of Total Direct Costs	
<b>Total Indirect Costs</b>	<b>\$53,714,000</b>	<b>\$53,714,000</b>		
<b>Contingency</b>	<b>\$45,397,000</b>	<b>\$45,397,000</b>	20% of Direct and Indirect Costs	
<b>Total Capital Investment (TCI)</b>	<b>\$272,384,000</b>	<b>\$272,384,000</b>	sum of direct capital costs, indirect capital costs, and contingency	
Capital Recovery Factor (CRF) = $i(1 + i)^n / (1 + i)^n - 1$	0.0820	0.0820	20 year life of equipment (years) @ 5.25% interest.	
<b>Annualized Capital Costs (CRF x TCI)</b>	<b>\$22,322,000</b>	<b>\$22,322,000</b>		
<b>OPERATING COSTS</b>				
<b>Operating &amp; Maintenance Costs</b>				
<b>Variable O&amp;M Costs</b>				
Increased Waste Disposal Cost	\$280,000	\$280,000	Based on disposal rate of \$6.53 per ton.	
Increased Lime Reagent Cost	-\$7,681,000	-\$7,681,000	Based on lime reagent cost of \$97 per ton.	
Hydrated Lime Reagent Cost	\$0	\$0	Based on hydrated lime cost of \$189 per ton.	
Limestone Reagent Cost	\$7,365,000	\$7,365,000	Based on limestone reagent cost of \$57 per ton.	
Increased Auxiliary Power Cost	\$2,452,000	\$2,301,000	Based on auxiliary power cost of \$38.07 per MWh (Unit 1) and \$35.72 (Unit 2).	
Increased Water Cost	\$33,000	\$33,000	Based on water cost of \$0.60 per 1,000 gallons.	
Increased bag and cage replacement	\$0	\$0	Based on bag and cage cost of \$141 per bag	
<b>Total Variable O&amp;M Costs</b>	<b>\$2,449,000</b>	<b>\$2,298,000</b>		
<b>Fixed O&amp;M Costs</b>				
Additional Operators per Shift	4	4		
Operating Labor	\$2,102,000	\$2,102,000	Assume \$60/hr for each additional operator	
Supervisor Labor	\$315,000	\$315,000	15% of Operating Labor. EPA Cost Manual Section 1, Chapter 2, page 2-31.	
Maintenance Materials	\$2,599,000	\$2,599,000	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs	
Maintenance Labor	\$0	\$0	Included in cost for maintenance materials.	
<b>Total Fixed O&amp;M Cost</b>	<b>\$5,016,000</b>	<b>\$5,016,000</b>		
<b>Indirect Operating Cost</b>				
Property Taxes	\$2,724,000	\$2,724,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.	
Insurance	\$2,724,000	\$2,724,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.	
Administration	\$5,448,000	\$5,448,000	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.	
<b>Total Indirect Operating Cost</b>	<b>\$10,896,000</b>	<b>\$10,896,000</b>		
<b>Total Annual Operating Cost</b>	<b>\$18,361,000</b>	<b>\$18,210,000</b>		
<b>TOTAL ANNUAL COST</b>				
Annualized Capital Cost	\$22,322,000	\$22,322,000		
Annual Operating Cost	\$18,361,000	\$18,210,000		
<b>Total Annual Cost</b>	<b>\$40,683,000</b>	<b>\$40,532,000</b>		

## APPENDIX D

### NO<sub>x</sub> CONTROL COST EFFECTIVENESS ESTIMATES

## NO<sub>x</sub> CONTROL COST EFFECTIVENESS ESTIMATES

### *BASILINE CAPACITY FACTORS/EMISSIONS AND PROJECTED ACTUAL EMISSION RATES*

Antelope Valley Station Units 1 & 2  
NO<sub>x</sub> Control Summary

Table 1. AVS Units 1 & 2 Operating Parameters

Parameter	Units	Unit 1	Unit 2	Notes
Nominal Power Output	MW gross	470	470	
Annual Heat Input	MMBtu/yr	34,816,500	36,633,799	Annual heat inputs and capacity factors for period July 2017 to June 2018.
Annual Capacity Factor	%	81%	85%	Capacity factor based on Design Hourly Heat Input (MBtu/hr) and Annual Baseline Heat Input (MBtu/yr)
Average Baseline Hourly Heat Input	MMBtu/hr	4,126	4,480	Average hourly heat input for periods July 2017 to June 2018. Emission rates in lb/hr based on Average baseline hourly heat input.
Hourly Heat Input	MMBtu/hr	4,930	4,930	AVS Boiler Design Data Sheet @ 100% MCR

Table 2. NO<sub>x</sub> Control Effectiveness

Control Technology	Unit 1					Unit 2				
	Control Efficiency	Expected Emissions	Emission Rate	Emission Rate	Expected Emissions Reduction	Control Efficiency	Expected Emissions	Emission Rate	Emission Rate	Expected Emissions Reduction
	(%)	(ton/year)	(lb/hr)	(lb/MMBtu)	(ton/year)	(%)	(ton/year)	(lb/hr)	(lb/MMBtu)	(ton/year)
SCR - Tail-End Configuration	52%	870	206	0.05	931	52%	916	224	0.05	988
SNCR	9%	1,636	388	0.09	165	10%	1,722	421	0.09	182
Baseline (OFA/LNCFS)		<b>1,802</b>	427	0.10			<b>1,904</b>	466	0.10	

Table 3. NO<sub>x</sub> Control Cost Effectiveness - Unit 1

Control Technology	Emissions	Tons of NO <sub>x</sub> Removed	Total Capital Requirement	Annualized Capital Cost	Annualized Outage Cost	Total Annual Operating Costs	Total Annual Costs	Average Cost Effectiveness	Incremental Cost Effectiveness
	(tpy)	(tpy)	(\$)	(\$/year)	(\$/year)	(\$/year)	(\$)	(\$/ton)	(\$/ton)
SCR - Tail-End Configuration	870	931	\$221,396,000	\$18,144,000		\$18,201,000	\$36,345,000	<b>\$39,035</b>	\$43,161
SNCR	1,636	165	\$16,356,000	\$1,340,000		\$1,945,000	\$3,285,000	<b>\$19,893</b>	
Baseline (OFA/LNCFS)	1,802								

Table 4. NO<sub>x</sub> Control Cost Effectiveness - Unit 2

Control Technology	Emissions	Tons of NO <sub>x</sub> Removed	Total Capital Requirement	Annualized Capital Cost	Annualized Outage Cost	Total Annual Operating Costs	Total Annual Costs	Average Cost Effectiveness	Incremental Cost Effectiveness
	(tpy)	(tpy)	(\$)	(\$/year)	(\$/year)	(\$/year)	(\$)	(\$/ton)	(\$/ton)
SCR - Tail-End Configuration	916	988	\$221,396,000	\$18,144,000		\$18,207,000	\$36,351,000	<b>\$36,792</b>	\$40,997
SNCR	1,722	182	\$16,356,000	\$1,340,000		\$1,970,000	\$3,310,000	<b>\$18,179</b>	
Baseline (OFA/LNCFS)	1,904								

AVS Units 1 and 2  
NO<sub>x</sub> Control Cost Evaluation  
SNCR

NO <sub>x</sub> Control Option Description	SNCR	
	Unit 1	Unit 2
Baseline NO <sub>x</sub> Emissions, lb/MMBtu	0.10	0.10
Post Upgrade NO <sub>x</sub> Emissions, lb/MMBtu	0.09	0.09
Capacity Factor used of Cost Estimates (%)	81%	85%

CAPITAL COSTS		Cost (2018\$)		Basis	
		Unit 1	Unit 2		
Direct Costs					
Purchased Equipment Costs (PEC)					
Equipment and Materials		\$7,411,000	\$7,411,000	Based on Sargent & Lundy's conceptual cost estimating system. Includes costs for equipment, material and installation.	
Instrumentation		\$0	\$0	Included in equipment and materials cost	
Sales Tax		\$371,000	\$371,000	5% of Equipment/Material Cost	
Freight		\$371,000	\$371,000	5% of Equipment/Material Cost	
Total PEC		\$8,153,000	\$8,153,000		
Direct Installation Costs					
Labor		\$2,066,000	\$2,066,000	Based on Sargent & Lundy's conceptual cost estimating system.	
Scaffolding		\$52,000	\$52,000	2.5% of Labor	
Mobilization / Demobilization		\$31,000	\$31,000	1.5% of Labor	
Labor Cost Due To Overtime Inefficiency		\$103,000	\$103,000	5% of Labor	
Total Direct Installation Costs		\$2,252,000	\$2,252,000		
Total Direct Costs (PEC + Direct Installation Costs)		\$10,405,000	\$10,405,000		
Indirect Costs					
Contractor's General and Administration Expense		\$1,041,000	\$1,041,000	10% of Total Direct Costs	
Contractor's Profit		\$520,000	\$520,000	5% of Total Direct Costs	
Engineering, Procurement, & Project Services		\$832,000	\$832,000	8% of Total Direct Costs	
Construction Management/Field Engineering		\$416,000	\$416,000	4% of Total Direct Costs	
S-U / Commissioning		\$156,000	\$156,000	1.5% of Total Direct Costs	
Spare Parts		\$52,000	\$52,000	0.5% of Total Direct Costs	
Owner's Cost		\$208,000	\$208,000	2% of Total Direct Costs	
Total Indirect Costs		\$3,225,000	\$3,225,000		
Contingency		\$2,726,000	\$2,726,000	20% of Direct and Indirect Costs	
Total Capital Investment (TCI)		\$16,356,000	\$16,356,000	sum of direct capital costs, indirect capital costs, and contingency	
Capital Recovery Factor (CRF) = $i(1 + i)^n / (1 + i)^n - 1$		0.0820	0.0820	20 year life of equipment (years) @ 5.25% interest.	
Annualized Capital Costs (CRF x TCI)		\$1,340,000	\$1,340,000		
OPERATING COSTS				Basis	
Operating & Maintenance Costs					
Variable O&M Costs					
Dry Urea Reagent Cost		\$461,000	\$485,000	Based on dry urea reagent cost of \$354 per ton.	
Ammonia Reagent Cost		\$0	\$0	Based on ammonia reagent cost of \$700 per ton.	
Water Cost		\$38,000	\$39,000	Based on water cost of \$0.60 per 1,000 gallons.	
Steam Cost		\$12,000	\$12,000	Based on steam cost of \$1.06 per MMBtu.	
Hydrated Lime Cost		\$0	\$0	Based on hydrated lime cost of \$189 per ton.	
Catalyst Replacement Cost		\$0	\$0	Based on catalyst cost of \$8,000 per m <sup>3</sup> and catalyst replacement cost of \$1,000 per m <sup>3</sup> .	
Auxiliary Power Cost		\$19,000	\$19,000	Based on auxiliary power cost of \$38.07 per MWh (Unit 1) and \$35.72 (Unit 2).	
Total Variable O&M Costs		\$530,000	\$555,000		
Fixed O&M Costs					
Additional Operators per shift		1	1		
Operating Labor		\$525,600	\$525,600	Assume \$60/hr for each additional operator	
Supervisor Labor		\$79,000	\$79,000	15% of Operating Labor. EPA Cost Manual Section 1, Chapter 2, page 2-31.	
Maintenance Materials		\$156,100	\$156,100	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs	
Maintenance Labor		\$0	\$0	Included in cost for maintenance materials.	
Total Fixed O&M Cost		\$760,700	\$760,700		
Indirect Operating Cost					
Property Taxes		\$163,600	\$163,600	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.	
Insurance		\$163,600	\$163,600	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.	
Administration		\$327,100	\$327,100	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.	
Total Indirect Operating Cost		\$654,300	\$654,300		
Total Annual Operating Cost		\$1,945,000	\$1,970,000		
TOTAL ANNUAL COST					
Annualized Capital Cost		\$1,340,000	\$1,340,000		
Annual Operating Cost		\$1,945,000	\$1,970,000		
Total Annual Cost		\$3,285,000	\$3,310,000		



AVS Units 1 and 2  
NO<sub>x</sub> Control Cost Evaluation  
SCR - Tail-End Configuration

NO <sub>x</sub> Control Option Description	SCR - Tail-End Configuration	
	Unit 1	Unit 2
Baseline NO <sub>x</sub> Emissions, lb/MMBtu	0.10	0.10
Post Upgrade NO <sub>x</sub> Emissions, lb/MMBtu	0.05	0.05
Capacity Factor used of Cost Estimates (%)	81%	85%

CAPITAL COSTS		Cost (2018\$)		Basis	
		Unit 1	Unit 2		
Direct Costs					
Purchased Equipment Costs (PEC)					
Equipment and Materials		\$74,544,000	\$74,544,000	Based on Sargent & Lundy's conceptual cost estimating system. Includes costs for equipment, material and installation. Included in equipment and materials cost 5% of Equipment/Material Cost 5% of Equipment/Material Cost	
Instrumentation		\$0	\$0		
Sales Tax		\$3,727,000	\$3,727,000		
Freight		\$3,727,000	\$3,727,000		
Total PEC		\$81,998,000	\$81,998,000		
Direct Installation Costs					
Labor		\$53,980,000	\$53,980,000	Based on Sargent & Lundy's conceptual cost estimating system. 2.5% of Labor 1.5% of Labor 5% of Labor	
Scaffolding		\$1,350,000	\$1,350,000		
Mobilization / Demobilization		\$810,000	\$810,000		
Labor Cost Due To Overtime Inefficiency		\$2,699,000	\$2,699,000		
Total Direct Installation Costs		\$58,839,000	\$58,839,000		
Total Direct Costs (PEC + Direct Installation Costs)		\$140,837,000	\$140,837,000		
Indirect Costs					
Contractor's General and Administration Expense		\$14,084,000	\$14,084,000	10% of Total Direct Costs	
Contractor's Profit		\$7,042,000	\$7,042,000	5% of Total Direct Costs	
Engineering, Procurement, & Project Services		\$11,267,000	\$11,267,000	8% of Total Direct Costs	
Construction Management/Field Engineering		\$5,633,000	\$5,633,000	4% of Total Direct Costs	
S-U / Commissioning		\$2,113,000	\$2,113,000	1.5% of Total Direct Costs	
Spare Parts		\$704,000	\$704,000	0.5% of Total Direct Costs	
Owner's Cost		\$2,817,000	\$2,817,000	2% of Total Direct Costs	
Total Indirect Costs		\$43,660,000	\$43,660,000		
Contingency		\$36,899,000	\$36,899,000	20% of Direct and Indirect Costs	
Total Capital Investment (TCI)		\$221,396,000	\$221,396,000	sum of direct capital costs, indirect capital costs, and contingency	
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$		0.0820	0.0820	20 year life of equipment (years) @ 5.25% interest.	
Annualized Capital Costs (CRF x TCI)		\$18,144,000	\$18,144,000		
OPERATING COSTS					
Operating & Maintenance Costs					
Variable O&M Costs					
Dry Urea Reagent Cost		\$0	\$0	Based on dry urea reagent cost of \$354 per ton.	
Ammonia Reagent Cost		\$262,000	\$276,000	Based on ammonia reagent cost of \$700 per ton.	
RO Water Cost		\$0	\$0	Based on water cost of \$0.60 per 1,000 gallons.	
Steam Cost		\$0	\$0	Based on steam cost of \$1.06 per MMBtu.	
Hydrated Lime Cost		\$294,000	\$309,000	Based on hydrated lime cost of \$189 per ton.	
Catalyst Replacement and Disposal Cost		\$4,257,000	\$4,257,000	Based on catalyst cost of \$8,000 per m³ and catalyst replacement cost of \$1,000 per m³.	
Auxiliary Power Cost		\$1,814,000	\$1,791,000	Based on auxiliary power cost of \$38.07 per MWh (Unit 1) and \$35.72 (Unit 2).	
Total Variable O&M Costs		\$6,627,000	\$6,633,000		
Fixed O&M Costs					
Additional Operators per Shift		1	1		
Operating Labor		\$526,000	\$526,000	Assume \$60/hr for each additional operator	
Supervisor Labor		\$79,000	\$79,000	15% of Operating Labor. EPA Cost Manual Section 1, Chapter 2, page 2-31.	
Maintenance Materials		\$2,113,000	\$2,113,000	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs	
Maintenance Labor		\$0	\$0	Included in cost for maintenance materials.	
Total Fixed O&M Cost		\$2,718,000	\$2,718,000		
Indirect Operating Cost					
Property Taxes		\$2,214,000	\$2,214,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.	
Insurance		\$2,214,000	\$2,214,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.	
Administration		\$4,428,000	\$4,428,000	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.	
Total Indirect Operating Cost		\$8,856,000	\$8,856,000		
Total Annual Operating Cost		\$18,201,000	\$18,207,000		
TOTAL ANNUAL COST					
Annualized Capital Cost		\$18,144,000	\$18,144,000		
Annual Operating Cost		\$18,201,000	\$18,207,000		
Total Annual Cost		\$36,345,000	\$36,351,000		

## NO<sub>x</sub> CONTROL COST EFFECTIVENESS ESTIMATES

### *100% CAPACITY FACTOR AND PROJECTED FUTURE MAXIMUM EMISSION RATES*

Antelope Valley Station Units 1 & 2  
NO<sub>x</sub> Control Summary

Table 1. AVS Units 1 & 2 Operating Parameters

Parameter	Units	Unit 1	Unit 2	Notes
Nominal Power Output	MW gross	450	450	
Annual Heat Input	MMBtu/yr	43,186,800	43,186,800	Based on hourly heat input (per Permit No. T5-F86003) and 100% capacity factor
Annual Capacity Factor	%	100%	100%	
Hourly Heat Input	MMBtu/hr	4,930	4,930	AVS Boiler Design Data Sheet @ 100% MCR

Table 2. NO<sub>x</sub> Control Effectiveness

Control Technology	Unit 1					Unit 2				
	Control Efficiency	Expected Emissions	Emission Rate	Emission Rate	Expected Emissions Reduction	Control Efficiency	Expected Emissions	Emission Rate	Emission Rate	Expected Emissions Reduction
	(%)	(ton/year)	(lb/hr)	(lb/MMBtu)	(ton/year)	(%)	(ton/year)	(lb/hr)	(lb/MMBtu)	(ton/year)
SCR - Tail-End Configuration	52%	1,080	247	0.05	1,155	52%	1,080	247	0.05	1,165
SNCR	9%	2,030	463	0.09	205	10%	2,030	463	0.09	215
Baseline (OFA/LNCFS)		2,235	510	0.10			2,244	512	0.10	

Table 3. NO<sub>x</sub> Control Cost Effectiveness - Unit 1

Control Technology	Emissions (tpy)	Tons of NO <sub>x</sub> Removed (tpy)	Total Capital Requirement (\$)	Annualized Capital Cost (\$/year)	Annualized Outage Cost (\$/year)	Total Annual Operating Costs (\$/year)	Total Annual Costs (\$)	Average Cost Effectiveness (\$/ton)	Incremental Cost Effectiveness (\$/ton)
SCR - Tail-End Configuration	1,080	1,155	\$221,396,000	\$18,144,000		\$18,788,000	\$36,932,000	\$31,977	\$35,278
SNCR	2,030	205	\$16,356,000	\$1,340,000		\$2,074,000	\$3,414,000	\$16,667	
Baseline (OFA/LNCFS)	2,235								

Table 4. NO<sub>x</sub> Control Cost Effectiveness - Unit 2

Control Technology	Emissions (tpy)	Tons of NO <sub>x</sub> Removed (tpy)	Total Capital Requirement (\$)	Annualized Capital Cost (\$/year)	Annualized Outage Cost (\$/year)	Total Annual Operating Costs (\$/year)	Total Annual Costs (\$)	Average Cost Effectiveness (\$/ton)	Incremental Cost Effectiveness (\$/ton)
SCR - Tail-End Configuration	1,080	1,165	\$221,396,000	\$18,144,000		\$18,649,000	\$36,793,000	\$31,589	\$35,131
SNCR	2,030	215	\$16,356,000	\$1,340,000		\$2,075,000	\$3,415,000	\$15,910	
Baseline (OFA/LNCFS)	2,244								

AVS Units 1 and 2  
NO<sub>x</sub> Control Cost Evaluation  
SNCR

NO <sub>x</sub> Control Option Description	SNCR	
	Unit 1	Unit 2
Baseline NO <sub>x</sub> Emissions, lb/MMBtu	0.10	0.10
Post Upgrade NO <sub>x</sub> Emissions, lb/MMBtu	0.09	0.09
Capacity Factor used of Cost Estimates (%)	100%	100%

CAPITAL COSTS		Cost (2018\$)		Basis
		Unit 1	Unit 2	
<b>Direct Costs</b>				
<b>Purchased Equipment Costs (PEC)</b>				
Equipment and Materials	\$7,411,000	\$7,411,000	Based on Sargent & Lundy's conceptual cost estimating system.	
Instrumentation	\$0	\$0	Included in equipment and materials cost	
Sales Tax	\$371,000	\$371,000	5% of Equipment/Material Cost	
Freight	\$371,000	\$371,000	5% of Equipment/Material Cost	
<i>Total PEC</i>	\$8,153,000	\$8,153,000		
<b>Direct Installation Costs</b>				
Labor	\$2,066,000	\$2,066,000	Based on Sargent & Lundy's conceptual cost estimating system.	
Scaffolding	\$52,000	\$52,000	2.5% of Labor	
Mobilization / Demobilization	\$31,000	\$31,000	1.5% of Labor	
Labor Cost Due To Overtime Inefficiency	\$103,000	\$103,000	5% of Labor	
<i>Total Direct Installation Costs</i>	\$2,252,000	\$2,252,000		
Total Direct Costs (PEC + Direct Installation Costs)	\$10,405,000	\$10,405,000		
<b>Indirect Costs</b>				
Contractor's General and Administration Expense	\$1,041,000	\$1,041,000	10% of Total Direct Costs	
Contractor's Profit	\$520,000	\$520,000	5% of Total Direct Costs	
Engineering, Procurement, & Project Services	\$832,000	\$832,000	8% of Total Direct Costs	
Construction Management/Field Engineering	\$416,000	\$416,000	4% of Total Direct Costs	
S-U / Commissioning	\$156,000	\$156,000	1.5% of Total Direct Costs	
Spare Parts	\$52,000	\$52,000	0.5% of Total Direct Costs	
Owner's Cost	\$208,000	\$208,000	2% of Total Direct Costs	
Total Indirect Costs	\$3,225,000	\$3,225,000		
Contingency	\$2,726,000	\$2,726,000	20% of Direct and Indirect Costs	
<b>Total Capital Investment (TCI)</b>	\$16,356,000	\$16,356,000	sum of direct capital costs, indirect capital costs, and contingency	
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$	0.0820	0.0820	20 year life of equipment (years) @ 5.25% interest.	
<b>Annualized Capital Costs (CRF x TCI)</b>	\$1,340,000	\$1,340,000		
<b>OPERATING COSTS</b>				
<b>Basis</b>				
<b>Operating &amp; Maintenance Costs</b>				
<b>Variable O&amp;M Costs</b>				
Dry Urea Reagent Cost	\$572,000	\$572,000	Based on dry urea reagent cost of \$354 per ton.	
Ammonia Reagent Cost	\$0	\$0	Based on ammonia reagent cost of \$700 per ton.	
Water Cost	\$47,000	\$47,000	Based on water cost of \$0.60 per 1,000 gallons.	
Steam Cost	\$16,000	\$18,000	Based on steam cost of \$1.06 per MMBtu.	
Hydrated Lime Cost	\$0	\$0	Based on hydrated lime cost of \$189 per ton.	
Catalyst Replacement Cost	\$0	\$0	Based on catalyst cost of \$8,000 per m <sup>3</sup> and catalyst replacement cost of \$1,000 per m <sup>3</sup> .	
Auxiliary Power Cost	\$24,000	\$23,000	Based on auxiliary power cost of \$38.07 per MWh (Unit 1) and \$35.72 (Unit 2).	
<i>Total Variable O&amp;M Costs</i>	\$659,000	\$660,000		
<b>Fixed O&amp;M Costs</b>				
Additional Operators per shift	1	1		
Operating Labor	\$525,600	\$525,600	Assume \$60/hr for each additional operator	
Supervisor Labor	\$79,000	\$79,000	15% of Operating Labor. EPA Cost Manual Section 1, Chapter 2, page 2-31.	
Maintenance Materials	\$156,100	\$156,100	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs	
Maintenance Labor	\$0	\$0	Included in cost for maintenance materials.	
<i>Total Fixed O&amp;M Cost</i>	\$760,700	\$760,700		
<b>Indirect Operating Cost</b>				
Property Taxes	\$163,600	\$163,600	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.	
Insurance	\$163,600	\$163,600	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.	
Administration	\$327,100	\$327,100	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.	
<i>Total Indirect Operating Cost</i>	\$654,300	\$654,300		
<b>Total Annual Operating Cost</b>	\$2,074,000	\$2,075,000		
<b>TOTAL ANNUAL COST</b>				
Annualized Capital Cost	\$1,340,000	\$1,340,000		
Annual Operating Cost	\$2,074,000	\$2,075,000		
<b>Total Annual Cost</b>	\$3,414,000	\$3,415,000		

AVS Units 1 and 2  
NO<sub>x</sub> Control Cost Evaluation  
SCR - Tail-End Configuration

NO <sub>x</sub> Control Option Description	SCR - Tail-End Configuration	
	Unit 1	Unit 2
Baseline NO <sub>x</sub> Emissions, lb/MMBtu	0.10	0.10
Post Upgrade NO <sub>x</sub> Emissions, lb/MMBtu	0.05	0.05
Capacity Factor used of Cost Estimates (%)	100%	100%

CAPITAL COSTS	Cost (2018\$)		Basis
	Unit 1	Unit 2	
<b>Direct Costs</b>			
<b>Purchased Equipment Costs (PEC)</b>			
Equipment and Materials	\$74,544,000	\$74,544,000	Based on Sargent & Lundy's conceptual cost estimating system.
Instrumentation	\$0	\$0	Included in equipment and materials cost
Sales Tax	\$3,727,000	\$3,727,000	5% of Equipment/Material Cost
Freight	\$3,727,000	\$3,727,000	5% of Equipment/Material Cost
<b>Total PEC</b>	<b>\$81,998,000</b>	<b>\$81,998,000</b>	
<b>Direct Installation Costs</b>			
Labor	\$53,980,000	\$53,980,000	Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding	\$1,350,000	\$1,350,000	2.5% of Labor
Mobilization / Demobilization	\$810,000	\$810,000	1.5% of Labor
Labor Cost Due To Overtime Inefficiency	\$2,699,000	\$2,699,000	5% of Labor
<b>Total Direct Installation Costs</b>	<b>\$58,839,000</b>	<b>\$58,839,000</b>	
<b>Total Direct Costs (PEC + Direct Installation Costs)</b>	<b>\$140,837,000</b>	<b>\$140,837,000</b>	
<b>Indirect Costs</b>			
Contractor's General and Administration Expense	\$14,084,000	\$14,084,000	10% of Total Direct Costs
Contractor's Profit	\$7,042,000	\$7,042,000	5% of Total Direct Costs
Engineering, Procurement, & Project Services	\$11,267,000	\$11,267,000	8% of Total Direct Costs
Construction Management/Field Engineering	\$5,633,000	\$5,633,000	4% of Total Direct Costs
S-U / Commissioning	\$2,113,000	\$2,113,000	1.5% of Total Direct Costs
Spare Parts	\$704,000	\$704,000	0.5% of Total Direct Costs
Owner's Cost	\$2,817,000	\$2,817,000	2% of Total Direct Costs
<b>Total Indirect Costs</b>	<b>\$43,660,000</b>	<b>\$43,660,000</b>	
Contingency	\$36,899,000	\$36,899,000	20% of Direct and Indirect Costs
<b>Total Capital Investment (TCI)</b>	<b>\$221,396,000</b>	<b>\$221,396,000</b>	sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$	0.0820	0.0820	20 year life of equipment (years) @ 5.25% interest.
<b>Annualized Capital Costs (CRF x TCI)</b>	<b>\$18,144,000</b>	<b>\$18,144,000</b>	
<b>OPERATING COSTS</b>			
<b>Operating &amp; Maintenance Costs</b>			
<b>Variable O&amp;M Costs</b>			
Dry Urea Reagent Cost	\$0	\$0	Based on dry urea reagent cost of \$354 per ton.
Ammonia Reagent Cost	\$325,000	\$325,000	Based on ammonia reagent cost of \$700 per ton.
RO Water Cost	\$0	\$0	Based on water cost of \$0.60 per 1,000 gallons.
Steam Cost	\$0	\$0	Based on steam cost of \$1.06 per MMBtu.
Hydrated Lime Cost	\$381,000	\$381,000	Based on hydrated lime cost of \$189 per ton.
Catalyst Replacement and Disposal Cost	\$4,257,000	\$4,257,000	Based on catalyst cost of \$8,000 per m <sup>3</sup> and catalyst replacement cost of \$1,000 per m <sup>3</sup> .
Auxiliary Power Cost	\$2,251,000	\$2,112,000	Based on auxiliary power cost of \$38.07 per MWh (Unit 1) and \$35.72 (Unit 2).
<b>Total Variable O&amp;M Costs</b>	<b>\$7,214,000</b>	<b>\$7,075,000</b>	
<b>Fixed O&amp;M Costs</b>			
Additional Operators per Shift	1	1	
Operating Labor	\$526,000	\$526,000	Assume \$60/hr for each additional operator
Supervisor Labor	\$79,000	\$79,000	15% of Operating Labor. EPA Cost Manual Section 1, Chapter 2, page 2-31.
Maintenance Materials	\$2,113,000	\$2,113,000	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor	\$0	\$0	Included in cost for maintenance materials.
<b>Total Fixed O&amp;M Cost</b>	<b>\$2,718,000</b>	<b>\$2,718,000</b>	
<b>Indirect Operating Cost</b>			
Property Taxes	\$2,214,000	\$2,214,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	\$2,214,000	\$2,214,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	\$4,428,000	\$4,428,000	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
<b>Total Indirect Operating Cost</b>	<b>\$8,856,000</b>	<b>\$8,856,000</b>	
<b>Total Annual Operating Cost</b>	<b>\$18,788,000</b>	<b>\$18,649,000</b>	
<b>TOTAL ANNUAL COST</b>			
Annualized Capital Cost	\$18,144,000	\$18,144,000	
Annual Operating Cost	\$18,788,000	\$18,649,000	
<b>Total Annual Cost</b>	<b>\$36,932,000</b>	<b>\$36,793,000</b>	

## B.2.c – Communications



June 20, 2019 : 9:16 AM

To: *Erin Dukart*

From: *Bachman, Tom A.*

CC: *Stroh, David E.; Seligman, Angela N.*

Subject: *AVS Four Factors Analysis*

Attachments: *Scubber Efficiency.pdf; image002.png;*

Erin:

I have reviewed the four factors analysis and have only a few comments:

1. On p.2-2 and Table 4-6, the design is based on all of the sulfur in the coal exiting the boiler. AP-42 indicates 25% of the sulfur in lignite is retained in the ash. This indicates the design emission rate is higher than it should be. This may effect the overall design of any new equipment ( including the cost) and annual operating costs. The design sulfur emission rate should be reevaluated and appropriate revision to the analysis made.
2. On p. 4-6, it is indicated the AVS has a Plantwide Applicability Limit (PAL). AVS does not have a PAL as described in the PSD rules. The cap on three-hour SO<sub>2</sub> emissions is different from a PAL (annual limit). The section should be revised.
3. In Tables 4-12 and 4-13, we believe the baseline reduction of SO<sub>2</sub> (87%) is high. Using the AP-42 emission factor of 30(S), we believe it is around 82 - 83% (see attachment).

If you have any questions, please feel free to contact me.

Tom Bachman  
Senior Env. Engr.  
Division of Air Quality

701.328.5188 • 701.328.5185 (fax) • [tbachman@nd.gov](mailto:tbachman@nd.gov) • [deq.nd.gov](http://deq.nd.gov) •  
918 East Divide Ave., Bismarck, ND 58501-1947

**ANTELOPE VALLEY STATION  
SO<sub>2</sub> SCRUBBER  
REMOVAL EFFICIENCY**

Year	PLANT	COAL BURNED (TONS)	AVG. SULFUR CONTENT (%)	BOILER EXIT SO <sub>2</sub> EMISSIONS (TONS)	ACTUAL SO <sub>2</sub> EMISSIONS (TONS)	SCRUBBER REMOVAL (%)	COAL-TO-STACK REMOVAL (%)
2000	AVS 1	2859172	0.71	30,450	6,640	78.2	83.6
2000	AVS 2	2,992,950	0.69	30,977	6,407	79.3	84.5
2001	AVS1	2,997,691	0.70	31,476	6,843	78.3	83.7
2001	AVS 2	2,283,892	0.70	23,981	5,226	78.2	83.7
2002	AVS 1	2,514,487	0.67	25,271	7,283	71.2	78.4
2002	AVS 2	2,833,115	0.67	28,473	6,580	76.9	82.7
2003	AVS 1	2,896,392	0.59	25,633	7,374	71.2	78.4
2003	AVS 2	3,009,046	0.59	26,630	7,654	71.3	78.4
2004	AVS 1	2,946,565	0.63	27,845	8,858	68.2	76.1
2004	AVS 2	2,502,053	0.64	24,020	5,276	78.0	83.5
2005	AVS 1	2,455,107	0.65	23,937	5,911	75.3	81.5
2005	AVS 2	2,932,021	0.63	27,708	7,163	74.1	80.6
2006	AVS 1	3,082,307	0.67	30,977	7,092	77.1	82.8

**ANTELOPE VALLEY STATION  
SO<sub>2</sub> SCRUBBER  
REMOVAL EFFICIENCY**

2006	AVS 2	2,899,414	0.65	28,269	7,433	73.7	80.3
2007	AVS 1	2,976,707	0.76	33,934	7,054	79.2	84.4
2007	AVS 2	2,519,337	0.74	27,965	6,618	76.3	82.3
2008	AVS 1	2,549,265	0.78	29,826	6,504	78.2	83.6
2008	AVS 2	2,791,136	0.77	32,238	7,790	75.8	81.9
2009	AVS 1	2,908,708	0.75	32,723	7,039	78.5	83.9
2009	AVS 2	2,876,852	0.8	34,522	7,359	78.7	84.0
2010	AVS 1	3,017,251	0.93	42,091	8,479	79.9	84.9
2010	AVS 2	2,435,302	0.93	33,972	6,413	81.1	85.8
2011	AVS 1	1,899,776	0.96	27,357	5,176	81.1	85.8
2011	AVS 2	2,642,530	0.93	36,863	8,730	76.3	82.2
2012	AVS 1	2,732,031	0.98	40,161	6,871	82.9	87.2
2012	AVS 2	2,660,454	0.96	38,311	7,035	81.6	86.2
2013	AVS 1	2,804,599	0.95	39,966	7,578	81.0	85.8
2013	AVS 2	2,369,861	0.91	32,349	6,076	81.2	85.9
2014	AVS 1	2,332,119	1.02	35,681	5,509	84.6	88.4

**ANTELOPE VALLEY STATION  
SO<sub>2</sub> SCRUBBER  
REMOVAL EFFICIENCY**

2014	AVS 2	2,583,418	0.99	38,364	6,975	81.8	86.4
2015	AVS 1	2,736,138	0.99	40,632	6,312	84.5	88.3
2015	AVS 2	2,833,973	0.98	41,659	6,717	83.9	87.9
2016	AVS 1	2,797,996	1.01	42,390	7,254	82.9	87.2
2016	AVS 2	2,184,054	0.97	31,778	5,089	84.0	88.0
2017	AVS 1	2,442,876	0.91	33,345	5,259	84.2	88.2
2017	AVS 2	2,826,520	0.93	39,430	7,603	80.7	85.5
2018	AVS 1	2,809,117	0.82	34,552	5,911	82.9	87.2
2018	AVS 2	2,628,612	0.86	33,909	6,126	81.9	86.5
<b>AVG.</b>	<b>AVS 1</b>					<b>78.9</b>	
<b>AVG.</b>	<b>AVS 2</b>					<b>78.7</b>	
<b>AVG.</b>	<b>AVS 1 &amp; 2</b>					<b>78.8</b>	
<b>AVG.</b>	<b>AVS 1 &amp; 2</b>					<b>82.8</b>	
<b>2013-2018 Avg.</b>	<b>AVS 1</b>			<b>37,761</b>	<b>6,304</b>	<b>83.3</b>	
<b>2013-2018 Avg.</b>	<b>AVS 2</b>			<b>36,248</b>	<b>6,431</b>	<b>82.3</b>	



NORTH DAKOTA ROUND II REGIONAL HAZE STATE  
IMPLEMENTATION PLAN DETERMINATION'S FOUR-FACTOR  
ANALYSIS FOR ANTELOPE VALLEY STATION  
RESPONSE TO AGENCY COMMENTS

July 12, 2019  
Project No. 13772-001



55 East Monroe Street • Chicago, IL 60603 USA • 312-269-2000  
[www.sargentlundy.com](http://www.sargentlundy.com)

## Introduction

In January 2019, Sargent & Lundy LLC (S&L) prepared a Round II Regional Haze Four-Factor Analysis for the Antelope Valley Station (AVS) on behalf of Basin Electric Power Cooperative (Basin). The analysis was prepared in response to a request made by the North Dakota Department of Environmental Quality (NDDEQ) and included an assessment of potentially available sulfur dioxide (SO<sub>2</sub>) and nitrogen oxide (NO<sub>x</sub>) emission reduction technologies that could be applied to AVS Unit 1 and 2.

NDDEQ tendered comments to Basin on June 20, 2019, regarding the AVS Four-Factor Analysis. The purpose of this document is to provide responses to the June 20 comments from NDDEQ.

## NDDEQ Comment 1

On p.2-2 and Table 4-6, the design is based on all of the sulfur in the coal exiting the boiler. AP-42 indicates 25% of the sulfur in lignite is retained in the ash. This indicates the design emission rate is higher than it should be. This may effect the overall design of any new equipment (including the cost) and annual operating costs. The design sulfur emission rate should be reevaluated and appropriate revision to the analysis made.

## S&L/Basin Response

We appreciate the agency's comment regarding calculation of the design SO<sub>2</sub> inlet rate; however, adjusting the design inlet rate to account for sulfur that may be retained in the ash would not have a significant impact on either capital or O&M costs presented in the Four-Factor Analysis. S&L used projected future fuel analyses (sulfur and HHV) provided by Basin to calculate a design inlet SO<sub>2</sub> rate. Projections were based on the annual average fuel sulfur content and average heating value of the fuel for each year over the next 20 years, taking into account historical deviations seen in the coal quality. Coal data were provided to Basin by the Freedom Mine. The design SO<sub>2</sub> rate of 3.39 lb/MBtu show in Table 4-6 of the report represents the highest annual average SO<sub>2</sub> emission rate assuming 100% conversion of fuel sulfur to SO<sub>2</sub> without taking into account any inherent SO<sub>2</sub> retention in the ash.



It appears that NDDEQ used the Fourth Edition Compilation of Air Pollutant Emissions Factors (AP-42) from 1985 to support its comment that S&L's design SO<sub>2</sub> emission rate (calculated assuming 100% conversion of fuel sulfur to SO<sub>2</sub>) is higher than it should be. That edition of AP-42 includes an assumption for lignite fuels that, on average, 75% of the fuel sulfur will be converted to SO<sub>2</sub> (i.e. 3.39 lb SO<sub>2</sub>/MBtu \* 0.75 = 2.54 lb SO<sub>2</sub>/MBtu). A more recent edition recommends using an emission factor of 30S (lb/ton) for lignite-fired pulverized coal (PC) boilers, where S = weight % sulfur content of the lignite on a wet basis (see, Fifth Edition Compilation of Air Pollutant Emissions Factors AP-42, Volume 1: Stationary Point and Area Sources, Chapter 1, Table 1.7-1). A conversion factor of 0.077 is used to convert from lb/ton to lb/MBtu assuming an average lignite heating value of 6,500 Btu/lb. Using this approach, the inlet SO<sub>2</sub> rate would be calculated as: (30)\*(1.09)\*(0.077) = 2.52 lb SO<sub>2</sub>/MBtu.

Although S&L used an uncontrolled SO<sub>2</sub> rate of 3.39 lb/MBtu as the design basis for the Four-Factor Analysis, that value was only used for the Projected Future Maximum Case. Uncontrolled SO<sub>2</sub> rates of 2.90 lb SO<sub>2</sub>/MBtu for Units 1 and 2 (see Table 4-4 of the Four Factor Analysis) were used for the Actual Average Case.

When reviewing the technically feasible SO<sub>2</sub> alternatives for the AVS station, costs associated with the DFGD upgrades are primarily O&M driven. Variable O&M costs for DFGD operational changes are predominantly a function of the lime consumption rate. Lime consumption rates were based on an uncontrolled SO<sub>2</sub> rate of 2.90 lb SO<sub>2</sub>/MBtu for the Actual Average Case. Revising the uncontrolled emission rate to 2.54 lb SO<sub>2</sub>/MBtu would reduce the lime consumption rate by approximately 15%; however, they would be a corresponding reduction in the quantity of SO<sub>2</sub> removed such that the change would not have an impact on the cost-effectiveness analysis.

For the capital driven SO<sub>2</sub> alternatives (i.e., new DFGD or new WFGD), capital costs are predominantly driven by the absorber size which is based on the flue gas volumetric flow rate rather than inlet SO<sub>2</sub> concentration. As such, the difference between designing new equipment for 2.54 lb SO<sub>2</sub>/MBtu and 2.90 lb SO<sub>2</sub>/MBtu will not have a significant impact on the cost-effectiveness analysis because the capital costs would essentially be the same.

### NDDEQ Comment 2

On p. 4-6, it is indicated the AVS has a Plantwide Applicability Limit (PAL). AVS does not have a PAL as described in the PSD rules. The cap on three-hour SO<sub>2</sub> emissions is different from a PAL (annual limit). The section should be revised.

### S&L/Basin Response

We will revise the section accordingly. Previous terminology that was used will be adjusted as follows: "AVS Units 1 and 2 have a combined 3-hour SO<sub>2</sub> ~~plantwide applicability limit (PAL)~~ of 3,845 lb/hr in their Title V Air Permit that allows the station to adjust operation of each unit's FGD system as long as they achieve the combined overall plantwide limit."

### NDDEQ Comment 3

In Tables 4-12 and 4-13, we believe the baseline reduction of SO<sub>2</sub> (87%) is high. Using the AP-42 emission factor of 30(S), we believe it is around 82 - 83% (see attachment).

### S&L/Basin Response

We agree that the existing DFGD alone may provide a removal efficiency of approximately 82-83%, while the coal-to-stack removal efficiency is closer to 87%. Removal efficiencies listed in Table 4-12 and 4-13 were calculated based on the controlled SO<sub>2</sub> emission rate achieved with each technology and assuming an inlet SO<sub>2</sub> rate of 2.90 lb/MBtu (see response to Comment 1). Removal efficiencies in Table 4-12 and 4-13 represent overall SO<sub>2</sub> removal and are provided for comparative purposes. However, it is important to note that the baseline SO<sub>2</sub> emission rates (in tpy) were not calculated using an uncontrolled emission rate of 2.90 lb SO<sub>2</sub>/MBtu; instead it was calculated based on the historic annual heat input and stack emission rate. Therefore, reducing the uncontrolled SO<sub>2</sub> rate, or adjusting the removal efficiencies, would not have an impact on the tons of SO<sub>2</sub> removed or the cost-effectiveness analysis.

### B.3 – Basin LOS

#### B.3.a – Department Request



May 2, 2018

**FILE**

Mr. Mike Paul  
Basin Electric Power Coop.  
1717 E Interstate Avenue  
Bismarck, ND 58503-0564

Re: Regional Haze  
Second Planning Period

Dear Mr. Paul:

The Department of Health (Department) has begun work on the second planning period (Round 2) State Implementation Plan (SIP) for regional haze. In Round 1 of the regional planning process, the emphasis was on Best Available Retrofit Technology (BART) and making reasonable progress towards the national visibility goal. In Round 2, there are no BART requirements; therefore, we will focus on making reasonable progress. The reasonable progress analysis will be made using the four factors in Section 169A(g)(1) of the Clean Air Act:

The four factors are:

1. The cost of compliance
2. The time necessary to achieve compliance
3. The energy and non-air quality environmental impact of compliance; and
4. The remaining useful life of any existing source subject to such requirements

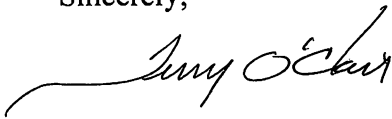
Guidance provided by the U.S. Environmental Protection Agency (Draft Guidance on Progress Tracking Metrics, Long Term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period at [https://www.epa.gov/sites/production/files/2016-07/documents/draft\\_regional\\_haze\\_guidance\\_july\\_2016.pdf](https://www.epa.gov/sites/production/files/2016-07/documents/draft_regional_haze_guidance_july_2016.pdf)) indicates the Department must address 80% of the visibility impairment caused by in-state sources. Data from the IMPROVE monitoring sites at Theodore Roosevelt National Park (TRNP) and Lostwood Wilderness Area (LWA) indicate that sulfates and nitrates continue to be the largest contributors to visibility impairment in these areas. The primary precursors of sulfates and nitrates are emissions of sulfur dioxide (SO<sub>2</sub>) and nitrogen oxides (NO<sub>x</sub>).

Coal-fired electrical generating units have been identified as one of the largest source of sulfur dioxide and nitrogen oxides in North Dakota. Therefore, the Department requests that you prepare a "four factors" analysis for your coal-fired electrical generating units. The analysis should be prepared using the draft EPA guidance noted above. The Department will identify other sources in North Dakota that will be required to submit a four factors analysis.

The Department will be working with the Western Regional Air Partnership (WRAP) to prepare the Round 2 SIP. WRAP will be conducting air quality modeling of regional emissions reductions in early 2019. The Department asks that your "four factors" analysis be submitted by January 31, 2019.

If you have any questions, please contact David Stroh of my staff at (701)328-5188.

Sincerely,

A handwritten signature in black ink, appearing to read "Terry O'Clair", with a long horizontal flourish extending to the left.

Terry L. O'Clair  
Director  
Division of Air Quality

TLO/TB:saj

xc: Cris Miller, Basin Electric Power Coop.

### B.3.b – Facility Response





January 31, 2019

Mr. Terry O'Clair  
North Dakota Department of Health  
918 East Divide Avenue, Second Floor  
Bismarck, ND 58501-1947

Dear Mr. O'Clair:

RE: Four Factor Analysis Submittal for Antelope Valley Station and Leland Olds Station

Enclosed, you will find one CD and three hard copies of Basin Electric Power Cooperative's (**Basin Electric**) Round II Regional Haze Determination Four Factor Analysis for the Antelope Valley and Leland Olds Stations. This analysis was performed as outlined in the North Dakota Department of Health's (**NDDH**) May 2, 2018, request. Basin Electric is aware that the four factor analysis is one component contributing to the NDDH's Round II Regional Haze State Implementation Plan's Determination for each of these emission sources.

North Dakota is relying on the Western Regional Air Partnership (**WRAP**) to develop the visibility modeling platform needed to evaluate visibility at the Class I areas and subsequently for the individual states to develop and assess compliance strategies that will be formalized within the Round II Regional Haze State Implementation Plan.

Basin Electric requests that the NDDH withhold its Round II Regional Haze Determination until a comparative evaluation of visibility from the various control alternatives have been performed. The timing of the visibility analysis is subject to model availability. Basin Electric will continue to monitor WRAP's model development and will coordinate closely with the NDDH prior to initiating visibility impact analysis.

Should you have any questions concerning this submittal, please do not hesitate to contact Erin Dukart, Environmental Compliance Administrator at [edukart@bepc.com](mailto:edukart@bepc.com) or 701.557.5557.

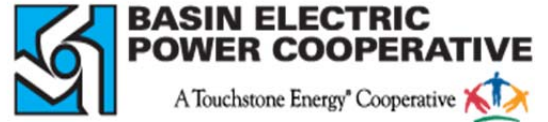
Sincerely,

Mike Paul  
Chief Technical Advisor

/efd/sw

Enclosures

cc: Erin Fox Dukart  
Keri Schiferl  
Casey Mutzenberger



# NORTH DAKOTA ROUND II REGIONAL HAZE STATE IMPLEMENTATION PLAN DETERMINATION'S FOUR-FACTOR ANALYSIS FOR LELAND OLDS STATION UNITS 1 AND 2

SL-014752

Final

January 30, 2019

Project No. 13772-002



55 East Monroe Street • Chicago, IL 60603-5780 USA • 312-269-2000  
[www.sargentlundy.com](http://www.sargentlundy.com)

## CONTENTS

<b>EXECUTIVE SUMMARY .....</b>	<b>1</b>
<b>1. INTRODUCTION .....</b>	<b>1-1</b>
<b>2. FACILITY DESCRIPTION.....</b>	<b>2-1</b>
<b>3. FOUR-FACTOR ANALYSIS REQUIREMENTS .....</b>	<b>3-1</b>
<b>3.1 REGIONAL HAZE RULE BACKGROUND .....</b>	<b>3-1</b>
3.1.1 First Implementation Period.....	3-3
3.1.2 Round II Regional Haze SIP Determination .....	3-7
<b>3.2 DESCRIPTIONS OF THE FOUR STATUTORY FACTORS.....</b>	<b>3-9</b>
3.2.1 Costs of Compliance .....	3-9
3.2.2 Time Necessary for Compliance .....	3-11
3.2.3 Energy and Non-Air Quality Environmental Impacts.....	3-12
3.2.4 Remaining Useful Life .....	3-13
3.2.5 Four Factor Analysis Approach .....	3-13
<b>4. SO<sub>2</sub> CONTROL EVALUATION .....</b>	<b>4-1</b>
<b>4.1 BASELINE SO<sub>2</sub> EMISSIONS .....</b>	<b>4-1</b>
<b>4.2 COAL SULFUR CONTENT.....</b>	<b>4-3</b>
<b>4.3 SO<sub>2</sub> EMISSIONS CONTROLS .....</b>	<b>4-4</b>
4.3.1 Identify Available SO <sub>2</sub> Control Options .....	4-4
4.3.2 Technical Feasibility of Available SO <sub>2</sub> Control Options .....	4-5
4.3.3 Evaluate Technically Feasible SO <sub>2</sub> Control Options for Effectiveness .....	4-12
<b>4.4 COSTS OF COMPLIANCE (STATUTORY FACTOR ONE) .....</b>	<b>4-14</b>
4.4.1 SO <sub>2</sub> Average Annual Economic Evaluation.....	4-16
4.4.2 SO <sub>2</sub> Potential-to-Emit Annual Economic Evaluation.....	4-18

<b>5. NO<sub>x</sub> CONTROL EVALUATION.....</b>	<b>5-1</b>
<b>5.1 BASELINE NO<sub>x</sub> EMISSIONS .....</b>	<b>5-1</b>
<b>5.2 NO<sub>x</sub> EMISSIONS CONTROLS .....</b>	<b>5-3</b>
5.2.1 Identify Available NO <sub>x</sub> Control Options .....	5-3
5.2.2 Technical Feasibility of Available NO <sub>x</sub> Control Options .....	5-3
5.2.3 Evaluate Technically Feasible NO <sub>x</sub> Control Options for Effectiveness .....	5-23
<b>5.3 NO<sub>x</sub> COST OF COMPLIANCE (STATUTORY FACTOR ONE) .....</b>	<b>5-25</b>
5.3.1 NO <sub>x</sub> Average Annual Economic Evaluation .....	5-26
5.3.2 NO <sub>x</sub> Potential-to-Emit Economic Evaluation .....	5-28
<b>6. TIME NECESSARY FOR COMPLIANCE (STATUTORY FACTOR TWO) .....</b>	<b>6-1</b>
<b>7. ENERGY AND NON-AIR QUALITY ENVIRONMENTAL IMPACTS (STATUTORY FACTOR THREE) .....</b>	<b>7-1</b>
<b>7.1 ENVIRONMENTAL IMPACTS .....</b>	<b>7-1</b>
<b>7.2 ENERGY IMPACTS .....</b>	<b>7-2</b>
<b>7.3 ENVIRONMENTAL / ENERGY IMPACTS SUMMARY .....</b>	<b>7-2</b>
<b>8. REMAINING USEFUL LIFE (STATUTORY FACTOR FOUR) .....</b>	<b>8-1</b>
<b>9. CONCLUSIONS .....</b>	<b>9-1</b>

**FIGURES/TABLES**

Figure 3-1. Federal Class I Areas .....	3-1
Figure 3-2. Regional Planning Organization Map.....	3-2
Table ES-1. Technically Feasible SO <sub>2</sub> Control Options.....	2
Table ES-2. Technically Feasible NO <sub>x</sub> Control Options.....	2
Table ES-3. Proposed Round II Determination's NO <sub>x</sub> Emission Rate .....	5
Table 2-1. Four Factor Analysis Design Basis Parameters .....	2-1
Table 3-1. Initial Planning Period SIP Summary .....	3-7
Table 3-2. Key Steps in Developing the Round II Determination.....	3-8
Table 4-1. Representative Baseline Periods for SO <sub>2</sub> Emissions .....	4-1

Table 4-2: Baseline Actual SO <sub>2</sub> Emissions .....	4-2
Table 4-3: Projected Future Maximum SO <sub>2</sub> Emissions.....	4-2
Table 4-4. Baseline LOS Coal Quality (Annual) .....	4-3
Table 4-5. Future LOS Coal Quality (Annual).....	4-3
Table 4-6. Design Basis for Future Projected LOS Coal Quality (Annual) .....	4-4
Table 4-7. Available SO <sub>2</sub> Control Options.....	4-5
Table 4-8. Potential WFGD Operational Improvements and Equipment Upgrades.....	4-5
Table 4-9. Technically Feasible SO <sub>2</sub> Control Options for LOS Unit 1 .....	4-11
Table 4-10. Technically Feasible SO <sub>2</sub> Control Options for LOS Unit 2 .....	4-12
Table 4-11. Evaluate Technically Feasible SO <sub>2</sub> Control Options by Effectiveness for LOS Unit 1 (Baseline Average Emissions).....	4-13
Table 4-12. Evaluate Technically Feasible SO <sub>2</sub> Control Options by Effectiveness for LOS Unit 2 (Baseline Average Emissions).....	4-13
Table 4-13. Evaluate Technically Feasible SO <sub>2</sub> Control Options by Effectiveness for LOS Unit 1 (Projected Future Maximum Emissions).....	4-14
Table 4-14. Evaluate Technically Feasible SO <sub>2</sub> Control Options by Effectiveness for LOS Unit 2 (Projected Future Maximum Emissions).....	4-14
Table 4-15. SO <sub>2</sub> Control Cost Summary (Average Annual) .....	4-16
Table 4-16. SO <sub>2</sub> Emissions Control System Cost Effectiveness (Average Annual).....	4-17
Table 4-17. SO <sub>2</sub> Control Cost Summary (Projected Future Maximum).....	4-18
Table 4-18. SO <sub>2</sub> Emissions Control System Cost Effectiveness (Projected Future Maximum).....	4-19
Table 5-1. Representative Baseline Periods for NO <sub>x</sub> Emissions.....	5-1
Table 5-2: Baseline Actual NO <sub>x</sub> Emissions .....	5-2
Table 5-3: Baseline Projected Future Maximum NO <sub>x</sub> Emissions.....	5-2
Table 5-4. Available NO <sub>x</sub> Control Options.....	5-3
Table 5-5. Technically Feasible NO <sub>x</sub> Control Options for LOS Unit 1 .....	5-21
Table 5-6. Technically Feasible NO <sub>x</sub> Control Options for LOS Unit 2 .....	5-22
Table 5-7. Evaluate Technically Feasible NO <sub>x</sub> Control Options by Effectiveness for LOS Unit 1 (Baseline Average Emissions) .....	5-23
Table 5-8. Evaluate Technically Feasible NO <sub>x</sub> Control Options by Effectiveness for LOS Unit 2 (Baseline Average Emissions) .....	5-24
Table 5-9. Evaluate Technically Feasible NO <sub>x</sub> Control Options for Effectiveness - LOS Unit 1 (Projected Future Maximum Emissions).....	5-24
Table 5-10. Evaluate Technically Feasible NO <sub>x</sub> Control Options for Effectiveness - LOS Unit 2 (Projected Future Maximum Emissions).....	5-25
Table 5-11. NO <sub>x</sub> Control Cost Summary (Annual Average) .....	5-27

Table 5-12. NO <sub>x</sub> Emissions Control System Cost Effectiveness (Annual Average) .....	5-27
Table 5-13. NO <sub>x</sub> Control Cost Summary (Projected Future Maximum) .....	5-29
Table 5-14. NO <sub>x</sub> Emissions Control System Cost Effectiveness (Projected Future Maximum).....	5-29
Table 6-1. SO <sub>2</sub> Emissions Control System Implementation Schedule .....	6-1
Table 6-2. NO <sub>x</sub> Emissions Control System Implementation Schedule .....	6-2
Table 7-1. Summary of Energy and Non-Air Quality Environmental Impacts .....	7-3
Table 9-1. Proposed Round II Determination's NO <sub>x</sub> Emission Rate .....	9-3

## APPENDICES

- A. North Dakota Department of Health Letter
- B. Leland Olds Station Units 1 and 2 Baseline Emissions
- C. SO<sub>2</sub> Control Cost Effectiveness Estimates
- D. NO<sub>x</sub> Control Cost Effectiveness Estimates

## ABBREVIATIONS/ACRONYMS

Abbreviation/Acronym	Explanation
ABS	ammonium bisulfate
acfm	actual cubic feet per minute
ASOFA	advanced separated overfire air
B&W	Babcock & Wilcox
BACT	Best Available Control Technology
BART	Best Available Retrofit Technology
Basin Electric	Basin Electric Power Cooperative
Ca	calcium
CAA	Clean Air Act
CaCO <sub>3</sub>	limestone
CATC	Clean Air Technology Center
CEMS	continuous emissions monitoring system
CFD	computational fluid dynamics
CFR	Code of Federal Regulations
CRF	capital recovery factor
DBA	dibasic acid
DSI	dry sorbent injection
dv	deciview
ESP	electrostatic precipitator
EPA	Environmental Protection Agency
EGU	electric generating unit
FGD	flue gas desulfurization
FIP	Federal Implementation Plan
G&A	general and administration
GHG	greenhouse gas
H <sub>2</sub> O	water
HHV	higher heating value
K	potassium
L/G	liquid-to-gas



NORTH DAKOTA ROUND II REGIONAL HAZE SIP  
DETERMINATION'S FOUR-FACTOR ANALYSIS FOR LELAND OLDS  
STATION UNITS 1 AND 2

vii

---

LNB	Low-NO <sub>x</sub> burner
LOS	Leland Olds Station
LTS	long-term strategy
Mg	magnesium
MMBtu	million British thermal units
MNL	multi-nozzle lance
MRYS	Milton R. Young Station
MW	megawatt
MWg	megawatt gross
N <sub>2</sub>	nitrogen
Na	sodium
ND	North Dakota
NDDH	North Dakota Department of Health
NH <sub>3</sub>	ammonia
NO	nitric oxide
NO <sub>2</sub>	nitrogen dioxide
NO <sub>x</sub>	nitrogen oxides
NSR	New Source Review
NSR	normalized stoichiometric ratio
OEM	original equipment manufacturer
OFA	overfire air
ORP	oxidation-reduction potential
O&M	operations and maintenance
PM	particulate matter
PRB	Powder River Basin
RBLC	RACT/BACT/LAER Clearinghouse
Round II Determination	Round II Regional Haze State Implementation Plan Determination
RPG	reasonable progress goals
RPO	Regional Planning Organization
RRI	rich reagent injection
S	sulfur
S&L	Sargent & Lundy, L.L.C.
SACR	selective autocatalytic reduction

---

NORTH DAKOTA ROUND II REGIONAL HAZE SIP  
DETERMINATION'S FOUR-FACTOR ANALYSIS FOR LELAND OLDS  
STATION UNITS 1 AND 2

**viii**

---

SCR	selective catalytic reduction
SIP	State Implementation Plan
SNCR	selective non-catalytic reduction
SO <sub>2</sub>	sulfur dioxide
SO <sub>3</sub>	sulfur trioxide
SOFA	separated overfire air
TAC	total annual cost
TCI	total capital investment
TE-SCR	tail-end SCR
URP	uniform rate of progress
WRAP	Western Region Air Partnership

---

## EXECUTIVE SUMMARY

The Leland Olds Station (LOS), located near Stanton, ND, has two generating units (Units 1 and 2) rated at 220 MW and 440 MW, respectively. Both units are designed to fire North Dakota lignite coal. LOS Unit 1 is a B&W opposed wall-fired unit that went online in 1966. LOS Unit 1 is equipped with an Emerson combustion optimizers, low-NO<sub>x</sub> burners (LNB), advanced separated overfire air (SOFA) and selective non-catalytic reduction (SNCR) for nitrogen oxide (NO<sub>x</sub>) control, wet limestone flue gas desulfurization (WFGD) system for sulfur dioxide (SO<sub>2</sub>) control, and electrostatic precipitators (ESP) for particulate matter (PM) control. LOS Unit 2 is a B&W cyclone-fired unit that went online in 1975. LOS Unit 2 is equipped with an Emerson combustion optimizer, SOFA, and SNCR for NO<sub>x</sub> control, WFGD for SO<sub>2</sub> control, and ESP for PM control.

On July 1, 1999, the U.S. Environmental Protection Agency (EPA) published regulations implementing Section 169A of the Clean Air Act (CAA), establishing a comprehensive visibility protection program for Federal Class I areas (the Regional Haze Rule).<sup>1</sup> The Regional Haze Rule requires each state to develop, and submit for approval by EPA, a state implementation plan (SIP) detailing the state's plan to protect visibility in Class I areas. The Regional Haze Rule established a schedule setting forth deadlines by which the states must submit their initial regional haze SIPs and subsequent revisions to the SIPs. Regional Haze SIPs for the initial planning period were due in 2007, with subsequent SIP updates due in 2018 and every 10 years thereafter.<sup>2</sup>

During the initial planning period, the North Dakota Department of Health (NDDH) concluded that best available retrofit technology (BART) for both of Basin Electric Cooperative's (Basin Electric) LOS units included new WFGDs for SO<sub>2</sub> control and SOFA with SNCR for NO<sub>x</sub> control. U.S. EPA initially disapproved NDDH's determination for LOS Unit 2 NO<sub>x</sub> emissions, and issued a proposed a Federal Implementation Plan (FIP) that included advanced SOFA plus selective catalytic reduction (SCR). Following the public notice and comment period for the proposed FIP, EPA reversed its position regarding the technical feasibility of SCR on LOS Unit 2 and decided to approve the State's BART determination for NO<sub>x</sub> control on LOS Unit 2.

---

<sup>1</sup> 64 FR 35713

<sup>2</sup> On January 10, 2017, EPA made a one-time adjustment to the due date for the second implementation period (2018 – 2028) by extending the deadline from July 31, 2018 to July 31, 2021 (82 FR 3078).

As part of the Round II Regional Haze State Implementation Plan Determination (Round II Determination), NDDH requested that Basin Electric prepare a four-factor analysis of SO<sub>2</sub> and NO<sub>x</sub> emissions control options for LOS Units 1 and 2. The analysis evaluates technically feasible SO<sub>2</sub> and NO<sub>x</sub> emission reduction measures for the following four statutory factors:

- Factor 1: The cost of compliance
- Factor 2: The time necessary to achieve compliance
- Factor 3: The energy and non-air quality environmental impact of compliance
- Factor 4: The remaining useful life of any existing source subject to such requirements

Sargent & Lundy LLC (S&L) and Basin Electric evaluated potentially available SO<sub>2</sub> and NO<sub>x</sub> emissions reduction options for LOS Units 1 and 2 to identify technically feasible control options for inclusion in the four factor analysis. The SO<sub>2</sub> and NO<sub>x</sub> control options included in this four factor analysis are identified in Table ES-1 and Table ES-2.

**Table ES-1. Technically Feasible SO<sub>2</sub> Control Options**

LOS Unit 1		LOS Unit 2	
Alt. No.	SO <sub>2</sub> Control Technology	Alt. No.	SO <sub>2</sub> Control Technology
B	FGD Upgrades – pH Buffer Addition	B	FGD Upgrades – pH Buffer Addition
A	FGD Operational Improvements – Ca:S Stoichiometry	A	FGD Operational Improvements – Ca:S Stoichiometry and Liquid-to-Gas Ratio
--	Baseline (existing WFGD)	--	Baseline (existing WFGD)

**Table ES-2. Technically Feasible NO<sub>x</sub> Control Options**

LOS Unit 1		LOS Unit 2	
Alt. No.	NO <sub>x</sub> Control Technology	Alt. No.	NO <sub>x</sub> Control Technology
		B	Optimized SNCR + rich reagent injection (RRI)
A	SCR – tail-end configuration <sup>(Note 1)</sup>	A	Optimized SNCR
--	Baseline (existing LNB / SOFA / SNCR)	--	Baseline (existing LNB / SOFA / SNCR)

Note 1. Tail-end SCR (TE-SCR) has not been installed on a North Dakota lignite-fired unit, and extended trials would be needed to better understand the design and operation of TE-SCR on LOS Unit 1. Nevertheless, during the initial planning period, NDDH concluded that TE-SCR was a technically feasible NO<sub>x</sub> control technology for a North Dakota lignite-fired boiler, and evaluated the costs and cost-effectiveness of the control system. For consistency with NDDH's conclusion from the first planning period, TE-SCR will be carried forward to the Four Factor Analysis.

The cost of compliance evaluation (Statutory Factor 1) prepared for SO<sub>2</sub> controls indicates that, from baseline emission rates, the average annual cost effectiveness of the technically feasible SO<sub>2</sub> control options for Unit 1 ranges from \$10,021 per ton (Alternative A) to \$17,948 per ton SO<sub>2</sub> removed (Alternative B), and for Unit 2 ranges from \$6,906 per ton (Alternative A) to \$13,946 per ton SO<sub>2</sub> removed (Alternative B). When evaluating projected future maximum emissions reductions, the average annual cost effectiveness of the technically feasible SO<sub>2</sub> control options for Unit 1 ranges from \$18,200 per ton (Alternative A) to \$18,948 per ton SO<sub>2</sub> removed (Alternative B), and for Unit 2 ranges from \$13,444 per ton (Alternative A) to \$15,462 per ton SO<sub>2</sub> removed (Alternative B).

The cost of compliance evaluation prepared for NO<sub>x</sub> controls indicates that, from baseline emission rates, the average annual cost effectiveness of the technically feasible NO<sub>x</sub> control options for Unit 1 is \$54,605 per ton NO<sub>x</sub> removed (Alternative A), and for Unit 2 ranges from \$1,896 per ton (Alternative A) to \$3,630 per ton NO<sub>x</sub> removed (Alternative B). When evaluating projected future maximum emissions reductions, the average annual cost effectiveness of the technically feasible NO<sub>x</sub> control options for Unit 1 is \$28,528 per ton NO<sub>x</sub> removed (Alternative A), and for Unit 2 ranges from \$1,588 per ton (Alternative A) to \$3,186 per ton NO<sub>x</sub> removed (Alternative B). For Unit 2, Alternatives A and B will also affect the units' net plant heat rate since the amount of water that will be injected with the urea will negatively impact boiler efficiency. Both alternatives do not include additional costs that would be incurred due to the loss in net generation.

The time necessary for compliance (Statutory Factor 2) for the SO<sub>2</sub> control options ranges from 3 months (Alternative A) to 12 months (Alternative B). For NO<sub>x</sub> control options, the time necessary for compliance ranges from 12 months (Alternatives A and B – Unit 2) to 52 months (Alternative A – Unit 1).

An evaluation of energy impacts and non-air environmental impacts (Statutory Factor 3) indicates that certain control options will increase auxiliary power requirements due to increased pressure drop, which would adversely impact net plant heat rate. Consequently, heat input to the boiler would need to increase to compensate for the increased auxiliary power requirements while achieving the same net plant output, or net output from the unit would decrease. Collateral environmental impacts potential include increases in water consumption, solid waste generation, sulfuric acid mist emissions, and ammonia emissions.

Regarding remaining useful life (Statutory Factor 4), under the current Basin Electric resource plan, the remaining useful life of LOS Unit 1 and 2 are considered to be greater than 20 years. Therefore, the remaining useful life has no impact on the annualized cost of control under the current regulatory framework.

Based on the results of the four factor analysis prepared for LOS SO<sub>2</sub> emissions reductions, WFGD Operational Improvements and WFGD Upgrades are cost prohibitive. The control cost evaluation indicates that the average cost effectiveness levels exceed \$6,900 per ton SO<sub>2</sub> removed. Therefore, Basin Electric is proposing that the existing WFGD systems on Units 1 and 2 represent appropriate controls for the Round II Determination.

The four factor analysis prepared for LOS Units 1 indicates that additional NO<sub>x</sub> controls are cost prohibitive. The cost effectiveness of installing a TE-SCR system on Unit 1 is over \$28,000 per ton NO<sub>x</sub> removed. Therefore, Basin Electric is proposing that the existing LNB / SOFA / SNCR system on Unit 1 represents appropriate controls for the Round II Determination. For Unit 2, the analysis indicates a cost effectiveness of \$1,600 ton for the optimized SNCR alternative. The implementation of the optimized SNCR decreases the actual hourly mass emission rate by approximately 100 lb per hr (from historical baseline emissions). However, it can increase ammonia emissions, and that effect would result in additional haze formation. As such, a 5<sup>th</sup> factor analysis (visibility improvement using modeling) is recommended for this option to determine whether there is any or only a trivial amount of visibility improvement. Basin Electric requests that the NDDH withhold their Round II Determination until the Western Region Area Partnership's cumulative modeling platform are available so that a visibility improvement assessment can be conducted. Basin Electric will then perform a comparative visibility improvement analysis between the two control alternatives and submit the results to the NDDH for consideration.

It is generally understood from previous visibility modeling efforts that increased ammonia injection has the opportunity of providing additional ammonia to the atmosphere. This increased ammonia availability within the emitted plume itself is known to contribute to increased visibility impairment due to more direct formation of ammonium sulfate and ammonium nitrate, especially in the winter months where fine particulate formation is ammonia limited. In fact, it is during the winter months that the NO<sub>x</sub> emissions have a visibility effect; the observed (and modeled) nitrate haze during the warmer months with more park visitation is negligible. As a result of the future modeling analysis, the actual visibility benefit of the optimized SNCR alternative may be considered minimal if not de-minimis.

For the Round II Determination, no change to the current Title V Operating Permit is proposed for SO<sub>2</sub> emissions on either LOS Unit 1 or 2 and no proposed change to the NO<sub>x</sub> emissions on LOS Unit 1. Table ES-3 includes a summary of the proposed Round II Determination's strategy for NO<sub>x</sub>, assessed NO<sub>x</sub> emissions on a 30-day rolling average basis and a proposed Round II Determination's emission rate on a 30-day rolling average basis for LOS

Unit 2. The proposed emissions limits include compliance margin to account for items such as variability in the operating load profile.

**Table ES-3. Proposed Round II Determination's NO<sub>x</sub> Emission Rate**

LOS Unit No.	Pollutant	Assessed Emission Rate lb/MMBtu <sup>(Note 2)</sup> (30-day rolling average)	Proposed Round II Determination's Emission Rate lb/MMBtu <sup>(Note 1)</sup> (30-day rolling average)	Control Technology
Unit 2	NO <sub>x</sub>	0.27	0.30	Optimized SNCR System

Note 1. The proposed Round II Determination's emission rate is a 14% reduction from the current permit limit of 0.35 lb NO<sub>x</sub>/MMBtu, 30-day rolling avg.

Note 2. The assessed emission rate represents the average emission rate that LOS Unit 2 would be expected to achieve on an on-going long-term basis under normal operating conditions.



## 1. INTRODUCTION

Sargent & Lundy, L.L.C. (S&L) was retained by Basin Electric Power Cooperative (Basin Electric) to prepare a Round II Regional Haze State Implementation Plan Determination's (Round II Determination) four-factor analysis for the control of sulfur dioxide (SO<sub>2</sub>) and nitrogen oxide (NO<sub>x</sub>) emissions from Basin Electric's Leland Olds Station (LOS) Units 1 and 2. This evaluation is in response to the North Dakota Department of Health's formal letter dated May 2, 2018, attached in Appendix A. The evaluation includes an assessment of potentially available emission reduction measures for the four statutory factors listed in 40 CFR 51.308(f)(2), and takes into consideration U.S. Environmental Protection Agency's (EPA's) *Draft Guidance on Progress Tracking Metrics, Long Term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period* (the "Draft EPA Guidance").<sup>3</sup> Technically feasible SO<sub>2</sub> and NO<sub>x</sub> emission reduction measures are evaluated for the following four statutory factors:

- Factor 1: The cost of compliance
- Factor 2: The time necessary to achieve compliance
- Factor 3: The energy and non-air quality environmental impact of compliance
- Factor 4: The remaining useful life of any existing source subject to such requirements

The Round II Determination's four factor analysis for LOS Units 1 and 2 is presented in the following sections:

- Section 2: Facility Description** contains information describing the facility, site location, and existing equipment.
- Section 3: Four-Factor Analysis Requirements** provides a brief description of the Regional Haze Program requirements set forth in 40 CFR 51.308.
- Section 4: SO<sub>2</sub> Control Evaluation** establishes representative baseline SO<sub>2</sub> emissions, identifies potentially available emission control technologies, evaluates each control option for technical feasibility and evaluates cost effectiveness of technically feasible control options.

<sup>3</sup> On September 11, 2018, EPA released a "*Regional Haze Reform Roadmap*" announcing its plan to "release a series of implementation tools and guidance documents that will help focus states' efforts and reduce and streamline the time and resources needed to meet the statutory and regulatory requirements for reducing regional haze in National Parks, wildlife refuges, and wilderness areas." EPA stated that it plans to issue a new guidance document on Regional Haze SIP Development by Spring, 2019. Basin Electric reserves the right to update and modify this four-factor analysis, as needed, to be consistent with any new guidance issued by the agency.

- Section 5:** **NO<sub>x</sub> Control Evaluation** establishes representative baseline NO<sub>x</sub> emissions, identifies potentially available emission control technologies, evaluates each control option for technical feasibility and evaluates cost effectiveness of technically feasible control options.
- Section 6:** **Time Necessary for Compliance (Statutory Factor Two)** provides typical timelines required to design, engineer, procure and install the technically feasible control options.
- Section 7:** **Energy and Non-Air Quality Environmental Impacts (Statutory Factor Three)** identifies the energy and non-air quality environmental impacts associated with each technically feasible control option.
- Section 8:** **Remaining Useful Life (Statutory Factor Four)** includes a discussion of the planned remaining useful life of LOS Units 1 and 2, including an evaluation of how remaining useful life affects the cost-effectiveness of each technically feasible control option.
- Section 9:** **Summary and Conclusions**

**Appendix A: North Dakota Department of Health Letter**

**Appendix B: Leland Olds Station Units 1 and 2 Baseline Emissions**

**Appendix C: SO<sub>2</sub> Control Cost Effectiveness Estimates**

**Appendix D: NO<sub>x</sub> Control Cost Effectiveness Estimates**

## 2. FACILITY DESCRIPTION

The Leland Olds Station (LOS), located near Stanton, ND, has two generating units (Units 1 and 2) rated at 220 MW and 440 MW, respectively. Both units are designed to fire North Dakota lignite coal. LOS Unit 1 is a Babcock and Wilcox (B&W) opposed wall-fired unit that went online in 1966. LOS Unit 1 is equipped with an Emerson combustion optimizer, low-NO<sub>x</sub> burners (LNB), advanced separated overfire air (SOFA) and selective non-catalytic reduction (SNCR) for NO<sub>x</sub> control, wet limestone flue gas desulfurization (WFGD) system for SO<sub>2</sub> control, and electrostatic precipitators (ESP) for particulate matter (PM) control. LOS Unit 2 is a B&W cyclone-fired unit that went online in 1975. LOS Unit 2 is equipped with an Emerson combustion optimizer, SOFA, and SNCR for NO<sub>x</sub> control, WFGD for SO<sub>2</sub> control, and ESP for PM control

Table 2-1 provides a summary of the design parameters used for the LOS Units 1 and 2 four factor analysis. The four factor analysis design parameters listed in Table 2-1 were developed from information provided by Basin Electric.

**Table 2-1. Four Factor Analysis Design Basis Parameters**

Parameter	LOS Unit 1	LOS Unit 2
Boiler type	PC opposed wall-fired	Cyclone-fired
Boiler manufacturer	B&W	B&W
Generating Capacity (MWg)	220	440
Design heat input (MMBtu/hr)	2,622	5,130
Average Hourly Heat Input for Baseline SO <sub>2</sub> period (MMBtu/hr)	1,851	3,779
Capacity Factor for Baseline SO <sub>2</sub> period (%)	68	69
Average Hourly Heat Input for Baseline NO <sub>x</sub> period (MMBtu/hr)	1,646	3,692
Capacity Factor for Baseline NO <sub>x</sub> period (%)	51	68
Full load flue gas conditions at WFGD Outlet		
Temperature (°F)	145	144

NORTH DAKOTA ROUND II STATE IMPLEMENTATION PLAN  
 DETERMINATION'S FOUR-FACTOR ANALYSIS FOR LELAND OLDS  
 UNITS 1 AND 2

**2-2**

Parameter	LOS Unit 1	LOS Unit 2
Mass flow rate (lb/hr)	3,028,000	6,396,000
Volumetric flow rate (acfm)	816,500	1,722,500
Baseline Fuel Parameters <sup>(1)</sup>		
Higher Heating Value (Btu/lb)	6,793	6,818
Fuel sulfur content (%)	1.06	1.04
SO <sub>2</sub> content (lb/MMBtu)	3.12	3.05
Projected Future Fuel Parameters <sup>(2)</sup>		
Higher Heating Value (Btu/lb)	6,595	
Fuel sulfur content (%)	1.23	
SO <sub>2</sub> content (lb/MMBtu)	3.73	

Note 1. Current fuel parameters are based on the actual annual average fuel sulfur content from 2014-2018 provided by Basin Electric.

Note 2. Projected future fuel parameters are based on anticipated annual average coal projections provided by Basin Electric from 2019-2040. Projected future sulfur and SO<sub>2</sub> content includes margin based on the actual deviation in annual average sulfur content from current coal data. Additional detail on coal sulfur provided in Section 4.2.

### 3. FOUR-FACTOR ANALYSIS REQUIREMENTS

#### 3.1 REGIONAL HAZE RULE BACKGROUND

Section 169A of the 1977 Amendments to the Clean Air Act (CAA) sets forth a program for protecting visibility in Federal Class I areas which calls for “the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory Federal Class I areas which impairment results from manmade air pollution.” Federal Class I areas include national parks, memorial parks, and wilderness areas over a certain size. Figure 3-1 shows the locations of the 156 federally mandated Class I areas. Federal Class I areas located within North Dakota include the Theodore Roosevelt National Park and the Lostwood National Wildlife Refuge.

**Figure 3-1. Federal Class I Areas**



On July 1, 1999, the U.S. EPA published regulations implementing Section 169A of the CAA, establishing a comprehensive visibility protection program for Federal Class I areas (the Regional Haze Rule).<sup>4</sup> The Regional Haze Rule requires each state to develop, and submit for approval by EPA, a state implementation plan (SIP) detailing the state's plan to protect visibility in Class I areas. Regional Haze SIPs must contain such emission limits, schedules of compliance, and other measures as may be necessary to make reasonable progress toward meeting the national visibility goal of achieving visibility in Class 1 areas which reflects natural conditions by 2064.

To address the combined visibility effects of various pollution sources over a wide geographic region, EPA designated five Regional Planning Organizations (RPOs) to assist with the coordination and cooperation needed to address the visibility issue. The five RPOs are shown in Figure 3-2. North Dakota is a member of the Western Regional Air Partnership (WRAP), which serves as the RPO for visibility protection at 118 Class I areas in 15 western states.

**Figure 3-2. Regional Planning Organization Map**



<sup>4</sup> 64 FR 35713

### **3.1.1 First Implementation Period**

The Regional Haze Rule established a schedule setting forth deadlines by which the states must submit their initial regional haze SIPs and subsequent revisions to the SIPs. Regional Haze SIPs for the initial planning period were due in 2007, with subsequent SIP updates due in 2018 and every 10 years thereafter.<sup>5</sup>

Regional Haze SIP requirements for the first planning period required that states incorporate into their plans the core program requirements in 40 CFR 51.308(d), including: (1) establishing reasonable progress goals (RPGs) for each Class I area within the state that provide for measurable progress towards achieving natural visibility conditions; (2) developing a long-term strategy (LTS) including enforceable emissions limitations and compliance schedules to achieve the RPGs; and (3) developing plans to monitor and assess the effectiveness of the LTS to achieve the RPGs over the prior implementation period and affirmation of or revision to the RPGs.

The Regional Haze Rule requires that states determine the consistent rate of progress over time needed to attain natural visibility conditions on the 20 percent most impaired days by the year 2064. This “glidepath” is referred to as the uniform rate of progress (URP) line. States must consider the URP, and the emission reduction measures needed to achieve this level of improvement, when developing their RPGs and LTS. Regulations at 40 CFR 51.308(g) require each state to submit progress reports, in the form of SIP revisions, every 5 years following the submission of the initial SIP. These progress reports must evaluate the progress made towards the RPGs for Class I areas located within the state as well as those Class I areas located outside the state that may be affected by emissions from within the state.

#### **3.1.1.1 Best Available Retrofit Technology**

As a one-time requirement during the first implementation period, potential best available retrofit technology (BART) controls had to be evaluated for certain large stationary sources. States were required to conduct BART determinations for “BART-eligible” sources anticipated to cause or contribute to any visibility impairment in one or more Class I area. BART-eligible sources included coal-fired electric generating units (EGUs) that were in existence on August 7, 1977, but not in operation prior to August 7, 1962. As an alternative to requiring source-

---

<sup>5</sup> On January 10, 2017, EPA made a one-time adjustment to the due date for the second implementation period (2018 – 2028) by extending the deadline from July 31, 2018 to July 31, 2021 (82 FR 3078).



specific BART controls, states also had the flexibility to adopt an emissions trading program or other alternative program as long as the alternative provided greater reasonable progress towards improving visibility than BART.

### **3.1.1.2 North Dakota's Initial Planning Period SIP**

The State of North Dakota submitted its regional haze SIP addressing the requirements of 40 CFR 51.308 to EPA for review on March 3, 2010 (the "Regional Haze SIP").<sup>6</sup> The Regional Haze SIP was prepared by the North Dakota Department of Health, Air Quality Division (NDDH). The SIP included BART determinations for seven steam EGUs identified as being subject to the BART requirements of 40 CFR 51.208(e) and a reasonable progress evaluation for six additional non-BART sources identified as having the potential to affect visibility in a Class I area.

Basin Electric's LOS Units 1 & 2 were evaluated by NDDH as subject-to-BART sources.<sup>7</sup> Based on its evaluation of available control technologies, NDDH concluded that BART for both LOS units included new WFGD for SO<sub>2</sub> control and SOFA with SNCR for NO<sub>x</sub> control. NDDH determined that selective catalytic reduction (SCR), a higher performing NO<sub>x</sub> control option, was not an available, and thus not a technically feasible, NO<sub>x</sub> control option.<sup>8</sup>

Basin Electric's AVS Units 1 & 2 were evaluated by NDDH under the reasonable progress requirements. Based on an evaluation of the four reasonable progress statutory factors (i.e., costs of compliance, time necessary for compliance, energy and non-air quality environmental impacts of compliance, and the remaining useful life of the units) plus an evaluation of incremental visibility improvement, NDDH concluded that requiring additional controls (beyond those required for the BART-eligible sources) would not substantially improve visibility in the Class I

---

<sup>6</sup> North Dakota State Implementation Plan for Regional Haze – 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, February 24, 2010. In addition to the initial SIP submittal, the State submitted a SIP Supplement No. 1 on July 27, 2010, and a SIP Amendment No. 1 on July 28, 2011 (collectively the "Regional Haze SIP").

<sup>7</sup> In addition to LOS Units 1 & 2, NDDH evaluated Great River Energy's Coal Creek Station Units 1 & 2; Great River Energy's Stanton Station Unit 1; and Minnkota Power Cooperative's Milton R. Young Station Units 1 & 2 as subject-to-BART sources.

<sup>8</sup> Regional Haze SIP, pg. 73. The State's evaluation of SCR for North Dakota lignite was included as Appendix B.5 to the Regional Haze SIP (Best Available Retrofit Technology – Selective Catalytic Reduction Technical Feasibility Analysis for North Dakota Lignite, July 2009). NDDH eliminated SCR from consideration as BART based on a finding that SCR was not technically feasible to control emissions from North Dakota lignite coal. In particular, NDDH noted that no SCR has ever been employed on an EGU burning North Dakota lignite, that North Dakota lignite has unique properties that have the potential to quickly degrade the SCR catalyst, and that no catalyst vendor would provide a guarantee of catalyst life without first conducting slipstream or pilot testing.

areas, and that for all reasonable progress sources evaluated individually and cumulatively, control technology costs (evaluated on a dollar per deciview improvement (\$/dv) basis) was excessive. Therefore, the Regional Haze SIP did not include additional control for AVS Units 1 & 2.<sup>9</sup>

On September 21, 2011, EPA published a Proposed Rule proposing to partially approve and partially disapprove specific aspects the Regional Haze SIP.<sup>10</sup> Among other things, EPA proposed to disapprove the State's determination of BART for LOS Unit 2 as well as the reasonable progress determination for AVS Units 1 & 2. EPA proposed to approve the remaining aspects of North Dakota's Regional Haze SIP, including that State's BART determination for SO<sub>2</sub> control at LOS (i.e., new WFGD) and the NO<sub>x</sub> BART determination for LOS Unit 1 (i.e., SOFA+SNCR).<sup>11</sup> Along with the proposed partial disapproval of North Dakota's SIP, EPA proposed the promulgation of a Federal Implementation Plan (FIP). The proposed FIP included, among other items: (1) a NO<sub>x</sub> BART determination and emission limits for LOS Unit 2; and (2) a reasonable progress determination and NO<sub>x</sub> emission limits for AVS Units 1 & 2. EPA proposed advanced SOFA (ASOFA) plus SCR and an emission rate of 0.07 lb/MMBtu (30-day rolling average) as BART for NO<sub>x</sub> control on LOS Unit 2. EPA also proposed LNB plus SOFA and an emission limit of 0.17 lb/MMBtu (30-day rolling average) as representing reasonable progress NO<sub>x</sub> control on AVS Units 1 & 2.<sup>12</sup>

Following the public notice and comment period EPA issued its Final Rule on April 6, 2012.<sup>13</sup> The Final Rule differed from the Proposed Rule in that EPA reversed its position regarding the technical feasibility of SCR on LOS

---

<sup>9</sup> *Id.* at pg. 188.

<sup>10</sup> 76 Fed. Reg. 58570, September 21, 2011 (the "Proposed FIP"). In addition to the proposed disapproval of the State's BART determination for Leland Olds Station Unit 2, EPA proposed disapproving the BART determinations for the Coal Creek Station and Milton R. Young Station (MRYS) Units 1 & 2.

<sup>11</sup> *Id.* at pg. 58619. Note that for LOS Unit 1 EPA stated that it did not agree with the State's cost analysis for SCR, but nonetheless found the elimination of SCR for LOS Unit 1 to be acceptable because LOS Unit 1 is relatively small (216 MW) compared to LOS Unit 2 (440 MW) and MRYS Units 1 & 2, and LOS Unit 1 had lower baseline NO<sub>x</sub> emission. (76 FR 58596, Table 22).

<sup>12</sup> *Id.* at pg. 58632. EPA eliminated higher performing NO<sub>x</sub> control options for AVS Units 1 & 2, including LNB + SNCR; SCR; and LNB + SCR, because their cost effectiveness values were significantly higher and/or the emission reductions were not that much higher than LNB. Considering the statutory factors, EPA found that it was not reasonable to insist on these higher control levels in the first; however, EPA noted that expected North Dakota to consider such controls in the next planning period.

<sup>13</sup> 77 Fed. Reg. 20894.

Unit 2 and decided to approve the State's BART determination for NO<sub>x</sub> control on LOS Unit 2.<sup>14</sup> Conversely, EPA finalized its determination that LNB+SOFA was required by reasonable progress for AVS Units 1 & 2.

EPA's decision to accept the BART determinations for LOS Unit 2 (and Minnkota Power Cooperative Inc.'s Milton R. Young Station (MRYS) Units 1 & 2) was based primarily on the decision in United States v. Minnkota Power Cooperative, Inc.<sup>15</sup> which concluded that the State's best available control technology (BACT) analysis for NO<sub>x</sub> control on MRYS Units 1 & 2 was not unreasonable, a conclusion that was contrary to EPA's position at the time of the Proposed FIP.<sup>16</sup> In explaining its decision to reverse its position that SCR was a technically feasible NO<sub>x</sub> control option for LOS Unit 2, EPA noted that the technical feasibility determination under the BACT and BART analyses was substantially the same, and that the BART Guidelines permit a state to rely upon a BACT determination for purposes of selecting BART unless new technologies have become available or best control levels for recent retrofits have become more stringent.<sup>17</sup> Noting that the District Court upheld North Dakota's BACT determination for MRYS Units 1 & 2, EPA concluded that it would be inappropriate to proceed with its proposed disapproval of SNCR as BART, and approved the State's determination that ASOFA+SNCR and an emission rate of 0.35 lb/MMBtu (30-day rolling average) was BART for NO<sub>x</sub> control on LOS Unit 2.

Emission controls required by the Regional Haze SIP for the Basin Electric's LOS and AVS stations are summarized in Table 3-1.

---

<sup>14</sup> *Id.* at pg. 20897-98. EPA also reversed its position and decided to approve the State's BART determination for NO<sub>x</sub> control on MRYS Units 1 & 2.

<sup>15</sup> United States v. Minnkota Power Cooperative, Inc., 831 F. Supp. 2d 1109, 1127-30 (D.ND. 2011).

<sup>16</sup> Contemporaneous with the Regional Haze SIP/FIP process, NDDH was also determining BACT for MRYS Units 1 & 2 pursuant to a Consent Decree entered into between the owner of the station (Minnkota), the State, and EPA under the CAA's Prevention of Significant Deterioration program. In its BACT analysis, NDDH concluded that SCR was technically infeasible on a lignite-fired cyclone boiler, and selected SNCR as BACT. EPA challenged the State's BACT determination in district court, contending that SCR was a technically feasible emission control option and should have been selected as BACT. On December 21, 2011, the District Court issued its decision on EPA's challenge of the State's BACT determination, finding that the State's conclusion that SCR was not technically feasible was not unreasonable. See, *U.S. v. Minnkota*, 831 F. Supp. 2d at 1127-30.

<sup>17</sup> 77 Fed. Reg. 20897.

**Table 3-1. Initial Planning Period SIP Summary**

Source & Unit	Pollutant	Control Device / Emission Limit
LOS Unit 1 (BART)	NO <sub>x</sub>	Basic SOFA + SNCR with an emission limit of 0.19 lb/MMBtu (30-day rolling average)
	SO <sub>2</sub>	New WFGD operating at 95% efficiency or below an emission limit of 0.15 lb/MMBtu (30-day rolling average)
LOS Unit 2 (BART)	NO <sub>x</sub>	Advanced SOFA + SNCR with an emission limit of 0.35 lb/MMBtu (30-day rolling average)
	SO <sub>2</sub>	New WFGD operating at 95% efficiency or below an emission limit of 0.15 lb/MMBtu (30-day rolling average)
AVS Unit 1 (reasonable progress)	NO <sub>x</sub>	LNB + SOFA with an emission limit of 0.17 lb/MMBtu (30-day rolling average)
	SO <sub>2</sub>	No additional control beyond the existing dry FGD / baghouse
AVS Unit 2 (reasonable progress)	NO <sub>x</sub>	LNB + SOFA with an emission limit of 0.17 lb/MMBtu (30-day rolling average)
	SO <sub>2</sub>	No additional control beyond the existing dry FGD / baghouse

### 3.1.1.3 BART Requirements for Leland Olds Station during First Planning Period

LOS Unit 1 and 2 commenced operation in 1966 and 1975, respectively; thus, both units were subject to BART requirements during the first planning period. The BART selected by NDDH for LOS Unit 1 and Unit 2 was WFGD for SO<sub>2</sub> control and SOFA and SNCR for NO<sub>x</sub> control with a compliance date of April 4, 2017.

A 0.15 lb SO<sub>2</sub>/MMBtu or 95% SO<sub>2</sub> removal on a 30-day rolling average limit was placed on each LOS Unit, which corresponds with the Presumptive BART SO<sub>2</sub> control level proposed by EPA for a WFGD. A NO<sub>x</sub> limit of 0.19 lb/MMBtu and 0.35 lb/MMBtu on a 30-day rolling average was placed on LOS Unit 1 and 2, respectively.

The WFGD systems for Units 1 and 2 were placed in early operation in 2012 (LOS Unit 2) and 2013 (LOS Unit 1), due to the increasing sulfur content of the fuel supply. The layered NO<sub>x</sub> control systems were placed in service in stages over several years with the systems fully in service and optimized in 2016 for both units.

### 3.1.2 Round II Regional Haze SIP Determination

The Round II Determination must be submitted to EPA for review by July 31, 2021. Among other requirements, the Round II Determination is required to include an assessment of the state's RPGs and LTS. To support states in

their efforts to develop the Round II Determination, in July 2016 EPA released a draft guidance document titled “*Draft Guidance on Progress Tracking Metrics, Long-term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period*” (“Draft EPA Guidance”).<sup>18</sup> The Draft EPA Guidance document describes key steps states should implement when developing their RPGs and LTS for the Round II Determination. Key steps identified in the Draft EPA Guidance are listed in Table 3-2.

**Table 3-2. Key Steps in Developing the Round II Determination**

1. <i>Ambient data analysis</i> – Quantify baseline, current and natural conditions and the URP that would achieve natural conditions by 2064 (40 CFR 51.308(f)(1))
2. <i>Screening of sources</i> – Identify the pollutants and emission sources for which a full reasonable progress analysis will be completed and explain why it is appropriate to limit the full analysis to only these sources (40 CFR 51.308(f)(2))
3. <i>Source and emission control measure analysis</i> – Identify potential emission control measures for sources selected in the screening step and develop data on the four statutory factors and visibility benefits if they will be considered (40 CFR 51.308(f)(2))
4. <i>Decisions on the content of the LTS</i> – Consider applicable factors and decide on new emission controls for incorporation into the LTS (40 CFR 51.308(f)(2))
5. <i>Regional scale modeling</i> – Model the emissions reductions that will result from implementation of the LTS and other enforceable measures that will reduce visibility impairment to set the RPGs for 2028 (40 CFR 51.308(f)(3))
6. <i>Progress, degradation and glidepath checks</i> – Demonstrate that there will be an improvement on the 20 percent most impaired days. Demonstrate that there is no degradation on the 20 percent clearest days. Compare the 2028 RPG for the 20 percent most impaired days to the 2028 point on the URP line (the glidepath) and, if required, provide additional justification for the reasonableness of the RPG. Revise the LTS if additional measures are identified as necessary to make reasonable progress. (40 CFR 51.308(f)(3))
7. <i>Additional requirements for SIPs</i> – Provide additional information necessary to ensure that other requirements of the Regional Haze rule are met.

The Draft EPA Guidance recommends that states evaluate all technically feasible emission control options for

<sup>18</sup> See, EPA-457/P-16-001. On September 11, 2018, EPA released a “*Regional Haze Reform Roadmap*” announcing its plan to “release a series of implementation tools and guidance documents that will help focus states’ efforts and reduce and streamline the time and resources needed to meet the statutory and regulatory requirements for reducing regional haze in National Parks, wildlife refuges, and wilderness areas.” EPA stated that it plans to issue a new guidance document on Regional Haze SIP Development by Spring, 2019. Basin Electric reserves the right to update and modify this four-factor analysis, as needed, to be consistent with any new guidance issued by the agency.

stationary sources and source categories identified as having the greatest potential to impact visibility at one or more Class I area. The Draft EPA Guidance recommends several options for states to consider when evaluating potential emission reductions, including work practices, replacement and retrofit controls, existing control upgrades, fuel switching, year-round operation of controls, and operating restrictions.<sup>19</sup>

Emission control evaluations must consider the four statutory factors identified in 40 CFR 51.308(f)(2)(i) (discussed in Section 3.2). In addition, the Draft EPA Guidance notes that control technology assessment recommendations presented in the BART Guidelines continue to be relevant as recommendations for how a state should evaluate and select emission control measures for stationary sources.<sup>20</sup> Recommendations in the BART Guidelines that continue to be relevant to the Round II Determination's four factor analysis are listed in the Appendix D of the Draft EPA Guidance, and include, in general, the recommended approach for evaluating the technical feasibility, effectiveness, costs, and cost-effectiveness of available emission control measures.<sup>21</sup>

### **3.2 DESCRIPTIONS OF THE FOUR STATUTORY FACTORS**

Under 40 CFR 51.308(f)(2)(i), states must consider four statutory factors when evaluating and determining emissions reduction measures from stationary sources, or groups of sources, that are necessary to make reasonable progress towards achieving natural visibility conditions. The four statutory factors are:

1. The costs of compliance;
2. The time necessary for compliance;
3. The energy and non-air quality environmental impacts of compliance; and
4. The remaining useful life of any potentially affected anthropogenic source of visibility impairment.

A brief description of each of the four statutory factors, and EPA's recommendations for evaluating each of the four factors (from the Draft EPA Guidance) is provided below.

#### **3.2.1 Costs of Compliance**

Cost estimates should be developed for each technically feasible control option. Costs include the total capital costs to engineer, design, procure, and install the control technology, and annual operations and maintenance

---

<sup>19</sup> See, Draft EPA Guidance, pgs. 85-86.

<sup>20</sup> Draft EPA Guidance, pg. 85. The BART Guidelines are published at 40 CFR Part 51 Appendix Y.

<sup>21</sup> Draft EPA Guidance, Appendix D, pgs. 186-196.

(O&M) costs. O&M costs include both fixed and variable O&M. Fixed O&M includes costs that are independent of control system operation and would be incurred even if the control system were shut down. Fixed O&M includes categories such as O&M labor, administrative charges, property taxes, and insurance. Variable O&M includes the cost of consumables, including reagent (e.g., lime or limestone, ammonia, urea, etc.), by-product management, water consumption, and auxiliary power requirements associated with operating the control system. For existing facilities, O&M cost estimates should represent the control option's incremental increase over current O&M costs.

Capital costs include all costs required to engineer, design, procure, and install equipment needed for the control system. The Draft EPA Guideline recommends that states adhere to the accounting principles described in Chapter 2 Section 1 of EPA's Air Pollution Control Cost Manual (the "Control Cost Manual") when calculating control system costs for a four factor analysis.<sup>22</sup>

Section 2.3 of the Control Cost Manual (Section 1, Chapter 2) describes the cost categories generally used to calculate the total capital cost of a retrofit control technology. Cost categories include total capital investment (TCI), which is defined to "include all costs required to purchase equipment needed for the control systems (purchased equipment costs), the costs of labor and materials for installing that equipment (direct installation costs), costs for site preparation and buildings, and certain other costs (indirect installation costs). TCI also includes costs for land, working capital, and off-site facilities." Direct installation costs include costs for foundations and supports, erecting and handling the equipment, electrical work, piping, insulation, and painting. Indirect installation costs include costs such as engineering costs; construction and field expenses (i.e., cost for construction supervisory personnel, office personnel, rental of temporary offices, etc.); contractor fees (for construction and engineering firms involved in the project); start-up and performance test costs (to get the control system running and to verify that it meets performance guarantees); and contingencies.<sup>23</sup>

The total annual cost (TAC) of a control option includes the annualized capital recovery cost plus the total annual O&M costs. The Control Cost Manual recommends using an equivalent uniform annual cash flow method to annualize the total capital investment by multiplying the total capital investment by a capital recovery factor

<sup>22</sup> EPA Air Pollution Control Cost Manual, Sixth Edition, EPA/452/B-02-001, January 2002.

<sup>23</sup> EPA Air Pollution Control Cost Manual, Sixth Edition, EPA/452/B-02-001, January 2002, pg. 2-5.



(CRF).<sup>24</sup> The product of the total capital investment and CRF gives a uniform end-of-year payment necessary to repay the initial capital investment in "n" years at an interest rate of "i". The CRF is calculated using the following equation:

$$CRF = \frac{i * (1 + i)^n}{(1 + i)^n - 1}$$

Where:

i = interest rate; and

n = economic life of the emission control system

The Draft EPA Guidance suggests that states may use generic cost estimates or estimating algorithms for estimating control system costs; however, source specific estimates prepared by knowledgeable engineering professionals provide more reliable information than generic cost estimates.<sup>25</sup> Source-specific cost estimate should be well documented for purposes of public comment and EPA review.<sup>26</sup>

The total annual cost of each control option (\$/yr) is divided by the total annual emissions reduction (tons/yr) to determine the control option's average cost-effectiveness on a \$/ton basis. Emissions reductions are calculated based on the difference between baseline annual emissions and post-control annual emissions. The Draft EPA Guidance generally recommends calculating baseline emissions based on projected 2028 emissions assuming source compliance with emission limits that have been adopted and are enforceable. As an alternative, baseline emissions may be based on representative data of past actual emissions, assuming there is no evident basis for using a different emissions rate. As such, the cost of compliance is based on historical baseline as well as future projected capacity factors and fuels.

### **3.2.2 Time Necessary for Compliance**

For stationary sources, the provisions of the BART Guidelines regarding the time necessary for compliance are relevant to the Round II Determination's analyses. EPA recommends that prior experiences with the planning and installation of new emission controls is the best guide to how much time a particular source will reasonably need for compliance. However, source-specific factors should be considered when evaluating the time necessary to

---

<sup>24</sup> Id., at pg 2-21.

<sup>25</sup> Draft EPA Guidance, pg. 91.

<sup>26</sup> Id.

engineer, procure, and install an available and technically feasible control option. Source-specific factors that affect the time necessary to install new emission controls should be identified and documented in the four factor analysis.

### **3.2.3 Energy and Non-Air Quality Environmental Impacts**

For stationary sources, the provisions of the BART Guidelines regarding energy impacts are relevant to Round II Determination's analyses. Energy impacts of an emission control measure are a matter of engineering design and control system operation; thus, EPA recommends that prior experience at similar sources will be informative. Energy impacts may be considered in terms of kilowatt-hours or fuels used to operate the control system. The energy impact analysis should focus on direct energy consumption at the source rather than indirect energy inputs needed to produce raw materials for the construction and operation of control equipment.

For stationary sources, the provisions of the BART Guidelines regarding non-air quality environmental impacts are relevant to the Round II Determination's analyses. Non-air quality impacts include solid or hazardous waste generation, increased water consumption, wastewater discharge, land use impacts, and impacts to threatened and endangered species or their natural habitat. Characterizing the non-air quality environmental impacts should be done on a source-specific basis. Other guidance intended for use in assessments under the National Environmental Policy Act may be relevant to this evaluation.

Even though states are not required to consider greenhouse gas (GHG) emission impacts, the Draft EPA Guidance encourages states to consider GHG impacts when developing their LTS.<sup>27</sup> As an example, some measures that would reduce emissions that contribute to visibility impairment will also reduce GHG emissions, such as measures that reduce the use of energy produced from combusting fossil fuels with relatively high GHG emissions. Conversely, control measures that require significant energy to capture visibility impairing emissions could result in increased GHG emission. Where a measure necessary to make reasonable progress towards natural visibility conditions would increase GHG emissions, Draft EPA Guidance encourages states to work to harmonize visibility and climate change objectives.<sup>28</sup>

---

<sup>27</sup> Draft EPA Guidance, pg. 92.

<sup>28</sup> *Id.*

### **3.2.4 Remaining Useful Life**

For stationary sources, the provisions of the BART Guidelines regarding remaining useful life are relevant to the Round II Determination's analyses. In general, the remaining useful life of the source itself will be longer than the useful life of the emission control measure under consideration unless there is an enforceable requirement for the source to cease operation sooner. Thus, the useful life of the control measure will normally be used in the four factor analysis to calculate emission reductions, amortized costs, and cost-effectiveness. However, if there is an enforceable requirement for the source to cease operation by a date before the end of what would otherwise be the useful life of the control measure under consideration, then the enforceable shutdown date should be used to calculate remaining useful life and evaluate control technology cost-effectiveness.

### **3.2.5 Four Factor Analysis Approach**

S&L used a top-down approach to identify and evaluate the technical feasibility and effectiveness of potentially available SO<sub>2</sub> and NO<sub>x</sub> control measures. S&L followed Steps 1 thru 3 of the top-down approach described in the BART Guidelines to identify all available retrofit emission control measures, eliminate technically infeasible options, and evaluate the effectiveness of the technically feasible options.<sup>29</sup> A brief description of each step is provided below.

#### ***Step 1 - Identify All Available Control Options***

Available control options are those air pollution control technologies with a practical potential for application to the emission unit and the regulated pollutant under evaluation. Air pollution control technologies can include a wide variety of available methods, systems, and techniques for control of the affected pollutant, and include not only existing controls for the source category but also take into account technology transfer of controls that have been applied to similar source categories and gas streams. Technologies which have not been applied to (or permitted for) full scale operations need not be considered as available.<sup>30</sup>

---

<sup>29</sup> See, 40 CFR Part 51 Appendix Y, Section IV.D.

<sup>30</sup> *Id.*, at IV.D.1.

In an effort to identify all potentially available emission control technologies, S&L searched a broad range of information sources including, but not necessarily limited to:

- EPA's RACT/BACT/LAER Clearinghouse (RBLC);
- EPA's New Source Review (NSR) and Clean Air Technology Center (CATC) Web sites;
- BART evaluations prepared during the initial Regional Haze planning period;
- Information from control technology vendors and engineering/environmental consultants;
- Federal and State NSR permits and BACT determinations for similar sources; and
- Technical journals, reports, newsletters and air pollution control seminars.

### ***Step 2 - Eliminate Technically Infeasible Control Options***

In Step 2, S&L evaluated the technical feasibility of the control options identified in Step 1 with respect to source-specific and unit-specific factors. Control technologies are technically feasible if either: (1) they have been installed and operated successfully for the type of source under review under similar conditions; or (2) the technology could be applied to the source under review. In order for a control option to be technically feasible, it must be "available" and "applicable" to the source under consideration. A technology is considered "available" if the source owner may obtain it through commercial channels. An available technology is "applicable" if it can reasonably be installed and operated on the source type under consideration.<sup>31</sup>

Control technologies that are technically infeasible (i.e., not available or not applicable to the source under consideration) are eliminated for further evaluation. A demonstration of technical infeasibility must be based on physical, chemical and engineering principals, and must show that technical difficulties would preclude the successful use of the control option on the emission unit under consideration. The economics of an option are not considered in the determination of technical feasibility/infeasibility.

### ***Step 3 - Evaluate Technically Feasible Control Technologies for Effectiveness***

Step 3 involves evaluating the control effectiveness of all the technically feasible control alternatives identified in Step 2 for the pollutant and emissions unit under review. Control effectiveness should be expressed using a metric that ensures an "apples-to-apples" comparison of emissions performance levels among options, and is generally

---

<sup>31</sup> A more detailed description of control technology "availability" and "applicability" is provided in 40 CFR Part 51 Appendix Y, Section IV.D.2.

expressed as the rate that a pollutant is emitted after installation of the control measure. Control technology evaluations for existing sources should consider ways to improve the performance of existing control devices. Special circumstances pertinent to the specific control technology under review should be identified and taken into consideration when assessing the capability of the control alternative and determining control effectiveness.

For this evaluation, S&L assessed the technically feasible SO<sub>2</sub> and NO<sub>x</sub> control options for effectiveness on LOS Unit 1, which is equipped with SOFA/LNB/SNCR/Emerson Combustion Optimizer for NO<sub>x</sub> control and WFGD for SO<sub>2</sub> control. In addition, control options were assessed for technical feasibility and effectiveness for LOS Unit 2. LOS Unit 2 is equipped with SOFA/SNCR/Emerson Combustion Optimizer for NO<sub>x</sub> control, and WFGD for SO<sub>2</sub> control.

## 4. SO<sub>2</sub> CONTROL EVALUATION

### 4.1 BASELINE SO<sub>2</sub> EMISSIONS

The first step in developing the four factor analysis is to establish LOS Units 1 and 2 baseline SO<sub>2</sub> emissions. To establish representative baseline emissions, S&L evaluated Units 1 and 2 operating data for the five year period between January 1, 2013 to September 30, 2018 to identify periods of normal operation (i.e., periods of operation when the boiler was not limited by infrequent or extraordinary operating restrictions). Based on review of fuels consumed, heat input to the boiler, boiler heat rates, power generation, and capacity factors, as well as input from Basin Electric, it was determined that the operating periods of January 1, 2013 to September 30, 2018 were representative of normal boiler operation. The Unit 2 WFGD system for SO<sub>2</sub> control was installed prior to the baseline period (October 2012); however, the Unit 1 WFGD system for SO<sub>2</sub> control was not placed in service until June 2013. Thus, the representative baseline periods for SO<sub>2</sub> emissions for the LOS Units are:

**Table 4-1. Representative Baseline Periods for SO<sub>2</sub> Emissions**

Pollutant	Representative Baseline Periods	
	LOS Unit 1	LOS Unit 2
SO <sub>2</sub> Emissions	6/1/2013 to 9/30/2018	1/1/2013 to 9/30/2018

Baseline annual SO<sub>2</sub> emissions were determined based on data obtained from the Units 1 and 2 continuous emissions monitoring system (CEMS) that was reported to EPA's Clean Air Markets. The maximum 24-consecutive month annual average emission rate during the representative time period was used to establish baseline annual emissions (in terms of tons per year). Representative baseline emission factors (in terms of pounds per million British Thermal Units (lb/MMBtu)) were developed using baseline annual emissions and the respective annual heat inputs. Table 4-2 provides a summary of the LOS Units 1 and 2 baseline SO<sub>2</sub> emissions. Additional details are included in Appendix B.

NORTH DAKOTA ROUND II STATE IMPLEMENTATION PLAN  
 DETERMINATION'S FOUR-FACTOR ANALYSIS FOR LELAND OLDS  
 UNITS 1 AND 2

**4-2**
**Table 4-2: Baseline Actual SO<sub>2</sub> Emissions**

LOS Unit	Baseline Controls	SO <sub>2</sub> Emission <sup>(Notes 1 and 2)</sup>			Capacity Factor During Baseline Period	Current SO <sub>2</sub> Control Percentage <sup>(Note 3)</sup>	Current Permit Limits (30-day rolling average)
		lb/hr	lb/MMBtu	tons/yr			
Unit 1	WFGD	166	0.09	697	68%	97.1%	0.15 lb/MMBtu or 95% SO <sub>2</sub> removal
Unit 2	WFGD	334	0.09	1,366	69%	97.1%	0.15 lb/MMBtu or 95% SO <sub>2</sub> removal

 Note 1. Unit 1 SO<sub>2</sub> emissions based on 24-month annual average for period February 2015 to January 2017.

 Note 2. Unit 2 SO<sub>2</sub> emissions based on 24-month annual average for period April 2016 to March 2018.

 Note 3. Control percentage calculated based on the range of current annual coal SO<sub>2</sub> content (3.12 lb/MMBtu on Unit 1 and 3.05 lb/MMBtu on Unit 2) between 2014-2018.

**Table 4-3: Projected Future Maximum SO<sub>2</sub> Emissions**

LOS Unit	Baseline Controls	SO <sub>2</sub> Emission <sup>(Note 1)</sup>			Capacity Factor for Future Maximum Emissions	Assumed SO <sub>2</sub> Control Percentage <sup>(Note 1)</sup>	Current Permit Limits (30-day rolling average)
		lb/hr	lb/MMBtu	tons/yr			
Unit 1	WFGD	235	0.09	1,030	100%	97.6	0.15 lb/MMBtu or 95% SO <sub>2</sub> removal
Unit 2	WFGD	454	0.09	1,989	100%	97.6	0.15 lb/MMBtu or 95% SO <sub>2</sub> removal

 Note 1. Baseline future maximum SO<sub>2</sub> emission based on a forecast future maximum coal SO<sub>2</sub> content of 3.73 lb/MMBtu, boiler design heat inputs of 2,622 MMBtu/hr (Unit 1) and 5,130 MMBtu/hr (Unit 2), current typical SO<sub>2</sub> removal of 96%, and assumes 100% capacity factor.



## 4.2 COAL SULFUR CONTENT

The generation of SO<sub>2</sub> is directly related to the sulfur content and heating value (HHV) of the fuel burned. LOS currently burns North Dakota Lignite fuel from the Freedom Mine. North Dakota lignite is characterized by a low heating value and relatively low sulfur content. Typical HHV and coal sulfur content provided by Basin Electric are listed in Table 4-4. The coal quality is based on actual annual fuel data provided by the facility between 2014 and 2018, which is a similar time period as the baseline emission rates.

**Table 4-4. Baseline LOS Coal Quality (Annual)**

Parameter	LOS Unit 1			LOS Unit 2		
	Minimum	Average	Maximum	Minimum	Average	Maximum
HHV (Btu/lb)	5,387	6,793	7,545	6,124	6,818	7,597
As-Received Sulfur (%)	0.56	1.06	1.90	0.61	1.04	1.78
Uncontrolled SO <sub>2</sub> (lb/MMBtu)	2.08	3.12	5.04	1.99	3.05	4.67
WFGD Design (lb/MMBtu)	--	--	3.9	--	--	3.9

When reviewing the as received coal data, the standard deviation of the coal sulfur content is 0.16% for both units.

In addition, Basin Electric provided anticipated future annual average coal quality projections for the facility between 2019 and 2040. The future range in coal quality is provided in Table 4-5.

**Table 4-5. Future LOS Coal Quality (Annual)**

Parameter	Minimum	Average	Maximum
HHV (Btu/lb)	6,595	6,650	6,722
As-Received Sulfur (%)	0.70	0.89	1.07
Uncontrolled SO <sub>2</sub> (lb/MMBtu)	2.10	2.67	3.22

The future anticipated coal quality listed in Table 4-5 are based on an annual average values and do not take into account potential deviations in the coal quality that could be seen on a short term basis. As such, the actual coal

sulfur content standard deviation (0.16%) from the current coal quality was applied, as stated above, to the maximum annual sulfur coal in Table 4-5. The results are shown in Table 4-6.

**Table 4-6. Design Basis for Future Projected LOS Coal Quality (Annual)**

Parameter	Unit 1	Unit 2
HHV (Btu/lb)	6,595	6,595
As-Received Sulfur (%)	1.23	1.23
Uncontrolled SO <sub>2</sub> (lb/MMBtu)	3.73	3.73
Uncontrolled SO <sub>2</sub> per Unit (lb/hr) <sup>(Note 1)</sup>	9,780	19,135
Uncontrolled SO <sub>2</sub> per Unit (tons/yr) <sup>(Note 1)</sup>	42,837	83,811

Note 1. Uncontrolled SO<sub>2</sub> emissions calculated at the design heat inputs of each Unit (2,622 MMBtu/hr for Unit 1 and 5,130 MMBtu/hr for Unit 2).

Based on the evaluation above, 3.73 lb SO<sub>2</sub>/MMBtu is used as the design basis for evaluating the SO<sub>2</sub> control technologies presented in this report is reasonable.

## **4.3 SO<sub>2</sub> EMISSIONS CONTROLS**

### **4.3.1 Identify Available SO<sub>2</sub> Control Options**

The first step in this SO<sub>2</sub> emissions control analysis is to identify, for the emission unit in question, all available SO<sub>2</sub> control options. Available control options are those air pollution control technologies and operational measures with a practical potential for application to the emission unit and the regulated pollutant under evaluation. As part of the first planning period for Regional Haze, the NDDH concluded that WFGD for SO<sub>2</sub> control was BART for LOS Units 1 and 2. As such, the facility is already equipped with modern high-efficiency post-combustion SO<sub>2</sub> control. For the Round II Determination's four factor analysis presented in this report, the NDDH requested Basin Electric to evaluate improvements or upgrades to the existing WFGD systems that could be made to reduce SO<sub>2</sub> emissions further. As such, S&L identified additional SO<sub>2</sub> control options for potential application to Unit 1 and 2 which are listed in Table 4-7.

**Table 4-7. Available SO<sub>2</sub> Control Options**

SO <sub>2</sub> Control Technologies
Existing FGD Operational Improvements
Existing FGD Design Changes and Equipment Upgrades

### 4.3.2 Technical Feasibility of Available SO<sub>2</sub> Control Options

Potentially available SO<sub>2</sub> control options identified in Table 4-7 were evaluated for technical feasibility (i.e., availability and applicability to LOS Unit 1 and 2) based on a review of physical, chemical, and engineering principals, and an assessment of commercial availability. Options determined to be technically infeasible, or options that have no practical application to LOS Unit 1 and 2, were eliminated from further review. S&L evaluated the effectiveness of the control options determined to be technically feasible, and established an emissions performance level (i.e., control emissions rate) for each.

#### 4.3.2.1 Operational Improvements and Equipment Upgrades on Existing WFGD

Operational and other design changes/upgrades to the existing WFGD may provide an opportunity for additional SO<sub>2</sub> removal and allow the units to achieve lower controlled SO<sub>2</sub> emissions. S&L, working with Basin Electric personnel, identified a number of potentially feasible operational changes that may be available to increase SO<sub>2</sub> removal efficiency with the existing equipment. Potentially available operational and design changes to the existing control system are summarized in Table 4-8. A detailed discussion of each of these options is provided in the sections below.

**Table 4-8. Potential WFGD Operational Improvements and Equipment Upgrades**

Existing FGD Operational Improvements
Limestone Quality
Ca:S Stoichiometric Ratio
Liquid-to-Gas (L/G) Ratio
Existing FGD Design Changes and Equipment Upgrades
Additional Spray Level
Optimized Spray Level Coverage
pH Buffer Additive

### Limestone Quality

The quantity of limestone ( $\text{CaCO}_3$ ) available in a wet scrubbing system compared to the amount of  $\text{SO}_2$  entering the system is called the stoichiometric ratio (generally referenced as the Ca:S stoichiometric ratio). Reagent quality directly affects the Ca:S stoichiometric ratio in WFGD control systems. Using a high quality limestone increases the availability of reagent to support process chemistry, and reduces the limestone slurry injection rate needed for  $\text{SO}_2$  removal. Better limestone quality allows for a potential increased  $\text{SO}_2$  reduction efficiency with fresh limestone slurry injection rates similar to existing rates.

Limestone quality typically ranges from 85-95% for use in WFGD systems. The higher quality limestone is often used in facilities that generate commercial grade saleable gypsum; this limestone would consist of a  $\text{CaCO}_3$  content of 95% or greater with minimal magnesium (<2.5%). For facilities that do not need to make a salable high quality WFGD byproduct, lower grade limestone quality is adequate. The quality required for disposable byproduct is typically between 85-90%  $\text{CaCO}_3$ . Since the limestone quality is lower, it will result in higher consumption rates when compared to high quality limestone (i.e. >95%).

The LOS WFGD byproduct is currently disposed, as such using a lower quality limestone is acceptable. The facility on average receives 90% or greater  $\text{CaCO}_3$  content, which is on the high end of quality for generating WFGD byproduct for disposal. Procuring a higher  $\text{CaCO}_3$  content limestone would not provide any valuable improvement in WFGD performance. Thus, for these reasons, changing the limestone quality is not a technically feasible  $\text{SO}_2$  control option for LOS, and will not be evaluated further.

### Ca:S Stoichiometric Ratio

Potential operational changes may be available to increase Ca:S stoichiometry in the WFGD by increasing the fresh limestone injected into the Unit 1 or 2 WFGD system. In a WFGD system, flue gas containing  $\text{SO}_2$  is brought into contact with limestone slurry droplets and the  $\text{SO}_2$  is absorbed into the water droplet. Within the droplet, the  $\text{SO}_2$  and calcium form calcium sulfite ( $\text{CaSO}_3$ ) and calcium sulfate ( $\text{CaSO}_4 \cdot 2\text{H}_2\text{O}$ ) byproduct. As the slurry falls through the flue gas, it eventually falls into the reaction tank, where it is stored for a few minutes before being recirculated back into the flue gas stream through the recycle spray headers.

As sulfur continues to react with the available  $\text{CaCO}_3$ , fresh limestone makeup to the system is required to maintain the necessary concentration and pH for the reactions and  $\text{SO}_2$  removal. More frequent fresh limestone addition will ensure that there is a higher concentration of available reagent in the recycle slurry.

S&L reviewed limestone addition data provided by LOS for Units 1 and 2. At LOS Unit 1, limestone feed rate is maintained relatively close to the maximum design stoichiometry based on the inlet SO<sub>2</sub> concentration. Increasing the fresh limestone addition rate to operate closer to the maximum design stoichiometry could provide nominal additional SO<sub>2</sub> removal. Further increases to limestone consumption beyond the design rate are not recommended, due to potential harmful effects of changes of slurry pH, which can lead to scaling concerns and oxidation-reduction potential (ORP) issues. LOS has already had issues with pH control and limestone addition beyond the design rate may drive the pH too high. As such, an increase in Ca:S stoichiometry to the design is considered to be a technically feasible SO<sub>2</sub> control option for LOS Unit 1. This adjustment to station work practices would require a slight increase in limestone addition to achieve an 11% reduction from the baseline SO<sub>2</sub> hourly rate (in lb/hr).

A similar analysis was conducted on Unit 2 limestone addition rates. Similarly, there is minor improvement to achieve maximum design stoichiometry at full load based on the inlet sulfur. It is not recommended to increase the rates above design, due to the aforementioned effects of operating outside of design pH range. However, increasing stoichiometry would have to be done in conjunction with increasing the L/G ratio. The L/G, which is a measurement of the volume of liquid slurry recycled in comparison to the volumetric flow rate of gas passing through the absorber, also typically has an effect on removal efficiency. Since the limestone injection rate and the L/G ratio rely upon each other for the system to operate as design, it is difficult to predict performance improvement with increased limestone alone. As such, for LOS Unit 2, increased limestone stoichiometry will be reviewed in conjunction with increasing the L/G ratio as discussed in the next section.

### Liquid-to-Gas Ratio

The L/G ratio in a WFGD is indicative of the total surface area of reagent available for the reaction with the acid gases in the flue gas, such as SO<sub>2</sub>. L/G is an important parameter for WFGD systems to account for the design contact between the available reagent and SO<sub>2</sub> in the flue gas. A higher L/G ratio corresponds to more liquid volume coverage within the cross-sectional area of a WFGD vessel. As the L/G ratio increases, there is additional contact of the flue gas with the limestone slurry as it passes through the absorber vessel, which can increase the removal efficiency.

L/G ratio can be improved by increasing the liquid flowrate through each recycle spray header. WFGD spray headers are designed with a spray volume coverage required by the performance of the system. As inlet conditions vary over time, the spray flow can be adjusted to maintain the necessary spray for design performance. Additionally, adjustments in unit load will cause the L/G ratio to vary; however if the system is setup at a constant

recycle slurry flow rate, the L/G ratio will be higher at lower loads, which provides higher SO<sub>2</sub> removal efficiencies.

S&L estimated recycle slurry flow rates based on pump operating data provided by LOS for Units 1 and 2. Based on the data provided, the Unit 1 pumps operate with three of the four spray levels always in service. Current industry practice for WFGD systems are such that the system is designed with a spare recycle pump and spray level in order to maintain SO<sub>2</sub> removal while performing maintenance activities on the recycle pumps. Furthermore, the recycle flow rate data suggest that all Unit 1 operating pumps are working at their maximum capacity at all times. This was confirmed by LOS operating personnel that explained that the recycle pumps are manually operated and not adjusted for operating load or SO<sub>2</sub> loading. This suggests there is no potential for increased L/G ratio without major modifications to the spray headers. For these reasons, changes to L/G ratio is not considered to be a technically feasible SO<sub>2</sub> reduction option for LOS Unit 1, and will not be evaluated further.

As mentioned in the previous section, Unit 2 is not operating at its maximum design L/G ratio. The design of the Unit 2 WFGD is based on four of five recycle pumps operating at maximum flow at full load, to satisfy the design operating profile; however, the facility has only been operating three at a time, due to lower inlet sulfur loading than design (3.9 lb/MMBtu) and is still maintaining SO<sub>2</sub> emissions below the permitted limit. Fuel forecasts suggest that the inlet sulfur loading could increase to 3.73 lb/MMBtu on a short term basis, within the next 5-10 years, from the baseline SO<sub>2</sub> fuel composition of 3.05 lb/MMBtu for Unit 2. As the facility starts to burn higher sulfur coal in comparison to the recent historical quality, the site personnel can manually place the fourth pump in service.

However, based on review of data provided by LOS, the flow rate of the pumps that are in operation is less than design, which is mainly due to the rigorous required maintenance to keep them at full efficiency and design flow rate. If the pumps are increased to maximum design capacity and the limestone is increased to the appropriate ratio (as referenced in the previous section), the Unit 2 WFGD would be expected to achieve a nominal reduction in SO<sub>2</sub> emissions at full load. For these reasons, operating changes resulting in an increase in Ca:S stoichiometry in conjunction with an increase in L/G is considered to be a technically feasible SO<sub>2</sub> control option for LOS Unit 2, and will be evaluated further. It is expected that the adjustment to station work practices may achieve a 15% reduction from the baseline SO<sub>2</sub> hourly rate (in lb/hr).

### *Additional Spray Level*

Another method to increase L/G ratio in a WFGD system is to increase the amount of spray levels. As mentioned previously, Units 1 and 2 are designed with a spare spray level to account for a certain level of redundancy for maintenance purposes. If increased L/G ratio cannot be obtained by increasing the throughput of slurry through the existing spray headers, an additional recycle pump and spray header may be added. An additional spray level would increase the L/G ratio by 33% on Unit 1 and 20% on Unit 2.

The original equipment manufacturer (OEM) provided correction curves that suggest an additional 1% removal efficiency could be achieved with all pumps and spray levels in service at both LOS units. As such, it is expected that installing an additional spray level would improve LOS Unit 1 and 2 performance. However, S&L reviewed the absorber drawings for each unit and concludes there is no room for an additional slurry spray level. Due to the location of the mist eliminators which are directly above the highest spray level and the inlet flue gas duct located directly below the first spray level, there is no room to install another spray level unless the top of the absorber is extended to make room for another spray level. All of the internals in this section would need to be restructured including the outlet cone ductwork to the chimney. For these reasons, an additional spray header is not considered to be a technically feasible SO<sub>2</sub> control option for LOS Unit 1 or 2, and will not be evaluated further.

### *Optimized Spray Level Coverage*

Another option for improving the design of the WFGD system is by ensuring there is full coverage of the slurry spray through the cross-sectional area of the absorber. Improving distribution of the slurry as well as spray nozzle design can reduce localized flue gas slippage as well as increase L/G. Improvements to spray design can provide better pattern of coverage, finer droplet size and more even coverage.

S&L consulted the WFGD OEM to determine if there have been any developments in spray header design since the LOS WFGD's were installed. The OEM concluded that the LOS WFGD systems were originally designed with state of the art spray coverage and up/down nozzle patterns, which is consistent with the most modern WFGD systems. As such no additional improvements could be made to the spray nozzle design to improve the WFGD efficiency. For these reasons, optimizing the spray nozzle design is not considered to be a technically feasible SO<sub>2</sub> control option for LOS Unit 1 or 2, and will not be evaluated further.



### pH Buffer Additive

As discussed previously, there is a limit to the amount of fresh limestone makeup that can be added to the WFGD. WFGD systems require a delicate balance of pH to allow for proper reaction kinetics and limit the scaling potential within the system. As SO<sub>2</sub> from the flue gas dissolves in the slurry, the water becomes acidic. Limestone is added, which neutralizes the slurry. However, limestone does not dissolve readily, thus making it difficult to neutralize the SO<sub>2</sub> as it enters. Since the solubility of limestone is minimal, there is only a small amount of dissolved limestone on the surface of the slurry droplet to react with SO<sub>2</sub>.

Additives have been developed for use in WFGD systems to improve the ability for limestone to neutralize and react with SO<sub>2</sub>. Thus use of additives such as dibasic acid (DBA) increase the removal efficiency in WFGD systems. DBA is a mixture of dicarboxylic acids, or carbon chains with carboxylic acids. The DBA quickly combines with free hydrogen ions at the gas-liquid interface, which hinders the slurry from dropping in pH. The increased alkalinity raises the solubility of SO<sub>2</sub> within the limestone slurry, thus expanding the efficiency of the absorber column.

The use of DBA in conjunction with increasing fresh limestone injection rates is expected to provide the WFGD with an additional 1% SO<sub>2</sub> removal efficiency. This performance could be obtained for the expected fuel sulfur content up to 3.73 lb/MMBtu. The facility is currently equipped with two common limestone ball mills, one operating and one spare, and a forwarding system with four slurry pumps. Based on the maximum future fuel sulfur content, the ball mills and slurry forwarding systems have sufficient capacity to provide the additional limestone required for Units 1 and 2 while still maintaining complete redundancy. Additional equipment for the DBA addition system would require a small tank and pump to add to the slurry holding tank. As such, DBA and increased limestone makeup is determined to be a technically feasible option for providing additional SO<sub>2</sub> removal efficiency on LOS Units 1 and 2.

#### **4.3.2.2 Technical Feasibility Summary**

Table 4-9 and Table 4-10 summarize the results of the feasibility evaluation of available control options for LOS Units 1 and 2.

**Table 4-9. Technically Feasible SO<sub>2</sub> Control Options for LOS Unit 1**

SO <sub>2</sub> Control Option	Technically Feasible (Yes/No)	Control Percentage (Note 1)	Technical Feasibility Summary
Existing FGD Operational Improvements:			
Limestone Quality	No	0%	Changing limestone quality in the existing WFGD control system is not a technically feasible operational change for LOS Unit 1.
Ca:S Stoichiometric Ratio	Yes	97.4%	Increasing the Ca:S stoichiometric ratio by increasing the quantity of fresh limestone to the system is considered a technically feasible option for LOS Unit 1.
L/G Ratio	No	0%	Increasing the slurry recirculation rate (L/G) on the existing WFGD control system is not a technically feasible option for LOS Unit 1.
Existing FGD Design Changes and Equipment Upgrades:			
Additional Spray Level	No	0%	Adding a spray level to the existing WFGD control system is not a technically feasible upgrade for LOS Unit 1.
Optimized Spray Level Coverage	No	0%	Optimizing the slurry spray level coverage on the existing WFGD control system is not a technically feasible option for LOS Unit 1.
pH Buffer Additive	Yes	98.2%	Incorporating pH buffer to the limestone slurry and increasing limestone addition rate is a technically feasible option for LOS Unit 1.

Note 1. Control percentage calculated using the baseline SO<sub>2</sub> coal quality of 3.12 lb/MMBtu and the achievable SO<sub>2</sub> emission rate for each technically feasible control option.

**Table 4-10. Technically Feasible SO<sub>2</sub> Control Options for LOS Unit 2**

SO <sub>2</sub> Control Option	Technically Feasible (Yes/No)	Control Percentage (Note 1)	Technical Feasibility Summary
Existing FGD Operational Improvements:			
Limestone Quality	No	0%	Changing limestone quality in the existing WFGD control system is not a technically feasible operational change for LOS Unit 2.
Ca:S Stoichiometric Ratio	Yes	97.5%	Increasing the Ca:S stoichiometric ratio by increasing the quantity of fresh limestone to the system is considered a technically feasible option for LOS Unit 2, but should be done in conjunction with increasing the slurry recirculation rate (L/G).
L/G Ratio	Yes		
Existing FGD Design Changes and Equipment Upgrades:			
Additional Spray Level	No	0%	Adding a spray level to the existing WFGD control system is not a technically feasible upgrade for LOS Unit 2.
Optimized Spray Level Coverage	No	0%	Optimizing the slurry spray level coverage on the existing WFGD control system is not a technically feasible option for LOS Unit 2.
pH Buffer Additive	Yes	98.4%	Incorporating pH buffer to the limestone slurry and increasing limestone addition rate is a technically feasible option for LOS Unit 2.

Note 1. Control percentage calculated using the baseline SO<sub>2</sub> coal quality of 3.05 lb/MMBtu and the achievable SO<sub>2</sub> emission rate for each technically feasible control option.

### 4.3.3 Evaluate Technically Feasible SO<sub>2</sub> Control Options for Effectiveness

The technically feasible SO<sub>2</sub> control technologies are listed in Table 4-11 and Table 4-12 in descending order of control efficiency. They also provide control option-specific SO<sub>2</sub> emission rates in terms of lb/MMBtu. Emission rates shown represent average emission rates that the control options would be expected to achieve during normal operations on a long-term averaging basis.

**Table 4-11. Evaluate Technically Feasible SO<sub>2</sub> Control Options by Effectiveness for LOS Unit 1  
(Baseline Average Emissions)**

Alt. No.	Control Technology	SO <sub>2</sub> Emission Rate <sup>(Note 1)</sup> lb/MMBtu	% Reduction from Baseline SO <sub>2</sub> Coal Quality <sup>(Note 2)</sup>	SO <sub>2</sub> Emission Rate <sup>(Note 1)</sup> lb/hr	SO <sub>2</sub> Emission Rate <sup>(Note 1)</sup> tons/yr
B	FGD Upgrades – pH Buffer Addition	0.055	98.2	102	427
A	FGD Operational Improvements – Ca:S Stoichiometry	0.08	97.4	148	622
--	Baseline (existing WFGD)	0.09	97.1	166	697
--	Permit Limit	0.15 (30-day)	95		

Note 1: Emission rates shown in Table 4-11 represent average emission rates that the control options would be expected to achieve on an on-going long-term basis under normal operating conditions for LOS Unit 1. Emission rates are provided for comparative purposes, and should not be construed to represent proposed permit limits. Corresponding permit limits must be evaluated on a control system-specific basis.

Note 2: Baseline SO<sub>2</sub> coal quality is 3.12 lb/MMBtu. See Section 4.2 for additional details on coal sulfur.

**Table 4-12. Evaluate Technically Feasible SO<sub>2</sub> Control Options by Effectiveness for LOS Unit 2  
(Baseline Average Emissions)**

Alt. No.	Control Technology	SO <sub>2</sub> Emission Rate <sup>(Note 1)</sup> lb/MMBtu	% Reduction from Baseline SO <sub>2</sub> Coal Quality <sup>(Note 2)</sup>	SO <sub>2</sub> Emission Rate <sup>(Note 1)</sup> lb/hr	SO <sub>2</sub> Emission Rate <sup>(Note 1)</sup> tons/yr
B	FGD Upgrades – pH Buffer Addition	0.05	98.4	189	772
A	FGD Operational Improvements – Ca:S Stoichiometry and L/G Ratio	0.075	97.6	283	1,158
--	Baseline (existing WFGD)	0.09	97.2	334	1,366
--	Permit Limit	0.15 (30-day)	95		

Note 1: Emission rates shown in Table 4-12 represent average emission rates that the control options would be expected to achieve on an on-going long-term basis under normal operating conditions for LOS Unit 2. Emission rates are provided for comparative purposes, and should not be construed to represent proposed permit limits. Corresponding permit limits must be evaluated on a control system-specific basis.

Note 2: Baseline SO<sub>2</sub> coal quality is 3.05 lb/MMBtu. See Section 4.2 for additional details on coal sulfur.

Table 4-13 and Table 4-14 provide control option-specific SO<sub>2</sub> emission rates in terms of lb/MMBtu based on the projected future maximum emission rates. Emission rates shown represent the projected future maximum emission rates that the control options would be expected to achieve during normal operations.

**Table 4-13. Evaluate Technically Feasible SO<sub>2</sub> Control Options by Effectiveness for LOS Unit 1  
(Projected Future Maximum Emissions)**

Alt. No.	Control Technology	SO <sub>2</sub> Emission Rate <sup>(Note 3)</sup> lb/MMBtu	% Reduction from Future SO <sub>2</sub> Coal Quality <sup>(Note 1)</sup>	SO <sub>2</sub> Emission Rate <sup>(Note 1)</sup> lb/hr	SO <sub>2</sub> Emission Rate <sup>(Note 2)</sup> tons/yr
B	FGD Upgrades – pH Buffer Addition	0.055	98.5	144	632
A	FGD Operational Improvements – Ca:S Stoichiometry	0.08	97.9	210	919
--	Baseline (existing WFGD)	0.09	97.6	235	1,030
--	Permit Limit	0.15 (30-day)	95		

Note 1: Future SO<sub>2</sub> coal quality is 3.73 lb/MMBtu. See Section 4.2 for additional details on coal sulfur.

Note 2: Annual SO<sub>2</sub> emissions based on 8,760 hours per year operation.

Note 3: Emission rates are provided for comparative purposes, and should not be construed to represent proposed emission limits. Corresponding permit limits must be evaluated on a control system-specific basis.

**Table 4-14. Evaluate Technically Feasible SO<sub>2</sub> Control Options by Effectiveness for LOS Unit 2  
(Projected Future Maximum Emissions)**

Alt. No.	Control Technology	SO <sub>2</sub> Emission Rate <sup>(Note 3)</sup> lb/MMBtu	% Reduction from Future SO <sub>2</sub> Coal Quality <sup>(Note 1)</sup>	SO <sub>2</sub> Emission Rate <sup>(Note 1)</sup> lb/hr	SO <sub>2</sub> Emission Rate <sup>(Note 2)</sup> tons/yr
B	FGD Upgrades – pH Buffer Addition	0.05	98.7	257	1,123
A	FGD Operational Improvements – Ca:S Stoichiometry and L/G Ratio	0.075	98.0	385	1,685
--	Baseline (existing WFGD)	0.09	97.6	454	1,989
--	Current Permit Limit	0.15 (30-day)	95		

Note 1: Future SO<sub>2</sub> coal quality is 3.73 lb/MMBtu. See Section 4.2 for additional details on coal sulfur.

Note 2: Annual SO<sub>2</sub> emissions based on 8,760 hours per year operation.

Note 3: Emission rates are provided for comparative purposes, and should not be construed to represent proposed emission limits. Corresponding permit limits must be evaluated on a control system-specific basis.

## 4.4 COSTS OF COMPLIANCE (STATUTORY FACTOR ONE)

The economic analysis performed as part of the four factor analysis examines the cost-effectiveness of each technically feasible control technology, on a dollar per ton of pollutant removed basis. Annual emissions,

calculated for a particular control device, are subtracted from baseline annual emissions to calculate tons of pollutant controlled per year. For units with existing controls, the base case represents existing baseline actual emissions. Annual costs for each control option are calculated relative to the base case by adding annual O&M costs to the annualized cost of capital and, if applicable, lost revenue due to extended outage required for installation of control equipment. Capital costs and lost revenues were annualized using a capital recovery factor based on an annual interest rate of 5.25% and equipment life of 20 years.<sup>32</sup> Cost effectiveness (\$/ton) of a particular control option is simply the annual cost (\$/yr) divided by the annual reduction in annual emissions (tons/yr). In addition to cost-effectiveness relative to the base case, the incremental cost-effectiveness to go from one level of control to the next, more stringent, level of control may also be calculated to evaluate the incremental cost effectiveness of the more stringent control.

Capital and O&M cost estimates were developed for each of the technically feasible SO<sub>2</sub> control options. The LOS Units 1 and 2 cost estimates are conceptual in nature; thus, S&L did not procure equipment quotes specifically for the Units 1 and 2 control system upgrades. Rather, equipment costs are based on conceptual designs developed for the retrofit control systems, preliminary equipment sizing developed for the major pieces of equipment (based on Units 1 and 2-specific design parameters, including typical fuel characteristics, full load heat input, and flue gas temperatures and flow rates), and recent pricing for similar equipment. S&L would characterize the cost estimates for the LOS Units 1 and 2 retrofit technologies as “concept screening” cost estimates generally based on parametric models, judgment, or analogy.

Control technology equipment costs for the retrofit options were developed by scaling cost estimates prepared by S&L for other similar projects. Major equipment costs were developed based on equipment costs recently developed for similar projects, and include the equipment, material, labor, and all other direct costs needed to retrofit the units with the control technology. Sub-accounts for the capital cost estimates (e.g., mobilization and demobilization, consumables, contractor general and administrative (G&A) expense, freight on materials, etc.) were developed by applying ratios from detailed cost estimates that were prepared for projects with similar scopes.

---

<sup>32</sup> The assumed 20-year equipment life is consistent with the control system equipment life used by NDDH in its evaluation of NO<sub>x</sub> and SO<sub>2</sub> control technologies for BART-eligible sources. (see, e.g., ND Regional Haze Final SIP, Appendix C.1, “BART Determination Study for Leland Olds Station Units 1 & 2, Basin Electric Power Cooperative, August 2006, pgs. 64 (NO<sub>x</sub> controls) and 158 (SO<sub>2</sub> controls). See also, ND Regional Haze Final SIP, Appendix C4, “NO<sub>x</sub> Best Available Control Technology Study for Milton R. Young Station Unit 1, Minnkota Power Cooperative, Inc., October 2006, pg. 3-22).

Fixed O&M costs include operating labor, maintenance labor, maintenance material, and administrative labor. Variable O&M costs include the cost of consumables, including reagent, water consumption, and auxiliary power requirements.<sup>33</sup> Auxiliary power requirements reflect the additional power requirements associated with the operation of the new control technology (compared to the existing technology). All O&M costs reflect the incremental increase in O&M costs compared to the costs incurred to operate the existing WFGD systems.

In addition to the cost effectiveness relative to the base case, the incremental cost-effectiveness to go from one level of control to the next more stringent level of control will also be calculated to evaluate the cost effectiveness of the more stringent control.

#### 4.4.1 SO<sub>2</sub> Average Annual Economic Evaluation

Table 4-15 and Table 4-16 present the capital costs and annual operating costs associated with installing and operating each technically feasible SO<sub>2</sub> control system for LOS Unit 1 and 2. They also show the average annual and incremental cost effectiveness for each control system. Additional cost details are provided in Appendix C.

**Table 4-15. SO<sub>2</sub> Control Cost Summary (Average Annual)**

LOS Unit No.	Alt. No.	SO <sub>2</sub> Control Option	Total Capital Investment \$	Annual Capital Recovery Cost \$/yr	Annual Operating Cost \$/yr	Total Annual Cost \$/yr
Unit 1	B	FGD Upgrades – pH Buffer Addition	\$8,266,000	\$677,000	\$4,156,000	\$4,833,000
	A	FGD Operational Improvements – Ca:S Stoichiometry	\$0	\$0	\$752,000	\$752,000
Unit 2	B	FGD Upgrades – pH Buffer Addition	\$11,560,000	\$947,000	\$7,340,000	\$8,287,000
	A	FGD Operational Improvements – Ca:S Stoichiometry and L/G Ratio	\$0	\$0	\$1,439,000	\$1,439,000

Note 1. Annual operating costs based on baseline SO<sub>2</sub> coal quality (3.12 and 3.05 lb/MMBtu for Units 1 and 2, respectively) and capacity factor during baseline SO<sub>2</sub> period for each LOS Unit.

<sup>33</sup> Variable O&M costs are based on the future coal SO<sub>2</sub> of 3.66 lb/MMBtu



**Table 4-16. SO<sub>2</sub> Emissions Control System Cost Effectiveness (Average Annual)**

LOS Unit No.	Alt. No.	SO <sub>2</sub> Control Option	Total Annual Cost \$	Expected Emission Reduction tons SO <sub>2</sub> /yr	Average Annual Cost-Effectiveness \$/ton SO <sub>2</sub> removed	Incremental Annual Cost-Effectiveness (Note 1) \$/ton SO <sub>2</sub> removed
Unit 1	B	FGD Upgrades – pH Buffer Addition	\$4,833,000	269	\$17,948	\$21,013
	A	FGD Operational Improvements – Ca:S Stoichiometry	\$752,000	75	\$10,021	
Unit 2	B	FGD Upgrades – pH Buffer Addition	\$8,287,000	594	\$13,946	\$17,748
	A	FGD Operational Improvements – Ca:S Stoichiometry and L/G Ratio	\$1,439,000	208	\$6,906	

Note 1. Incremental cost-effectiveness represents the incremental increase in annual costs (\$/yr) divided by the incremental increase in annual SO<sub>2</sub> emissions reductions (tons/yr) between a control option and the next most effective option.

Note 2. Expected emission reductions and average annual cost-effectiveness based on baseline SO<sub>2</sub> coal quality (3.12 and 3.05 lb/MMBtu for Units 1 and 2, respectively) and capacity factor during baseline SO<sub>2</sub> period for each LOS Unit.

Table 4-16 indicates that the average annual cost effectiveness of the technically feasible SO<sub>2</sub> control options for Unit 1 range from \$10,021 per ton (FGD operational improvements – Increase Ca:S stoichiometric ratio) to \$17,948 per ton (FGD upgrades – pH buffer addition) SO<sub>2</sub> removed; and for Unit 2 ranges from \$6,906 per ton to \$13,946 per ton of SO<sub>2</sub> removed.

Operational improvements to the Unit 1 existing WFGD system by improving Ca:S stoichiometric ratio is expected to achieve approximately 11% SO<sub>2</sub> reduction from the baseline for a cost effectiveness of approximately \$10,000 per ton. This is due to the expected operating costs of increased limestone consumption in comparison with the limited additional SO<sub>2</sub> removal on an annual basis. Upgrading the existing WFGD system with pH buffer addition on Unit 1 is expected to achieve approximately 39% SO<sub>2</sub> reduction from baseline emission rates. The cost effectiveness of this option is approximately \$18,000 per ton. The cost is mainly driven by pH buffer additive costs with limited annual SO<sub>2</sub> emission reduction. Compared to the operational improvements alone, the incremental cost effectiveness of the upgrades is approximately \$21,000 per ton for Unit 1.

Operational improvements to the Unit 2 existing WFGD system by improving Ca:S stoichiometric ratio is expected to achieve approximately 15% SO<sub>2</sub> reduction from the baseline at a cost effectiveness of approximately \$7,000 per ton. This is due to the expected operating costs of increased limestone consumption in comparison with the limited additional SO<sub>2</sub> removal on an annual basis. Upgrading the existing WFGD system with pH buffer addition on Unit 2 is expected to achieve approximately 44% SO<sub>2</sub> reduction from baseline emission rates. The cost effectiveness of this option is approximately \$14,000 per ton. The cost is mainly driven by pH buffer additive costs with limited annual SO<sub>2</sub> emission reduction. Compared to the operational improvements alone, the incremental cost effectiveness of the upgrades is approximately \$18,000 per ton for Unit 2.

#### 4.4.2 SO<sub>2</sub> Potential-to-Emit Annual Economic Evaluation

Table 4-17 presents the capital costs and annual operating costs associated with building and operating each control system; annual operating costs are based on the units operating at 100% capacity factor and future coal quality considering potential variability.

**Table 4-17. SO<sub>2</sub> Control Cost Summary (Projected Future Maximum)**

LOS Unit No.	Alt. No.	SO <sub>2</sub> Control Option	Total Capital Investment \$	Annual Capital Recovery Cost \$/yr	Annual Operating Cost \$/yr	Total Annual Cost \$/yr
Unit 1	B	FGD Upgrades – pH Buffer Addition	\$8,266,000	\$677,000	\$6,865,000	\$7,542,000
	A	FGD Operational Improvements – Ca:S Stoichiometry	\$0	\$0	\$2,019,000	\$2,019,000
Unit 2	B	FGD Upgrades – pH Buffer Addition	\$11,560,000	\$947,000	\$12,429,000	\$13,376,000
	A	FGD Operational Improvements – Ca:S Stoichiometry and L/G Ratio	\$0	\$0	\$4,078,000	\$4,078,000

Note 1. Annual operating costs based on projected future maximum SO<sub>2</sub> coal quality (3.73 lb/MMBtu) and 100% capacity factor for each LOS Unit.

Table 4-18 shows the average annual and incremental cost effectiveness for each control system with emissions reductions and cost effectiveness values based on 100% capacity factors and projected future maximum emission rates. Additional cost details are provided in Appendix C.

**Table 4-18. SO<sub>2</sub> Emissions Control System Cost Effectiveness  
(Projected Future Maximum)**

LOS Unit No.	Alt. No.	SO <sub>2</sub> Control Option	Total Annual Cost \$	Expected Emission Reduction tons SO <sub>2</sub> /yr	Average Annual Cost-Effectiveness \$/ton SO <sub>2</sub> removed	Incremental Annual Cost-Effectiveness (Note 1) \$/ton SO <sub>2</sub> removed
Unit 1	B	FGD Upgrades – pH Buffer Addition	\$7,542,000	398	\$18,948	\$19,237
	A	FGD Operational Improvements – Ca:S Stoichiometry	\$2,019,000	111	\$18,200	
Unit 2	B	FGD Upgrades – pH Buffer Addition	\$13,376,000	865	\$15,462	\$16,552
	A	FGD Operational Improvements – Ca:S Stoichiometry and L/G Ratio	\$4,078,000	303	\$13,444	

Note 1. Incremental cost-effectiveness represents the incremental increase in annual costs (\$/yr) divided by the incremental increase in annual SO<sub>2</sub> emissions reductions (tons/yr) between a control option and the next most effective option.

Note 2. Expected emission reductions and average annual cost-effectiveness based on baseline SO<sub>2</sub> coal quality (3.73 lb/MMBtu) and 100% capacity factor for each LOS Unit.

Table 4-18 indicates that the average annual cost effectiveness of the technically feasible SO<sub>2</sub> control options for Unit 1 range from \$18,200 per ton (FGD operational improvements – Increase Ca:S stoichiometric ratio) to \$18,948 per ton (FGD upgrades – pH buffer addition) SO<sub>2</sub> removed; and for Unit 2 ranges from \$13,444 per ton to \$15,462 per ton of SO<sub>2</sub> removed.

Operational improvements to the Unit 1 existing WFGD system by improving Ca:S stoichiometric ratio is expected to achieve approximately 11% SO<sub>2</sub> reduction from the baseline for a cost effectiveness of approximately \$18,000 per ton. This is due to the expected operating costs of increased limestone consumption in comparison with the limited additional SO<sub>2</sub> removal on an annual basis. Upgrading the existing WFGD system with pH buffer addition on Unit 1 is expected to achieve approximately 39% SO<sub>2</sub> reduction from baseline emission rates. The cost effectiveness of this option is approximately \$19,000 per ton. The cost is mainly driven by pH buffer additive costs with limited annual SO<sub>2</sub> emission reduction. Compared to the operational improvements alone, the incremental cost effectiveness of the upgrades is approximately \$19,000 per ton for Unit 1.

Operational improvements to the Unit 2 existing WFGD system by improving Ca:S stoichiometric ratio is expected to achieve approximately 15% SO<sub>2</sub> reduction from the baseline at a cost effectiveness of approximately \$13,000 per ton. This is due to the expected operating costs of increased limestone consumption in comparison with the limited additional SO<sub>2</sub> removal on an annual basis. Upgrading the existing WFGD system with pH buffer addition on Unit 2 is expected to achieve approximately 44% SO<sub>2</sub> reduction from baseline emission rates. The cost effectiveness of this option is approximately \$15,000 per ton. The cost is mainly driven by pH buffer additive costs with limited annual SO<sub>2</sub> emission reduction. Compared to the operational improvements alone, the incremental cost effectiveness of the upgrades is approximately \$16,000 per ton for Unit 2.

## 5. NO<sub>x</sub> CONTROL EVALUATION

### 5.1 BASELINE NO<sub>x</sub> EMISSIONS

The first step in developing the four factor analysis is to establish LOS Units 1 and 2 baseline NO<sub>x</sub> emissions. To establish representative baseline emissions, S&L evaluated Units 1 and 2 operating data for the five year period between January 1, 2013 to September 30, 2018 to identify periods of normal operation (i.e., periods of operation when the boiler was not limited by infrequent or extraordinary operating restrictions). Based on review of fuels consumed, heat input to the boiler, boiler heat rates, power generation, and capacity factors, as well as input from Basin Electric, it was determined that the operating periods of January 1, 2013 to September 30, 2018 were representative of normal boiler operation. However, during the baseline operating period, the BART compliance emission control technologies were installed. SNCR systems for NO<sub>x</sub> control were placed into service and considered optimized in September 2017 for Unit 1 and in April 2017 for Unit 2. Thus, the representative baseline periods for NO<sub>x</sub> emissions for the LOS Units are:

**Table 5-1. Representative Baseline Periods for NO<sub>x</sub> Emissions**

Pollutant	Representative Baseline Periods	
	LOS Unit 1	LOS Unit 2
NO <sub>x</sub> Emissions	9/1/2017 to 9/30/2018	4/1/2017 to 9/30/2018

Baseline annual NO<sub>x</sub> emissions were determined based on data obtained from the Units 1 and 2 CEMS that was reported to EPA's Clean Air Markets. The maximum 12-consecutive month annual average emission rate during the representative time period was used to establish baseline annual emissions (in terms of tons/yr). A 12-month average was used rather than 24-month averaging timeframe (as used in the SO<sub>2</sub> evaluation) due to the recent NO<sub>x</sub> control optimization technology implementation. Representative baseline emission factors (in terms of pounds per million British Thermal Units (lb/MMBtu)) were developed using baseline annual emissions and the respective annual heat inputs. Table 4-2 provides a summary of the LOS Units 1 and 2 baseline NO<sub>x</sub> emissions. Additional details are included in Appendix B.

**Table 5-2: Baseline Actual NO<sub>x</sub> Emissions**

LOS Unit	Baseline Controls	NO <sub>x</sub> Emission <sup>(Note 1)</sup>			Capacity Factor During Baseline Period	Current Permit Limits
		lb/hr	lb/MMBtu	tons/yr		
Unit 1	LNB / SOFA / SNCR	255	0.15	905	51%	0.19 lb/MMBtu (30-day average)
Unit 2	SOFA / SNCR	1,099	0.30	4,530	68%	0.35 lb/MMBtu (30-day average)

 Note 1. Unit 1 annual NO<sub>x</sub> emissions for period July 2017 to June 2018.

 Note 2. Unit 2 annual NO<sub>x</sub> emissions for period April 2017 to March 2018.

**Table 5-3: Baseline Projected Future Maximum NO<sub>x</sub> Emissions**

LOS Unit	Baseline Controls	NO <sub>x</sub> Emission <sup>(Note 1)</sup>			Capacity Factor for Future Maximum Emissions	Current Permit Limits
		lb/hr	lb/MMBtu	tons/yr		
Unit 1	LNB / SOFA / SNCR	406	0.15	1,779	100%	0.19 lb/MMBtu (30-day average)
Unit 2	SOFA / SNCR	1,528	0.30	6,692	100%	0.35 lb/MMBtu (30-day average)

 Note 1. Baseline future maximum NO<sub>x</sub> emission based on boiler design heat input of 2,622 MMBtu/hr (Unit 1) and 5,130 MMBtu/hr (Unit 2) and assumes 100% capacity factor.

## 5.2 NO<sub>x</sub> EMISSIONS CONTROLS

### 5.2.1 Identify Available NO<sub>x</sub> Control Options

Based on a review of available NO<sub>x</sub> control technologies installed on existing opposed-fired pulverized coal boilers and cyclone boilers designed to fire lignite coal, NO<sub>x</sub> control techniques can be divided into pre-combustion strategies and post-combustion controls. NO<sub>x</sub> control options identified for potential application to LOS Unit 1 and 2 are listed in Table 5-4.

**Table 5-4. Available NO<sub>x</sub> Control Options**

NO <sub>x</sub> Control Technologies
Selective Catalytic Reduction - High Dust, Low Dust or Tail End Configuration (TE-SCR)
Optimized Selective Non-Catalytic Reduction (SNCR)
Rich Reagent Injection (RRI)
Optimized SCR + RRI
Gas Reburn
Innovative Technologies (i.e. NO <sub>x</sub> Star, Water Injection, LoTOX, PerNO <sub>x</sub> ide, Water Injection)

### 5.2.2 Technical Feasibility of Available NO<sub>x</sub> Control Options

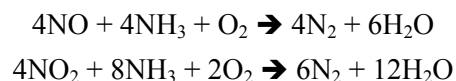
Potentially available NO<sub>x</sub> control options identified in Table 5-4 were evaluated for technical feasibility (i.e. availability and applicability to LOS Unit 1 and 2) based on a review of physical, chemical, and engineering principals, and an assessment of commercial availability. Options deemed to be technically infeasible, or options that have no practical application to LOS Unit 1 and 2, were eliminated from further review. S&L evaluated the effectiveness of the control options determined to be technically feasible, and established an emission performance level (i.e., controlled emission rate) for each.

#### 5.2.2.1 Selective Catalytic Reduction

SCR is a process by which ammonia (NH<sub>3</sub>) reacts with nitric oxide (NO) and nitrogen dioxide (NO<sub>2</sub>), collectively NO<sub>x</sub>, in the presence of a catalyst to reduce the NO<sub>x</sub> to nitrogen (N<sub>2</sub>) and water. SCR technology has been applied



to NO<sub>x</sub>-bearing flue gases generated from power generating facilities burning various types of coal, including bituminous, subbituminous, and Texas lignite). The principal reactions resulting in NO<sub>x</sub> reduction are:



Because these reactions proceed slowly at typical boiler exit gas temperatures of a coal-fired steam EGU, a catalyst is used to increase the reaction rate between NO<sub>x</sub> and ammonia. Depending on the specific constituents in the flue gas, a typical temperature range of 550°F to 780°F is necessary to achieve normal performance of the catalyst. For the typical coal-fired boiler, optimal performance will be in the range of approximately 650°F to 750°F.

In general, there are three candidate SCR configurations that can be employed on coal-fired steam EGUs. The SCR configuration designations generally describe the location of the SCR reaction vessel in relation to other post-combustion air quality control systems. Candidate SCR configurations include:

- High-dust configuration
- Low-dust configuration
- Tail-end configuration

Each of these configurations is described below as they may be applied at LOS Unit 1 and 2.

#### High-Dust Configuration

In a high-dust configuration, the SCR reactor is located in the flue gas stream between the economizer outlet and the air heater inlet. This configuration locates the SCR within the inherently optimal temperature range environment for NO<sub>x</sub> reduction (i.e., 650°F to 750°F); however, flue gas characteristics at the economizer outlet can also have detrimental effects on the SCR catalyst. As an example, the high-dust SCR configuration exposes the SCR catalyst to high levels of fly ash loading. High levels of fly ash can result in significant erosion of the catalyst, resulting in more frequent cleaning cycles and catalyst replacement. A second major concern with the high-dust configuration at LOS Units 1 and 2 is the presence of high levels of sodium (both in the vapor-phase and as submicron aerosols) in the North Dakota lignite-derived flue gas. Sodium is a known SCR catalyst poison, and also affects the adhesive and cohesive characteristics of the fly ash, which in turn, would have an adverse effect on the SCR catalyst and reactor vessel.

SCR catalyst deactivation occurs through two primary mechanisms: physical deactivation and chemical poisoning. Physical deactivation is caused by either exposure of the catalyst to excessive temperatures (thermal deactivation)

or masking of the catalyst due to entrainment of particulate from the flue gas stream (fouling). Chemical deactivation is caused by either an irreversible reaction of the catalyst with a contaminant in the gas stream (poisoning) or a reversible absorption of a contaminant on the surface of the catalyst (inhibition). Loss of catalyst activity through thermal degradation or poisoning is permanent, and reactivity can only be restored by replacing the catalyst.

In a North Dakota lignite application, SCR catalyst poisoning is expected to result from the presence of trace elements and strong alkaline substances in flue gas, including sodium (Na), potassium (K), calcium (Ca), and magnesium (Mg). Alkaline metals can chemically attach to active catalyst pore sites and cause deactivation. Sodium and potassium are of prime concern especially in their water-soluble forms, which are more mobile and can penetrate into the catalyst pores. Earth metals, especially calcium, can react with sulfur trioxide (SO<sub>3</sub>) absorbed within the catalyst to form CaSO<sub>4</sub> and blind the catalyst.

North Dakota lignite contains relatively high levels of organically associated alkali and alkaline-earth elements, including Na, K, Ca, and Mg. Sodium levels in North Dakota lignite are typically 5 to 20 times higher than sodium levels in bituminous and subbituminous coals, and sodium compounds can represent between 5% and 11% of the ash generated from firing North Dakota lignite. These sodium levels, occurring in both the vapor phase and particulate phase, along with relatively high levels of potassium and calcium, significantly increase the potential for catalyst deactivation, plugging, and erosion. Based on the ash chemistry, a conventional high dust SCR arrangement would likely experience unacceptable catalyst deactivation rates.

As noted in Section 3.1.1.2, during the first Regional Haze planning period, NDDH prepared a comprehensive technical feasibility assessment of high dust SCR on lignite-fired boilers (North Dakota Regional Haze SIP, Appendix B-5).<sup>34</sup> The NDDH concluded, based on the unique characteristics of North Dakota lignite-derived flue gas, that the high-dust SCR configuration was not a technically feasible or commercially available NO<sub>x</sub> control option for North Dakota lignite-fired boilers such as LOS Unit 1 and 2.<sup>35</sup> This determination was consistent with

---

<sup>34</sup> See, North Dakota State Implementation Plan for Regional Haze, February 24, 2010, Appendix B.5, Best Available Retrofit Technology – Selective Catalytic Reduction Technical Feasibility Analysis for North Dakota Lignite, July 2009.

<sup>35</sup> See, North Dakota State Implementation Plan for Regional Haze, February 24, 2010, Appendix B.9, Best Available Retrofit Technology – Selective Catalytic Reduction Technical Feasibility Analysis for North Dakota Lignite, July 2009, pg. 19.

the NDDH's NO<sub>x</sub> BACT determination for MRYS Units 1 & 2.<sup>36</sup> Reasons upon which NDDH based its conclusion that high-dust SCR was not a technically feasible option for North Dakota lignite-fired boilers included, but were not limit to:<sup>37</sup>

- 1) North Dakota lignite<sup>38</sup> has a higher organic matter content and contains a higher proportion of alkali metal constituents, especially sodium, than subbituminous coal. Approximately 75% of the total sodium in lignite is associated with the organic fraction of the lignite. During combustion, organic and water-soluble sodium vaporizes; consequently, combustion of the coal leads to higher flue-gas concentrations of alkali metals in vapor form.
- 2) The unburned or partially burned organic fraction of North Dakota lignite contains more sodium than other coals. Sodium can react with silicate particles causing a "stickiness" quality to the flue gas ash, resulting in increased ash deposition on heat transfer surfaces. Larger particles can fracture from heat-transfer surfaces (a.k.a. popcorn ash) and enter the flue gas stream. Consequently, deposition on surfaces of catalytic reactors occurs and rates of deposition are higher.
- 3) NO<sub>x</sub> reduction occurs on the flat surfaces of a catalyst and in pores within the flat surfaces. The pores are open to the flue gas passing through the catalyst reactor. Condensed vapors, alkali sulfates and alkaline-earth oxides and silicates are minute particles (less than 1 microns), which enter pores of the catalyst (a.k.a. plugging) and prevent catalytic reaction with NO<sub>x</sub>. Residual alkali vapors (Na, K, and Ca) displace hydrogen on fresh catalyst, which prevents catalytic reaction with NO<sub>x</sub> (a.k.a. poisoning) and reacts with sulfate to cause blinding of catalyst surfaces. Pore condensation of sodium also causes catalyst deactivation, which is a major deactivation mechanism. The rate of catalyst deactivation depends on the concentration and form of alkali in the flue gas; higher Na and K accelerate catalyst poisoning, blinding and plugging.
- 4) During the development of the initial planning period SIP, NDDH found that there were no SCR systems planned, constructed, or operating in the flue gas stream of boilers fired with North Dakota lignite. North Dakota lignite has certain coal characteristics that are uniquely different than Texas or Gulf Coast lignites, such as the larger proportion of organic matter and association of alkali, sodium specifically, with that organic matter.
- 5) Slipstream SCR reactors of the same design were installed at three power plants to test SCR for NO<sub>x</sub> emissions control. One of the plants was cyclone fired with North Dakota lignite and the others with subbituminous coal. Deposition on the reactor surface after two months using the lignite was significantly greater; the deposits were rich in sodium, calcium, and sulfur. The tests confirmed catalyst blinding and

<sup>36</sup> As noted in section 3.1.1.2, contemporaneous with the Regional Haze SIP/FIP process, NDDH also prepared a BACT analysis for MRYS Units 1 & 2. In its BACT analysis, NDDH concluded that SCR was technically infeasible on a lignite-fired cyclone boiler, and selected SNCR as BACT. On December 21, 2011, the District Court issued a decision finding that the State's conclusion that SCR was not technically feasible was not unreasonable. See, U.S. v. Minnkota, 831 F. Supp. 2d at 1127-30

<sup>37</sup> Findings and conclusions are summarized from the North Dakota Regional Haze SIP, Appendix B.5, pgs. 15-19.

<sup>38</sup> Although the BART determination specifically references Fort Union lignite, the findings would apply to all North Dakota lignites.

plugging, but did not provide rates for catalyst deactivation. Tests also indicated that the deposits causing blinding and plugging of pores contained more sodium compared to Powder River Basin (PRB) coal.

Based on these findings, NDDH concluded that additional pilot scale testing would be required to assess issues specifically associated with the North Dakota lignite-generated flue gas characteristics, including potential impacts associated with:

- the high level of soluble alkali in North Dakota lignite;
- the potential abrasive qualities of North Dakota lignite ash; and
- particle size and sticky nature of high alkaline North Dakota lignite ash.

The NDDH concluded that without pilot scale testing the long term NO<sub>x</sub> reduction efficiency, the volume of the reactor, the catalyst pitch and life of catalyst, could not be predicted with a high degree of confidence. Noting that the BART Guidelines do not require source owners/operators to conduct extended trials to learn how to apply a technology on a totally new and dissimilar source type, and that technologies in the pilot scale testing stages of development are not considered as “available” for purposes of BART, NDDH determined that high dust SCR was not available, and thus, not technically feasible for units combusting North Dakota lignite.<sup>39</sup>

Although the first planning period BART determinations, focused on North Dakota lignite-fired cyclone boilers (i.e., LOS Unit 2 and MRYS Units 1 & 2), technical issues regarding the high level of soluble alkali in North Dakota lignite, the particle size and sticky nature of high alkaline fly ash, and the potential abrasive qualities of North Dakota lignite ash would apply equally to wall-fired and tangentially fired boilers. Technical issues identified by NDDH during the first planning period would also apply to LOS Unit 1; therefore, findings and conclusions from the first planning period BART determinations (Regional Haze SIP, Appendix B.5) and the MRYS Unit 1 & 2 BACT analysis, are incorporated by reference into this four-factor analysis.

---

<sup>39</sup> *Id.* at pg. 19. NDDH reached a similar conclusion in its BACT determination for NO<sub>x</sub> control on MRYS Units 1 & 2, finding that high-dust SCR had not been deployed on the same or a similar source, and that the flue gas characteristics of North Dakota lignite are significantly different from other sources that have applied high-dust SCR. The NDDH found that these unique characteristics present significant challenges to the successful application of high-dust SCR for NO<sub>x</sub> control, and that pilot testing would be needed to evaluate applicability of the control technology. Thus, NDDH concluded that because high-dust SCR is neither “available” nor “applicable” to the MRYS units, the control technology was technically infeasible and excluded from consideration as BACT. (See, Best Available Control Technology Determination for Control of Nitrogen Oxides for M.R. Young Station Units 1 and 2, April 2010).

Based on a review of SCR installations on coal-fired boilers and a review of reported advances in SCR catalysts since the first planning period, deactivation rates due to soluble alkali compounds in the flue gas (including soluble sodium and potassium compounds) and the adhesive/cohesive characteristics and potential abrasive qualities of the North Dakota lignite-derived fly ash still remain a concern for North Dakota lignite-fired boilers. SCR has not been installed and successfully operated on a North Dakota lignite-fired boiler, and the bench scale and pilot-scale studies needed to better understand ash behavior and catalyst blinding/erosion with North Dakota lignite-derived fly ash, and to better understand catalyst deactivation mechanisms associated with high soluble alkali compound concentrations in the flue gas have not been required or completed. Pilot-scale studies are needed to evaluate these issues to inform the development of advanced catalyst formulations, and to support the engineering and design studies needed to mitigate for potential deactivation routes (e.g., removing soluble alkali compounds from the flue gas and SCR design considerations such as catalyst formulation, catalyst pitch, reactor velocity, and catalyst surface and volume). Pilot-scale tests and engineering/design studies have not advanced since the first planning period's exhaustive analysis. These issues have not been resolved since the first planning period and still remain a significant barrier to the design and successful operation of high dust SCR on North Dakota lignite-fired boilers.

The BART Guidelines state that “[a] control technique is considered available...if it has reached the stage of licensing and commercial availability.”<sup>40</sup> Commercial availability follows bench scale and laboratory testing and pilot scale testing. Consequently, the guidelines state that “you would not consider technologies in the pilot scale testing stages of development as ‘available’ for purposes of BART review.”<sup>41</sup> Furthermore, source owners/operators are not expected to conduct extended trials to learn how to apply a technique on a dissimilar source type.<sup>42</sup> These BART guidelines also apply as a recommendation for the development of the LTS in the Round II Determination and four factor analysis.<sup>43</sup> Because there are still unresolved issues associated with catalyst poisoning, catalyst blinding and plugging, and catalyst erosion; and engineering solutions have not yet been determined or demonstrated and the high dust configuration has not moved beyond pilot scale testing, high dust SCR is still not available, and thus, not a technically feasible NO<sub>x</sub> control technology for LOS Unit 1 and 2.

---

<sup>40</sup> 40 CFR Part 51 Appendix Y, Section D.2.1.

<sup>41</sup> Id.

<sup>42</sup> Id.

<sup>43</sup> See, Draft EPA Guidelines, pg. 183.

### Low-Dust Configuration

The low-dust configuration is typically located in the flue gas stream between a hot-side ESP and the air heater inlet. Employing this configuration would represent a relatively low level of exposure to fly ash (with the exception of submicron ash particles), but a potentially high level of vapor-phase alkalis, such as sodium. Also, the location of this configuration in the flue gas path is inherently in an optimal temperature range for SCR technology of 650°F to 750°F. However, the cold-side ESP employed at LOS Units 1 and 2 for particulate control would preclude the application of a normal low-dust SCR configuration at this unit. A corollary to the low-dust/hot-side ESP configuration is the low-dust/cold-side ESP configuration. However, this low-dust configuration would require both a capital cost-intensive and operating cost-intensive gas-to-gas heater to facilitate reheating the flue gas to 550°F to 600°F. Considering the expected SO<sub>3</sub> levels in the flue gas from this configuration at LOS Unit 1 or 2, a gas temperature of 600°F would be appropriate to prevent formation of ammonium bisulfate/sulfate in the catalyst bed, while still supporting an acceptable reaction rate for NO<sub>x</sub> reduction. Furthermore, there are no examples of this configuration being implemented on a North Dakota lignite-fired unit. Therefore, considering these significant financial disadvantages and the uncertainties associated with the efficient capture of sodium constituents in the flue gas by the cold-side ESP, this type of configuration is not a technically feasible NO<sub>x</sub> control option for application at LOS Units 1 and 2.

### Tail-End Configuration

In the tail-end configuration, the SCR reaction vessel is located in the flue gas stream after the particulate and FGD control systems. The potential advantage of a tail-end SCR (TE-SCR) configuration at LOS is that the flue gas will have passed through the WFGD system prior to the SCR catalyst. As such, there is the possibility that the mass transfer mechanism that results in the capture of SO<sub>2</sub> will also capture some of the vapor-phase sodium and the sodium-enriched submicron particles, reducing the risk of catalyst poisoning and/or deactivation.

Successful operation of the tail-end configuration would also require a capital and operating cost-intensive gas-to-gas heat exchanger to reheat the flue gas from approximately 140°F downstream of the existing WFGD to approximately 550°F. Due to the limited removal efficiency of SO<sub>3</sub> across a WFGD, the formation of ammonia bisulfate (ABS) is of concern. As such, an additional in-duct heating element should be employed to raise the SCR inlet temperature to 600°F, using natural gas duct burners. Since LOS does not have natural gas on site, a new pipeline would have to be constructed for approximately 26 miles. After the flue gas passes through the SCR (at

approximately 550°F), it would pass through the hot side of the gas-to-gas heat exchanger to cool the flue gas to 150°F prior to the exhaust stack.

In addition, SO<sub>3</sub> emissions are expected to increase with a TE-SCR. SCR catalyst is known to oxidize SO<sub>2</sub>-to-SO<sub>3</sub> as the flue gas passes through the layers of catalyst and has the potential to require additional air pollution control requirements for sulfuric acid mist. Therefore, if a TE-SCR is implemented, a hydrated lime dry sorbent injection (DSI) system could be required upstream of the WFGD to remove the potential increase in SO<sub>3</sub> from the SCR.

During the first planning period, NDDH initially concluded, based on preliminary information provided by SCR catalyst vendors, that the TE-SCR configuration would be a technically feasible option for units firing North Dakota lignite.<sup>44</sup> However, as part of the MRYS NO<sub>x</sub> BACT determination process, detailed information describing the expected ash characteristics and flue gas characteristics was provided to two SCR catalyst vendors (CERAM Environmental, Inc. (CERAM) and Haldor Topsoe, Inc.). Based on their review of the data, both vendors concluded that they would not be able to provide a catalyst life guarantee for either low-dust or TE-SCR without pilot-scale testing.<sup>45</sup>

During the BACT review process, both companies made statements bringing into question the technical feasibility of either low-dust or TE-SCR. For example, CERAM stated that the high levels of sodium oxide (Na<sub>2</sub>O) in the ash for North Dakota lignite are not commonly found in subbituminous and bituminous coals which are fired in boilers equipped with SCR systems, and that it was unaware of any SCR application experience in the industry with the level and form of sodium in the North Dakota lignite-derived ash. CERAM stated further that small aerosol particles can penetrate and neutralize active catalyst sites even in dry conditions, and that catalyst installed even in low dust and tail-end locations can be poisoned from exposure to the high levels of phosphorous, sodium, and potassium found in the mineral analyses provided for the MRYS BACT analysis.<sup>46</sup> Similarly, Haldor Topsoe stated that the potential exists that physical deactivation due to catalyst blinding and plugging could be severe enough to make SCR a non-viable option for controlling NO<sub>x</sub> emissions.

---

<sup>44</sup> See, North Dakota Regional Haze SIP, Appendix B.5, pg. 25.

<sup>45</sup> See, United States v. Minnkota, 831 F. Supp. 2d, at 1117.

<sup>46</sup> *Id.*



Based on information provided by SCR design engineering firms and SCR catalyst vendors, NDDH made the following findings and conclusions with respect to the technical feasibility of low-dust and TE-SCR on a North Dakota lignite-fired boiler:<sup>47</sup>

- 1) There has never been a full scale SCR of any type installed on a facility that burns North Dakota lignite.
- 2) To determine technical feasibility of TE-SCR, one must compare the flue gas characteristics generated from firing North Dakota lignite to the flue gas characteristics of other source types to which these control technologies have been applied previously.
- 3) Flue gas characteristics of boilers firing North Dakota lignite are significantly different from other boilers where SCR has been applied.
- 4) North Dakota lignite contains high quantities of soluble sodium and potassium which can cause catalyst reaction site poisoning, blinding, and plugging of catalyst pores and channels, and that the soluble sodium and potassium can also form sulfates that can blind and plug the catalyst pores and plug the catalyst channels.
- 5) Both CERAM and Haldor Topsoe indicated that they would not provide a guarantee for the catalyst life without successful pilot scale testing being done.

Technologies in the pilot scale testing phase of development need not be considered as available control technologies. Based on the fact that SCR technology had not been installed nor effectively operated on an North Dakota lignite-fired unit, the lack of a commercially viable vendor guarantee, and the need to conduct pilot-scale testing to evaluate potentially significant operational and design issues, NDDH concluded that the use of SCR technology, including low-dust and TE-SCR, on the lignite-fired MRYS boilers would be technically infeasible.<sup>48</sup>

Although the MRYS BACT determination, and the initial planning period BART determinations, focused on North Dakota lignite-fired cyclone boilers (i.e., LOS Unit 2 and MRYS Units 1 & 2), technical issues regarding the high level of soluble alkali in North Dakota lignite-derived flue gas would also apply to LOS Unit 1. Therefore, findings and conclusions included in the MRYS Units 1 & 2 BACT analysis and the initial planning period BART determinations (Regional Haze SIP, Appendix B.5) are incorporated by reference into this four-factor analysis.

Based on a current review of SCR installations on coal-fired boilers, and a review of reported advances in SCR catalysts since the first planning period, deactivation rates due to soluble alkali compounds in the flue gas

---

<sup>47</sup> Findings and conclusions are summarized from United States v. Minnkota, pgs 1115-1116.

<sup>48</sup> Best Available Control Technology Determination for Control of Nitrogen Oxides for M.R. Young Station Units 1 and 2, April, 2010, pg. 21.

(including soluble sodium and potassium compounds) still remain a concern for North Dakota lignite-fired boilers. TE-SCR has not been demonstrated on a North Dakota lignite-fired boiler, and there are still significant technical concerns associated with the availability of existing SCR catalysts on a lignite-fired unit. Catalyst in a TE-SCR will still be vulnerable to alkali poisoning, pore pluggage and premature catalyst deactivation, and it is not known whether the comparatively high levels of soluble sodium and potassium in North Dakota lignite will be effectively removed by the upstream WFGD. Furthermore, the potential exists for fine particulate remaining in the flue gas to get into the catalyst pores reducing catalyst activity. Pilot-scale studies are needed to better understand catalyst deactivation mechanisms associated with high soluble alkali compound concentrations in the flue gas have not been completed.

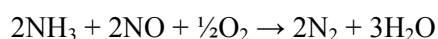
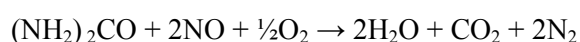
In order to understand the effect of North Dakota lignite-derived flue gas on TE-SCR catalyst, identify potential design solutions, and evaluate the technical feasibility and effectiveness of TE-SCR at LOS Unit 1 with any degree of certainty, pilot scale testing of the control configuration would be needed. Because there are unresolved issues associated with catalyst poisoning, it is very unlikely that Basin Electric could obtain a viable commercial offering for TE-SCR on LOS Unit 1 without extended pilot-scale tests.

During the first planning period NDDH determined that TE-SCR was not available, and thus, not a technically feasible NO<sub>x</sub> control option for North Dakota lignite-fired boilers. Although the NDDH's control technology evaluation during the first planning period specifically focused on North Dakota lignite-fired cyclone boilers, technical issues regarding catalyst deactivation mechanisms associated with the high level of soluble alkali in North Dakota lignite would apply equally to wall-fired and tangentially-fired boilers. The administrative record developed during the first planning period, including the BART determinations and MRYS BACT analysis, supports the conclusion that TE-SCR is also not an available NO<sub>x</sub> control option for LOS Unit 1. An evaluation of SCR installations and reported advances in SCR catalysts since the first planning period, coupled with the fact that TE-SCR has not been demonstrated on a North Dakota lignite-fired boiler, and the likelihood that Basin Electric could not obtain a viable commercial offering for TE-SCR without extended pilot-scale testing, continues to support the conclusion that TE-SCR is not an available NO<sub>x</sub> control technology. Nevertheless, because the first planning period BART analysis (and the MRYS BACT analysis) focused on cyclone boilers, Basin Electric has elected to include TE-SCR as a potentially feasible control option and carry it forward to the cost impact evaluation (section 5.3.2) for LOS Unit 1. Based on controlled NO<sub>x</sub> emissions achieved in practice at existing bituminous- and subbituminous-fired unit, S&L assumed that the TE-SCR control option could achieve an average controlled

NO<sub>x</sub> emission rate of 0.05 lb/MMBtu. Due to the previous ruling on North Dakota lignite-fired cyclone boilers, SCR on will not be evaluated further on LOS Unit 2.

#### **5.2.2.2 Optimized Selective Non-Catalytic Reduction**

SNCR involves the direct injection of ammonia or urea ((NH<sub>2</sub>)<sub>2</sub>CO) at high flue gas temperatures (approximately 1,600°F – 2,100°F) in an oxidizing environment. The ammonia or urea reacts with NO<sub>x</sub> in the flue gas to produce N<sub>2</sub> and water as shown below.



Flue gas temperature at the point of reagent injection can greatly affect NO<sub>x</sub> removal efficiencies and the quantity of ammonia or urea that will pass through the SNCR unreacted (referred to as ammonia slip). In general, SNCR reactions are effective in the range of 1,600°F – 2,100°F. At temperatures below the desired operating range, the NO<sub>x</sub> reduction reactions diminish and unreacted NH<sub>3</sub> emissions increase. Above the desired temperature range, NH<sub>3</sub> is oxidized to NO<sub>x</sub> resulting in low NO<sub>x</sub> reduction efficiencies.

Mixing of the reactant and flue gas within the reaction zone is an important factor to SNCR performance. In large boilers, the physical distance over which reagent must be dispersed increases, and the surface area/volume ratio of the convective pass decreases. Furnace geometry, urea spray coverage, and droplet size must be considered when developing good mixing of reagent and flue gas, delivery of reagent in the proper temperature window, and sufficient residence time of the reagent and flue gas in that temperature window. As the boiler cycles in load, the optimum injection region may change. Thus most facilities require multiple injection zones which are placed in and out of service as the unit ramps in load. This can include modifying the zones of injectors that are operating and different loads and temperatures.

Retractable multi-nozzle lances (MNLs) are sometimes used to improve SNCR performance, especially if the furnace exit flue gas temperatures are too high. The retractable lances allow injection into the appropriate temperature zone more so than wall injectors, depending on the unit load and temperatures. The MNLs also help improve performance by refining the spray pattern for quicker vaporization of the conveying water. MNLs are often used in conjunction with wall injection to provide optimized coverage while reducing reagent cost.

In addition to temperature and mixing, several other factors influence the performance of an SNCR system, including residence time, reagent-to-NO<sub>x</sub> ratio, and fuel sulfur content. Increasing the normalized stoichiometric ratio (NSR) can improve NO<sub>x</sub> removal. This is completed by increasing urea solution flow through the injectors or changing the concentration of urea in the solution. However, too high of reagent injection rates will increase the ammonia slip beyond the recommended 10 ppmvd limit. Above this concentration, there are expected to be major impacts to the formation of ammonia salts on the boiler tube banks, reducing heat transfer efficiency, and air heater baskets, causing corrosion.

Overall, the application of SNCR on pulverized coal or cyclone boilers is feasible due to having reasonable temperature windows and residence time; however, the potential NO<sub>x</sub> reduction is boiler-specific. Based on the NDDH conclusions in the First Regional Haze Implementation Period, SNCR was determined to be cost-effective for NO<sub>x</sub> control on Units 1 and 2. LOS Units 1 and 2 installed SNCR in 2014 and 2015, respectively, and started compliance with a new NO<sub>x</sub> limit in April 2017. As such, SNCR systems on Units 1 and 2 have been operational during the baseline period. Therefore, confirmation of optimization of the existing system will be explored as an option on Units 1 and 2, since SNCR is included in the baseline.

Prior to implementing the SNCR systems on Units 1 and 2, LOS personnel tuned SOFA systems for better boiler stoichiometry control and installed combustion optimization systems. The effect of these two systems prior to implementation of the SNCR resulted in much lower NO<sub>x</sub> formation in the Unit 1 and 2 boilers. As such, removal efficiencies of the SNCR are based on a pre-SNCR value which includes the benefit of modifications since the First Implementation Phase.

For LOS Unit 1, SNCR boiler computational fluid dynamics (CFD) modeling was completed to understand the best performance expected prior to implementation and tuning of the system. Based on the SOFA, LNB, and combustion optimization systems, SNCR was predicted to achieve 20% removal with an outlet NO<sub>x</sub> rate just over 0.17 lb/MMBtu. Based on flow and NO<sub>x</sub> CEMS data, average performance of the SNCR is currently slightly below 0.17 lb/MMBtu. As such, the current SNCR system is considered fully optimized based on the expected CFD modeling; any additional urea injection may result in negative impacts with ammonia slip emissions. Also, MNLs were initially modeled in addition to the wall injectors and were found to improve removal efficiency by another 6%; however, the optimal locations of the MNLs were determined to have physical interferences which would have limited the possibility of installation and thus were not installed. As such, MNLs are considered

technically infeasible as part of this evaluation. For these reasons, SNCR optimization is not considered to be a technically feasible NO<sub>x</sub> control option for LOS Unit 1, and will not be evaluated further.

As discussed previously, the SNCR on LOS Unit 2 was implemented after SOFA tuning, combustion optimization, and four vent ports were relocated. As such, the pre-SNCR baseline emission rate is much lower than the 0.67 lb/MMBtu uncontrolled baseline reported in the First Implementation Phase. S&L and Basin Electric consulted SNCR OEMs to determine the expected SNCR performance for a cyclone boiler similar to LOS Unit 2, considering the pre-SNCR baseline. The OEM, who performed a significant amount of modeling when the SNCR system was being designed on Unit 2, suggested that the SNCR system could be further optimized. Improvement of the stoichiometry would be required, by relocating all cyclone vent ports. Additionally, due to revised temperatures within the boiler from the new SOFA, vent port relocations, and combustion optimizers, the current urea injection lances are recommended to be relocated for better utilization of the reagent.

By optimizing LOS Unit 2's SNCR system based on additional vent port relocation and SNCR injection lance relocation, the unit may be able to achieve an additional 10% reduction from the annual baseline NO<sub>x</sub> rate or approximately 0.27 lb/MMBtu at the boiler outlet at full load. This is consistent with greater than 25% reduction from an estimated pre-SNCR NO<sub>x</sub> rate. In this case for LOS Unit 2, the limiting factor for optimized SNCR operation is full load. Overall, it is expected that optimization of the Unit 2 SNCR system at all loads is a technically feasible option to reduce NO<sub>x</sub> emissions and will be evaluated further.

### **5.2.2.3 Rich Reagent Injection**

Similar to SNCR, the concept of RRI is to use a nitrogen-containing additive (urea) injected into a reducing environment to promote peak NO<sub>x</sub> reduction efficiency. RRI is a commercial technology for cyclone boilers only, thus is not an applicable option for LOS Unit 1. In contrast to SNCR, RRI typically is applied with only one injection level in the lower furnace near the cyclone barrels (temperature window of 2000°F-2600°F). The technology requires a sub-stoichiometric oxygen concentration near the barrels at <0.95. This allows for a higher injection rate of reagent without oxidizing to NO<sub>x</sub> due to the sub-stoichiometry. Injection at this location also creates lower level of excess NH<sub>3</sub> emissions (ammonia slip), while injecting at an NSR of 2.0-3.0.

Due to the changes of the lower furnace stoichiometry, RRI is often not a technically feasible option at lower loads. Once the stoichiometric ratio increases to >1.0, there is the potential for NO<sub>x</sub> generation due to the reaction of

ammonia with oxygen, especially if the injection location and rate is not optimized. Based on these limitations, RRI alone is considered most effective at full load.

The RRI process is a commercially available process and has been predicted to typically reduce NO<sub>x</sub> emissions by 20-40% at full load with no ammonia slip, but is highly dependent on the stoichiometry. However, this technology provides the most beneficial reduction at full load, due to the cyclone temperature window and stoichiometry. At mid- and low-loads, the predicted reduction is less than the current SNCR baseline operation at these loads. Therefore, low load operation is considered the limiting factor of RRI alone and the effectiveness of RRI is marginalized at mid-loads. SNCR would still be needed to achieve a similar reduction at low load. As such, RRI on its own is not a technically feasible NO<sub>x</sub> reduction technology due to its limited operating conditions throughout all load ranges and will not be considered further.

#### **5.2.2.4 Optimized SNCR + RRI**

While RRI alone will provide beneficial NO<sub>x</sub> reduction at full load only, coupling RRI with SNCR will provide a balanced approach to NO<sub>x</sub> reduction through all load ranges. RRI and SNCR injectors are located at different elevations of the furnace and in different temperature windows. The system utilizes a high urea injection rate, staged at multiple locations throughout the boiler. The main advantage of this combined system is that the SNCR can provide better NO<sub>x</sub> reduction at mid- and low-loads and at a lower NSR than RRI alone. Therefore, this combined system is expected to be able to provide a lower emission rate through all load ranges.

Similarly to SNCR and RRI, the only way SNCR + RRI will provide beneficial results is by relocating the remaining vent ports and keeping the SOFA tuned. This relocation will change the lower furnace O<sub>2</sub> stoichiometry, to be around 0.90 instead of 1.0. Due to negative impacts to the boiler with regards to slagging, 0.90 is the lowest stoichiometry that the unit can operate consistently with target coal quality. At full load, RRI + SNCR was modeled to provide reduction from pre-SNCR emissions. However, as discussed previously, RRI provides the largest benefit at full load; therefore, low- or mid-load operation would be the limiting factor.

Boiler CFD modeling of the SNCR and RRI systems was previously conducted with different assumptions of SOFA and vent port relocation performance. However, S&L consulted the CFD modeling company to provide insight into what performance could be achieved with the revised pre-SNCR baseline NO<sub>x</sub> emission rate. This information was also provided to an SNCR+RRI system OEM who suggested that an additional 43% reduction

from the annual baseline could be guaranteed at full load, which would provide an outlet emission rate of 0.17 lb/MMBtu. This is consistent with greater than 50% reduction from an estimated pre-SNCR NO<sub>x</sub> rate.

Alternatively to the optimized SNCR case, low load operation is the limiting factor for SNCR+RRI performance. RRI becomes ineffective at low load and the OEM suggested that almost no NO<sub>x</sub> reduction would occur at this load due to RRI. Initial modeling suggested that increasing the urea NSR to 3.0 at low load could achieve an additional 2% reduction, but there is a concern about ammonia slip rates with this operating profile.

The SNCR + RRI combination would require all new penetrations for the RRI system as well as the relocation of the existing SNCR system as discussed in 5.2.2.2. The RRI system will require a larger urea storage tank, additional water treatment equipment for solutionizing, additional pump forwarding capacity, new piping to lower boiler elevations, additional boiler penetrations, injectors, and all balance of plant related equipment. At the lower elevation for the RRI ports, the most optimal injection location happens to occur at the same elevation of the windbox. Therefore specialized retractable and cooled injection lances with windbox modifications would be required. This design creates engineering and operational challenges that are normally avoided by injecting reagent in more accessible areas of the boiler.

Overall, the implementation of an RRI system along with optimization of the existing SNCR system is a technically feasible NO<sub>x</sub> control option on Unit 2. Based on input from previous CFD modeling and SNCR OEMs, it is expected that LOS Unit 2 could achieve an outlet NO<sub>x</sub> rate of 0.22 lb/MMBtu with an ammonia slip of 10 ppmvd with vent port relocation, optimized SNCR, and RRI.

#### **5.2.2.5 Gas Reburn**

Gas reburn is a retrofit technique that has been used to control NO<sub>x</sub> emissions from coal- and oil-fired boilers. Gas reburn involves combustion in three distinct zones within the boiler: (1) a primary combustion zone, where the primary fuel is fired using conventional burners; (2) a reburn zone, where secondary fuel, typically natural gas, is introduced into the boiler; and (3) an overfire air burnout zone.

In the primary zone of coal-fired boilers, coal is fired through LNBs, at a rate corresponding to approximately 80% to 90% of the total heat input. Natural gas reburn fuel is then injected above the primary combustion zone under fuel-rich conditions at a rate corresponding to approximately 10% to 20% of the total heat input (on a Btu/hour basis). The fuel-rich reburn zone creates a reducing (sub-stoichiometric) region within the boiler where the natural gas, principally methane, breaks down to produce hydrocarbon radicals (CH and CH<sub>2</sub>). The



hydrocarbon radicals react with  $\text{NO}_x$  produced in the primary combustion zone to form nitrogen and water vapor. Because the natural gas is not completely combusted in the reburn zone, gases exiting the reburn zone will contain considerable CO and unburned hydrocarbons; therefore, additional OFA is introduced above the reburn zone to complete the combustion process.

Critical design parameters that affect the feasibility and performance of a gas reburn retrofit system include: (1) baseline  $\text{NO}_x$  concentration; (2) reburn zone temperature, residence time, and stoichiometry; (3) OFA burnout zone temperature and residence time; and (4) mixing of the reburn fuel and overfire air with the bulk flue gas.

Gas reburn can have a positive impact on emissions of  $\text{NO}_x$ ; however, in order to make a meaningful prediction of the  $\text{NO}_x$  removal capabilities at LOS, extensive testing at each unit would be required because the performance is significantly dependent upon boiler operating characteristics. In addition, lack of natural gas available on site precludes the ability to test and implement this control option on LOS Units 1 and 2, which use fuel oil as the startup fuel. As such, gas reburn is not considered a technically feasible  $\text{NO}_x$  control technology at LOS Units 1 and 2.

#### **5.2.2.6 Innovative Technologies**

##### *$\text{NO}_x\text{Star}^{\text{TM}}$*

The  $\text{NO}_x\text{Star}^{\text{TM}}$  process, also known as selective autocatalytic reduction (SACR), uses a continuous controlled amount of ammonia-based reagent with relatively small amounts of hydrocarbon to reduce  $\text{NO}_x$  emissions. The hydrocarbon is introduced into the flue gas at the convective pass of the boiler, with elevated temperatures. At the elevated temperatures, the hydrocarbon auto-ignites to form a plasma of free radicals that auto catalyzes the reaction of  $\text{NH}_3$  and  $\text{NO}_x$  to form  $\text{N}_2$  and  $\text{H}_2\text{O}$ . The hydrocarbon and ammonia are added through banks of nozzles in the superheat or reheat sections of the boiler. The injection location is determined by the location of the temperature windows for the "plasma creation zone" as well as the reaction zone for the ammonia.

To date, only one full-scale demonstration has been conducted to evaluate the technology on utility-sized boilers similar to LOS. The process is an emerging  $\text{NO}_x$  control, and there is limited information available to evaluate its technical feasibility and long-term effectiveness on a large lignite-fired boiler. Potential  $\text{NO}_x$  removal efficiencies would be a function of  $\text{NH}_3$ - $\text{NO}_x$  mixing, flue gas temperature, flue gas composition, and residence time downstream of the injection lances.

Because this is an emerging technology, long-term full-scale demonstration testing is required to demonstrate its effectiveness at LOS. It is likely that extensive design engineering and testing would be required to evaluate the technical feasibility and long-term effectiveness of the control system. Detailed design of the lances, mixing, optimization of the reagent supply across the boiler convective pass, flue gas temperatures, and flow distribution would have to be studied. Interference with the tube pendants in the convective pass may also make this more difficult to install. Installing a hydrocarbon distribution grid may present a problem with large boilers because of the span needed to uniformly distribute the reagent, interference with the tube pendants in the convective pass, and an additional booster fan may be needed. As such, NO<sub>x</sub>Star™ is not considered a technically feasible NO<sub>x</sub> control technology at LOS.

#### PerNO<sub>x</sub>ide

PerNO<sub>x</sub>ide utilizes hydrogen peroxide (H<sub>2</sub>O<sub>2</sub>) to reduce NO<sub>x</sub> emissions. Hydrogen peroxide is injected into the ducts ahead of the air preheater and oxidizes the NO to NO<sub>2</sub>, which is then captured in a downstream FGD system. To date, the technology has only been tested on a pilot-scale, and it has not been demonstrated on any coal-fired boilers. It is likely that extensive design engineering and testing would be required to evaluate the scale-up potential and long-term effectiveness of the system on LOS. As such, PerNO<sub>x</sub>ide is not considered a technically feasible NO<sub>x</sub> control technology at LOS.

#### LoTOX®

The LoTO<sub>x</sub> system is a gas-phase, low-temperature oxidation system, wherein ozone is injected into the flue gas stream to oxidize NO and NO<sub>2</sub> to N<sub>2</sub>O<sub>5</sub> before being removed in a WFGD. This highly oxidized species of NO<sub>x</sub> is water-soluble and rapidly reacts with water to form nitric acid. The conversion of NO<sub>x</sub> to nitric acid occurs as the N<sub>2</sub>O<sub>5</sub> contacts liquid sprays in the WFGD. The nitric acid would react with the alkali compounds in the WFGD and would be eliminated via the WFGD waste and byproduct streams. The LoTO<sub>x</sub> system requires on demand ozone generation from a liquid oxygen supply.

The LoTO<sub>x</sub> system has been successfully applied in refinery applications however; there are no full-scale installations on coal-fired boilers. According to vendors, one coal-fired boiler demonstration on a 25-MW boiler was performed which showed 90% NO<sub>x</sub> removal. It is likely that extensive design engineering and testing would be required to evaluate the scale-up potential and long-term effectiveness of the system at LOS. As such, LoTO<sub>x</sub> is not considered a technically feasible NO<sub>x</sub> control technology at LOS.

### Water Injection

The principle behind this technology is to inject an atomized water spray into the high-NO<sub>x</sub> production zones of a cyclone burner or in the core of the flame for other furnaces. The water spray reduces the temperature and results in lower NO<sub>x</sub> production within this zone. Developers claim that water injection through burners used in tangential-fired and wall-fired units will also lower the flame temperature and, hence, lower NO<sub>x</sub> production. However, only laboratory results are available to demonstrate this technology's effectiveness in coal-fired applications.

Water injection is well demonstrated for combustion turbine applications for NO<sub>x</sub> reduction. However, there is insufficient experience and demonstration data in coal-fired applications. As such, water injection is not considered a technically feasible NO<sub>x</sub> control technology at LOS.

#### **5.2.2.7 Technical Feasibility Summary**

Table 5-5 and Table 5-6 summarize the results of the feasibility evaluation of available control options for LOS Unit 1 and 2.

**Table 5-5. Technically Feasible NO<sub>x</sub> Control Options for LOS Unit 1**

NO <sub>x</sub> Control Option	Technically Feasible (Yes/No)	Control Percentage (Note 1)	Technical Feasibility Summary
Optimized Selective Non-Catalytic Reduction (SNCR)	No	0%	SNCR is not considered an available and technically feasible NO <sub>x</sub> control technology for LOS Unit 1. Performance in the field was tuned to achieve the best computational model runs.
Rich Reagent Injection (RRI)	No	0%	RRI is not available on LOS Unit 1.
Optimized SNCR + RRI	No	0%	SNCR + RRI is not available on LOS Unit 1.
Gas Reburn	No	0%	Gas reburn is not considered an available or technically feasible NO <sub>x</sub> control technology at LOS Unit 1.
Innovative Technologies: NO <sub>x</sub> Star™ PerNO <sub>x</sub> ide LoTO <sub>x</sub> Water Injection	No	0%	Innovative NO <sub>x</sub> control technologies are evaluated in Section 5.2.2.6. In all cases, the technologies have not been demonstrated on a large North Dakota lignite-fired boiler. Extensive testing and design engineering would be required to evaluate the technical feasibility and long-term effectiveness of each innovative control system on LOS Units 1 and 2. Therefore, the innovative NO <sub>x</sub> control technologies are not considered available control options and are not technically feasible NO <sub>x</sub> control options for LOS Unit 1.
Selective Catalytic Reduction (SCR)			
High-dust configuration	No	0%	Due to significant unresolved issues associated with catalyst poisoning, catalyst blinding and plugging, and catalyst erosion; and based on the finding that engineering solutions have not been determined or demonstrated and the high dust configuration has not moved beyond pilot scale testing, high dust SCR is not an available or technically feasible NO <sub>x</sub> control technology for LOS Unit 1.
Low-dust configuration	No	0%	Because LOS Unit 1 is equipped with existing WFGD control systems, low-dust SCR has no practical application on the unit, and low-dust SCR is not considered an available or technically feasible NO <sub>x</sub> control option for LOS Unit 1.
Tail-end configuration	Yes	82.8%	EPA's reconsideration of North Dakota's NO <sub>x</sub> BART determination focused on cyclone boilers firing North Dakota lignite, and did not specifically address PC-boilers firing North Dakota lignite. Therefore, for consistency with the approach NDDH used during the First Implementation Period (i.e., assuming technical feasibility, TE-SCR will be carried forward to the four factor analysis on LOS Unit 1.

Note 1. Control percentage calculated using the uncontrolled NO<sub>x</sub> emission rate and the achievable NO<sub>x</sub> emission rate for each technically feasible control option.

**Table 5-6. Technically Feasible NO<sub>x</sub> Control Options for LOS Unit 2**

NO <sub>x</sub> Control Option	Technically Feasible (Yes/No)	Control Percentage (Note 1)	Technical Feasibility Summary
Optimized Selective Non-Catalytic Reduction (SNCR)	Yes	60%	SNCR is considered an available and technically feasible NO <sub>x</sub> control technology for LOS Unit 2. Computational fluid dynamic modeling and temperature mapping of the boiler would be needed to confirm that the incremental reduction in NO <sub>x</sub> emissions is achievable without creating unacceptable operational issues.
Rich Reagent Injection (RRI)	No	0%	RRI is not considered a technically feasible NO <sub>x</sub> control option at all loads at LOS Unit 2.
Optimized SNCR + RRI	Yes	67%	SNCR + RRI is considered an available and technically feasible NO <sub>x</sub> control technology for LOS Unit 2. Computational fluid dynamic modeling and temperature mapping of the boiler would be needed to confirm that the incremental reduction in NO <sub>x</sub> emissions is achievable without creating unacceptable operational issues.
Gas Reburn	No	0%	Gas reburn is not considered an available or technically feasible NO <sub>x</sub> control technology at LOS Unit 2.
Innovative Technologies: NO <sub>x</sub> Star™ PerNO <sub>x</sub> ide LoTO <sub>x</sub> Water Injection	No	0%	Innovative NO <sub>x</sub> control technologies are evaluated in Section 5.2.2.6. In all cases, the technologies have not been demonstrated on a large North Dakota lignite-fired boiler. Extensive testing and design engineering would be required to evaluate the technical feasibility and long-term effectiveness of each innovative control system on LOS Units 1 and 2. Therefore, the innovative NO <sub>x</sub> control technologies are not considered available control options and are not technically feasible NO <sub>x</sub> control options for LOS Unit 2.
Selective Catalytic Reduction (SCR)			
High-dust configuration	No	0%	Due to significant unresolved issues associated with catalyst poisoning, catalyst blinding and plugging, and catalyst erosion; and based on the finding that engineering solutions have not been determined or demonstrated and the high dust configuration has not moved beyond pilot scale testing, high dust SCR is not an available or technically feasible NO <sub>x</sub> control technology for LOS Unit 2.
Low-dust configuration	No	0%	Because LOS Unit 1 and 2 is equipped with existing WFGD control systems, low-dust SCR has no practical application on the unit, and low-dust SCR is not considered an available or technically feasible NO <sub>x</sub> control option for LOS Unit 2.

NO <sub>x</sub> Control Option	Technically Feasible (Yes/No)	Control Percentage (Note 1)	Technical Feasibility Summary
Tail-end configuration	No	0%	Based on EPA's 2015 Notice of final action on reconsideration (see, 80 FR 8550), and the continued lack of demonstration testing and commercial guarantees, TE-SCR is considered to be a technically infeasible control option for LOS Unit 2.

Note 1. Control percentage calculated using the uncontrolled NO<sub>x</sub> emission rate and the achievable NO<sub>x</sub> emission rate for each technically feasible control option.

### 5.2.3 Evaluate Technically Feasible NO<sub>x</sub> Control Options for Effectiveness

The technically feasible NO<sub>x</sub> control technologies are listed in in descending order of control efficiency. Table 5-7 and Table 5-8 also provide control option-specific NO<sub>x</sub> emission rates in terms of lb/MMBtu. Emission rates shown represent average emission rates that the control options would be expected to achieve during normal operations.

**Table 5-7. Evaluate Technically Feasible NO<sub>x</sub> Control Options by Effectiveness for LOS Unit 1 (Baseline Average Emissions)**

Alt. No.	Control Technology	NO <sub>x</sub> Emission Rate (Note 1) lb/MMBtu	% Reduction from Uncontrolled NO <sub>x</sub> (Notes 2, 3)	NO <sub>x</sub> Emission Rate (Note 1) lb/hr	NO <sub>x</sub> Emission Rate (Note 1) tons/yr
A	Selective catalytic reduction (SCR) – tail-end configuration (Note 2)	0.05	83	82	292
--	Baseline (existing LNB / SOFA / SNCR)	0.15	47	255	905
--	Permit Limit	0.19 (30-day)	--		

Note 1. Emission rates shown represent average emission rates that the control options would be expected to achieve on an on-going long-term basis under normal operating conditions for LOS Unit 1. Emission rates are provided for comparative purposes, and should not be construed to represent proposed emission limits. Corresponding permit limits must be evaluated on a control system-specific basis.

Note 2. Percent reduction from uncontrolled pre-BART (SNCR/OFA) upgrade NO<sub>x</sub> emission rate of 0.29 lb/MMBtu.

Note 3. TE-SCR has not been installed on a North Dakota lignite-fired unit, and extended trials would be needed to better understand the design and operation of TE-SCR on LOS Unit 1. Nevertheless, during the initial planning period, NDDH concluded that TE-SCR was a technically feasible NO<sub>x</sub> control technology for a North Dakota lignite-fired boiler, and evaluated the costs and cost-effectiveness of the control system. For consistency with NDDH's conclusion from the first planning period, TE-SCR will be carried forward to the four factor analysis.

**Table 5-8. Evaluate Technically Feasible NO<sub>x</sub> Control Options by Effectiveness for LOS Unit 2  
(Baseline Average Emissions)**

Alt. No.	Control Technology	NO <sub>x</sub> Emission Rate <sup>(Note 1)</sup> lb/MMBtu	% Reduction from Uncontrolled NO <sub>x</sub> <sup>(Notes 2, 3)</sup>	NO <sub>x</sub> Emission Rate <sup>(Note 1)</sup> lb/hr	NO <sub>x</sub> Emission Rate <sup>(Note 1)</sup> tons/yr
B	Optimized SNCR + RRI	0.22	67	812	3,346
A	Optimized SNCR	0.27	60	997	4,107
--	Baseline (existing LNB / SOFA / SNCR)	0.30	56	1,099	4,530
--	Permit Limit	0.35 (30-day)	--		

Note 1. Emission rates shown represent average emission rates that the control options would be expected to achieve on an on-going long-term basis under normal operating conditions for LOS Unit 2. Emission rates are provided for comparative purposes, and should not be construed to represent proposed emission limits. Corresponding permit limits must be evaluated on a control system-specific basis.

Note 2. Percent reduction from uncontrolled pre-BART (SNCR/OFA) upgrade NO<sub>x</sub> emission rate of 0.67 lb/MMBtu.

Table 5-9 provides control option-specific NO<sub>x</sub> emission rates in terms of lb/MMBtu based on the projected future maximum emission rates. Emission rates shown represent the projected future maximum emission rates that the control options would be expected to achieve during normal operations.

**Table 5-9. Evaluate Technically Feasible NO<sub>x</sub> Control Options for Effectiveness - LOS Unit 1  
(Projected Future Maximum Emissions)**

Alt. No.	Control Technology	NO <sub>x</sub> Emission Rate <sup>(Note 1)</sup> lb/MMBtu	% Reduction from Uncontrolled NO <sub>x</sub> <sup>(Notes 2, 3)</sup>	NO <sub>x</sub> Emission Rate <sup>(Note 1)</sup> lb/hr	NO <sub>x</sub> Emission Rate <sup>(Note 1)</sup> tons/yr
A	Selective catalytic reduction (SCR) – tail-end configuration <sup>(Note 2)</sup>	0.05	83	131	574
--	Baseline (existing LNB / SOFA / SNCR)	0.15	47	406	1,779
--	Permit Limit	0.19 (30-day)	--		

Note 1. Emission rates shown represent average emission rates that the control options would be expected to achieve on an on-going long-term basis under normal operating conditions for LOS Unit 1. Emission rates are provided for comparative purposes, and should not be construed to represent proposed emission limits. Corresponding permit limits must be evaluated on a control system-specific basis.

Note 2. Reduction from pre-BART (SNCR/OFA) upgrade NO<sub>x</sub> emission rates of 0.29 lb/MMBtu.

Note 3. TE-SCR has not been installed on a North Dakota lignite-fired unit, and extended trials would be needed to better understand the design and operation of TE-SCR on LOS Unit 1. Nevertheless, during the initial planning period, NDDH concluded that TE-SCR was a technically feasible NO<sub>x</sub> control technology for a North Dakota lignite-fired boiler, and evaluated the costs and cost-effectiveness of the control system. For consistency with NDDH's conclusion from the first planning period, TE-SCR will be carried forward to the four factor analysis.



**Table 5-10. Evaluate Technically Feasible NO<sub>x</sub> Control Options for Effectiveness - LOS Unit 2  
(Projected Future Maximum Emissions)**

Alt. No.	Control Technology	NO <sub>x</sub> Emission Rate <sup>(Note 1)</sup> lb/MMBtu	% Reduction from Uncontrolled NO <sub>x</sub> <sup>(Note 2)</sup>	NO <sub>x</sub> Emission Rate <sup>(Note 1)</sup> lb/hr	NO <sub>x</sub> Emission Rate <sup>(Note 1)</sup> tons/yr
B	Optimized SNCR + RRI	0.22	67	1,129	4,943
A	Optimized SNCR	0.27	60	1,385	6,067
--	Baseline (existing LNB / SOFA / SNCR)	0.30	56	1,528	6,692
--	Permit Limit	0.35 (30-day)	--		

Note 1. Emission rates shown represent average emission rates that the control options would be expected to achieve on an on-going long-term basis under normal operating conditions for LOS Unit 1. Emission rates are provided for comparative purposes, and should not be construed to represent proposed emission limits. Corresponding permit limits must be evaluated on a control system-specific basis.

Note 2. Reduction from pre-BART (SNCR/OFA) upgrade NO<sub>x</sub> emission rates of 0.67 lb/MMBtu.

### 5.3 NO<sub>x</sub> COST OF COMPLIANCE (STATUTORY FACTOR ONE)

The economic analysis performed as part of the four factor analysis examines the cost-effectiveness of each technically feasible control technology, on a dollar per ton of pollutant removed basis. Annual emissions, calculated for a particular control device, are subtracted from baseline annual emissions to calculate tons of pollutant controlled per year. For units with existing controls, the base case represents existing baseline actual emissions. Annual costs for each control option are calculated relative to the base case by adding annual O&M costs to the annualized cost of capital and, if applicable, lost revenue due to extended outage required for installation of control equipment. Capital costs and lost revenues were annualized using a capital recovery factor based on an annual interest rate of 5.25% and equipment life of 20 years.<sup>49</sup> Cost effectiveness (\$/ton) of a particular control option is simply the annual cost (\$/yr) divided by the annual reduction in annual emissions (ton/yr). In addition to cost-effectiveness relative to the base case, the incremental cost-effectiveness to go from one level of control to the next, more stringent, level of control may also be calculated to evaluate the incremental cost effectiveness of the more stringent control.

<sup>49</sup> The assumed 20-year equipment life is consistent with the control system equipment life used by NDDH in its evaluation of NO<sub>x</sub> and SO<sub>2</sub> control technologies for BART-eligible sources. (see, e.g., ND Regional Haze Final SIP, Appendix C.1, "BART Determination Study for Leland Olds Station Units 1 & 2, Basin Electric Power Cooperative, August 2006, pgs. 64 (NO<sub>x</sub> controls) and 158 (SO<sub>2</sub> controls). See also, ND Regional Haze Final SIP, Appendix C4, "NO<sub>x</sub> Best Available Control Technology Study for Milton R. Young Station Unit 1, Minnkota Power Cooperative, Inc., October 2006, pg. 3-22).

Capital and O&M cost estimates were developed for each of the technically feasible NO<sub>x</sub> control options. The LOS Units 1 and 2 cost estimates are conceptual in nature; thus, S&L did not procure equipment quotes specifically for the Units 1 and 2 control system upgrades. Rather, equipment costs are based on conceptual designs developed for the retrofit control systems, preliminary equipment sizing developed for the major pieces of equipment (based on Units 1 and 2-specific design parameters, including typical fuel characteristics, full load heat input, and flue gas temperatures and flow rates), and recent pricing for similar equipment. S&L would characterize the cost estimates for the LOS Units 1 and 2 retrofit technologies as “concept screening” cost estimates generally based on parametric models, judgment, or analogy.

Control technology equipment costs for the retrofit options were developed by scaling cost estimates prepared by S&L for other similar projects. Major equipment costs were developed based on equipment costs recently developed for similar projects, and include the equipment, material, labor, and all other direct costs needed to retrofit the units with the control technology. Sub-accounts for the capital cost estimates (e.g., mobilization and demobilization, consumables, contractor G&A expense, freight on materials, etc.) were developed by applying ratios from detailed cost estimates that were prepared for projects with similar scopes.

Fixed O&M costs include operating labor, maintenance labor, maintenance material, and administrative labor. Variable O&M costs include the cost of consumables, including reagent, water consumption, and auxiliary power requirements.<sup>50</sup> Auxiliary power requirements reflect the additional power requirements associated with the operation of the new control technology (compared to the existing technology). All O&M costs reflect the incremental increase in O&M costs compared to the costs incurred to operate the existing SNCR systems.

In addition to the cost effectiveness relative to the base case, the incremental cost-effectiveness to go from one level of control to the next more stringent level of control will also be calculated to evaluate the cost effectiveness of the more stringent control.

### **5.3.1 NO<sub>x</sub> Average Annual Economic Evaluation**

Table 5-11 presents the capital costs and annual operating costs associated with building and operating each control system. Table 5-13 shows the average annual and incremental cost effectiveness for each control system. Annual

---

<sup>50</sup> Variable O&M costs are based on the future SO<sub>2</sub> coal of 3.66 lb/MMBtu.

operating costs included in Table 5-11 are based on actual baseline period capacity factors of 61% for Unit 1 and 68% for Unit 2. The emissions reductions and cost effectiveness values included in Table 5-12 are based on baseline emission rates and projected actual emissions for each control option. Additional cost details are provided in Appendix D.

**Table 5-11. NO<sub>x</sub> Control Cost Summary (Annual Average)**

LOS Unit No.	Alt. No.	NO <sub>x</sub> Control Option	Total Capital Investment \$	Annual Capital Recovery Cost \$/yr	Annual Operating Cost \$/yr	Total Annual Cost \$/yr
Unit 1	A	Selective catalytic reduction (SCR) – tail-end configuration	\$227,717,000	\$18,662,000	\$14,809,000	\$33,471,000
Unit 2	B	Optimized SNCR + RRI	\$8,562,000	\$702,000	\$3,594,000	\$4,296,000
	A	Optimized SNCR	\$3,089,000	\$253,000	\$549,000	\$802,000

**Table 5-12. NO<sub>x</sub> Emissions Control System Cost Effectiveness (Annual Average)**

LOS Unit No.	Alt. No.	NO <sub>x</sub> Control Option	Total Annual Cost \$	Expected Emission Reduction (Note 2) tons NO <sub>x</sub> /yr	Average Annual Cost-Effectiveness (Note 2) \$/ton NO <sub>x</sub> removed	Incremental Annual Cost-Effectiveness (Note 1) \$/ton NO <sub>x</sub> removed
Unit 1	A	Selective catalytic reduction (SCR) – tail-end configuration	\$33,471,000	613	\$54,605	
Unit 2	B	Optimized SNCR + RRI (Note 3)	\$4,296,000	1,183	\$3,630	\$4,594
	A	Optimized SNCR (Note 3)	\$802,000	423	\$1,896	

Note 1. Incremental cost-effectiveness represents the incremental increase in annual costs (\$/yr) divided by the incremental increase in annual NO<sub>x</sub> emissions reductions (tons/yr) between a control option and the next most effective option.

Note 2. Expected emission reductions and average annual cost-effectiveness based on baseline NO<sub>x</sub> emission rate and capacity factor during baseline NO<sub>x</sub> period for each LOS Unit.

Note 3. Costs have not been included in this analysis for the subsequent loss in net generation or the cost to purchase replacement power. These costs would need to be included.

Table 5-12 indicates that the average annual cost effectiveness of the technically feasible NO<sub>x</sub> control option for Unit 1 is \$51,605 per ton (SCR – tail-end configuration); and for Unit 2 ranges from \$1,896 per ton to \$3,630 per ton NO<sub>x</sub> removed.

TE-SCR system costs have been included for Unit 1 to remain consistent with the approach used by NDDH during the initial planning period. Based on preliminary cost estimates, the cost effectiveness of a TE-SCR system is approximately \$54,600 per ton. The high cost is driven by the high capital expenses required for implementation with limited expected annual NO<sub>x</sub> reduction, due to a low baseline emission rate on Unit 1.

Optimization of the existing SNCR system on Unit 2 is expected to achieve approximately 10% NO<sub>x</sub> reduction from baseline emission rates. The cost effectiveness of this option is approximately \$1,900 per ton. The cost is driven by the increased urea consumption and the relocation costs. If RRI is included in addition to the optimization of the SNCR, the cost effectiveness of the combined option is approximately \$3,600 per ton, with a reduction of 26% from baseline emission rates. Compared to the optimized SNCR alone, the incremental cost effectiveness is approximately \$4,600 per ton. Major increase to urea consumption rates with RRI is the driver of the cost for this option. It should also be noted that an additional \$5.5 million is required for the RRI system implementation, which is ineffective while the unit is operating at low load. The facility is often dispatched at low load. Furthermore, the optimized SNCR and optimized SNCR + RRI options will also affect the units' net plant heat rate since the amount of water that will be injected with the urea will negatively impact boiler efficiency. Costs have not been included in this analysis, due to time constraints, for the subsequent loss in net generation which would increase the cost effectiveness of these two options. It would be expected that there would be a greater negative impact with the SNCR + RRI option. If requested, updated costs can be provided to NDDH.

### **5.3.2 NO<sub>x</sub> Potential-to-Emit Economic Evaluation**

Table 5-13 presents the capital costs and annual operating costs associated with building and operating each control system; annual operating costs are based on the units operating at 100% capacity factor. Table 5-14 shows the average annual and incremental cost effectiveness for each control system with emissions reductions and cost effectiveness values based on 100% capacity factors and potential-to-emit emission rates. Additional cost details are provided in Appendix D.

**Table 5-13. NO<sub>x</sub> Control Cost Summary (Projected Future Maximum)**

LOS Unit No.	Alt. No.	NO <sub>x</sub> Control Option	Total Capital Investment \$	Annual Capital Recovery Cost \$/yr	Annual Operating Cost <sup>(Note 1)</sup> \$/yr	Total Annual Cost \$/yr
Unit 1	A	Selective catalytic reduction (SCR) – tail-end configuration	\$227,717,000	\$18,662,000	\$15,722,000	\$34,384,000
Unit 2	B	Optimized SNCR + RRI	\$8,562,000	\$702,000	\$4,868,000	\$5,570,000
	A	Optimized SNCR	\$3,089,000	\$253,000	\$739,000	\$992,000

Note 1. Annual operating costs based on baseline NO<sub>x</sub> emissions and 100% capacity factor for each LOS

**Table 5-14. NO<sub>x</sub> Emissions Control System Cost Effectiveness (Projected Future Maximum)**

LOS Unit No.	Alt. No.	NO <sub>x</sub> Control Option	Total Annual Cost \$	Expected Emission Reduction tons NO <sub>x</sub> /yr	Average Annual Cost-Effectiveness <sup>(Note 2)</sup> \$/ton NO <sub>x</sub> removed	Incremental Annual Cost-Effectiveness <sup>(Note 1)</sup> \$/ton NO <sub>x</sub> removed
Unit 1	A	Selective catalytic reduction (SCR) – tail-end configuration	\$34,384,000	1,205	\$28,528	
Unit 2	B	Optimized SNCR + RRI	\$5,570,000	1,748	\$3,186	\$4,075
	A	Optimized SNCR	\$992,000	625	\$1,588	

Note 1. Incremental cost-effectiveness represents the incremental increase in annual costs (\$/yr) divided by the incremental increase in annual NO<sub>x</sub> emissions reductions (tons/yr) between a control option and the next most effective option.

Note 2. Expected emission reductions and average annual cost-effectiveness based on baseline NO<sub>x</sub> emissions and 100% capacity factor for each LOS Unit.

Table 5-14 indicates that the average annual cost effectiveness of the technically feasible NO<sub>x</sub> control option for Unit 1 is \$28,528 per ton (SCR – tail-end configuration); and for Unit 2 ranges from \$1,588 per ton to \$3,186 per ton NO<sub>x</sub> removed.

TE-SCR system costs have been included for Unit 1 to remain consistent with the approach used by NDDH during the initial planning period. Based on preliminary cost estimates, the cost effectiveness of a TE-SCR system is

approximately \$28,500 per ton. The high cost is driven by the high capital expenses required for implementation with limited expected annual NO<sub>x</sub> reduction, due to a low baseline emission rate on Unit 1.

Optimization of the existing SNCR system on Unit 2 is expected to achieve approximately 10% NO<sub>x</sub> reduction from baseline emission rates. The cost effectiveness of this option is approximately \$1,600 per ton. The cost is driven by the increased urea consumption and the relocation costs. If RRI is included in addition to the optimization of the SNCR, the cost effectiveness of the combined option is approximately \$3,200 per ton, with a reduction of 26% from baseline emission rates. Compared to the optimized SNCR alone, the incremental cost effectiveness is approximately \$4,000 per ton. Major increase to urea consumption rates with RRI is the driver of the cost for this option. It should also be noted that an additional \$5.5 million is required for the RRI system implementation, which is ineffective while the unit is operating at low load. The facility is often dispatched at low load. Furthermore, the optimized SNCR and optimized SNCR + RRI options will also affect the units' net plant heat rate since the amount of water that will be injected with the urea will negatively impact boiler efficiency. Costs have not been included in this analysis, due to time constraints, for the subsequent loss in net generation which would increase the cost effectiveness of these two options. It would be expected that there would be a greater negative impact with the SNCR + RRI option. If requested, updated costs can be provided to NDDH.

## 6. TIME NECESSARY FOR COMPLIANCE (STATUTORY FACTOR TWO)

The time necessary for compliance is generally defined as the time needed for full implementation of the technically feasible control options. This includes the time needed to develop and implement the regulations, as well as the time needed to install the selected control equipment. The time needed to install the control equipment includes time for equipment procurement, design, fabrication, and installation. Therefore, compliance deadlines must consider the time necessary for compliance by setting a compliance deadline that provides a reasonable amount of time for the source to implement the control measure. Basin Electric assumes a greater or equal amount of time would be provided as during the first planning phase, which was five years.

Table 6-1 and Table 6-2 include estimated timeframes needed to implement each of the technically feasible controls. The estimated timeframes do not account for time needed for North Dakota to develop and implement the regulations; therefore, the scheduled activities identified below commence immediately after SIP approval and are subject to the maintenance outage schedules of the individual unit.

**Table 6-1. SO<sub>2</sub> Emissions Control System Implementation Schedule**

LOS Unit No.	SO <sub>2</sub> Control Option	Alt No.	Design / Specification / Procurement (months)	Detail Design / Fabrication (months)	Construction / Commissioning / Startup / Training (months)	Compliance Date (months after SIP approval)
Unit 1	FGD Operational Improvements – Ca:S Stoichiometry (Note 1)	A	0	0	3	No later than 60 months
Unit 2	FGD Operational Improvements – Ca:S Stoichiometry and L/G Ratio (Note 1)	A	0	0	3	No later than 60 months
Unit 1 and 2	FGD Upgrades – pH Buffer Addition	B	4	4	4	No later than 60 months

Note 1. Although this option would not require design/fabrication and construction months, Basin Electric would need 2-3 months to update O&M manuals and personnel training for the change to the work practice of the existing WFGD systems.



NORTH DAKOTA ROUND II STATE IMPLEMENTATION PLAN  
 DETERMINATION'S FOUR-FACTOR ANALYSIS FOR LELAND OLDS  
 UNITS 1 AND 2

**6-2**
**Table 6-2. NO<sub>x</sub> Emissions Control System Implementation Schedule**

LOS Unit No.	NO <sub>x</sub> Control Option	Alt No.	Design / Specification / Procurement (months)	Detail Design / Fabrication (months)	Construction / Commissioning / Startup / Training (months)	Compliance Date (months after SIP approval)
Unit 2	Optimized SNCR	A	4	4	4	No later than 60 months
Unit 2	Optimized SNCR + RRI	B	6	6	4	No later than 60 months
Unit 1	Selective Catalytic Reduction (SCR) - Tail End Configuration	A	10	18	24	No later than 60 months

## **7. ENERGY AND NON-AIR QUALITY ENVIRONMENTAL IMPACTS (STATUTORY FACTOR THREE)**

The primary purpose of the environmental impact analysis is to assess collateral environmental impacts due to control of the regulated pollutant in question. Environmental impacts may include solid or hazardous waste generation, discharges of polluted water from a control device, visibility impacts, increased emissions of other criteria or non-criteria pollutants, increased water consumption, and land use impacts from waste disposal.

### **7.1 ENVIRONMENTAL IMPACTS**

LOS Unit 1 is currently equipped with combustion optimizer/LNB/OFA/SNCR for NO<sub>x</sub> control and WFGD for SO<sub>2</sub> control. LOS Unit 2 is equipped with combustion optimizer/SOFA/SNCR for NO<sub>x</sub> control and WFGD for SO<sub>2</sub> control. The limestone reactant used in a WFGD system reacts with SO<sub>2</sub> in the flue gas to form calcium sulfate and calcium sulfite solids. The solids are either recycled to the system for reuse or removed from the system as nonhazardous solid waste. The existing wet scrubbing system also requires water to slurry the limestone prior to injection into the absorber. Based on the design of the control system, LOS Unit 1 and 2 currently use approximately 75 gpm and 153 gpm of water, respectively to slurry the limestone (at full load). In addition the Unit 1 and 2 SNCR systems use approximately 9 and 30 gpm, of water, respectively to dilute the urea reagent before injection in the boiler. Collateral environmental impacts associated with the existing LOS Units 1 and 2 control systems include water consumption and increased solid waste generation. There were no collateral impacts associated with the LNB/SOFA/OFA systems.

Based on a review of potential non-air quality environmental impacts, no significant collateral environmental impacts were identified for any of the SO<sub>2</sub> and NO<sub>x</sub> control options included in this evaluation except for the TE-SCR option. The TE-SCR catalyst oxidizes some of the SO<sub>2</sub> to SO<sub>3</sub> in addition to catalyzing the reaction between NO<sub>x</sub> and ammonia. There could be the potential for increased SO<sub>3</sub> emissions with the use of a TE-SCR. The SO<sub>3</sub> will react with the moisture in the stack to form sulfuric acid emissions. In addition the TE-SCR options utilize ammonia as the reagent for the reactions with NO<sub>x</sub> to occur. There will be some ammonia slip emission from a TE-SCR in the range of 2 ppm. There is no means to capture the ammonia slip emissions from the TE-SCR since it would be installed downstream of the existing WFGD system. The implementation of the optimized SNCR can also increase ammonia emissions.

It is generally understood from previous visibility modeling efforts that increased ammonia injection has the opportunity of providing additional ammonia to the atmosphere. This increased ammonia availability within the emitted plume itself is known to contribute to increased visibility impairment due to more direct formation of ammonium sulfate and ammonium nitrate, more so in the winter months where fine particulate formation is ammonia limited.

## **7.2 ENERGY IMPACTS**

Options that include increasing the Ca:S ratio will increase the auxiliary power consumption due to increased recycle pump operation and the TE-SCR option will increase pressure drop through the control system, increasing auxiliary power requirements. Both of these options will adversely affect the unit's net plant heat rate (Btu heat input per MW<sub>Net</sub> output).<sup>51</sup> Consequently, heat input to the boiler would need to increase to compensate for the increased auxiliary power requirements while achieving the same net plant output, or net output from the unit would decrease. In addition, the optimized SNCR and optimized SNCR + RRI options will also affect the units' net plant heat rate since the amount of water that will be injected with the urea will negatively impact boiler efficiency. Costs have not been included in this analysis, due to time constraints, for the subsequent loss in net generation.

Although several of the control options have energy impacts, none of the impacts are considered significant enough as to disqualify any of the options from consideration in the four factor analysis. In order to account for potential energy impacts associated with each option, the auxiliary power cost associated with operating the control systems have been included as an annual operating cost in the economic impact assessment.

## **7.3 ENVIRONMENTAL / ENERGY IMPACTS SUMMARY**

A summary of the Statutory Factor 3 environmental and energy impact analysis is provided in Table 7-1.

---

<sup>51</sup> Heat rate represents the amount of heat input to the boiler (Btu) required to generate one megawatt (MW) net electric output and is reported as Btu/MW<sub>Net</sub>.

**Table 7-1. Summary of Energy and Non-Air Quality Environmental Impacts**

Control Option	Collateral Environmental & Energy Impacts
<b>Baseline</b>	<ul style="list-style-type: none"> <li>➤ LOS Units 1 and 2 are currently equipped with WFGD and SNCR control systems. Existing collateral environmental and energy impacts include:</li> <li>➤ Solid WFGD by-product management and disposal</li> <li>➤ Increased water consumption</li> <li>➤ Increased auxiliary power requirements and heat rate penalty</li> </ul>
<b><u>SO<sub>2</sub> Control Options</u></b>	
WFGD Operational Improvements	<ul style="list-style-type: none"> <li>➤ Increased water consumption</li> <li>➤ Increased solid by-product management and disposal</li> <li>➤ Increased auxiliary power requirements and heat rate penalty</li> </ul>
<b><u>NO<sub>x</sub> Control Options</u></b>	
Selective Catalytic Reduction (SCR) - Tail End Configuration	<ul style="list-style-type: none"> <li>➤ Increased auxiliary power requirements and heat rate penalty</li> <li>➤ Potential increase in ammonia slip emissions</li> <li>➤ Potential increase in SO<sub>3</sub> emissions</li> </ul>
Optimized SNCR or SNCR + RRI	<ul style="list-style-type: none"> <li>➤ Increased water consumption</li> <li>➤ Increased auxiliary power requirements and heat rate penalty</li> <li>➤ Potential increase in ammonia slip emissions</li> </ul>

## **8. REMAINING USEFUL LIFE (STATUTORY FACTOR FOUR)**

The evaluation of technically feasible NO<sub>x</sub> and SO<sub>2</sub> controls options should consider the source's "remaining useful life" in determining the costs of compliance. The remaining useful life is the difference between the date that controls would be put in place and the date that the facility permanently ceases operation. If the remaining useful life of the unit is shorter than the useful life of a particular control option, the remaining useful life should be used annualizing costs. If the remaining useful life exceeds the useful life of the control options, the remaining use life has no effect on the cost evaluation.

Under the current LOS resource plan, the remaining useful life of LOS Unit 1 and 2 is greater than 20 years. Therefore, the remaining useful life has no impact on the annualized cost of control under the current regulatory framework.

## 9. CONCLUSIONS

At the request of NDDH, a four factor analysis was prepared for LOS Units 1 and 2 for use in their Round II Determination. The analysis identified technically feasible SO<sub>2</sub> and NO<sub>x</sub> control options for the units, and evaluated each of the control measures for the following four statutory factors:

1. The costs of compliance;
2. The time necessary for compliance;
3. The energy and non-air quality environmental impacts of compliance; and
4. The remaining useful life of any potentially affected anthropogenic source of visibility impairment.

The cost of compliance evaluation (Statutory Factor 1) prepared for SO<sub>2</sub> controls indicates that, from baseline emission rates, the average annual cost effectiveness of the technically feasible SO<sub>2</sub> control options for Unit 1 ranges from \$10,021 per ton (Alternative A) to \$17,948 per ton SO<sub>2</sub> removed (Alternative B), and for Unit 2 ranges from \$6,906 per ton (Alternative A) to \$13,946 per ton SO<sub>2</sub> removed (Alternative B) from historical baselines. When evaluating projected future maximum emissions reductions, the average annual cost effectiveness of the technically feasible SO<sub>2</sub> control options for Unit 1 ranges from \$18,200 per ton (Alternative A) to \$18,948 per ton SO<sub>2</sub> removed (Alternative B), and for Unit 2 ranges from \$13,444 per ton (Alternative A) to \$15,462 per ton SO<sub>2</sub> removed (Alternative B).

The cost of compliance evaluation prepared for NO<sub>x</sub> controls indicates that, from baseline emission rates, the average annual cost effectiveness of the technically feasible NO<sub>x</sub> control options for Unit 1 is \$54,605 per ton NO<sub>x</sub> removed (Alternative A), and for Unit 2 ranges from \$1,896 per ton (Alternative A) to \$3,630 per ton NO<sub>x</sub> removed (Alternative B) from historical baselines. When evaluating projected future maximum emissions reductions, the average annual cost effectiveness of the technically feasible NO<sub>x</sub> control options for Unit 1 is \$28,528 per ton NO<sub>x</sub> removed (Alternative A), and for Unit 2 ranges from \$1,588 per ton (Alternative A) to \$3,186 per ton NO<sub>x</sub> removed (Alternative B). For Unit 2, Alternatives A and B will also affect the units' net plant heat rate since the amount of water that will be injected with the urea will negatively impact boiler efficiency. Both alternatives do not include additional costs that would be incurred due to the loss in net generation.

The time necessary for compliance (Statutory Factor 2) for the SO<sub>2</sub> control options ranges from 3 months (Alternative A) to 12 months (Alternative B). For NO<sub>x</sub> control options, the time necessary for compliance ranges from 12 months (Alternatives A and B – Unit 2) to 52 months (Alternative A – Unit 1).

An evaluation of energy impacts and non-air environmental impacts (Statutory Factor 3) indicates that certain control options will increase auxiliary power requirements due to increased pressure drop, which would adversely impact net plant heat rate. Consequently, heat input to the boiler would need to increase to compensate for the increased auxiliary power requirements while achieving the same net plant output, or net output from the unit would decrease. Collateral environmental impacts include potential increases in water consumption, solid waste generation, sulfuric acid mist emissions and ammonia emissions.

Regarding remaining useful life (Statutory Factor 4), under the current Basin Electric resource plan, the remaining useful life of LOS Units 1 and 2 are considered to be greater than 20 years. Therefore, the remaining useful life has no impact on the annualized cost of control under the current regulatory framework.

Based on the results of the four factor analysis prepared for LOS SO<sub>2</sub> emissions reductions, WFGD Operational Improvements and WFGD Upgrades are cost prohibitive. The control cost evaluation indicates that the average cost effectiveness levels exceed \$6,900 per ton SO<sub>2</sub> removed. Therefore, Basin Electric is proposing that the existing WFGD systems on Units 1 and 2 represent appropriate controls for the Round II Determination.

The four factor analysis prepared for LOS Units 1 indicates that additional NO<sub>x</sub> controls are cost prohibitive. The cost effectiveness of installing a TE-SCR system on Unit 1 is over \$28,000 per ton NO<sub>x</sub> removed. Therefore, Basin Electric is proposing that the existing LNB / SOFA / SNCR system on Unit 1 represents appropriate controls for the Round II Determination. For Unit 2, the analysis indicates a cost effectiveness of \$1,600 ton for the optimized SNCR alternative. The implementation of the optimized SNCR decreases the actual hourly mass emission rate by approximately 100 lb per hr (from historical baseline emissions). However, it can increase ammonia emissions, and that effect would result in additional haze formation. As such, a 5<sup>th</sup> factor analysis (visibility improvement using modeling) is recommended for this option to determine whether there is any or only a trivial amount of visibility improvement. Basin Electric requests that the NDDH withhold their Round II Determination until the Western Region Area Partnership's cumulative modeling platform are available so that a visibility improvement assessment can be conducted. Basin Electric will then perform a comparative visibility improvement analysis between the two control alternatives and submit the results to the NDDH for consideration.



It is generally understood from previous visibility modeling efforts that increased ammonia injection has the opportunity of providing additional ammonia to the atmosphere. This increased ammonia availability within the emitted plume itself is known to contribute to increased visibility impairment due to more direct formation of ammonium sulfate and ammonium nitrate, especially in the winter months where fine particulate formation is ammonia limited. In fact, it is during the winter months that the NO<sub>x</sub> emissions have a visibility effect; the observed (and modeled) nitrate haze during the warmer months with more park visitation is negligible. As a result of the future modeling analysis, the actual visibility benefit of the optimized SNCR alternative may be considered minimal if not de-minimis.

For the Round II Determination, no change to the current Title V Operating Permit is proposed for SO<sub>2</sub> emissions on either LOS Unit 1 or 2 and no proposed change to the NO<sub>x</sub> emissions on LOS Unit 1. Table ES-3 includes a summary of the proposed Round II Determination's strategy for NO<sub>x</sub>, assessed NO<sub>x</sub> emissions on a 30-day rolling average basis and a proposed Round II Determination's emission rate on a 30-day rolling average basis for LOS Unit 2. The proposed emissions limits include compliance margin to account for items such as variability in the operating load profile.

**Table 9-1. Proposed Round II Determination's NO<sub>x</sub> Emission Rate**

LOS Unit No.	Pollutant	Assessed Emission Rate lb/MMBtu <sup>(Note 2)</sup> (30-day rolling average)	Proposed Round II Emission Rate <sup>(Note 1)</sup> (30-day rolling average)	Control Technology
Unit 2	NO <sub>x</sub>	0.27	0.30	Optimized SNCR System

Note 1. The proposed Round II Determination's emission rate is a 14% reduction from the current permit limit of 0.35 lb NO<sub>x</sub>/MMBtu, 30-day rolling avg.

Note 2. The assessed emission rate represents the average emission rate that LOS Unit 2 would be expected to achieve on an on-going long-term basis under normal operating conditions.

## APPENDIX A

### NORTH DAKOTA DEPARTMENT OF HEALTH LETTER



May 2, 2018

**RECEIVED MAY 04 2018**

Mr. Mike Paul  
Basin Electric Power Coop.  
1717 E Interstate Avenue  
Bismarck, ND 58503-0564

Re: Regional Haze  
Second Planning Period

Dear Mr. Paul:

The Department of Health (Department) has begun work on the second planning period (Round 2) State Implementation Plan (SIP) for regional haze. In Round 1 of the regional planning process, the emphasis was on Best Available Retrofit Technology (BART) and making reasonable progress towards the national visibility goal. In Round 2, there are no BART requirements; therefore, we will focus on making reasonable progress. The reasonable progress analysis will be made using the four factors in Section 169A(g)(1) of the Clean Air Act:

The four factors are:

1. The cost of compliance
2. The time necessary to achieve compliance
3. The energy and non-air quality environmental impact of compliance; and
4. The remaining useful life of any existing source subject to such requirements

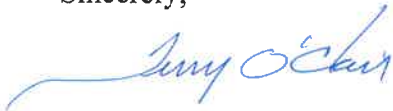
Guidance provided by the U.S. Environmental Protection Agency (Draft Guidance on Progress Tracking Metrics, Long Term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period at [https://www.epa.gov/sites/production/files/2016-07/documents/draft\\_regional\\_haze\\_guidance\\_july\\_2016.pdf](https://www.epa.gov/sites/production/files/2016-07/documents/draft_regional_haze_guidance_july_2016.pdf)) indicates the Department must address 80% of the visibility impairment caused by in-state sources. Data from the IMPROVE monitoring sites at Theodore Roosevelt National Park (TRNP) and Lostwood Wilderness Area (LWA) indicate that sulfates and nitrates continue to be the largest contributors to visibility impairment in these areas. The primary precursors of sulfates and nitrates are emissions of sulfur dioxide (SO<sub>2</sub>) and nitrogen oxides (NO<sub>x</sub>).

Coal-fired electrical generating units have been identified as one of the largest source of sulfur dioxide and nitrogen oxides in North Dakota. Therefore, the Department requests that you prepare a "four factors" analysis for your coal-fired electrical generating units. The analysis should be prepared using the draft EPA guidance noted above. The Department will identify other sources in North Dakota that will be required to submit a four factors analysis.

The Department will be working with the Western Regional Air Partnership (WRAP) to prepare the Round 2 SIP. WRAP will be conducting air quality modeling of regional emissions reductions in early 2019. The Department asks that your "four factors" analysis be submitted by January 31, 2019.

If you have any questions, please contact David Stroh of my staff at (701)328-5188.

Sincerely,

A handwritten signature in blue ink, reading "Terry O'Clair".

Terry L. O'Clair  
Director  
Division of Air Quality

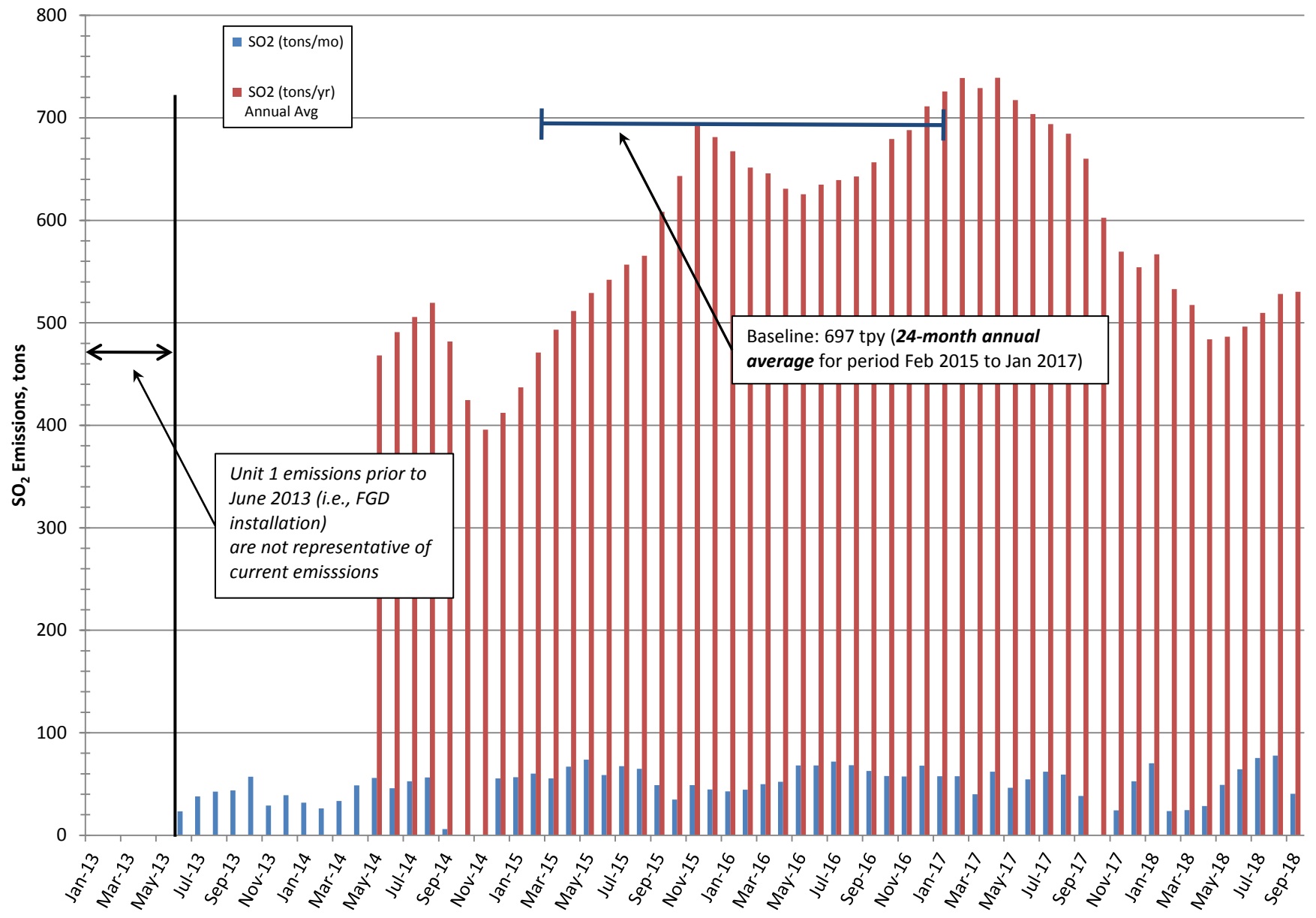
TLO/TB:saj

xc: Cris Miller, Basin Electric Power Coop.

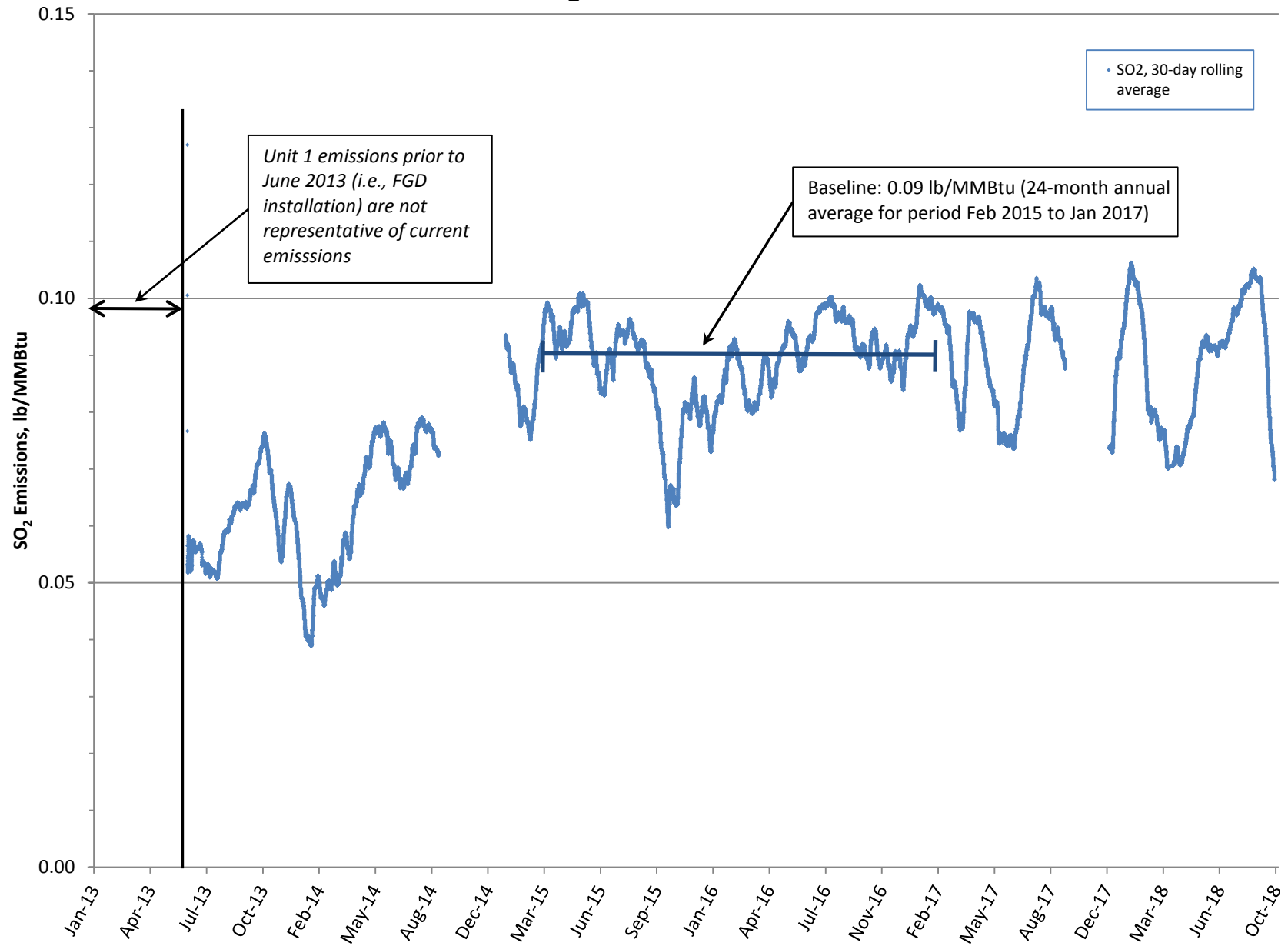
## APPENDIX B

### LELAND OLDS STATION UNITS 1 AND 2 BASELINE EMISSIONS

## LOS Unit 1 - Baseline SO<sub>2</sub> Emissions (tons) [1/2013 to 9/2018]

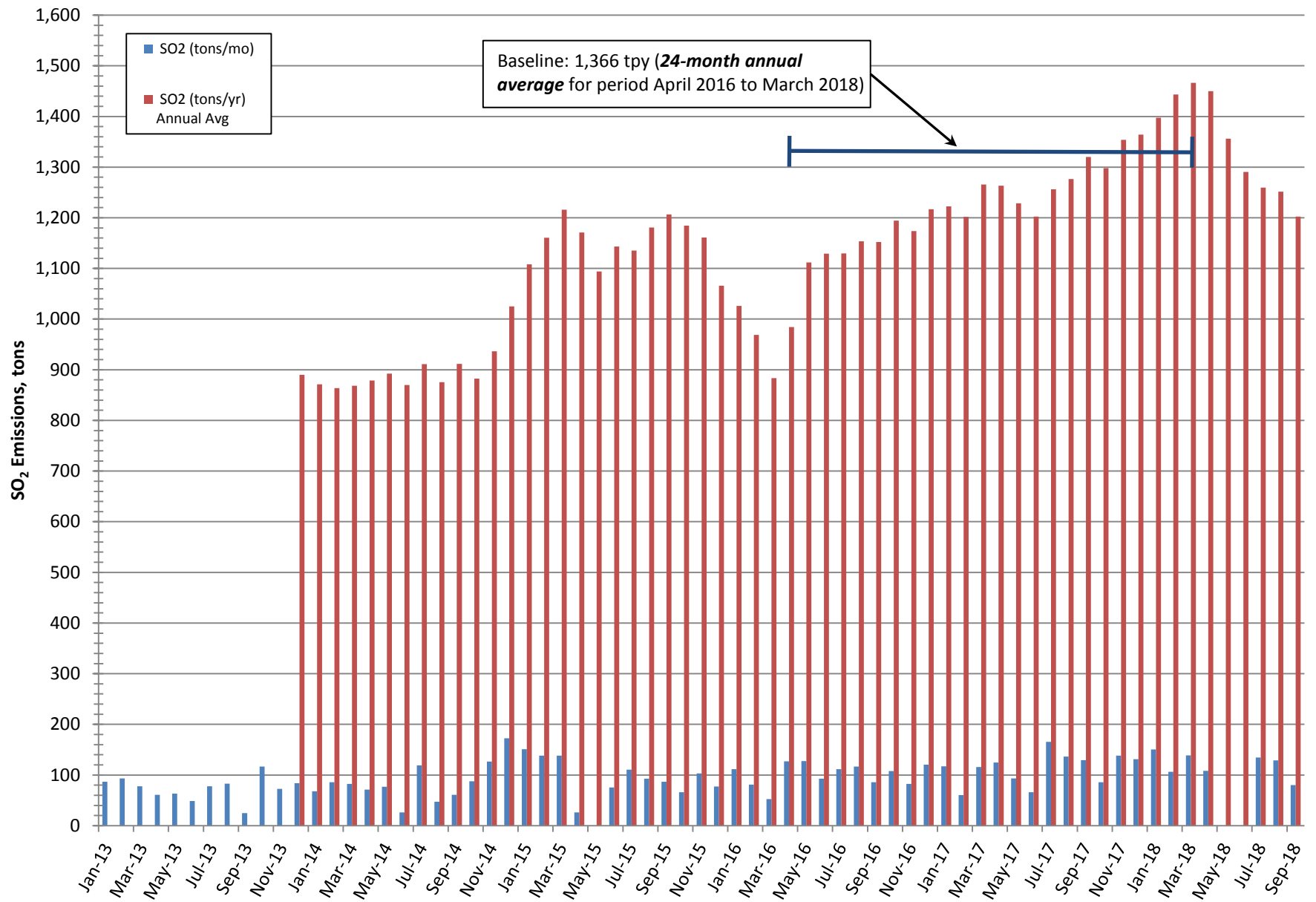


## LOS Unit 1 - Baseline SO<sub>2</sub> Emissions (lb/MMBtu) [1/2013 - 9/2018]

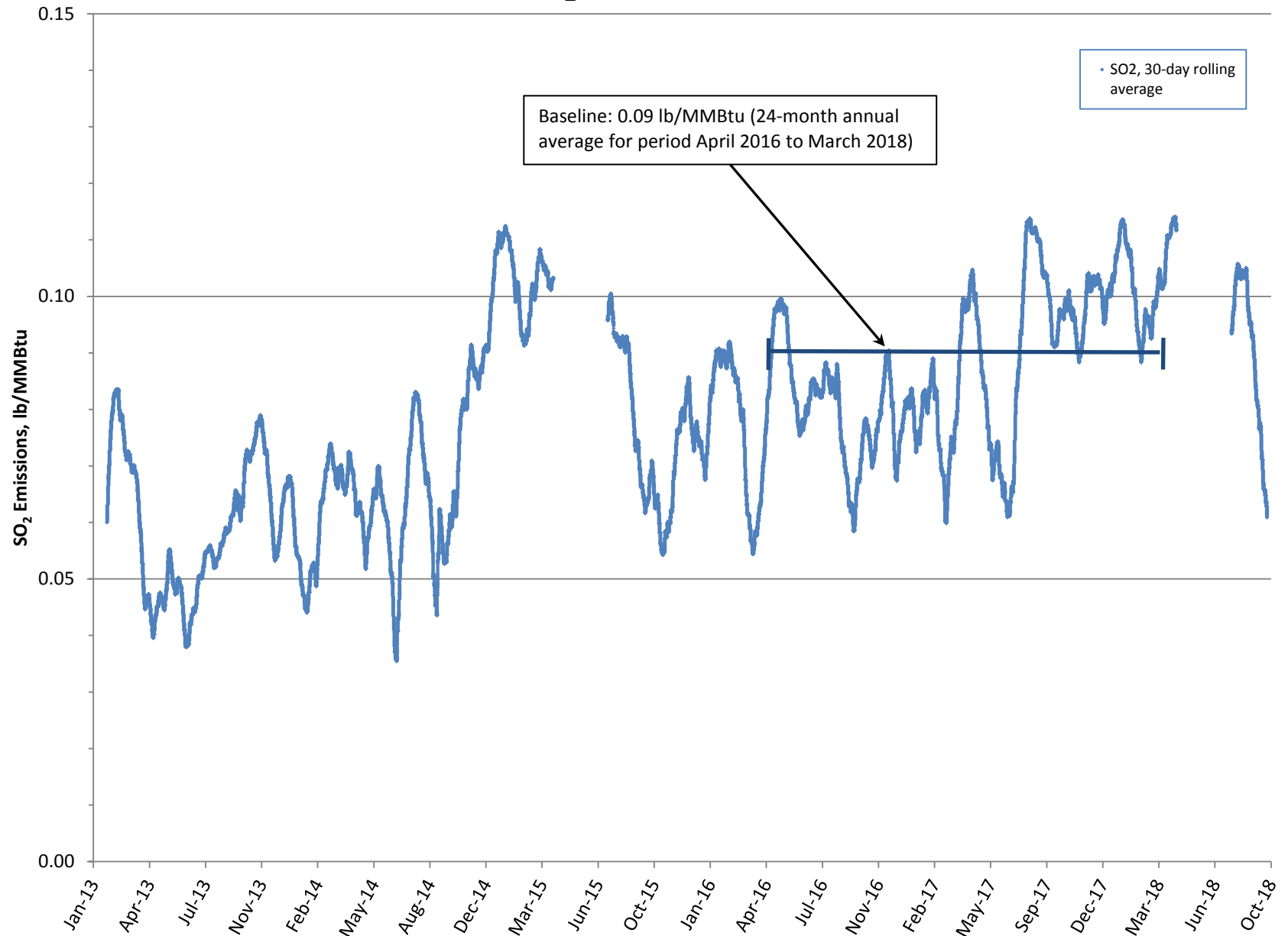




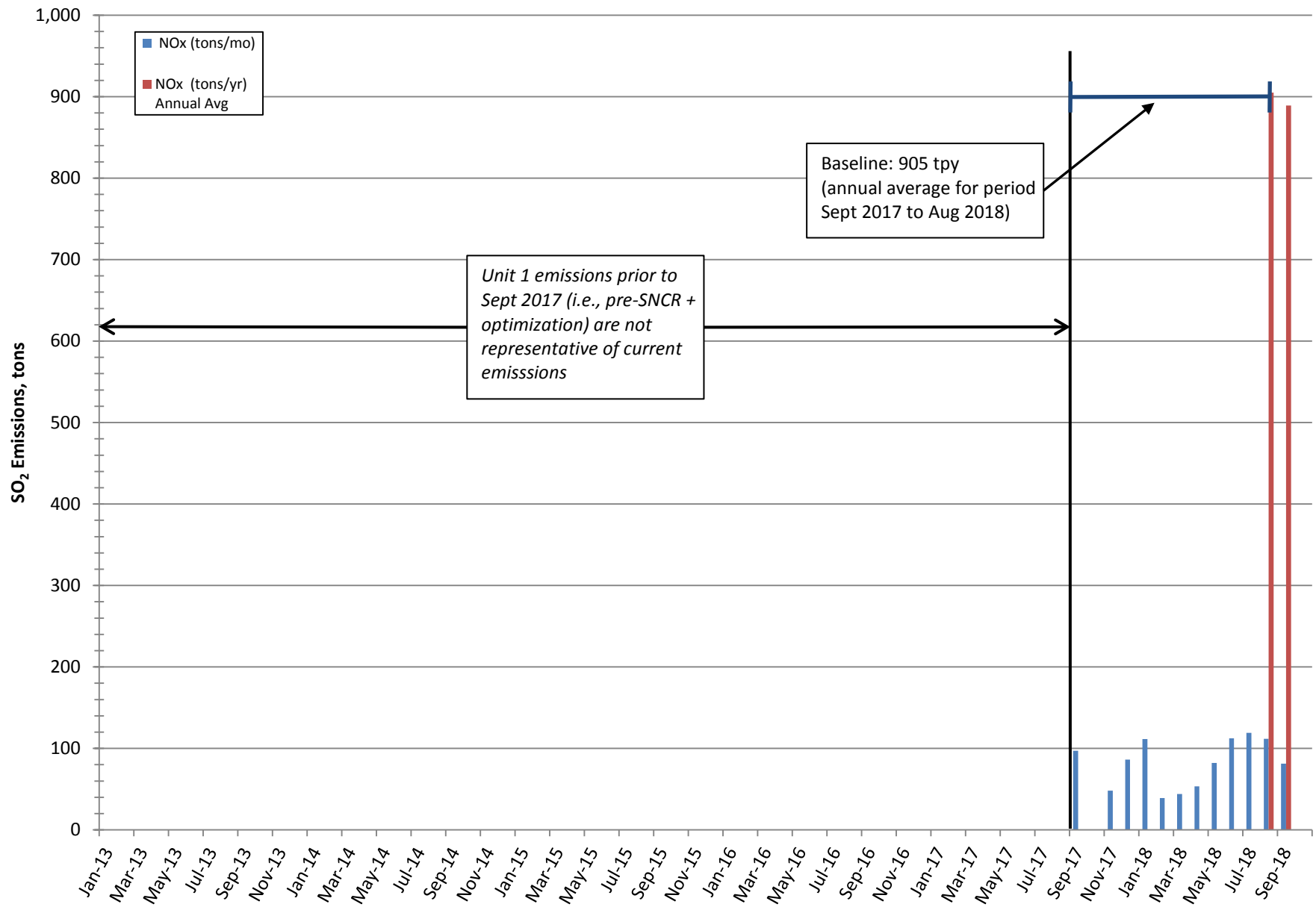
## LOS Unit 2 - Baseline SO<sub>2</sub> Emissions (tons) [1/2013 to 9/2018]



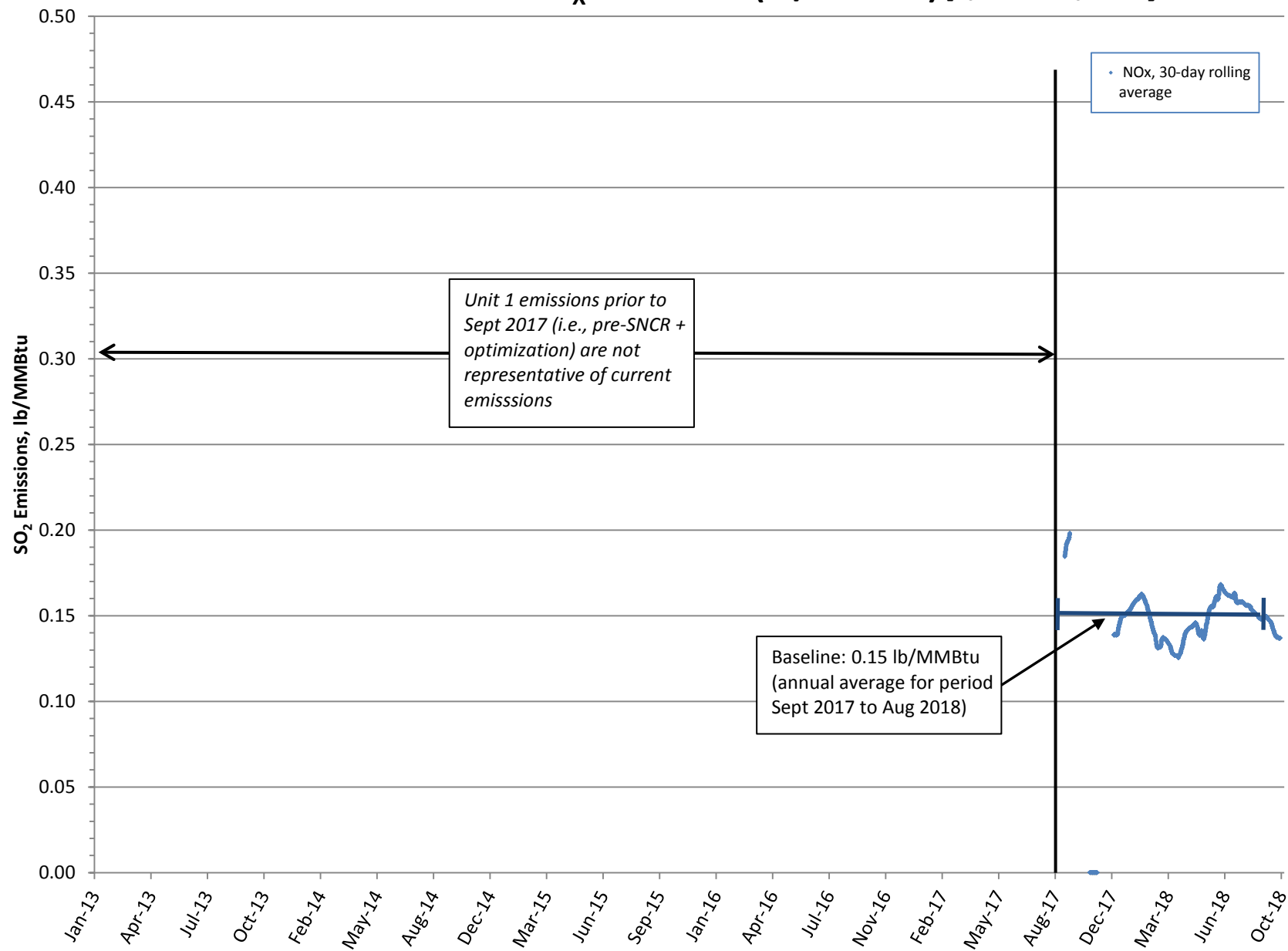
## LOS Unit 2 - Baseline SO<sub>2</sub> Emissions (lb/MMBtu) [1/2013 - 9/2018]



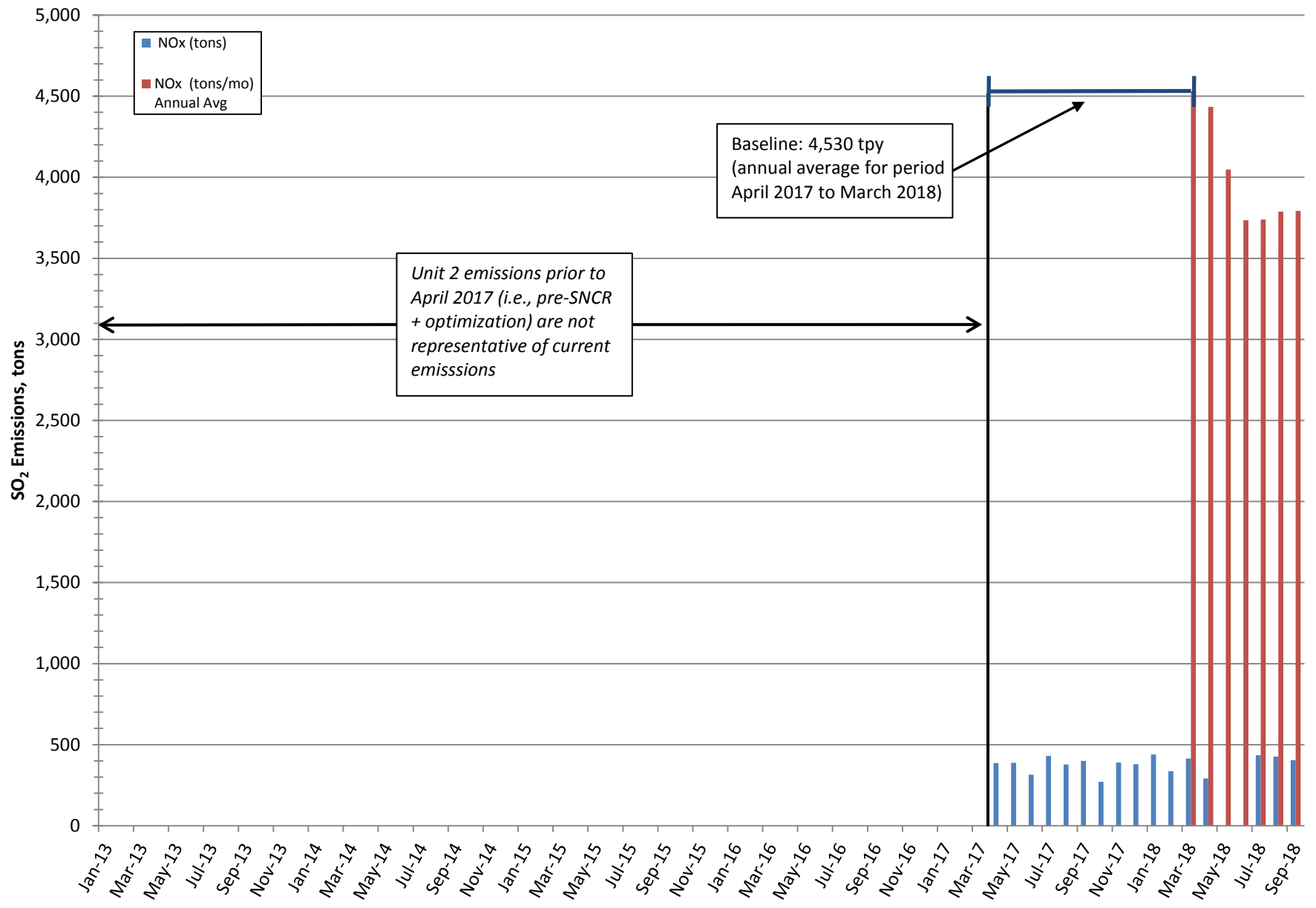
## LOS Unit 1 - Baseline NO<sub>x</sub> Emissions (tons) [1/2013 to 9/2018]



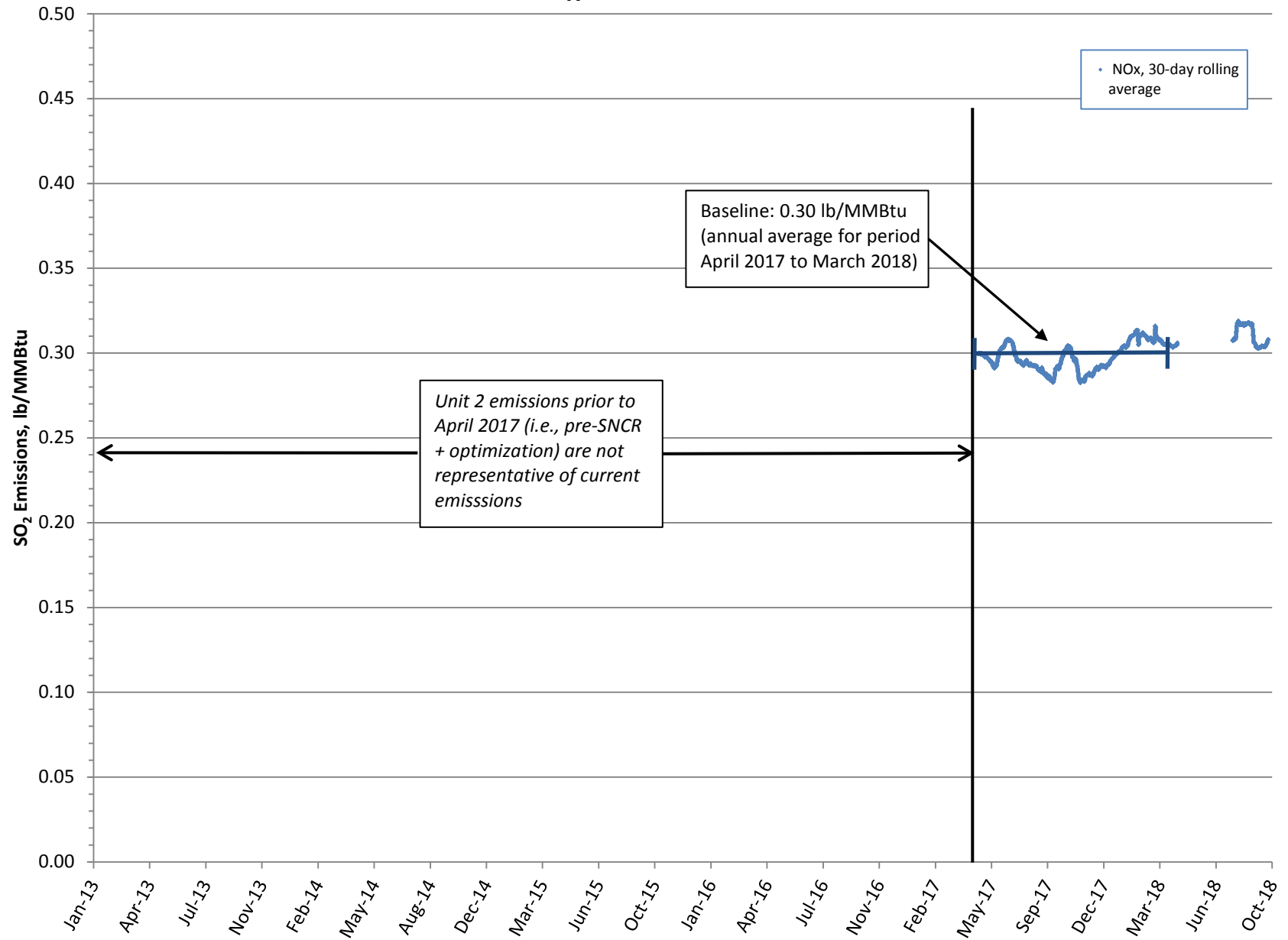
## LOS Unit 1 - Baseline NO<sub>x</sub> Emissions (lb/MMBtu) [1/2013 - 6/2018]



## LOS Unit 2 - Baseline NO<sub>x</sub> Emissions (tons) [1/2013 to 9/2018]



## LOS Unit 2 - Baseline NO<sub>x</sub> Emissions (lb/MMBtu) [1/2013 - 6/2018]



## APPENDIX C

### SO<sub>2</sub> CONTROL COST EFFECTIVENESS ESTIMATES



## SO<sub>2</sub> CONTROL COST EFFECTIVENESS ESTIMATES

### *BASILINE CAPACITY FACTORS/EMISSIONS AND PROJECTED ACTUAL EMISSION RATES*

Leland Olds Station Units 1 & 2  
SO<sub>2</sub> Control Summary

Table 1. LOS Units 1 & 2 Operating Parameters

Parameter	Units	Unit 1	Unit 2	Notes
Nominal Power Output	MW	220	440	
Annual Heat Input	MMBtu/yr	15,538,351	30,867,575	- Unit 1: 24-month annual average for period February 2015 to January 2017 - Unit 2: 24-month annual average for period April 2016 to March 2018
Annual Capacity Factor	%	68%	69%	- Capacity factor based on Design Hourly Heat Input (MMBtu/hr) and Annual Baseline Heat Input (MMBtu/yr)
Average Baseline Hourly Heat Input	MMBtu/hr	1,851	3,779	- Hourly emission rates based on Average Baseline Hourly Heat Input (MMBtu/hr)
Design Hourly Heat Input	MMBtu/hr	2,622	5,130	Permit No. T5-F73004

Table 2. SO<sub>2</sub> Control Effectiveness

Control Technology	Unit 1					Unit 2				
	Control Efficiency (%)	Expected Emissions (ton/year)	Emission Rate (lb/hr)	Emission Rate (lb/MMBtu)	Expected Emissions Reduction (ton/year)	Control Efficiency (%)	Expected Emissions (ton/year)	Emission Rate (lb/hr)	Emission Rate (lb/MMBtu)	Expected Emissions Reduction (ton/year)
FGD Upgrades - pH Buffer Addition	98.2%	427	102	0.055	269	98.4%	772	189	0.05	594
FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio and L/G Ratio						97.6%	1,158	283	0.075	208
FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio	97.4%	622	148	0.08	75					
Baseline (WFGD)	97.1%	697	166	0.09		97.2%	1,366	334	0.09	
Uncontrolled SO <sub>2</sub>		24,248	5,777	3.12			48,170	11,793	3.12	

Table 3. SO<sub>2</sub> Control Cost Effectiveness - Unit 1

Control Technology	Emissions (tpy)	Tons of SO <sub>2</sub> Removed (tpy)	Total Capital Requirement (\$)	Annualized Capital Cost (\$/year)	Annualized Outage Cost (\$/year)	Total Annual Operating Costs (\$/year)	Total Annual Costs (\$)	Average Cost Effectiveness (\$/ton)	Incremental Cost Effectiveness (\$/ton)
FGD Upgrades - pH Buffer Addition	427	269	\$8,266,000	\$677,000	\$0	\$4,156,000	\$4,833,000	\$17,948	\$21,011
FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio	622	75	\$0	\$0	\$0	\$752,000	\$752,000	\$10,021	
Baseline Unit 1 (WFGD)	697								

Table 4. SO<sub>2</sub> Control Cost Effectiveness - Unit 2

Control Technology	Emissions (tpy)	Tons of SO <sub>2</sub> Removed (tpy)	Total Capital Requirement (\$)	Annualized Capital Cost (\$/year)	Annualized Outage Cost (\$/year)	Total Annual Operating Costs (\$/year)	Total Annual Costs (\$)	Average Cost Effectiveness (\$/ton)	Incremental Cost Effectiveness (\$/ton)
FGD Upgrades - pH Buffer Addition	772	594	\$11,560,000	\$947,000		\$7,340,000	\$8,287,000	\$13,946	\$17,748
FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio and L/G Ratio	1,158	208	\$0	\$0		\$1,439,000	\$1,439,000	\$6,906	
Baseline Unit 2 (WFGD)	1,366								

LOS Units 1 and 2

SO<sub>2</sub> Control Cost Evaluation

FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio

SO <sub>2</sub> Control Option Description	FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio	
	Unit 1	Unit 2
Baseline SO <sub>2</sub> Emissions, lb/MMBtu	0.09	
Post Upgrade SO <sub>2</sub> Emissions, lb/MMBtu	0.00	
Capacity Factor used of Cost Estimates (%)	68%	

CAPITAL COSTS		Cost (2018\$)	Basis
	Unit 1	Unit 2	
<b>Direct Costs</b>			
<b>Purchased Equipment Costs (PEC)</b>			
Equipment and Materials	\$0		Based on Sargent & Lundy's conceptual cost estimating system.
Instrumentation	\$0		Included in equipment and materials cost
Sales Tax	\$0		5% of Equipment/Material Cost
Freight	\$0		5% of Equipment/Material Cost
Total PEC	\$0		
<b>Direct Installation Costs</b>			
Labor	\$0		Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding	\$0		2.5% of Labor
Mobilization / Demobilization	\$0		1.5% of Labor
Labor Cost Due To Overtime Inefficiency	\$0		5% of Labor
Total Direct Installation Costs	\$0		
Total Direct Costs (PEC + Direct Installation Costs)	\$0		
<b>Indirect Costs</b>			
Contractor's General and Administration Expense	\$0		10% of Total Direct Costs
Contractor's Profit	\$0		5% of Total Direct Costs
Engineering, Procurement, & Project Services	\$0		8% of Total Direct Costs
Construction Management/Field Engineering	\$0		4% of Total Direct Costs
S-U / Commissioning	\$0		1% of Total Direct Costs
Spare Parts	\$0		0.5% of Total Direct Costs
Owner's Cost	\$0		2% of Total Direct Costs
Total Indirect Costs	\$0		
Contingency	\$0		20% of Direct and Indirect Costs
Total Capital Investment (TCI)	\$0		sum of direct costs, indirect costs, and contingency
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$	0.0820		20 year life of equipment (years) @ 7% interest.
Annualized Capital Costs (CRF x TCI)	\$0		
<b>OPERATING COSTS</b>			
<b>Operating &amp; Maintenance Costs</b>			
<b>Variable O&amp;M Costs</b>			
Increased Waste Disposal Cost	\$148,000		Based on disposal rate of \$8.70 per ton.
Increased Limestone Cost	\$595,000		Based on limestone cost of \$57 per ton.
DBA Cost	\$0		Based on DBA cost of \$500 per ton.
Increased Auxiliary Power Cost	\$0		Based on auxiliary power cost of \$48.06 per MWh (Unit 1) and \$40.47 (Unit 2).
Increased Water Cost	\$9,000		Based on water cost of \$1.00 per 1000 gallons.
Total Variable O&M Costs	\$752,000		
<b>Fixed O&amp;M Costs</b>			
Additional Operators per shift	0		Assume no additional operators
Operating Labor	\$0		N/A
Supervisor Labor	\$0		N/A
Maintenance Materials	\$0		includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor	\$0		included in cost for maintenance materials.
Total Fixed O&M Cost	\$0		
<b>Indirect Operating Cost</b>			
Property Taxes	\$0		1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	\$0		1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	\$0		2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Total Indirect Operating Cost	\$0		
Total Annual Operating Cost	\$752,000		
<b>TOTAL ANNUAL COST</b>			
Annualized Capital Cost	\$0		
Annual Operating Cost	\$752,000		
Total Annual Cost	\$752,000		

LOS Units 1 and 2

SO<sub>2</sub> Control Cost Evaluation

FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio and L/G Ratio

SO <sub>2</sub> Control Option Description	FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio and L/G Ratio	
	Unit 1	Unit 2
Baseline SO <sub>2</sub> Emissions, lb/MMBtu		0.09
Post Upgrade SO <sub>2</sub> Emissions, lb/MMBtu		0.075
Capacity Factor used of Cost Estimates (%)		69%

CAPITAL COSTS		Cost (2018\$)		Basis
	Unit 1	Unit 2		
<b>Direct Costs</b>				
<b>Purchased Equipment Costs (PEC)</b>				
Equipment and Materials		\$0	Based on Sargent & Lundy's conceptual cost estimating system.	
Instrumentation		\$0	Included in equipment and materials cost	
Sales Tax		\$0	5% of Equipment/Material Cost	
Freight		\$0	5% of Equipment/Material Cost	
Total PEC		\$0		
<b>Direct Installation Costs</b>				
Labor		\$0	Based on Sargent & Lundy's conceptual cost estimating system.	
Scaffolding		\$0	2.5% of Labor	
Mobilization / Demobilization		\$0	1.5% of Labor	
Labor Cost Due To Overtime Inefficiency		\$0	5% of Labor	
Total Direct Installation Costs		\$0		
Total Direct Costs (PEC + Direct Installation Costs)		\$0		
<b>Indirect Costs</b>				
Contractor's General and Administration Expense		\$0	10% of Total Direct Costs	
Contractor's Profit		\$0	5% of Total Direct Costs	
Engineering, Procurement, & Project Services		\$0	8% of Total Direct Costs	
Construction Management/Field Engineering		\$0	4% of Total Direct Costs	
S-U / Commissioning		\$0	1% of Total Direct Costs	
Spare Parts		\$0	0.5% of Total Direct Costs	
Owner's Cost		\$0	2% of Total Direct Costs	
Total Indirect Costs		\$0		
Contingency		\$0	20% of Direct and Indirect Costs	
<b>Total Capital Investment (TCI)</b>				
		\$0	sum of direct costs, indirect costs, and contingency	
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$		0.0820	20 year life of equipment (years) @ 7% interest.	
Annualized Capital Costs (CRF x TCI)		\$0		
<b>OPERATING COSTS</b>				
<b>Operating &amp; Maintenance Costs</b>				
<b>Variable O&amp;M Costs</b>				
Increased Waste Disposal Cost		\$233,000	Based on disposal rate of \$8.70 per ton.	
Increased Limestone Cost		\$939,000	Based on limestone cost of \$57 per ton.	
DBA Cost		\$0	Based on DBA cost of \$500 per ton.	
Increased Auxiliary Power Cost		\$254,000	Based on auxiliary power cost of \$48.06 per MWh (Unit 1) and \$40.47 (Unit 2).	
Increased Water Cost		\$13,000	Based on water cost of \$1.00 per 1000 gallons.	
Total Variable O&M Costs		\$1,439,000		
<b>Fixed O&amp;M Costs</b>				
Additional Operators per shift		0	Assume no additional operators	
Operating Labor		\$0	N/A	
Supervisor Labor		\$0	N/A	
Maintenance Materials		\$0	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs	
Maintenance Labor		\$0	Included in cost for maintenance materials.	
Total Fixed O&M Cost		\$0		
<b>Indirect Operating Cost</b>				
Property Taxes		\$0	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.	
Insurance		\$0	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.	
Administration		\$0	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.	
Total Indirect Operating Cost		\$0		
Total Annual Operating Cost		\$1,439,000		
<b>TOTAL ANNUAL COST</b>				
Annualized Capital Cost		\$0		
Annual Operating Cost		\$1,439,000		
Total Annual Cost		\$1,439,000		

LOS Units 1 and 2  
SO<sub>2</sub> Control Cost Evaluation  
FGD Upgrades - pH Buffer Addition

SO <sub>2</sub> Control Option Description	FGD Upgrades - pH Buffer Addition	
	Unit 1	Unit 2
Baseline SO <sub>2</sub> Emissions, lb/MMBtu	0.09	0.09
Post Upgrade SO <sub>2</sub> Emissions, lb/MMBtu	0.06	0.05
Capacity Factor used of Cost Estimates (%)	68%	69%

CAPITAL COSTS		Cost (2018\$)		Basis	
		Unit 1	Unit 2		
Direct Costs					
Purchased Equipment Costs (PEC)					
Equipment and Materials	\$2,878,000	\$4,027,000	Based on Sargent & Lundy's conceptual cost estimating system. Included in equipment and materials cost 5% of Equipment/Material Cost 5% of Equipment/Material Cost		
Instrumentation	\$0	\$0			
Sales Tax	\$144,000	\$201,000			
Freight	\$144,000	\$201,000			
Total PEC	\$3,166,000	\$4,429,000			
Direct Installation Costs					
Labor	\$1,919,000	\$2,684,000	Based on Sargent & Lundy's conceptual cost estimating system. 2.5% of Labor 1.5% of Labor 5% of Labor		
Scaffolding	\$48,000	\$67,000			
Mobilization / Demobilization	\$29,000	\$40,000			
Labor Cost Due To Overtime Inefficiency	\$96,000	\$134,000			
Total Direct Installation Costs	\$2,092,000	\$2,925,000			
Total Direct Costs (PEC + Direct Installation Costs)	\$5,258,000	\$7,354,000			
Indirect Costs					
Contractor's General and Administration Expense	\$526,000	\$735,000	10% of Total Direct Costs		
Contractor's Profit	\$263,000	\$368,000	5% of Total Direct Costs		
Engineering, Procurement, & Project Services	\$421,000	\$588,000	8% of Total Direct Costs		
Construction Management/Field Engineering	\$210,000	\$294,000	4% of Total Direct Costs		
S-U / Commissioning	\$79,000	\$110,000	1.5% of Total Direct Costs		
Spare Parts	\$26,000	\$37,000	0.5% of Total Direct Costs		
Owner's Cost	\$105,000	\$147,000	2% of Total Direct Costs		
Total Indirect Costs	\$1,630,000	\$2,279,000			
Contingency	\$1,378,000	\$1,927,000	20% of Direct and Indirect Costs		
Total Capital Investment (TCI)	\$8,266,000	\$11,560,000	sum of direct capital costs, indirect capital costs, and contingency		
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$	0.0820	0.0820	20 year life of equipment (years) @ 7% interest.		
Annualized Capital Costs (CRF x TCI)	\$677,000	\$947,000			
OPERATING COSTS					
Operating & Maintenance Costs					
Variable O&M Costs					
Increased Waste Disposal Cost	\$154,000	\$245,000	Based on disposal rate of \$8.70 per ton. Based on limestone cost of \$57 per ton. Based on DBA cost of \$500 per ton. Based on auxiliary power cost of \$48.06 per MWh (Unit 1) and \$40.47 (Unit 2). Based on water cost of \$1.00 per 1000 gallons.		
Increased Limestone Cost	\$620,000	\$989,000			
DBA Cost	\$2,963,000	\$5,265,000			
Increased Auxiliary Power Cost	\$0	\$254,000			
Increased Water Cost	\$9,000	\$14,000			
Total Variable O&M Costs	\$3,746,000	\$6,767,000			
Fixed O&M Costs					
Additional Operators per shift	0	0	Assume no additional operators		
Operating Labor	\$0	\$0	N/A		
Supervisor Labor	\$0	\$0	N/A		
Maintenance Materials	\$79,000	\$110,000	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs		
Maintenance Labor	\$0	\$0	Included in cost for maintenance materials.		
Total Fixed O&M Cost	\$79,000	\$110,000			
Indirect Operating Cost					
Property Taxes	\$83,000	\$116,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.		
Insurance	\$83,000	\$116,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.		
Administration	\$165,000	\$231,000	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.		
Total Indirect Operating Cost	\$331,000	\$463,000			
Total Annual Operating Cost	\$4,156,000	\$7,340,000			
TOTAL ANNUAL COST					
Annualized Capital Cost	\$677,000	\$947,000			
Annual Operating Cost	\$4,156,000	\$7,340,000			
Total Annual Cost	\$4,833,000	\$8,287,000			

## SO<sub>2</sub> CONTROL COST EFFECTIVENESS ESTIMATES

### *100% CAPACITY FACTOR AND PROJECTED FUTURE MAXIMUM EMISSION RATES*

**Leland Olds Station Units 1 & 2  
SO<sub>2</sub> Control Summary**

**Table 1. LOS Units 1 & 2 Operating Parameters**

Parameter	Units	Unit 1	Unit 2	Notes
Nominal Power Output	MW	220	440	
Annual Heat Input	MMBtu/yr	22,968,720	44,938,800	- Unit 1: 24-month annual average for period February 2015 to January 2017 - Unit 2: 24-month annual average for period April 2016 to March 2018
Annual Capacity Factor	%	100%	100%	
Hourly Heat Input	MMBtu/hr	2,622	5,130	Permit No. T5-F73004

**Table 2. SO<sub>2</sub> Control Effectiveness**

Control Technology	Unit 1					Unit 2				
	Control Efficiency	Expected Emissions	Emission Rate	Emission Rate	Expected Emissions Reduction	Control Efficiency	Expected Emissions	Emission Rate	Emission Rate	Expected Emissions Reduction
	(%)	(ton/year)	(lb/hr)	(lb/MMBtu)	(ton/year)	(%)	(ton/year)	(lb/hr)	(lb/MMBtu)	(ton/year)
FGD Upgrades - pH Buffer Addition	98.5%	632	144	0.055	398	98.7%	1,123	257	0.05	865
FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio and L/G Ratio						98.0%	1,685	385	0.075	303
FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio	97.9%	919	210	0.08	111					
Baseline (WFGD)	97.6%	1,030	235	0.09		97.6%	1,989	454	0.09	
Uncontrolled SO <sub>2</sub>		42,838	9,780	3.73			83,813	19,135	3.73	

**Table 3. SO<sub>2</sub> Control Cost Effectiveness - Unit 1**

Control Technology	Emissions	Tons of SO <sub>2</sub> Removed	Total Capital Requirement	Annualized Capital Cost	Annualized Outage Cost	Total Annual Operating Costs	Total Annual Costs	Average Cost Effectiveness	Incremental Cost Effectiveness
	(tpy)	(tpy)	(\$)	(\$/year)	(\$/year)	(\$/year)	(\$)	(\$/ton)	(\$/ton)
FGD Upgrades - pH Buffer Addition	632	398	\$8,266,000	\$677,000	\$0	\$6,865,000	\$7,542,000	<b>\$18,948</b>	\$19,237
FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio	919	111	\$0	\$0	\$0	\$2,019,000	\$2,019,000	<b>\$18,200</b>	
Baseline Unit 1 (WFGD)	1,030								

**Table 4. SO<sub>2</sub> Control Cost Effectiveness - Unit 2**

Control Technology	Emissions	Tons of SO <sub>2</sub> Removed	Total Capital Requirement	Annualized Capital Cost	Annualized Outage Cost	Total Annual Operating Costs	Total Annual Costs	Average Cost Effectiveness	Incremental Cost Effectiveness
	(tpy)	(tpy)	(\$)	(\$/year)	(\$/year)	(\$/year)	(\$)	(\$/ton)	(\$/ton)
FGD Upgrades - pH Buffer Addition	1,123	865	\$11,560,000	\$947,000		\$12,429,000	\$13,376,000	<b>\$15,462</b>	\$16,552
FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio and L/G Ratio	1,685	303	\$0	\$0		\$4,078,000	\$4,078,000	<b>\$13,444</b>	
Baseline Unit 2 (WFGD)	1,989								



LOS Units 1 and 2

SO<sub>2</sub> Control Cost Evaluation

FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio

SO <sub>2</sub> Control Option Description	FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio	
	Unit 1	Unit 2
Baseline SO <sub>2</sub> Emissions, lb/MMBtu	0.09	
Post Upgrade SO <sub>2</sub> Emissions, lb/MMBtu	0.00	
Capacity Factor used of Cost Estimates (%)	100%	

CAPITAL COSTS		Cost (2018\$)	Basis
	Unit 1	Unit 2	
<b>Direct Costs</b>			
<b>Purchased Equipment Costs (PEC)</b>			
Equipment and Materials	\$0		Based on Sargent & Lundy's conceptual cost estimating system.
Instrumentation	\$0		Included in equipment and materials cost
Sales Tax	\$0		5% of Equipment/Material Cost
Freight	\$0		5% of Equipment/Material Cost
Total PEC	\$0		
<b>Direct Installation Costs</b>			
Labor	\$0		Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding	\$0		2.5% of Labor
Mobilization / Demobilization	\$0		1.5% of Labor
Labor Cost Due To Overtime Inefficiency	\$0		5% of Labor
Total Direct Installation Costs	\$0		
Total Direct Costs (PEC + Direct Installation Costs)	\$0		
<b>Indirect Costs</b>			
Contractor's General and Administration Expense	\$0		10% of Total Direct Costs
Contractor's Profit	\$0		5% of Total Direct Costs
Engineering, Procurement, & Project Services	\$0		8% of Total Direct Costs
Construction Management/Field Engineering	\$0		4% of Total Direct Costs
S-U / Commissioning	\$0		1% of Total Direct Costs
Spare Parts	\$0		0.5% of Total Direct Costs
Owner's Cost	\$0		2% of Total Direct Costs
Total Indirect Costs	\$0		
Contingency	\$0		20% of Direct and Indirect Costs
Total Capital Investment (TCI)	\$0		sum of direct costs, indirect costs, and contingency
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$	0.0820		20 year life of equipment (years) @ 7% interest.
Annualized Capital Costs (CRF x TCI)	\$0		
<b>OPERATING COSTS</b>			
<b>Operating &amp; Maintenance Costs</b>			
<b>Variable O&amp;M Costs</b>			
Increased Waste Disposal Cost	\$397,000		Based on disposal rate of \$8.70 per ton.
Increased Limestone Cost	\$1,599,000		Based on limestone cost of \$57 per ton.
DBA Cost	\$0		Based on DBA cost of \$500 per ton.
Increased Auxiliary Power Cost	\$0		Based on auxiliary power cost of \$48.06 per MWh (Unit 1) and \$40.47 (Unit 2).
Increased Water Cost	\$23,000		Based on water cost of \$1.00 per 1000 gallons.
Total Variable O&M Costs	\$2,019,000		
<b>Fixed O&amp;M Costs</b>			
Additional Operators per shift	0		Assume no additional operators
Operating Labor	\$0		N/A
Supervisor Labor	\$0		N/A
Maintenance Materials	\$0		includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor	\$0		included in cost for maintenance materials.
Total Fixed O&M Cost	\$0		
<b>Indirect Operating Cost</b>			
Property Taxes	\$0		1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	\$0		1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	\$0		2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Total Indirect Operating Cost	\$0		
Total Annual Operating Cost	\$2,019,000		
<b>TOTAL ANNUAL COST</b>			
Annualized Capital Cost	\$0		
Annual Operating Cost	\$2,019,000		
Total Annual Cost	\$2,019,000		

LOS Units 1 and 2

SO<sub>2</sub> Control Cost Evaluation

FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio and L/G Ratio

SO <sub>2</sub> Control Option Description	FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio and L/G Ratio	
	Unit 1	Unit 2
Baseline SO <sub>2</sub> Emissions, lb/MMBtu		0.09
Post Upgrade SO <sub>2</sub> Emissions, lb/MMBtu		0.075
Capacity Factor used of Cost Estimates (%)		100%

CAPITAL COSTS		Cost (2018\$)		Basis
		Unit 1	Unit 2	
<b>Direct Costs</b>				
<b>Purchased Equipment Costs (PEC)</b>				
Equipment and Materials			\$0	Based on Sargent & Lundy's conceptual cost estimating system.
Instrumentation			\$0	Included in equipment and materials cost
Sales Tax			\$0	5% of Equipment/Material Cost
Freight			\$0	5% of Equipment/Material Cost
Total PEC			\$0	
<b>Direct Installation Costs</b>				
Labor			\$0	Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding			\$0	2.5% of Labor
Mobilization / Demobilization			\$0	1.5% of Labor
Labor Cost Due To Overtime Inefficiency			\$0	5% of Labor
Total Direct Installation Costs			\$0	
Total Direct Costs (PEC + Direct Installation Costs)			\$0	
<b>Indirect Costs</b>				
Contractor's General and Administration Expense			\$0	10% of Total Direct Costs
Contractor's Profit			\$0	5% of Total Direct Costs
Engineering, Procurement, & Project Services			\$0	8% of Total Direct Costs
Construction Management/Field Engineering			\$0	4% of Total Direct Costs
S-U / Commissioning			\$0	1% of Total Direct Costs
Spare Parts			\$0	0.5% of Total Direct Costs
Owner's Cost			\$0	2% of Total Direct Costs
Total Indirect Costs			\$0	
Contingency			\$0	20% of Direct and Indirect Costs
Total Capital Investment (TCI)			\$0	sum of direct costs, indirect costs, and contingency
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$			0.0820	20 year life of equipment (years) @ 7% interest.
Annualized Capital Costs (CRF x TCI)			\$0	
<b>OPERATING COSTS</b>				
<b>Operating &amp; Maintenance Costs</b>				
<b>Variable O&amp;M Costs</b>				
Increased Waste Disposal Cost			\$729,000	Based on disposal rate of \$8.70 per ton.
Increased Limestone Cost			\$2,938,000	Based on limestone cost of \$57 per ton.
DBA Cost			\$0	Based on DBA cost of \$500 per ton.
Increased Auxiliary Power Cost			\$370,000	Based on auxiliary power cost of \$48.06 per MWh (Unit 1) and \$40.47 (Unit 2).
Increased Water Cost			\$41,000	Based on water cost of \$1.00 per 1000 gallons.
Total Variable O&M Costs			\$4,078,000	
<b>Fixed O&amp;M Costs</b>				
Additional Operators per shift			0	Assume no additional operators
Operating Labor			\$0	N/A
Supervisor Labor			\$0	N/A
Maintenance Materials			\$0	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor			\$0	Included in cost for maintenance materials.
Total Fixed O&M Cost			\$0	
<b>Indirect Operating Cost</b>				
Property Taxes			\$0	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance			\$0	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration			\$0	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Total Indirect Operating Cost			\$0	
Total Annual Operating Cost			\$4,078,000	
<b>TOTAL ANNUAL COST</b>				
Annualized Capital Cost			\$0	
Annual Operating Cost			\$4,078,000	
Total Annual Cost			\$4,078,000	

LOS Units 1 and 2  
SO<sub>2</sub> Control Cost Evaluation  
FGD Upgrades - pH Buffer Addition

SO <sub>2</sub> Control Option Description	FGD Upgrades - pH Buffer Addition	
	Unit 1	Unit 2
Baseline SO <sub>2</sub> Emissions, lb/MMBtu	0.09	0.09
Post Upgrade SO <sub>2</sub> Emissions, lb/MMBtu	0.06	0.05
Capacity Factor used of Cost Estimates (%)	100%	100%

CAPITAL COSTS		Cost (2018\$)		Basis	
		Unit 1	Unit 2		
Direct Costs					
Purchased Equipment Costs (PEC)					
Equipment and Materials	\$2,878,000	\$4,027,000		Based on Sargent & Lundy's conceptual cost estimating system.	
Instrumentation	\$0	\$0		Included in equipment and materials cost	
Sales Tax	\$144,000	\$201,000		5% of Equipment/Material Cost	
Freight	\$144,000	\$201,000		5% of Equipment/Material Cost	
Total PEC	\$3,166,000	\$4,429,000			
Direct Installation Costs					
Labor	\$1,919,000	\$2,684,000		Based on Sargent & Lundy's conceptual cost estimating system.	
Scaffolding	\$48,000	\$67,000		2.5% of Labor	
Mobilization / Demobilization	\$29,000	\$40,000		1.5% of Labor	
Labor Cost Due To Overtime Inefficiency	\$96,000	\$134,000		5% of Labor	
Total Direct Installation Costs	\$2,092,000	\$2,925,000			
Total Direct Costs (PEC + Direct Installation Costs)	\$5,258,000	\$7,354,000			
Indirect Costs					
Contractor's General and Administration Expense	\$526,000	\$735,000		10% of Total Direct Costs	
Contractor's Profit	\$263,000	\$368,000		5% of Total Direct Costs	
Engineering, Procurement, & Project Services	\$421,000	\$588,000		8% of Total Direct Costs	
Construction Management/Field Engineering	\$210,000	\$294,000		4% of Total Direct Costs	
S-U / Commissioning	\$79,000	\$110,000		1.5% of Total Direct Costs	
Spare Parts	\$26,000	\$37,000		0.5% of Total Direct Costs	
Owner's Cost	\$105,000	\$147,000		2% of Total Direct Costs	
Total Indirect Costs	\$1,630,000	\$2,279,000			
Contingency	\$1,378,000	\$1,927,000		20% of Direct and Indirect Costs	
Total Capital Investment (TCI)	\$8,266,000	\$11,560,000		sum of direct capital costs, indirect capital costs, and contingency	
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$	0.0820	0.0820		20 year life of equipment (years) @ 7% interest.	
Annualized Capital Costs (CRF x TCI)	\$677,000	\$947,000			
OPERATING COSTS					
Operating & Maintenance Costs					
Variable O&M Costs					
Increased Waste Disposal Cost	\$408,000	\$751,000		Based on disposal rate of \$8.70 per ton.	
Increased Limestone Cost	\$1,644,000	\$3,027,000		Based on limestone cost of \$57 per ton.	
DBA Cost	\$4,380,000	\$7,665,000		Based on DBA cost of \$500 per ton.	
Increased Auxiliary Power Cost	\$0	\$370,000		Based on auxiliary power cost of \$48.06 per MWh (Unit 1) and \$40.47 (Unit 2).	
Increased Water Cost	\$23,000	\$43,000		Based on water cost of \$1.00 per 1000 gallons.	
Total Variable O&M Costs	\$6,455,000	\$11,856,000			
Fixed O&M Costs					
Additional Operators per shift	0	0		Assume no additional operators	
Operating Labor	\$0	\$0		N/A	
Supervisor Labor	\$0	\$0		N/A	
Maintenance Materials	\$79,000	\$110,000		Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs	
Maintenance Labor	\$0	\$0		Included in cost for maintenance materials.	
Total Fixed O&M Cost	\$79,000	\$110,000			
Indirect Operating Cost					
Property Taxes	\$83,000	\$116,000		1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.	
Insurance	\$83,000	\$116,000		1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.	
Administration	\$165,000	\$231,000		2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.	
Total Indirect Operating Cost	\$331,000	\$463,000			
Total Annual Operating Cost	\$6,865,000	\$12,429,000			
TOTAL ANNUAL COST					
Annualized Capital Cost	\$677,000	\$947,000			
Annual Operating Cost	\$6,865,000	\$12,429,000			
Total Annual Cost	\$7,542,000	\$13,376,000			

## APPENDIX D

### NO<sub>x</sub> CONTROL COST EFFECTIVENESS ESTIMATES

## NO<sub>x</sub> CONTROL COST EFFECTIVENESS ESTIMATES

### *BASILINE CAPACITY FACTORS/EMISSIONS AND PROJECTED ACTUAL EMISSION RATES*

**Leland Olds Station Units 1 & 2  
NO<sub>x</sub> Control Summary**

**Table 1. LOS Units 1 & 2 Operating Parameters**

Parameter	Units	Unit 1	Unit 2	Notes
Nominal Power Output	MW	220	440	
Annual Heat Input	MMBtu/yr	11,681,110	30,419,273	- Unit 1: Annual average for period July 2017 to June 2018 - Unit 2: Annual average for period April 2017 to March 2018
Annual Capacity Factor	%	51%	68%	- Capacity factor based on Design Hourly Heat Input (MMBtu/hr) and Annual Baseline Heat Input (MMBtu/yr)
Average Baseline Hourly Heat Input	MMBtu/hr	1,646	3,692	- Hourly emission rates based on Average Baseline Hourly Heat Input (MMBtu/hr)
Design Hourly Heat Input	MMBtu/hr	2,622	5,130	Permit No. T5-F73004

**Table 2. NO<sub>x</sub> Control Effectiveness**

Control Technology	Unit 1					Unit 2				
	Control Efficiency (%)	Expected Emissions (ton/year)	Emission Rate (lb/hr)	Emission Rate (lb/MMBtu)	Expected Emissions Reduction (ton/year)	Control Efficiency (%)	Expected Emissions (ton/year)	Emission Rate (lb/hr)	Emission Rate (lb/MMBtu)	Expected Emissions Reduction (ton/year)
SCR - Tail-End Configuration	82.8%	292	82	0.05	613					
SNCR Optimization + RRI						67.2%	3,346	812	0.22	1,183
SNCR Optimization						59.7%	4,107	997	0.27	423
Baseline (Unit 1: LNB/ASOFA/SNCR, Unit 2: ASOFA/SNCR)	46.6%	905	255	0.15		55.6%	4,530	1,099	0.30	
Uncontrolled NO <sub>x</sub>		1,694	477	0.29			10,190	2,473	0.67	

**Table 3. NO<sub>x</sub> Control Cost Effectiveness - Unit 1**

Control Technology	Emissions (tpy)	Tons of SO <sub>2</sub> Removed (tpy)	Total Capital Requirement (\$)	Annualized Capital Cost (\$/year)	Annualized Outage Cost (\$/year)	Total Annual Operating Costs (\$/year)	Total Annual Costs (\$)	Average Cost Effectiveness (\$/ton)	Incremental Cost Effectiveness (\$/ton)
SCR - Tail-End Configuration	292	613	\$227,717,000	\$18,662,000	\$0	\$14,809,000	\$33,471,000	\$54,605	
Baseline Unit 1	905								

**Table 4. NO<sub>x</sub> Control Cost Effectiveness - Unit 2**

Control Technology	Emissions (tpy)	Tons of SO <sub>2</sub> Removed (tpy)	Total Capital Requirement (\$)	Annualized Capital Cost (\$/year)	Annualized Outage Cost (\$/year)	Total Annual Operating Costs (\$/year)	Total Annual Costs (\$)	Average Cost Effectiveness (\$/ton)	Incremental Cost Effectiveness (\$/ton)
SNCR Optimization + RRI	3,346	1,183	\$8,562,000	\$702,000	\$0	\$3,594,000	\$4,296,000	\$3,630	\$4,594
SNCR Optimization	4,107	423	\$3,089,000	\$253,000	\$0	\$549,000	\$802,000	\$1,896	
Baseline Unit 2	4,530								

LOS Units 1 and 2  
NO<sub>x</sub> Control Cost Evaluation  
SNCR Optimization

NO <sub>x</sub> Control Option Description	SNCR Optimization	
	Unit 1	Unit 2
Baseline NO <sub>x</sub> Emissions, lb/MMBtu		0.30
Post Upgrade NO <sub>x</sub> Emissions, lb/MMBtu		0.27
Capacity Factor used of Cost Estimates (%)		68%

CAPITAL COSTS	Cost (2018\$)		Basis
	Unit 1	Unit 2	
<b>Direct Costs</b>			
<b>Purchased Equipment Costs (PEC)</b>			
Equipment and Materials		\$1,147,000	Based on Sargent & Lundy's conceptual cost estimating system.
Instrumentation		\$0	Included in equipment and materials cost
Sales Tax		\$57,000	5% of Equipment/Material Cost
Freight		\$57,000	5% of Equipment/Material Cost
<b>Total PEC</b>		\$1,261,000	
<b>Direct Installation Costs</b>			
Labor		\$646,000	Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding		\$16,000	2.5% of Labor
Mobilization / Demobilization		\$10,000	1.5% of Labor
Labor Cost Due To Overtime Inefficiency		\$32,000	5% of Labor
<b>Total Direct Installation Costs</b>		\$704,000	
<b>Total Direct Costs (PEC + Direct Installation Costs)</b>		<b>\$1,965,000</b>	
<b>Indirect Costs</b>			
Contractor's General and Administration Expense		\$197,000	10% of Total Direct Costs
Contractor's Profit		\$98,000	5% of Total Direct Costs
Engineering, Procurement, & Project Services		\$157,000	8% of Total Direct Costs
Construction Management/Field Engineering		\$79,000	4% of Total Direct Costs
S-U / Commissioning		\$29,000	1.5% of Total Direct Costs
Spare Parts		\$10,000	0.5% of Total Direct Costs
Owner's Cost		\$39,000	2% of Total Direct Costs
<b>Total Indirect Costs</b>		<b>\$609,000</b>	
Contingency		<b>\$515,000</b>	20% of Direct and Indirect Costs
<b>Total Capital Investment (TCI)</b>		<b>\$3,089,000</b>	sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$		0.0820	20 year life of equipment (years) @ 8% interest.
<b>Annualized Capital Costs (CRF x TCI)</b>		<b>\$253,000</b>	
<b>OPERATING COSTS</b>			<b>Basis</b>
<b>Operating &amp; Maintenance Costs</b>			
<b>Variable O&amp;M Costs</b>			
Dry Urea Reagent Cost		\$369,000	Based on dry urea reagent cost of \$354 per ton.
Ammonia Reagent Cost		\$0	Based on ammonia reagent cost of \$700 per ton.
Water Cost		\$8,000	Based on water cost of \$1.47 per 1,000 gallons.
Steam Cost		\$17,000	Based on steam cost of \$1.06 per MMBtu.
Hydrated Lime Cost		\$0	Based on hydrated lime cost of \$150 per ton.
Catalyst Replacement Cost		\$0	Based on catalyst cost of \$8,000 per m <sup>3</sup> and catalyst replacement cost of \$1,000 per m <sup>3</sup> .
Auxiliary Power Cost		\$2,000	Based on auxiliary power cost of \$48.06 per MWh (Unit 1) and \$40.47 (Unit 2).
<b>Total Variable O&amp;M Costs</b>		\$396,000	
<b>Fixed O&amp;M Costs</b>			
Additional Operators per shift		0	
Operating Labor		\$0	Assume \$49.5/hr for each additional operator
Supervisor Labor		\$0	N/A
Maintenance Materials		\$29,500	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor		\$0	Included in cost for maintenance materials.
<b>Total Fixed O&amp;M Cost</b>		\$29,500	
<b>Indirect Operating Cost</b>			
Property Taxes		\$30,900	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance		\$30,900	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration		\$61,800	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
<b>Total Indirect Operating Cost</b>		\$123,600	
<b>Total Annual Operating Cost</b>		<b>\$549,000</b>	
<b>TOTAL ANNUAL COST</b>			
Annualized Capital Cost		\$253,000	
Annual Operating Cost		\$549,000	
<b>Total Annual Cost</b>		<b>\$802,000</b>	



LOS Units 1 and 2  
NO<sub>x</sub> Control Cost Evaluation  
SNCR Optimization + RRI

NO <sub>x</sub> Control Option Description	SNCR Optimization + RRI	
	Unit 1	Unit 2
Baseline NO <sub>x</sub> Emissions, lb/MMBtu		0.30
Post Upgrade NO <sub>x</sub> Emissions, lb/MMBtu		0.22
Capacity Factor used of Cost Estimates (%)		68%

CAPITAL COSTS	Cost (2018\$)		Basis
	Unit 1	Unit 2	
<b>Direct Costs</b>			
<b>Purchased Equipment Costs (PEC)</b>			
Equipment and Materials		\$3,324,000	Based on Sargent & Lundy's conceptual cost estimating system.
Instrumentation		\$0	Included in equipment and materials cost
Sales Tax		\$166,000	5% of Equipment/Material Cost
Freight		\$166,000	5% of Equipment/Material Cost
<b>Total PEC</b>		\$3,656,000	
<b>Direct Installation Costs</b>			
Labor		\$1,642,000	Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding		\$41,000	2.5% of Labor
Mobilization / Demobilization		\$25,000	1.5% of Labor
Labor Cost Due To Overtime Inefficiency		\$82,000	5% of Labor
<b>Total Direct Installation Costs</b>		\$1,790,000	
<b>Total Direct Costs (PEC + Direct Installation Costs)</b>		<b>\$5,446,000</b>	
<b>Indirect Costs</b>			
Contractor's General and Administration Expense		\$545,000	10% of Total Direct Costs
Contractor's Profit		\$272,000	5% of Total Direct Costs
Engineering, Procurement, & Project Services		\$436,000	8% of Total Direct Costs
Construction Management/Field Engineering		\$218,000	4% of Total Direct Costs
S-U / Commissioning		\$82,000	1.5% of Total Direct Costs
Spare Parts		\$27,000	0.5% of Total Direct Costs
Owner's Cost		\$109,000	2% of Total Direct Costs
<b>Total Indirect Costs</b>		<b>\$1,689,000</b>	
Contingency		<b>\$1,427,000</b>	20% of Direct and Indirect Costs
<b>Total Capital Investment (TCI)</b>		<b>\$8,562,000</b>	sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$		0.0820	20 year life of equipment (years) @ 8% interest.
<b>Annualized Capital Costs (CRF x TCI)</b>		<b>\$702,000</b>	
<b>OPERATING COSTS</b>			<b>Basis</b>
<b>Operating &amp; Maintenance Costs</b>			
<b>Variable O&amp;M Costs</b>			
Dry Urea Reagent Cost		\$2,490,000	Based on dry urea reagent cost of \$354 per ton.
Ammonia Reagent Cost		\$0	Based on ammonia reagent cost of \$700 per ton.
Water Cost		\$57,000	Based on water cost of \$1.47 per 1,000 gallons.
Steam Cost		\$111,000	Based on steam cost of \$1.06 per MMBtu.
Hydrated Lime Cost		\$0	Based on hydrated lime cost of \$150 per ton.
Catalyst Replacement Cost		\$0	Based on catalyst cost of \$8,000 per m <sup>3</sup> and catalyst replacement cost of \$1,000 per m <sup>3</sup> .
Auxiliary Power Cost		\$12,000	Based on auxiliary power cost of \$48.06 per MWh (Unit 1) and \$40.47 (Unit 2).
<b>Total Variable O&amp;M Costs</b>		\$2,670,000	
<b>Fixed O&amp;M Costs</b>			
Additional Operators per shift		1	
Operating Labor		\$434,000	Assume \$49.5/hr for each additional operator
Supervisor Labor		\$65,000	N/A
Maintenance Materials		\$82,000	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor		\$0	Included in cost for maintenance materials.
<b>Total Fixed O&amp;M Cost</b>		\$581,000	
<b>Indirect Operating Cost</b>			
Property Taxes		\$86,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance		\$86,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration		\$171,000	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
<b>Total Indirect Operating Cost</b>		\$343,000	
<b>Total Annual Operating Cost</b>		<b>\$3,594,000</b>	
<b>TOTAL ANNUAL COST</b>			
Annualized Capital Cost		\$702,000	
Annual Operating Cost		\$3,594,000	
<b>Total Annual Cost</b>		<b>\$4,296,000</b>	

LOS Units 1 and 2  
NO<sub>x</sub> Control Cost Evaluation  
SCR - Tail-End Configuration

NO <sub>x</sub> Control Option Description	SCR - Tail-End Configuration	
	Unit 1	Unit 2
Baseline NO <sub>x</sub> Emissions, lb/MMBtu	0.15	0.30
Post Upgrade NO <sub>x</sub> Emissions, lb/MMBtu	0.05	0.05
Capacity Factor used of Cost Estimates (%)	51%	68%

CAPITAL COSTS		Cost (2018\$)	Basis
	Unit 1	Unit 2	
Direct Costs			
Purchased Equipment Costs (PEC)			
Equipment and Materials	\$76,672,000		Based on Sargent & Lundy's conceptual cost estimating system.
Instrumentation	\$0		Included in equipment and materials cost
Sales Tax	\$3,834,000		5% of Equipment/Material Cost
Freight	\$3,834,000		5% of Equipment/Material Cost
Total PEC	\$84,340,000		
Direct Installation Costs			
Labor	\$55,521,000		Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding	\$1,388,000		2.5% of Labor
Mobilization / Demobilization	\$833,000		1.5% of Labor
Labor Cost Due To Overtime Inefficiency	\$2,776,000		5% of Labor
Total Direct Installation Costs	\$60,518,000		
Total Direct Costs (PEC + Direct Installation Costs)	\$144,858,000		
Indirect Costs			
Contractor's General and Administration Expense	\$14,486,000		10% of Total Direct Costs
Contractor's Profit	\$7,243,000		5% of Total Direct Costs
Engineering, Procurement, & Project Services	\$11,589,000		8% of Total Direct Costs
Construction Management/Field Engineering	\$5,794,000		4% of Total Direct Costs
S-U / Commissioning	\$2,173,000		1.5% of Total Direct Costs
Spare Parts	\$724,000		0.5% of Total Direct Costs
Owner's Cost	\$2,897,000		2% of Total Direct Costs
Total Indirect Costs	\$44,906,000		
Contingency	\$37,953,000		20% of Direct and Indirect Costs
Total Capital Investment (TCI)	\$227,717,000		sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$	0.0820		20 year life of equipment (years) @ 8% interest.
Annualized Capital Costs (CRF x TCI)	\$18,662,000		
OPERATING COSTS			
Operating & Maintenance Costs			
Variable O&M Costs			
Dry Urea Reagent Cost	-\$274,000		Based on dry urea reagent cost of \$354 per ton.
Ammonia Reagent Cost	\$242,000		Based on ammonia reagent cost of \$700 per ton.
RO Water Cost	-\$3,000		Based on water cost of \$1.47 per 1,000 gallons.
Steam Cost	\$181,000		Based on steam cost of \$1.06 per MMBtu.
Hydrated Lime Cost	\$97,000		Based on hydrated lime cost of \$150 per ton.
Catalyst Replacement and Disposal Cost	\$2,081,000		Based on catalyst cost of \$8,000 per m <sup>3</sup> and catalyst replacement cost of \$1,000 per m <sup>3</sup> .
Auxiliary Power Cost	\$705,000		Based on auxiliary power cost of \$48.06 per MWh (Unit 1) and \$40.47 (Unit 2).
Total Variable O&M Costs	\$3,029,000		
Fixed O&M Costs			
Additional Operators per Shift	1		
Operating Labor	\$434,000		Assume \$49.5/hr for each additional operator
Supervisor Labor	\$65,000		15% of Operating Labor. EPA Cost Manual Section 1, Chapter 2, page 2-31.
Maintenance Materials	\$2,173,000		Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor	\$0		Included in cost for maintenance materials.
Total Fixed O&M Cost	\$2,672,000		
Indirect Operating Cost			
Property Taxes	\$2,277,000		1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	\$2,277,000		1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	\$4,554,000		2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Total Indirect Operating Cost	\$9,108,000		
Total Annual Operating Cost	\$14,809,000		
TOTAL ANNUAL COST			
Annualized Capital Cost	\$18,662,000		
Annual Operating Cost	\$14,809,000		
Total Annual Cost	\$33,471,000		

## NO<sub>x</sub> CONTROL COST EFFECTIVENESS ESTIMATES

### *100% CAPACITY FACTOR AND PROJECTED FUTURE MAXIMUM EMISSION RATES*

**Leland Olds Station Units 1 & 2  
NO<sub>x</sub> Control Summary**

**Table 1. LOS Units 1 & 2 Operating Parameters**

Parameter	Units	Unit 1	Unit 2	Notes
Nominal Power Output	MW	220	440	
Annual Heat Input	MMBtu/yr	22,968,720	44,938,800	- Unit 1: Annual average for period July 2017 to June 2018 - Unit 2: Annual average for period April 2017 to March 2018
Annual Capacity Factor	%	100%	100%	
Hourly Heat Input	MMBtu/hr	2,622	5,130	Permit No. T5-F73004

**Table 2. NO<sub>x</sub> Control Effectiveness**

Control Technology	Unit 1					Unit 2				
	Control Efficiency	Expected Emissions	Emission Rate	Emission Rate	Expected Emissions Reduction	Control Efficiency	Expected Emissions	Emission Rate	Emission Rate	Expected Emissions Reduction
	(%)	(ton/year)	(lb/hr)	(lb/MMBtu)	(ton/year)	(%)	(ton/year)	(lb/hr)	(lb/MMBtu)	(ton/year)
SCR - Tail-End Configuration	82.8%	574	131	0.05	1,205					
SNCR Optimization + RRI						67.2%	4,943	1,129	0.22	1,748
SNCR Optimization						59.7%	6,067	1,385	0.27	625
Baseline (Unit 1: LNB/ASOFA/SNCR, Unit 2: ASOFA/SNCR)	46.6%	1,779	406	0.15		55.6%	6,692	1,528	0.30	
Uncontrolled NO <sub>x</sub>		3,330	760	0.29			15,054	2,473	0.67	

**Table 3. NO<sub>x</sub> Control Cost Effectiveness - Unit 1**

Control Technology	Emissions	Tons of SO <sub>2</sub> Removed	Total Capital Requirement	Annualized Capital Cost	Annualized Outage Cost	Total Annual Operating Costs	Total Annual Costs	Average Cost Effectiveness	Incremental Cost Effectiveness
	(tpy)	(tpy)	(\$)	(\$/year)	(\$/year)	(\$/year)	(\$)	(\$/ton)	(\$/ton)
SCR - Tail-End Configuration	574	1,205	\$227,717,000	\$18,662,000	\$0	\$15,722,000	\$34,384,000	\$28,528	
Baseline Unit 1	1,779								

**Table 4. NO<sub>x</sub> Control Cost Effectiveness - Unit 2**

Control Technology	Emissions	Tons of SO <sub>2</sub> Removed	Total Capital Requirement	Annualized Capital Cost	Annualized Outage Cost	Total Annual Operating Costs	Total Annual Costs	Average Cost Effectiveness	Incremental Cost Effectiveness
	(tpy)	(tpy)	(\$)	(\$/year)	(\$/year)	(\$/year)	(\$)	(\$/ton)	(\$/ton)
SNCR Optimization + RRI	4,943	1,748	\$8,562,000	\$702,000	\$0	\$4,868,000	\$5,570,000	\$3,186	\$4,075
SNCR Optimization	6,067	625	\$3,089,000	\$253,000	\$0	\$739,000	\$992,000	\$1,588	
Baseline Unit 2	6,692								

LOS Units 1 and 2  
NO<sub>x</sub> Control Cost Evaluation  
SNCR Optimization

NO <sub>x</sub> Control Option Description	SNCR Optimization	
	Unit 1	Unit 2
Baseline NO <sub>x</sub> Emissions, lb/MMBtu		0.30
Post Upgrade NO <sub>x</sub> Emissions, lb/MMBtu		0.27
Capacity Factor used of Cost Estimates (%)		100%

CAPITAL COSTS	Cost (2018\$)		Basis
	Unit 1	Unit 2	
<b>Direct Costs</b>			
<b>Purchased Equipment Costs (PEC)</b>			
Equipment and Materials		\$1,147,000	Based on Sargent & Lundy's conceptual cost estimating system.
Instrumentation		\$0	Included in equipment and materials cost
Sales Tax		\$57,000	5% of Equipment/Material Cost
Freight		\$57,000	5% of Equipment/Material Cost
<b>Total PEC</b>		\$1,261,000	
<b>Direct Installation Costs</b>			
Labor		\$646,000	Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding		\$16,000	2.5% of Labor
Mobilization / Demobilization		\$10,000	1.5% of Labor
Labor Cost Due To Overtime Inefficiency		\$32,000	5% of Labor
<b>Total Direct Installation Costs</b>		\$704,000	
<b>Total Direct Costs (PEC + Direct Installation Costs)</b>		<b>\$1,965,000</b>	
<b>Indirect Costs</b>			
Contractor's General and Administration Expense		\$197,000	10% of Total Direct Costs
Contractor's Profit		\$98,000	5% of Total Direct Costs
Engineering, Procurement, & Project Services		\$157,000	8% of Total Direct Costs
Construction Management/Field Engineering		\$79,000	4% of Total Direct Costs
S-U / Commissioning		\$29,000	1.5% of Total Direct Costs
Spare Parts		\$10,000	0.5% of Total Direct Costs
Owner's Cost		\$39,000	2% of Total Direct Costs
<b>Total Indirect Costs</b>		<b>\$609,000</b>	
Contingency		\$515,000	20% of Direct and Indirect Costs
<b>Total Capital Investment (TCI)</b>		<b>\$3,089,000</b>	sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$		0.0820	20 year life of equipment (years) @ 8% interest.
<b>Annualized Capital Costs (CRF x TCI)</b>		<b>\$253,000</b>	
<b>OPERATING COSTS</b>			<b>Basis</b>
<b>Operating &amp; Maintenance Costs</b>			
<b>Variable O&amp;M Costs</b>			
Dry Urea Reagent Cost		\$546,000	Based on dry urea reagent cost of \$354 per ton.
Ammonia Reagent Cost		\$0	Based on ammonia reagent cost of \$700 per ton.
Water Cost		\$13,000	Based on water cost of \$1.47 per 1,000 gallons.
Steam Cost		\$24,000	Based on steam cost of \$1.06 per MMBtu.
Hydrated Lime Cost		\$0	Based on hydrated lime cost of \$150 per ton.
Catalyst Replacement Cost		\$0	Based on catalyst cost of \$8,000 per m <sup>3</sup> and catalyst replacement cost of \$1,000 per m <sup>3</sup> .
Auxiliary Power Cost		\$3,000	Based on auxiliary power cost of \$48.06 per MWh (Unit 1) and \$40.47 (Unit 2).
<b>Total Variable O&amp;M Costs</b>		\$586,000	
<b>Fixed O&amp;M Costs</b>			
Additional Operators per shift		0	
Operating Labor		\$0	Assume \$49.5/hr for each additional operator
Supervisor Labor		\$0	N/A
Maintenance Materials		\$29,500	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor		\$0	Included in cost for maintenance materials.
<b>Total Fixed O&amp;M Cost</b>		\$29,500	
<b>Indirect Operating Cost</b>			
Property Taxes		\$30,900	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance		\$30,900	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration		\$61,800	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
<b>Total Indirect Operating Cost</b>		\$123,600	
<b>Total Annual Operating Cost</b>		<b>\$739,000</b>	
<b>TOTAL ANNUAL COST</b>			
Annualized Capital Cost		\$253,000	
Annual Operating Cost		\$739,000	
<b>Total Annual Cost</b>		<b>\$992,000</b>	

LOS Units 1 and 2  
NO<sub>x</sub> Control Cost Evaluation  
SNCR Optimization + RRI

NO <sub>x</sub> Control Option Description	SNCR Optimization + RRI	
	Unit 1	Unit 2
Baseline NO <sub>x</sub> Emissions, lb/MMBtu		0.30
Post Upgrade NO <sub>x</sub> Emissions, lb/MMBtu		0.22
Capacity Factor used of Cost Estimates (%)		100%

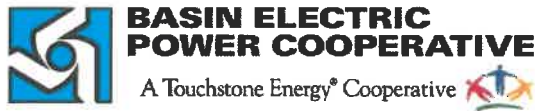
CAPITAL COSTS	Cost (2018\$)		Basis
	Unit 1	Unit 2	
<b>Direct Costs</b>			
<b>Purchased Equipment Costs (PEC)</b>			
Equipment and Materials		\$3,324,000	Based on Sargent & Lundy's conceptual cost estimating system.
Instrumentation		\$0	Included in equipment and materials cost
Sales Tax		\$166,000	5% of Equipment/Material Cost
Freight		\$166,000	5% of Equipment/Material Cost
<b>Total PEC</b>		\$3,656,000	
<b>Direct Installation Costs</b>			
Labor		\$1,642,000	Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding		\$41,000	2.5% of Labor
Mobilization / Demobilization		\$25,000	1.5% of Labor
Labor Cost Due To Overtime Inefficiency		\$82,000	5% of Labor
<b>Total Direct Installation Costs</b>		\$1,790,000	
<b>Total Direct Costs (PEC + Direct Installation Costs)</b>		<b>\$5,446,000</b>	
<b>Indirect Costs</b>			
Contractor's General and Administration Expense		\$545,000	10% of Total Direct Costs
Contractor's Profit		\$272,000	5% of Total Direct Costs
Engineering, Procurement, & Project Services		\$436,000	8% of Total Direct Costs
Construction Management/Field Engineering		\$218,000	4% of Total Direct Costs
S-U / Commissioning		\$82,000	1.5% of Total Direct Costs
Spare Parts		\$27,000	0.5% of Total Direct Costs
Owner's Cost		\$109,000	2% of Total Direct Costs
<b>Total Indirect Costs</b>		<b>\$1,689,000</b>	
<b>Contingency</b>		<b>\$1,427,000</b>	20% of Direct and Indirect Costs
<b>Total Capital Investment (TCI)</b>		<b>\$8,562,000</b>	sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$		0.0820	20 year life of equipment (years) @ 8% interest.
<b>Annualized Capital Costs (CRF x TCI)</b>		<b>\$702,000</b>	
<b>OPERATING COSTS</b>			<b>Basis</b>
<b>Operating &amp; Maintenance Costs</b>			
<b>Variable O&amp;M Costs</b>			
Dry Urea Reagent Cost		\$3,679,000	Based on dry urea reagent cost of \$354 per ton.
Ammonia Reagent Cost		\$0	Based on ammonia reagent cost of \$700 per ton.
Water Cost		\$84,000	Based on water cost of \$1.47 per 1,000 gallons.
Steam Cost		\$164,000	Based on steam cost of \$1.06 per MMBtu.
Hydrated Lime Cost		\$0	Based on hydrated lime cost of \$150 per ton.
Catalyst Replacement Cost		\$0	Based on catalyst cost of \$8,000 per m <sup>3</sup> and catalyst replacement cost of \$1,000 per m <sup>3</sup> .
Auxiliary Power Cost		\$17,000	Based on auxiliary power cost of \$48.06 per MWh (Unit 1) and \$40.47 (Unit 2).
<b>Total Variable O&amp;M Costs</b>		\$3,944,000	
<b>Fixed O&amp;M Costs</b>			
Additional Operators per shift		1	
Operating Labor		\$434,000	Assume \$49.5/hr for each additional operator
Supervisor Labor		\$65,000	N/A
Maintenance Materials		\$82,000	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor		\$0	Included in cost for maintenance materials.
<b>Total Fixed O&amp;M Cost</b>		\$581,000	
<b>Indirect Operating Cost</b>			
Property Taxes		\$86,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance		\$86,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration		\$171,000	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
<b>Total Indirect Operating Cost</b>		\$343,000	
<b>Total Annual Operating Cost</b>		<b>\$4,868,000</b>	
<b>TOTAL ANNUAL COST</b>			
Annualized Capital Cost		\$702,000	
Annual Operating Cost		\$4,868,000	
<b>Total Annual Cost</b>		<b>\$5,570,000</b>	

LOS Units 1 and 2  
NO<sub>x</sub> Control Cost Evaluation  
SCR - Tail-End Configuration

NO <sub>x</sub> Control Option Description	SCR - Tail-End Configuration	
	Unit 1	Unit 2
Baseline NO <sub>x</sub> Emissions, lb/MMBtu	0.15	0.30
Post Upgrade NO <sub>x</sub> Emissions, lb/MMBtu	0.05	0.00
Capacity Factor used of Cost Estimates (%)	100%	100%

CAPITAL COSTS	Cost (2018\$)		Basis
	Unit 1	Unit 2	
<b>Direct Costs</b>			
<b>Purchased Equipment Costs (PEC)</b>			
Equipment and Materials	\$76,672,000		Based on Sargent & Lundy's conceptual cost estimating system.
Instrumentation	\$0		Included in equipment and materials cost
Sales Tax	\$3,834,000		5% of Equipment/Material Cost
Freight	\$3,834,000		5% of Equipment/Material Cost
<b>Total PEC</b>	<b>\$84,340,000</b>		
<b>Direct Installation Costs</b>			
Labor	\$55,521,000		Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding	\$1,388,000		2.5% of Labor
Mobilization / Demobilization	\$833,000		1.5% of Labor
Labor Cost Due To Overtime Inefficiency	\$2,776,000		5% of Labor
<b>Total Direct Installation Costs</b>	<b>\$60,518,000</b>		
<b>Total Direct Costs (PEC + Direct Installation Costs)</b>	<b>\$144,858,000</b>		
<b>Indirect Costs</b>			
Contractor's General and Administration Expense	\$14,486,000		10% of Total Direct Costs
Contractor's Profit	\$7,243,000		5% of Total Direct Costs
Engineering, Procurement, & Project Services	\$11,589,000		8% of Total Direct Costs
Construction Management/Field Engineering	\$5,794,000		4% of Total Direct Costs
S-U / Commissioning	\$2,173,000		1.5% of Total Direct Costs
Spare Parts	\$724,000		0.5% of Total Direct Costs
Owner's Cost	\$2,897,000		2% of Total Direct Costs
<b>Total Indirect Costs</b>	<b>\$44,906,000</b>		
Contingency	\$37,953,000		20% of Direct and Indirect Costs
<b>Total Capital Investment (TCI)</b>	<b>\$227,717,000</b>		sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$	0.0820		20 year life of equipment (years) @ 8% interest.
<b>Annualized Capital Costs (CRF x TCI)</b>	<b>\$18,662,000</b>		
<b>OPERATING COSTS</b>			
<b>Operating &amp; Maintenance Costs</b>			
<b>Variable O&amp;M Costs</b>			
Dry Urea Reagent Cost	-\$540,000		Based on dry urea reagent cost of \$354 per ton.
Ammonia Reagent Cost	\$475,000		Based on ammonia reagent cost of \$700 per ton.
RO Water Cost	-\$7,000		Based on water cost of \$1.47 per 1,000 gallons.
Steam Cost	\$357,000		Based on steam cost of \$1.06 per MMBtu.
Hydrated Lime Cost	\$190,000		Based on hydrated lime cost of \$150 per ton.
Catalyst Replacement and Disposal Cost	\$2,081,000		Based on catalyst cost of \$8,000 per m <sup>3</sup> and catalyst replacement cost of \$1,000 per m <sup>3</sup> .
Auxiliary Power Cost	\$1,386,000		Based on auxiliary power cost of \$48.06 per MWh (Unit 1) and \$40.47 (Unit 2).
<b>Total Variable O&amp;M Costs</b>	<b>\$3,942,000</b>		
<b>Fixed O&amp;M Costs</b>			
Additional Operators per Shift	1		
Operating Labor	\$434,000		Assume \$49.5/hr for each additional operator
Supervisor Labor	\$65,000		15% of Operating Labor. EPA Cost Manual Section 1, Chapter 2, page 2-31.
Maintenance Materials	\$2,173,000		Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor	\$0		Included in cost for maintenance materials.
<b>Total Fixed O&amp;M Cost</b>	<b>\$2,672,000</b>		
<b>Indirect Operating Cost</b>			
Property Taxes	\$2,277,000		1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	\$2,277,000		1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	\$4,554,000		2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
<b>Total Indirect Operating Cost</b>	<b>\$9,108,000</b>		
<b>Total Annual Operating Cost</b>	<b>\$15,722,000</b>		
<b>TOTAL ANNUAL COST</b>			
Annualized Capital Cost	\$18,662,000		
Annual Operating Cost	\$15,722,000		
<b>Total Annual Cost</b>	<b>\$34,384,000</b>		





November 20, 2019

Mr. James L. Semerad  
North Dakota Department of Environmental Quality  
918 East Divide Avenue, Second Floor  
Bismarck, ND 58501-1947

Dear Mr. Semerad:

RE: Four Factor Analysis Updated Steam Costs for Leland Olds Station

As you are aware, Basin Electric Power Cooperative (Basin Electric) submitted a Round II Regional Haze Determination Four-Factor Analysis (Analysis) for the Leland Olds Station (LOS) on January 31, 2019. On July 26, 2019, Basin Electric submitted responses via e-mail to questions posed by the North Dakota Department of Environmental Quality (NDDEQ) regarding the Analysis.

Upon further review, Basin Electric has determined that the steam cost that was used in previous submittals was not accurate. Enclosed please find updated steam costs for LOS and revised cost-effectiveness of NOx reduction technologies reflective of this updated steam cost. This submittal is based on the best information Basin Electric has at this time. However, it is subject to change based on further analysis.

If you have any questions concerning this submittal, please do not hesitate to contact me at [edukart@bepc.com](mailto:edukart@bepc.com) or 701.557.5557.

Sincerely,

Erin Fox Dukart  
Senior Environmental Compliance Administrator

Enclosure

cc: Kentucky Sago  
Tyler Schilke  
Casey Mutzenberger  
Matthew Ehrman  
Jamey Backus

NORTH DAKOTA ROUND II REGIONAL HAZE STATE  
IMPLEMENTATION PLAN DETERMINATION'S FOUR-FACTOR  
ANALYSIS FOR LELAND OLDS STATION  
STEAM COST UPDATE

November 12, 2019

Project No. 13772-002



55 East Monroe Street • Chicago, IL 60603 USA • 312-269-2000  
[www.sargentlundy.com](http://www.sargentlundy.com)

In January 2019, Sargent & Lundy LLC (S&L) prepared a Round II Regional Haze Four-Factor Analysis for the Leland Olds Station (LOS) on behalf of Basin Electric Power Cooperative (Basin). The analysis was prepared in response to a request made by the North Dakota Department of Environmental Quality (NDDEQ) and included an assessment of potentially available sulfur dioxide (SO<sub>2</sub>) and nitrogen oxide (NO<sub>x</sub>) emission reduction technologies that could be applied to LOS Units 1 and 2. LOS Unit 1 is a nominal 220 MW lignite-fired pulverized coal steam electric generating unit equipped with low-NO<sub>x</sub> burners (LNB), advanced separated overfire air (SOFA) and selective non-catalytic reduction (SNCR) for NO<sub>x</sub> control and wet flue gas desulfurization (FGD) for SO<sub>2</sub> control. LOS Unit 2 is a nominal 440 MW lignite-fired cyclone boiler equipped with SOFA and SNCR for NO<sub>x</sub> control and wet FGD for SO<sub>2</sub> control.

Based on a review of available technologies, one NO<sub>x</sub> emission reduction technology was determined to be technically feasible and available to LOS Unit 1: (1) installation of tail-end selective catalytic reduction (TE-SCR). Furthermore, only two NO<sub>x</sub> emission reduction technologies were determined to be technically feasible and available to LOS Unit 2: (1) optimizing the existing SNCR system; and (2) installation of rich reagent injection (RRI). SNCR technology reduces NO<sub>x</sub> in the flue gas by utilizing a urea [(NH<sub>2</sub>)<sub>2</sub>CO] reagent. Aqueous urea solution is injected into the boiler where it is converted to ammonia (NH<sub>3</sub>) which reacts with NO<sub>x</sub> and oxygen to form molecular nitrogen and water vapor. The concept of RRI is similar to SNCR in that urea is injected into the boiler, specifically in the lower furnace to achieve NO<sub>x</sub> reduction. Alternatively, SCR systems inject ammonia into the flue gas upstream of a catalyst bed to provide significant NO<sub>x</sub> reduction. Operating costs associated with both SNCR and RRI include the cost of the urea and steam used to produce the urea solution, while TE-SCR utilizes steam to reheat the flue gas prior to the catalyst bed.

Following submittal of the Four-Factor Analysis, Basin requested that S&L revisit the steam cost that was used to develop operating costs for the technically feasible NO<sub>x</sub> reduction technologies. The purpose of this supplemental report is to inform the NDDEQ of changes made to the steam costs and the impact of those changes on the cost-effectiveness of the NO<sub>x</sub> reduction technologies. A brief description of the basis for the revised steam costs is provided as well as revisions to the steam cost calculations.

As part of the SNCR and RRI systems, liquid urea solution is injected into the boiler for NO<sub>x</sub> control. LOS currently purchases a dry urea for use in the existing SNCR which requires solutionizing prior to injection. As part of the urea solutionizing system, plant steam generated in the boiler is used to heat the reverse osmosis (RO) solutionizing water from 60°F to 165-180°F. Once the water reaches about 180°F it is transferred into a solutionizing tank. Dry urea is added to the solutionizing tanks via a dry urea connection at the top of each tank. Urea and heated water are added in a ratio to make a 50% aqueous solution of urea. The solution is mixed until the dry urea dissolves completely; a solutionizing pump then sends the solution to the urea storage tank(s).

S&L prepared the original four-factor analysis for different technologies based on an indicative steam cost of \$1.06/MMBtu for both LOS units. Subsequently, based on site-specific cost information provided by LOS, it became apparent that these indicative costs were substantially lower than the steam production costs specific to LOS. As such, this prompted S&L to revisit the analysis with a more accurate forecast of steam costs at LOS. Steam production costs include the cost of lignite fuel, fuel handling costs, and boiler efficiency. Fuel costs make up a majority of the cost of steam production. Efficiency is also considered in the costs, as not all the heat from combusting coal is transferred to steam, since there are various heat losses within the boiler island.

LOS reviewed their fuel and operating cost projections through 2028 associated with steam generation in the boilers. LOS forecasts a lignite cost of \$2.047/MMBtu in 2028 with fuel handling costs estimated to be \$0.137/MMBtu, resulting in a total fuel cost of \$2.184/MMBtu. In addition, LOS provided monthly operating reports for boiler efficiency on each unit. The average efficiency is approximately 80.43% and 82.25% for Unit 1 and Unit 2, respectively. These average efficiencies were used to calculate steam cost in conjunction with the fuel and material handling costs. As such, in order to account for the losses, nearly 20% more fuel is needed to generate the required steam for the urea solutionizing process. In conclusion, taking all the new site-specific information into account, the steam cost of \$1.06/MMBtu was revised to \$2.715/MMBtu for Unit 1 and \$2.655 for Unit 2.

Accounting for changes to steam prices and other adjustments as described in the letter submitted to the NDDEQ dated July 26, 2019, the revised cost effectiveness values are included below. Revised cost

NORTH DAKOTA ROUND II REGIONAL HAZE SIP  
DETERMINATION'S FOUR-FACTOR ANALYSIS FOR LELAND OLDS  
STATION

## STEAM COST UPDATE

effectiveness estimates are included in Attachment 1 for the annual average case and Attachment 2 for the future maximum case.

CONTROL TECHNOLOGY	NOx Control Cost Effectiveness (\$/ton)	
	Annual Average	Future Max
SCR – Tail End Configuration (Unit 1)	\$55,068	\$28,990
SNCR Optimization with RRI (Unit 2)	\$4,607	\$4,063
SNCR Optimization (Unit 2)	\$2,201	\$1,895

NORTH DAKOTA ROUND II REGIONAL HAZE SIP  
DETERMINATION'S FOUR-FACTOR ANALYSIS FOR LELAND OLDS  
STATION

STEAM COST UPDATE

---

***Attachment 1: NO<sub>x</sub> Cost-Effectiveness Estimates***  
***BASELINE CAPACITY FACTORS/EMISSIONS AND PROJECTED ACTUAL***  
***EMISSION RATES***

Leland Olds Station Units 1 & 2  
NO<sub>x</sub> Control Summary

Table 1. LOS Units 1 & 2 Operating Parameters

Parameter	Units	Unit 1	Unit 2	Notes
Nominal Power Output	MW	220	440	
Annual Heat Input	MMBtu/yr	11,681,110	30,419,273	- Unit 1: Annual average for period July 2017 to June 2018 - Unit 2: Annual average for period April 2017 to March 2018  - Capacity factor based on Design Hourly Heat Input (MMBtu/hr) and Annual Baseline Heat Input (MMBtu/yr) - Hourly emission rates based on Average Baseline Hourly Heat Input (MMBtu/hr)
Annual Capacity Factor	%	51%	68%	
Average Baseline Hourly Heat Input	MMBtu/hr	1,646	3,692	
Design Hourly Heat Input	MMBtu/hr	2,622	5,130	Permit No. T5-F73004

Table 2. NO<sub>x</sub> Control Effectiveness

Control Technology	Unit 1					Unit 2				
	Control Efficiency	Expected Emissions	Emission Rate	Emission Rate	Expected Emissions Reduction	Control Efficiency	Expected Emissions	Emission Rate	Emission Rate	Expected Emissions Reduction
	(%)	(ton/year)	(lb/hr)	(lb/MMBtu)	(ton/year)	(%)	(ton/year)	(lb/hr)	(lb/MMBtu)	(ton/year)
SCR - Tail-End Configuration	82.8%	292	82	0.05	613					
SNCR Optimization + RRI						67.2%	3,346	812	0.22	1,183
SNCR Optimization						59.7%	4,107	997	0.27	423
Baseline (Unit 1: LNB/ASOFA/SNCR, Unit 2: ASOFA/SNCR)	46.6%	905	255	0.15		55.6%	4,530	1,099	0.30	
Uncontrolled NO <sub>x</sub>		1,694	477	0.29			10,190	2,473	0.67	

Table 3. NO<sub>x</sub> Control Cost Effectiveness - Unit 1

Control Technology	Emissions	Tons of NO <sub>x</sub> Removed	Total Capital Requirement	Annualized Capital Cost	Annualized Outage Cost	Total Annual Operating Costs	Total Annual Costs	Average Cost Effectiveness	Incremental Cost Effectiveness
	(tpy)	(tpy)	(\$)	(\$/year)	(\$/year)	(\$/year)	(\$)	(\$/ton)	(\$/ton)
SCR - Tail-End Configuration	292	613	\$227,717,000	\$18,662,000	\$0	\$15,002,000	\$33,664,000	\$54,920	
Baseline Unit 1	905								

Table 4. NO<sub>x</sub> Control Cost Effectiveness - Unit 2

Control Technology	Emissions	Tons of NO <sub>x</sub> Removed	Total Capital Requirement	Annualized Capital Cost	Annualized Outage Cost	Total Annual Operating Costs	Total Annual Costs	Average Cost Effectiveness	Incremental Cost Effectiveness
	(tpy)	(tpy)	(\$)	(\$/year)	(\$/year)	(\$/year)	(\$)	(\$/ton)	(\$/ton)
SNCR Optimization + RRI	3,346	1,183	\$11,342,000	\$930,000	\$0	\$4,473,000	\$5,403,000	\$4,566	\$5,890
SNCR Optimization	4,107	423	\$3,089,000	\$253,000	\$0	\$671,000	\$924,000	\$2,185	
Baseline Unit 2	4,530								



LOS Units 1 and 2  
NO<sub>x</sub> Control Cost Evaluation  
SNCR Optimization

NO <sub>x</sub> Control Option Description	SNCR Optimization	
	Unit 1	Unit 2
Baseline NO <sub>x</sub> Emissions, lb/MMBtu		0.30
Post Upgrade NO <sub>x</sub> Emissions, lb/MMBtu		0.27
Capacity Factor used of Cost Estimates (%)		68%

CAPITAL COSTS		Cost (2018\$)	Basis
		Unit 1      Unit 2	
<b>Direct Costs</b>			
<b>Purchased Equipment Costs (PEC)</b>			
Equipment and Materials		\$1,147,000	
Instrumentation		\$0	Included in equipment and materials cost
Sales Tax		\$57,000	5% of Equipment/Material Cost
Freight		\$57,000	5% of Equipment/Material Cost
<i>Total PEC</i>		\$1,261,000	
<b>Direct Installation Costs</b>			
Labor		\$646,000	Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding		\$16,000	2.5% of Labor
Mobilization / Demobilization		\$10,000	1.5% of Labor
Labor Cost Due To Overtime Inefficiency		\$32,000	5% of Labor
<i>Total Direct Installation Costs</i>		\$704,000	
Total Direct Costs (PEC + Direct Installation Costs)		<b>\$1,965,000</b>	
<b>Indirect Costs</b>			
Contractor's General and Administration Expense		\$197,000	10% of Total Direct Costs
Contractor's Profit		\$98,000	5% of Total Direct Costs
Engineering, Procurement, & Project Services		\$157,000	8% of Total Direct Costs
Construction Management/Field Engineering		\$79,000	4% of Total Direct Costs
S-U / Commissioning		\$29,000	1.5% of Total Direct Costs
Spare Parts		\$10,000	0.5% of Total Direct Costs
Owner's Cost		\$39,000	2% of Total Direct Costs
Total Indirect Costs		<b>\$609,000</b>	
Contingency		<b>\$515,000</b>	20% of Direct and Indirect Costs
<b>Total Capital Investment (TCI)</b>		<b>\$3,089,000</b>	sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$		0.0820	20 year life of equipment (years) @ 5.25% interest.
<b>Annualized Capital Costs (CRF x TCI)</b>		<b>\$253,000</b>	
<b>OPERATING COSTS</b>			<b>Basis</b>
<b>Operating &amp; Maintenance Costs</b>			
<b>Variable O&amp;M Costs</b>			
Dry Urea Reagent Cost		\$369,000	Based on dry urea reagent cost of \$354 per ton.
Ammonia Reagent Cost		\$0	Based on ammonia reagent cost of \$700 per ton.
Water Cost		\$8,000	Based on water cost of \$1.47 per 1,000 gallons.
Steam Cost		\$34,000	Based on steam cost of \$2.184 per MMBtu.
Hydrated Lime Cost		\$0	Based on hydrated lime cost of \$150 per ton.
Catalyst Replacement Cost		\$0	Based on catalyst cost of \$8,000 per m <sup>3</sup> and catalyst replacement cost of \$1,000 per m <sup>3</sup> .
Auxiliary Power Cost		\$2,000	Based on auxiliary power cost of \$48.06 per MWh (Unit 1) and \$40.47 (Unit 2).
Replacement Power Cost		\$105,000	Based on heat rate penalty of 0.22% and replacement coal cost of \$1.57/MBtu.
<i>Total Variable O&amp;M Costs</i>		\$518,000	

LOS Units 1 and 2  
NO<sub>x</sub> Control Cost Evaluation  
SNCR Optimization

NO <sub>x</sub> Control Option Description	SNCR Optimization	
	Unit 1	Unit 2
Baseline NO <sub>x</sub> Emissions, lb/MMBtu		0.30
Post Upgrade NO <sub>x</sub> Emissions, lb/MMBtu		0.27
Capacity Factor used of Cost Estimates (%)		68%

<b>Fixed O&amp;M Costs</b>			
Additional Operators per shift		0	
Operating Labor		\$0	Assume \$49.5/hr for each additional operator
Supervisor Labor		\$0	N/A
Maintenance Materials		\$29,500	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor		\$0	Included in cost for maintenance materials.
<i>Total Fixed O&amp;M Cost</i>		\$29,500	
<b>Indirect Operating Cost</b>			
Property Taxes		\$30,900	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance		\$30,900	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration		\$61,800	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
<i>Total Indirect Operating Cost</i>		\$123,600	
<b>Total Annual Operating Cost</b>		<b>\$671,000</b>	
<b>TOTAL ANNUAL COST</b>			
Annualized Capital Cost		\$253,000	
Annual Operating Cost		\$671,000	
<b>Total Annual Cost</b>		<b>\$924,000</b>	

LOS Units 1 and 2  
NO<sub>x</sub> Control Cost Evaluation  
SNCR Optimization + RRI

NO <sub>x</sub> Control Option Description	SNCR Optimization + RRI	
	Unit 1	Unit 2
Baseline NO <sub>x</sub> Emissions, lb/MMBtu		0.30
Post Upgrade NO <sub>x</sub> Emissions, lb/MMBtu		0.22
Capacity Factor used of Cost Estimates (%)		68%

CAPITAL COSTS		Cost (2018\$)	Basis
		Unit 1      Unit 2	
<b>Direct Costs</b>			
<b>Purchased Equipment Costs (PEC)</b>			
Equipment and Materials		\$4,530,000	
Instrumentation		\$0	Included in equipment and materials cost
Sales Tax		\$227,000	5% of Equipment/Material Cost
Freight		\$227,000	5% of Equipment/Material Cost
<i>Total PEC</i>		\$4,984,000	
<b>Direct Installation Costs</b>			
Labor		\$2,047,000	Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding		\$51,000	2.5% of Labor
Mobilization / Demobilization		\$31,000	1.5% of Labor
Labor Cost Due To Overtime Inefficiency		\$102,000	5% of Labor
<i>Total Direct Installation Costs</i>		\$2,231,000	
Total Direct Costs (PEC + Direct Installation Costs)		<b>\$7,215,000</b>	
<b>Indirect Costs</b>			
Contractor's General and Administration Expense		\$722,000	10% of Total Direct Costs
Contractor's Profit		\$361,000	5% of Total Direct Costs
Engineering, Procurement, & Project Services		\$577,000	8% of Total Direct Costs
Construction Management/Field Engineering		\$289,000	4% of Total Direct Costs
S-U / Commissioning		\$108,000	1.5% of Total Direct Costs
Spare Parts		\$36,000	0.5% of Total Direct Costs
Owner's Cost		\$144,000	2% of Total Direct Costs
Total Indirect Costs		<b>\$2,237,000</b>	
Contingency		<b>\$1,890,000</b>	20% of Direct and Indirect Costs
<b>Total Capital Investment (TCI)</b>		<b>\$11,342,000</b>	sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$		0.0820	20 year life of equipment (years) @ 5.25% interest.
<b>Annualized Capital Costs (CRF x TCI)</b>		<b>\$930,000</b>	
<b>OPERATING COSTS</b>			<b>Basis</b>
<b>Operating &amp; Maintenance Costs</b>			
<b>Variable O&amp;M Costs</b>			
Dry Urea Reagent Cost		\$2,490,000	Based on dry urea reagent cost of \$354 per ton.
Ammonia Reagent Cost		\$0	Based on ammonia reagent cost of \$700 per ton.
Water Cost		\$57,000	Based on water cost of \$1.47 per 1,000 gallons.
Steam Cost		\$229,000	Based on steam cost of \$2.184 per MMBtu.
Hydrated Lime Cost		\$0	Based on hydrated lime cost of \$150 per ton.
Catalyst Replacement Cost		\$0	Based on catalyst cost of \$8,000 per m <sup>3</sup> and catalyst replacement cost of \$1,000 per m <sup>3</sup> .
Auxiliary Power Cost		\$39,000	Based on auxiliary power cost of \$48.06 per MWh (Unit 1) and \$40.47 (Unit 2).
Replacement Power Cost		\$598,000	Based on heat rate penalty of 1.25% and replacement coal cost of \$1.57/MBtu.
<i>Total Variable O&amp;M Costs</i>		\$3,413,000	

LOS Units 1 and 2  
NO<sub>x</sub> Control Cost Evaluation  
SNCR Optimization + RRI

NO <sub>x</sub> Control Option Description	SNCR Optimization + RRI	
	Unit 1	Unit 2
Baseline NO <sub>x</sub> Emissions, lb/MMBtu		0.30
Post Upgrade NO <sub>x</sub> Emissions, lb/MMBtu		0.22
Capacity Factor used of Cost Estimates (%)		68%

<b>Fixed O&amp;M Costs</b>			
Additional Operators per shift		1	
Operating Labor		\$434,000	Assume \$49.5/hr for each additional operator
Supervisor Labor		\$65,000	N/A
Maintenance Materials		\$108,000	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor		\$0	Included in cost for maintenance materials.
<i>Total Fixed O&amp;M Cost</i>		\$607,000	
<b>Indirect Operating Cost</b>			
Property Taxes		\$113,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance		\$113,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration		\$227,000	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
<i>Total Indirect Operating Cost</i>		\$453,000	
<b>Total Annual Operating Cost</b>		<b>\$4,473,000</b>	
<b>TOTAL ANNUAL COST</b>			
Annualized Capital Cost		\$930,000	
Annual Operating Cost		\$4,473,000	
<b>Total Annual Cost</b>		<b>\$5,403,000</b>	

LOS Units 1 and 2  
NO<sub>x</sub> Control Cost Evaluation  
SCR - Tail-End Configuration

NO <sub>x</sub> Control Option Description	SCR - Tail-End Configuration	
	Unit 1	Unit 2
Baseline NO <sub>x</sub> Emissions, lb/MMBtu	0.15	
Post Upgrade NO <sub>x</sub> Emissions, lb/MMBtu	0.05	
Capacity Factor used of Cost Estimates (%)	51%	

CAPITAL COSTS	Cost (2018\$)		Basis
	Unit 1	Unit 2	
<b>Direct Costs</b>			
<b>Purchased Equipment Costs (PEC)</b>			
Equipment and Materials	\$76,672,000		\$0
Instrumentation	\$0		Included in equipment and materials cost
Sales Tax	\$3,834,000		5% of Equipment/Material Cost
Freight	\$3,834,000		5% of Equipment/Material Cost
<i>Total PEC</i>	\$84,340,000		
<b>Direct Installation Costs</b>			
Labor	\$55,521,000		Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding	\$1,388,000		2.5% of Labor
Mobilization / Demobilization	\$833,000		1.5% of Labor
Labor Cost Due To Overtime Inefficiency	\$2,776,000		5% of Labor
<i>Total Direct Installation Costs</i>	\$60,518,000		
Total Direct Costs (PEC + Direct Installation Costs)	<b>\$144,858,000</b>		
<b>Indirect Costs</b>			
Contractor's General and Administration Expense	\$14,486,000		10% of Total Direct Costs
Contractor's Profit	\$7,243,000		5% of Total Direct Costs
Engineering, Procurement, & Project Services	\$11,589,000		8% of Total Direct Costs
Construction Management/Field Engineering	\$5,794,000		4% of Total Direct Costs
S-U / Commissioning	\$2,173,000		1.5% of Total Direct Costs
Spare Parts	\$724,000		0.5% of Total Direct Costs
Owner's Cost	\$2,897,000		2% of Total Direct Costs
Total Indirect Costs	<b>\$44,906,000</b>		
Contingency	<b>\$37,953,000</b>		20% of Direct and Indirect Costs
<b>Total Capital Investment (TCI)</b>	<b>\$227,717,000</b>		sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$	0.0820		20 year life of equipment (years) @ 5.25% interest.
<b>Annualized Capital Costs (CRF x TCI)</b>	<b>\$18,662,000</b>		
<b>OPERATING COSTS</b>			
<b>Operating &amp; Maintenance Costs</b>			
<b>Variable O&amp;M Costs</b>			
Dry Urea Reagent Cost	-\$274,000		Based on dry urea reagent cost of \$354 per ton.
Ammonia Reagent Cost	\$242,000		Based on ammonia reagent cost of \$700 per ton.
RO Water Cost	-\$3,000		Based on water cost of \$1.47 per 1,000 gallons.
Steam Cost	\$374,000		Based on steam cost of \$2.184 per MMBtu.
Hydrated Lime Cost	\$97,000		Based on hydrated lime cost of \$150 per ton.
Catalyst Replacement and Disposal Cost	\$2,081,000		Based on catalyst cost of \$8,000 per m <sup>3</sup> and catalyst replacement cost of \$1,000 per m <sup>3</sup> .
Auxiliary Power Cost	\$705,000		Based on auxiliary power cost of \$48.06 per MWh (Unit 1) and \$40.47 (Unit 2).
Replacement Power Cost	\$0		Based on replacement coal cost of \$1.57/Mbtu.
<i>Total Variable O&amp;M Costs</i>	\$3,222,000		

LOS Units 1 and 2  
NO<sub>x</sub> Control Cost Evaluation  
SCR - Tail-End Configuration

NO <sub>x</sub> Control Option Description	SCR - Tail-End Configuration	
	Unit 1	Unit 2
Baseline NO <sub>x</sub> Emissions, lb/MMBtu	0.15	
Post Upgrade NO <sub>x</sub> Emissions, lb/MMBtu	0.05	
Capacity Factor used of Cost Estimates (%)	51%	

<b>Fixed O&amp;M Costs</b>		
Additional Operators per Shift	1	
Operating Labor	\$434,000	Assume \$49.5/hr for each additional operator 15% of Operating Labor. EPA Cost Manual Section 1, Chapter 2, page 2-31.
Supervisor Labor	\$65,000	
Maintenance Materials	\$2,173,000	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor	\$0	Included in cost for maintenance materials.
<i>Total Fixed O&amp;M Cost</i>	\$2,672,000	
<b>Indirect Operating Cost</b>		
Property Taxes	\$2,277,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	\$2,277,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	\$4,554,000	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
<i>Total Indirect Operating Cost</i>	\$9,108,000	
<b>Total Annual Operating Cost</b>	<b>\$15,002,000</b>	
<b>TOTAL ANNUAL COST</b>		
Annualized Capital Cost	\$18,662,000	
Annual Operating Cost	\$15,002,000	
<b>Total Annual Cost</b>	<b>\$33,664,000</b>	

NORTH DAKOTA ROUND II REGIONAL HAZE SIP  
DETERMINATION'S FOUR-FACTOR ANALYSIS FOR LELAND OLDS  
STATION

STEAM COST UPDATE

---

***Attachment 2: NO<sub>x</sub> Cost-Effectiveness Estimates***  
***100% CAPACITY FACTOR AND PROJECTED FUTURE MAXIMUM EMISSION RATE***



Leland Olds Station Units 1 & 2  
NO<sub>x</sub> Control Summary

Table 1. LOS Units 1 & 2 Operating Parameters

Parameter	Units	Unit 1	Unit 2	Notes
Nominal Power Output	MW	220	440	
Annual Heat Input	MMBtu/yr	22,968,720	44,938,800	- Unit 1: Annual average for period July 2017 to June 2018 - Unit 2: Annual average for period April 2017 to March 2018
Annual Capacity Factor	%	100%	100%	
Hourly Heat Input	MMBtu/hr	2,622	5,130	Permit No. T5-F73004

Table 2. NO<sub>x</sub> Control Effectiveness

	Unit 1					Unit 2				
Control Technology	Control Efficiency	Expected Emissions	Emission Rate	Emission Rate	Expected Emissions Reduction	Control Efficiency	Expected Emissions	Emission Rate	Emission Rate	Expected Emissions Reduction
	(%)	(ton/year)	(lb/hr)	(lb/MMBtu)	(ton/year)	(%)	(ton/year)	(lb/hr)	(lb/MMBtu)	(ton/year)
SCR - Tail-End Configuration	82.8%	574	131	0.05	1,205					
SNCR Optimization + RRI						67.2%	4,943	1,129	0.22	1,748
SNCR Optimization						59.7%	6,067	1,385	0.27	625
Baseline (Unit 1: LNB/ASOFA/SNCR, Unit 2: ASOFA/SNCR)	46.6%	1,779	406	0.15		55.6%	6,692	1,528	0.30	
Uncontrolled NO <sub>x</sub>		3,330	760	0.29			15,054	2,473	0.67	

Table 3. NO<sub>x</sub> Control Cost Effectiveness - Unit 1

Control Technology	Emissions	Tons of NO <sub>x</sub> Removed	Total Capital Requirement	Annualized Capital Cost	Annualized Outage Cost	Total Annual Operating Costs	Total Annual Costs	Average Cost Effectiveness	Incremental Cost Effectiveness
	(tpy)	(tpy)	(\$)	(\$/year)	(\$/year)	(\$/year)	(\$)	(\$/ton)	(\$/ton)
SCR - Tail-End Configuration	574	1,205	\$227,717,000	\$18,662,000	\$0	\$16,100,000	\$34,762,000	\$28,841	
Baseline Unit 1	1,779								

Table 4. NO<sub>x</sub> Control Cost Effectiveness - Unit 2

Control Technology	Emissions	Tons of NO <sub>x</sub> Removed	Total Capital Requirement	Annualized Capital Cost	Annualized Outage Cost	Total Annual Operating Costs	Total Annual Costs	Average Cost Effectiveness	Incremental Cost Effectiveness
	(tpy)	(tpy)	(\$)	(\$/year)	(\$/year)	(\$/year)	(\$)	(\$/ton)	(\$/ton)
SNCR Optimization + RRI	4,943	1,748	\$11,342,000	\$930,000	\$0	\$6,101,000	\$7,031,000	\$4,022	\$5,214
SNCR Optimization	6,067	625	\$3,089,000	\$253,000	\$0	\$920,000	\$1,173,000	\$1,877	
Baseline Unit 2	6,692								

**Leland Olds Station Units 1 & 2  
NO<sub>x</sub> Control Summary**

LOS Units 1 and 2  
NO<sub>x</sub> Control Cost Evaluation  
SNCR Optimization

NO <sub>x</sub> Control Option Description	SNCR Optimization	
	Unit 1	Unit 2
Baseline NO <sub>x</sub> Emissions, lb/MMBtu		0.30
Post Upgrade NO <sub>x</sub> Emissions, lb/MMBtu		0.27
Capacity Factor used of Cost Estimates (%)		100%

CAPITAL COSTS		Cost (2018\$)	Basis
		Unit 1      Unit 2	
<b>Direct Costs</b>			
<b>Purchased Equipment Costs (PEC)</b>			
Equipment and Materials		\$1,147,000	Based on Sargent & Lundy's conceptual cost estimating system.
Instrumentation		\$0	Included in equipment and materials cost
Sales Tax		\$57,000	5% of Equipment/Material Cost
Freight		\$57,000	5% of Equipment/Material Cost
<i>Total PEC</i>		\$1,261,000	
<b>Direct Installation Costs</b>			
Labor		\$646,000	Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding		\$16,000	2.5% of Labor
Mobilization / Demobilization		\$10,000	1.5% of Labor
Labor Cost Due To Overtime Inefficiency		\$32,000	5% of Labor
<i>Total Direct Installation Costs</i>		\$704,000	
Total Direct Costs (PEC + Direct Installation Costs)		<b>\$1,965,000</b>	
<b>Indirect Costs</b>			
Contractor's General and Administration Expense		\$197,000	10% of Total Direct Costs
Contractor's Profit		\$98,000	5% of Total Direct Costs
Engineering, Procurement, & Project Services		\$157,000	8% of Total Direct Costs
Construction Management/Field Engineering		\$79,000	4% of Total Direct Costs
S-U / Commissioning		\$29,000	1.5% of Total Direct Costs
Spare Parts		\$10,000	0.5% of Total Direct Costs
Owner's Cost		\$39,000	2% of Total Direct Costs
Total Indirect Costs		<b>\$609,000</b>	
Contingency		<b>\$515,000</b>	20% of Direct and Indirect Costs
<b>Total Capital Investment (TCI)</b>		<b>\$3,089,000</b>	sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$		0.0820	20 year life of equipment (years) @ 5.25% interest.
<b>Annualized Capital Costs (CRF x TCI)</b>		<b>\$253,000</b>	
<b>OPERATING COSTS</b>			<b>Basis</b>
<b>Operating &amp; Maintenance Costs</b>			
<b>Variable O&amp;M Costs</b>			
Dry Urea Reagent Cost		\$546,000	Based on dry urea reagent cost of \$354 per ton.
Ammonia Reagent Cost		\$0	Based on ammonia reagent cost of \$700 per ton.
Water Cost		\$13,000	Based on water cost of \$1.47 per 1,000 gallons.
Steam Cost		\$50,000	Based on steam cost of \$2.184 per MMBtu.
Hydrated Lime Cost		\$0	Based on hydrated lime cost of \$150 per ton.
Catalyst Replacement Cost		\$0	Based on catalyst cost of \$8,000 per m <sup>3</sup> and catalyst replacement cost of \$1,000 per m <sup>3</sup> .
Auxiliary Power Cost		\$3,000	Based on auxiliary power cost of \$48.06 per MWh (Unit 1) and \$40.47 (Unit 2).
Replacement Power Cost		\$155,000	Based on heat rate penalty of 0.22% and replacement coal cost of \$1.57/MBtu.
<i>Total Variable O&amp;M Costs</i>		\$767,000	

LOS Units 1 and 2  
NO<sub>x</sub> Control Cost Evaluation  
SNCR Optimization

NO <sub>x</sub> Control Option Description	SNCR Optimization	
	Unit 1	Unit 2
Baseline NO <sub>x</sub> Emissions, lb/MMBtu		0.30
Post Upgrade NO <sub>x</sub> Emissions, lb/MMBtu		0.27
Capacity Factor used of Cost Estimates (%)		100%

<b>Fixed O&amp;M Costs</b>			
Additional Operators per shift		0	
Operating Labor		\$0	Assume \$49.5/hr for each additional operator
Supervisor Labor		\$0	N/A
Maintenance Materials		\$29,500	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor		\$0	Included in cost for maintenance materials.
<i>Total Fixed O&amp;M Cost</i>		\$29,500	
<b>Indirect Operating Cost</b>			
Property Taxes		\$30,900	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance		\$30,900	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration		\$61,800	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
<i>Total Indirect Operating Cost</i>		\$123,600	
<b>Total Annual Operating Cost</b>		<b>\$920,000</b>	
<b>TOTAL ANNUAL COST</b>			
Annualized Capital Cost		\$253,000	
Annual Operating Cost		\$920,000	
<b>Total Annual Cost</b>		<b>\$1,173,000</b>	

LOS Units 1 and 2  
NO<sub>x</sub> Control Cost Evaluation  
SNCR Optimization + RRI

NO <sub>x</sub> Control Option Description	SNCR Optimization + RRI	
	Unit 1	Unit 2
Baseline NO <sub>x</sub> Emissions, lb/MMBtu		0.30
Post Upgrade NO <sub>x</sub> Emissions, lb/MMBtu		0.22
Capacity Factor used of Cost Estimates (%)		100%

CAPITAL COSTS		Cost (2018\$)	Basis
		Unit 1      Unit 2	
<b>Direct Costs</b>			
<b>Purchased Equipment Costs (PEC)</b>			
Equipment and Materials		\$4,530,000	Based on Sargent & Lundy's conceptual cost estimating system.
Instrumentation		\$0	Included in equipment and materials cost
Sales Tax		\$227,000	5% of Equipment/Material Cost
Freight		\$227,000	5% of Equipment/Material Cost
<i>Total PEC</i>		\$4,984,000	
<b>Direct Installation Costs</b>			
Labor		\$2,047,000	Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding		\$51,000	2.5% of Labor
Mobilization / Demobilization		\$31,000	1.5% of Labor
Labor Cost Due To Overtime Inefficiency		\$102,000	5% of Labor
<i>Total Direct Installation Costs</i>		\$2,231,000	
Total Direct Costs (PEC + Direct Installation Costs)		<b>\$7,215,000</b>	
<b>Indirect Costs</b>			
Contractor's General and Administration Expense		\$722,000	10% of Total Direct Costs
Contractor's Profit		\$361,000	5% of Total Direct Costs
Engineering, Procurement, & Project Services		\$577,000	8% of Total Direct Costs
Construction Management/Field Engineering		\$289,000	4% of Total Direct Costs
S-U / Commissioning		\$108,000	1.5% of Total Direct Costs
Spare Parts		\$36,000	0.5% of Total Direct Costs
Owner's Cost		\$144,000	2% of Total Direct Costs
Total Indirect Costs		<b>\$2,237,000</b>	
Contingency		<b>\$1,890,000</b>	20% of Direct and Indirect Costs
<b>Total Capital Investment (TCI)</b>		<b>\$11,342,000</b>	sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$		0.0820	20 year life of equipment (years) @ 5.25% interest.
<b>Annualized Capital Costs (CRF x TCI)</b>		<b>\$930,000</b>	
<b>OPERATING COSTS</b>			<b>Basis</b>
<b>Operating &amp; Maintenance Costs</b>			
<b>Variable O&amp;M Costs</b>			
Dry Urea Reagent Cost		\$3,679,000	Based on dry urea reagent cost of \$354 per ton.
Ammonia Reagent Cost		\$0	Based on ammonia reagent cost of \$700 per ton.
Water Cost		\$84,000	Based on water cost of \$1.47 per 1,000 gallons.
Steam Cost		\$338,000	Based on steam cost of \$2.184 per MMBtu.
Hydrated Lime Cost		\$0	Based on hydrated lime cost of \$150 per ton.
Catalyst Replacement Cost		\$0	Based on catalyst cost of \$8,000 per m <sup>3</sup> and catalyst replacement cost of \$1,000 per m <sup>3</sup> .
Auxiliary Power Cost		\$57,000	Based on auxiliary power cost of \$48.06 per MWh (Unit 1) and \$40.47 (Unit 2).
Replacement Power Cost		\$883,000	Based on heat rate penalty of 1.25% and replacement coal cost of \$1.57/MBtu.
<i>Total Variable O&amp;M Costs</i>		\$5,041,000	

LOS Units 1 and 2  
NO<sub>x</sub> Control Cost Evaluation  
SNCR Optimization + RRI

NO <sub>x</sub> Control Option Description	SNCR Optimization + RRI	
	Unit 1	Unit 2
Baseline NO <sub>x</sub> Emissions, lb/MMBtu		0.30
Post Upgrade NO <sub>x</sub> Emissions, lb/MMBtu		0.22
Capacity Factor used of Cost Estimates (%)		100%

<b>Fixed O&amp;M Costs</b>			
Additional Operators per shift		1	
Operating Labor		\$434,000	Assume \$49.5/hr for each additional operator
Supervisor Labor		\$65,000	N/A
Maintenance Materials		\$108,000	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor		\$0	Included in cost for maintenance materials.
<i>Total Fixed O&amp;M Cost</i>		\$607,000	
<b>Indirect Operating Cost</b>			
Property Taxes		\$113,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance		\$113,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration		\$227,000	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
<i>Total Indirect Operating Cost</i>		\$453,000	
<b>Total Annual Operating Cost</b>		<b>\$6,101,000</b>	
<b>TOTAL ANNUAL COST</b>			
Annualized Capital Cost		\$930,000	
Annual Operating Cost		\$6,101,000	
<b>Total Annual Cost</b>		<b>\$7,031,000</b>	

LOS Units 1 and 2  
NO<sub>x</sub> Control Cost Evaluation  
SCR - Tail-End Configuration

NO <sub>x</sub> Control Option Description	SCR - Tail-End Configuration	
	Unit 1	Unit 2
Baseline NO <sub>x</sub> Emissions, lb/MMBtu	0.15	
Post Upgrade NO <sub>x</sub> Emissions, lb/MMBtu	0.05	
Capacity Factor used of Cost Estimates (%)	100%	

CAPITAL COSTS	Cost (2018\$)		Basis
	Unit 1	Unit 2	
<b>Direct Costs</b>			
<b>Purchased Equipment Costs (PEC)</b>			
Equipment and Materials	\$76,672,000		Based on Sargent & Lundy's conceptual cost estimating system.
Instrumentation	\$0		Included in equipment and materials cost
Sales Tax	\$3,834,000		5% of Equipment/Material Cost
Freight	\$3,834,000		5% of Equipment/Material Cost
<i>Total PEC</i>	\$84,340,000		
<b>Direct Installation Costs</b>			
Labor	\$55,521,000		Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding	\$1,388,000		2.5% of Labor
Mobilization / Demobilization	\$833,000		1.5% of Labor
Labor Cost Due To Overtime Inefficiency	\$2,776,000		5% of Labor
<i>Total Direct Installation Costs</i>	\$60,518,000		
Total Direct Costs (PEC + Direct Installation Costs)	\$144,858,000		
<b>Indirect Costs</b>			
Contractor's General and Administration Expense	\$14,486,000		10% of Total Direct Costs
Contractor's Profit	\$7,243,000		5% of Total Direct Costs
Engineering, Procurement, & Project Services	\$11,589,000		8% of Total Direct Costs
Construction Management/Field Engineering	\$5,794,000		4% of Total Direct Costs
S-U / Commissioning	\$2,173,000		1.5% of Total Direct Costs
Spare Parts	\$724,000		0.5% of Total Direct Costs
Owner's Cost	\$2,897,000		2% of Total Direct Costs
Total Indirect Costs	\$44,906,000		
Contingency	\$37,953,000		20% of Direct and Indirect Costs
<b>Total Capital Investment (TCI)</b>	\$227,717,000		sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$	0.0820		20 year life of equipment (years) @ 5.25% interest.
<b>Annualized Capital Costs (CRF x TCI)</b>	\$18,662,000		
<b>OPERATING COSTS</b>			
<b>Operating &amp; Maintenance Costs</b>			
<b>Variable O&amp;M Costs</b>			
Dry Urea Reagent Cost	-\$540,000		Based on dry urea reagent cost of \$354 per ton.
Ammonia Reagent Cost	\$475,000		Based on ammonia reagent cost of \$700 per ton.
RO Water Cost	-\$7,000		Based on water cost of \$1.47 per 1,000 gallons.
Steam Cost	\$735,000		Based on steam cost of \$2.184 per MMBtu.
Hydrated Lime Cost	\$190,000		Based on hydrated lime cost of \$150 per ton.
Catalyst Replacement and Disposal Cost	\$2,081,000		Based on catalyst cost of \$8,000 per m <sup>3</sup> and catalyst replacement cost of \$1,000 per m <sup>3</sup> .
Auxiliary Power Cost	\$1,386,000		Based on auxiliary power cost of \$48.06 per MWh (Unit 1) and \$40.47 (Unit 2).
Replacement Power Cost	\$0		Based on replacement coal cost of \$1.57/MBtu.
<i>Total Variable O&amp;M Costs</i>	\$4,320,000		



LOS Units 1 and 2  
NO<sub>x</sub> Control Cost Evaluation  
SCR - Tail-End Configuration

NO <sub>x</sub> Control Option Description	SCR - Tail-End Configuration	
	Unit 1	Unit 2
Baseline NO <sub>x</sub> Emissions, lb/MMBtu	0.15	
Post Upgrade NO <sub>x</sub> Emissions, lb/MMBtu	0.05	
Capacity Factor used of Cost Estimates (%)	100%	

<b>Fixed O&amp;M Costs</b>		
Additional Operators per Shift	1	
Operating Labor	\$434,000	Assume \$49.5/hr for each additional operator 15% of Operating Labor. EPA Cost Manual Section 1, Chapter 2, page 2-31.
Supervisor Labor	\$65,000	
Maintenance Materials	\$2,173,000	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor	\$0	Included in cost for maintenance materials.
<i>Total Fixed O&amp;M Cost</i>	\$2,672,000	
<b>Indirect Operating Cost</b>		
Property Taxes	\$2,277,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	\$2,277,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	\$4,554,000	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
<i>Total Indirect Operating Cost</i>	\$9,108,000	
<b>Total Annual Operating Cost</b>	<b>\$16,100,000</b>	
<b>TOTAL ANNUAL COST</b>		
Annualized Capital Cost	\$18,662,000	
Annual Operating Cost	\$16,100,000	
<b>Total Annual Cost</b>	<b>\$34,762,000</b>	

### B.3.c – Communications

April 22, 2019 : 9:44 AM

To: Erin Dukart

From: Bachman, Tom A.

CC: Stroh, David E.; Seligman, Angela N.

Subject: Leland Olds Station 4 Factor Analysis

Attachments: image004.png; image001.png; image005.png;

Erin:

I note in Table 4-6 of the Four-Factors analysis that the uncontrolled SO<sub>2</sub> emission rates assume all of the sulfur in the coal is emitted from the boiler. Based on the AP-42 emission factor for lignite, about 25% of the sulfur is retained in the bottom ash (varies depending on the sodium content of the ash). Using the AP-42 emission factor (30S), I calculate the uncontrolled emission rate at 2.80 lb/MMBtu. Since it is stated that 3.73 lb/MMBtu was used as the design basis for evaluating the SO<sub>2</sub> controls, it appears this section should be revised.

The Four-Factors analysis indicates that SNCR was placed in to service at Leland Olds Unit 1 in September 2017 and April 2017 for Unit 2. Your April 18th email regarding the WRAP Regional Haze modeling indicates the average NO<sub>x</sub> emission rate from 2017-2018 was used. The 2028 projections for NO<sub>x</sub> are somewhat higher than the baseline emissions in the January 30, 2019 Four-Factors analysis (1,267 tons versus 905 for Unit 1 and 4,718 tons versus 4,530 tons for Unit 2) while the SO<sub>2</sub> emissions essentially remained the same (700 tons versus 697 tons for Unit 1 and 1,371 tons versus 1,366 tons for Unit 2). Were the NO<sub>x</sub> emission rates (1.892 lb/MW-net) and 3.376 lb/MW-net) calculated using data from the entire year - 2017 - or just the part of the year when the SNCR was operating? What is the reason for NO<sub>x</sub> increasing but not SO<sub>2</sub>?

I assume the baseline emission rates in the Four-Factors analysis will be updated to match the 2028 projections? The Four-Factors analysis sections on baseline emissions (2028 projections) should include the 2028 generation forecast as part of the justification.

If you have any questions, please feel free to contact me.

Tom Bachman  
*Senior Environmental Engineer*

701.328.5188 • tbachman@nd.gov • Division of Air Quality

health.nd.gov • 918 E. Divide Ave • Bismarck, ND 58501-1947 • [Provide Feedback](#)

**From:** Bachman, Tom A.  
**Sent:** Monday, April 15, 2019 10:55 AM  
**To:** Erin Dukart <EDukart@bepc.com>; Stroh, David E. <deStroh@nd.gov>; Seligman, Angela N. <aseligman@nd.gov>  
**Cc:** Mike Paul <MPaul@bepc.com>; Semerad, Jim L. <jsemerad@nd.gov>  
**Subject:** RE: Leland Olds Station 4 Factor Analysis

Erin:

Thanks for the information.

I have reviewed the Leland Olds Station four-factors analysis and there are a couple of items that could be included in your resubmittal.

1. It is indicated that "Sargent and Lundy's conceptual cost estimating system" was used to develop certain costs. When

cost estimates are not based on EPA's Control Cost Manual, more documentation is required to substantiate the costs. Please supply additional data to support these costs.

1. The Tables in Appendix C indicate an economic life of 20 years and an interest rate of 7% were used in the economic analyses (Appendix D indicates 20 years and 8% interest). The capital recovery factor listed appears to be based on 20 years and 5.25% interest (5.25% was suggested by the Department). The tables should be corrected.

If you have any questions, please contact me.

Tom Bachman  
*Senior Environmental Engineer*

701.328.5188 • [tbachman@nd.gov](mailto:tbachman@nd.gov) • Division of Air Quality

[health.nd.gov](http://health.nd.gov) • 918 E. Divide Ave • Bismarck, ND 58501-1947 • [Provide Feedback](#)

**From:** Erin Dukart <[EDukart@bepc.com](mailto:EDukart@bepc.com)>

**Sent:** Friday, April 12, 2019 10:13 AM

**To:** Bachman, Tom A. <[tbachman@nd.gov](mailto:tbachman@nd.gov)>; Stroh, David E. <[deStroh@nd.gov](mailto:deStroh@nd.gov)>; Seligman, Angela N. <[aseligman@nd.gov](mailto:aseligman@nd.gov)>

**Cc:** Mike Paul <[MPaul@bepc.com](mailto:MPaul@bepc.com)>

**Subject:** Leland Olds Station 4 Factor Analysis

**CAUTION:** This email originated from an outside source. Do not click links or open attachments unless you know they are safe.

Mr. Bachman,

As you know, Basin Electric submitted Four Factor Analyses for the Leland Olds Station (LOS) and the Antelope Valley Station (AVS) on January 31, 2019. Since that submission, we have determined that the costs associated with Rich Reagent Injection (RRI) for LOS Unit 2 did not take into account the losses due to decreased efficiency. We are in the process of rectifying this oversight and determining what the appropriate and more accurate costs should be. We expect that analysis to be complete within the next few weeks and will submit it to the Department at that time. We apologize for any confusion as a result of this additional analysis, but wanted to let you know that it will be coming. If you have any questions, please don't hesitate to contact me.

Thanks,  
Erin

**Erin Fox Dukart**

Environmental Compliance Administrator

Basin Electric Power Cooperative

1717 E Interstate Avenue | Bismarck, ND 58503

Direct: 701.557.5557 | Cell: 701.426.8116 | Fax: 701.557.5338

[edukart@bepc.com](mailto:edukart@bepc.com) | [\\_basinelectric.com](http://basinelectric.com)

## Stroh, David E.

---

**From:** Erin Dukart <EDukart@bepc.com>  
**Sent:** Friday, July 26, 2019 11:31 AM  
**To:** Stroh, David E.; Bachman, Tom A.; Seligman, Angela N.  
**Subject:** Basin Electric Responses to LOS 4 Factor Analysis Comments  
**Attachments:** FFA\_Leland Olds Station - Response to Agency Comments\_072619.pdf

**Categories:** RH Facility

---

**CAUTION:** This email originated from an outside source. Do not click links or open attachments unless you know they are safe.

---

Good morning,

Attached please find Basin Electric Power Cooperative's responses to the North Dakota Department of Environmental Quality's comments on the Leland Olds Station's Four-Factor Analysis. I apologize for not providing these responses to you sooner. If you have any questions or if there is additional information that we can provide, please contact me. The attachment contains the best information Basin Electric has at this time, but is subject to change based on further analysis.

Thanks,  
Erin

### Erin Fox Dukart

Environmental Compliance Administrator  
Basin Electric Power Cooperative  
1717 E Interstate Avenue | Bismarck, ND 58503  
Direct: 701.557.5557 | Cell: 701.426.8116 | Fax: 701.557.5338  
[edukart@bepc.com](mailto:edukart@bepc.com) | [basinelectric.com](http://basinelectric.com)





NORTH DAKOTA ROUND II REGIONAL HAZE STATE  
IMPLEMENTATION PLAN DETERMINATION'S FOUR-FACTOR  
ANALYSIS FOR LELAND OLDS STATION  
RESPONSE TO AGENCY COMMENTS

July 26, 2019  
Project No. 13772-002



55 East Monroe Street • Chicago, IL 60603 USA • 312-269-2000  
[www.sargentlundy.com](http://www.sargentlundy.com)

## Introduction

In January 2019, Sargent & Lundy LLC (S&L) prepared a Round II Regional Haze Four-Factor Analysis for the Leland Olds Station (LOS) on behalf of Basin Electric Power Cooperative (Basin). The analysis was prepared in response to a request made by the North Dakota Department of Environmental Quality (NDDEQ) and included an assessment of potentially available sulfur dioxide (SO<sub>2</sub>) and nitrogen oxide (NO<sub>x</sub>) emission reduction technologies that could be applied to LOS Unit 1 and 2. As a result, two NO<sub>x</sub> emission reduction technologies were determined to be technically feasible and available to LOS Unit 2: (1) optimizing the existing selective non-catalytic reduction (SNCR) system; and (2) installation of rich reagent injection (RRI). The concept of RRI is similar to SNCR in that urea is injected into the boiler, specifically in the lower furnace to achieve NO<sub>x</sub> reduction.

Following submittal of the Four-Factor Analysis, Basin requested that S&L perform a technical and economic evaluation of the potential impact to the efficiency and net plant heat rate of LOS Unit 2 with the installation of either of these two technologies. These updates account for heat rate impacts associated with the technologies. The adjustments made are based on industry experience which suggests that the additional water injected into the boiler with the urea solution will partially quench the heat generated and lower furnace temperatures, thereby decreasing boiler efficiency. A decrease to the boiler efficiency will increase the unit heat rate and require additional fuel to be fired to generate the same power output. As such, the impact of heat rate degradation due to SNCR and RRI is accounted for in the economic analysis by including purchase of additional fuel as replacement power as part of the facility's variable operating costs. For LOS Unit 2, the increased urea injection rate for the optimized SNCR is estimated to result in a 0.22% heat rate penalty, while the SNCR + RRI option is estimated to result in a 1.25% penalty. The difference in the heat rate penalty is due to the much higher water injection rate with RRI and the resulting temperature impact.

Furthermore, Basin requested S&L to revisit the effort required to implement the future potential RRI system, specifically with regards to the compressed air system. A significant amount of compressed air is utilized to atomize the urea for injection near the cyclones. Upon further review, the LOS operators determined that there would need to be significant expansion of the existing compressed air system, used for the existing SNCR, if RRI would be incorporated. In addition, review of the RRI lance location determined that there would need to be special modifications required based on OEM recommendation.



The RRI configuration for the removal rates referenced in the FFA would require windbox modifications for the lance penetration. As such, S&L revised the capital and operating cost expenses to incorporate the appropriate compressed air system expansion and windbox modifications.

In addition, NDDEQ tendered comments to Basin on April 15 and April 22, 2019, regarding the LOS Four-Factor Analysis. The purpose of this document is to provide responses to the April 15 and April 22 comments from NDDEQ, and to provide updated cost effectiveness tables for LOS Unit 2 (included in Appendix A and B attached hereto) that take into account costs associated with impacts to the net plant heat rate from the installation and operation of SNCR and/or RRI and the required compressed air system expansion.

#### NDDEQ Comment

It is indicated that “Sargent & Lundy’s conceptual cost estimating system” was used to develop certain costs. When cost estimates are not based on EPA’s Control Cost Manual, more documentation is required to substantiate the costs. Please supply additional data to support these costs.

#### S&L/Basin Response

S&L has considerable experience with the federal and state environmental regulations affecting power plant operations, as well as the specification, evaluation, selection, and implementation of emission control technologies for both gas- and coal-fueled utility power facilities, including extensive experience with air pollution control technologies. For example, since 2000, S&L has provided, or is currently providing, engineering services for the implementation of over 40 wet FGD projects, 30 dry FGD projects, 25 dry sorbent injection (DSI) projects, 60 selective catalytic reduction projects (SCR) and 30 selective non-catalytic reduction (SNCR) projects all of which are technologies that were analyzed as part of the Four-Factor Analysis.

Cost estimates for the Basin Four-Factor Analysis were, to the extent practical, prepared in accordance with the methodology described in EPA’s Control Cost Manual and represent study-level cost estimates. Capital costs for major equipment were developed using equipment costs for similar sized units (adjusted for actual equipment sizing), an approach allowed by the Control Cost Manual. Site-specific balance-of-plant (BOP) costs that LOS would incur to retrofit the control

system onto the existing unit were estimated based on site-specific general arrangements and project-specific indirect cost factors. Default factors from EPA's Control Cost Manual were used to calculate indirect capital costs, as applicable. Specifically, cost estimates were prepared with the following general approach and site-specific information:

- Boiler operating parameters were reviewed and mass balances were prepared to calculate flue gas flows across the range of operating conditions and to size the air pollution control equipment.
- Fuel characteristics were evaluated and used to size the material handling, material storage, and piping systems.
- Plant design data were used to estimate absorber sizing, reagent storage and preparation systems, dewatering systems and byproduct handling systems for air pollution control equipment.
- Aerial views of the plant and plant general arrangements were used to identify the general vicinity in which major equipment would be located.

The capital cost estimates were prepared for the major control system components, equipment, material, labor, instrumentation, etc. Capital costs were annualized using the methodology described in the Control Cost Manual, and annual operating and maintenance (O&M) costs were added to the annualized cost of capital to generate a total annual cost. Detailed cost effectiveness worksheets were provided identifying the O&M costs including, variable O&M costs (i.e. reagent, waste disposal, auxiliary power and water), indirect operating costs (i.e. property taxes, insurance, and administrative services), and fixed O&M costs (i.e. operating personnel as well as maintenance material and labor) for all of the air pollution control options. Default factors from EPA's Control Cost Manual were used to calculate fixed O&M costs, as applicable. The approach used by S&L to generate capital cost estimates, O&M costs, and total annual costs is in accordance with the methodology outlined in the Control Cost Manual.

#### NDDEQ Comment

The tables in Appendix C indicate an economic life of 20 years and an interest rate of 7% were used in the economic analyses (Appendix D indicates 20 years and 8% interest). The capital recovery factor listed appears to be based on 20 years and 5.25% interest (5.25% was suggested by the Department). The tables should be corrected.

S&L/Basin Response

NDDEQ is correct that the capital recovery factor used in the Four-Factor Analysis is based on a 5.25% interest rate and 20 years. While the worksheet implied 7.0% interest rate was used, the calculation was correct by using 5.25%. S&L has provided cost effectiveness tables, correcting the typo, attached in Appendices A and B.

NDDEQ Comment

I note in Table 4-6 of the Four-Factor Analysis that the uncontrolled SO<sub>2</sub> emission rates assume all of the sulfur in the coal is emitted from the boiler. Based on the AP-42 emission factor for lignite, about 25% of the sulfur is retained in the bottom ash (varies depending on the sodium content of the ash). Using the AP-42 emission factor (30S), I calculate the uncontrolled emission rate at 2.80 lb/MMBtu. Since it is stated that 3.73 lb/MMBtu was used as the design basis for evaluating the SO<sub>2</sub> controls, it appears this section should be revised.

S&L/Basin Response

We appreciate the agency's comment regarding calculation of the baseline SO<sub>2</sub> inlet rate. S&L used projected future fuel analyses (sulfur and HHV) provided by Basin to calculate the baseline inlet SO<sub>2</sub> rate. Projections were based on the annual average fuel sulfur content and average heating value of the fuel for each year over the next 20 years, taking into account historical deviations seen in the coal quality. Coal data were provided to Basin by the Freedom Mine. The baseline SO<sub>2</sub> rate of 3.73 lb/MBtu represents the highest annual average SO<sub>2</sub> emission rate assuming 100% conversion of fuel sulfur to SO<sub>2</sub> and without taking into account any inherent SO<sub>2</sub> capture.

NDDEQ used the Fourth Edition Compilation of Air Pollutant Emissions Factors (AP-42) from 1985 to adjust the baseline inlet SO<sub>2</sub> rate. That edition of AP-42 includes an assumption for lignite fuels that, on average, 75% of the fuel sulfur will be converted to SO<sub>2</sub> (i.e.  $3.73 \text{ lb SO}_2/\text{MBtu} \times 0.75 = 2.80 \text{ lb SO}_2/\text{MBtu}$ ). However, a more recent edition recommends using an emission factor of 30S (lb/ton) for lignite-fired cyclone boilers, where S = weight % sulfur content of the lignite on a wet basis (see, Fifth Edition Compilation of Air Pollutant Emissions Factors AP-42, Volume 1: Stationary Point and Area Sources, Chapter 1, Table 1.7-1). A conversion factor of 0.077 is used to convert from lb/ton to

lb/MBtu assuming an average lignite heating value of 6,500 Btu/lb. Using this approach, the inlet SO<sub>2</sub> rate would be calculated as:  $(30) \times (1.23) \times (0.077) = 2.84$  lb SO<sub>2</sub>/MBtu.

Although the report states that S&L used an uncontrolled SO<sub>2</sub> rate of 3.73 lb/MBtu as the design basis for the Four-Factor Analysis, this value was only used for the Projected Future Maximum Case. Uncontrolled SO<sub>2</sub> rates of 3.12 lb SO<sub>2</sub>/MBtu and 3.05 lb SO<sub>2</sub>/MBtu for Units 1 and 2 (see Table 4-4 of the Four Factor Analysis), respectively were used for the Actual Average Case. In addition, since the LOS units already have new wet FGD's the only technically feasible SO<sub>2</sub> alternatives are upgrades to the existing wet FGD systems which are primarily O&M driven. Variable O&M costs that are impacted include reagent consumption such as pH buffer and limestone. Variable O&M costs were based on uncontrolled SO<sub>2</sub> rates of 3.12 lb SO<sub>2</sub>/MBtu and 3.05 lb SO<sub>2</sub>/MBtu for Units 1 and 2, respectively for the Actual Average Case. The difference between 2.80 lb SO<sub>2</sub>/MBtu and 3.12 or 3.05 lb SO<sub>2</sub>/MBtu will not have a significant impact on the FGD cost-effectiveness analysis because the variable O&M costs are relatively small.

#### NDDEQ Comment

The Four-Factor Analysis indicates that SNCR was placed in to service at Leland Olds Unit 1 in September 2017 and April 2017 for Unit 2. Your April 18th email regarding the WRAP Regional Haze modeling indicates the average NO<sub>x</sub> emission rate from 2017-2018 was used. The 2028 projections for NO<sub>x</sub> are somewhat higher than the baseline emissions in the January 30, 2019 Four-Factor Analysis (1,267 tons versus 905 for Unit 1 and 4,718 tons versus 4,530 tons for Unit 2) while the SO<sub>2</sub> emissions essentially remained the same (700 tons versus 697 tons for Unit 1 and 1,371 tons versus 1,366 tons for Unit 2). Were the NO<sub>x</sub> emission rates (1.892 lb/MW-net and 3.376 lb/MW-net) calculated using data from the entire year - 2017 - or just the part of the year when the SNCR was operating? What is the reason for NO<sub>x</sub> increasing but not SO<sub>2</sub>? I assume the baseline emission rates in the Four-Factor Analysis will be updated to match the 2028 projections? The Four-Factor analysis sections on baseline emissions (2028 projections) should include the 2028 generation forecast as part of the justification.

#### S&L/Basin Response

Basin to respond.

## ***APPENDIX A***

### SO<sub>2</sub> CONTROL COST EFFECTIVENESS ESTIMATES

## SO<sub>2</sub> CONTROL COST EFFECTIVENESS ESTIMATES

### *BASILINE CAPACITY FACTORS/EMISSIONS AND PROJECTED ACTUAL EMISSION RATES*

Leland Olds Station Units 1 & 2  
SO<sub>2</sub> Control Summary

Table 1. LOS Units 1 & 2 Operating Parameters

Parameter	Units	Unit 1	Unit 2	Notes
Nominal Power Output	MW	220	440	
Annual Heat Input	MMBtu/yr	15,538,351	30,867,575	- Unit 1: 24-month annual average for period February 2015 to January 2017 - Unit 2: 24-month annual average for period April 2016 to March 2018
Annual Capacity Factor	%	68%	69%	- Capacity factor based on Design Hourly Heat Input (MMBtu/hr) and Annual Baseline Heat Input (MMBtu/yr)
Average Baseline Hourly Heat Input	MMBtu/hr	1,851	3,779	- Hourly emission rates based on Average Baseline Hourly Heat Input (MMBtu/hr)
Design Hourly Heat Input	MMBtu/hr	2,622	5,130	Permit No. T5-F73004

Table 2. SO<sub>2</sub> Control Effectiveness

Control Technology	Unit 1					Unit 2				
	Control Efficiency (%)	Expected Emissions (ton/year)	Emission Rate (lb/hr)	Emission Rate (lb/MMBtu)	Expected Emissions Reduction (ton/year)	Control Efficiency (%)	Expected Emissions (ton/year)	Emission Rate (lb/hr)	Emission Rate (lb/MMBtu)	Expected Emissions Reduction (ton/year)
FGD Upgrades - pH Buffer Addition	98.2%	427	102	0.055	269	98.4%	772	189	0.05	594
FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio and L/G Ratio						97.6%	1,158	283	0.075	208
FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio	97.4%	622	148	0.08	75					
Baseline (WFGD)	97.1%	697	166	0.09		97.2%	1,366	334	0.09	
Uncontrolled SO <sub>2</sub>		24,248	5,777	3.12			48,170	11,793	3.12	

Table 3. SO<sub>2</sub> Control Cost Effectiveness - Unit 1

Control Technology	Emissions (tpy)	Tons of SO <sub>2</sub> Removed (tpy)	Total Capital Requirement (\$)	Annualized Capital Cost (\$/year)	Annualized Outage Cost (\$/year)	Total Annual Operating Costs (\$/year)	Total Annual Costs (\$)	Average Cost Effectiveness (\$/ton)	Incremental Cost Effectiveness (\$/ton)
FGD Upgrades - pH Buffer Addition	427	269	\$8,266,000	\$677,000	\$0	\$4,156,000	\$4,833,000	<b>\$17,948</b>	\$21,011
FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio	622	75	\$0	\$0	\$0	\$752,000	\$752,000	<b>\$10,021</b>	
Baseline Unit 1 (WFGD)	697								

Table 4. SO<sub>2</sub> Control Cost Effectiveness - Unit 2

Control Technology	Emissions (tpy)	Tons of SO <sub>2</sub> Removed (tpy)	Total Capital Requirement (\$)	Annualized Capital Cost (\$/year)	Annualized Outage Cost (\$/year)	Total Annual Operating Costs (\$/year)	Total Annual Costs (\$)	Average Cost Effectiveness (\$/ton)	Incremental Cost Effectiveness (\$/ton)
FGD Upgrades - pH Buffer Addition	772	594	\$11,560,000	\$947,000		\$7,340,000	\$8,287,000	<b>\$13,946</b>	\$17,748
FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio and L/G Ratio	1,158	208	\$0	\$0		\$1,439,000	\$1,439,000	<b>\$6,906</b>	
Baseline Unit 2 (WFGD)	1,366								

LOS Units 1 and 2

SO<sub>2</sub> Control Cost Evaluation

FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio and L/G Ratio

SO <sub>2</sub> Control Option Description	FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio and L/G Ratio	
	Unit 1	Unit 2
Baseline SO <sub>2</sub> Emissions, lb/MMBtu		0.09
Post Upgrade SO <sub>2</sub> Emissions, lb/MMBtu		0.075
Capacity Factor used of Cost Estimates (%)		69%

CAPITAL COSTS	Cost (2018\$)		Basis
	Unit 1	Unit 2	
<b>Direct Costs</b>			
<b>Purchased Equipment Costs (PEC)</b>			
Equipment and Materials		\$0	Based on Sargent & Lundy's conceptual cost estimating system.
Instrumentation		\$0	Included in equipment and materials cost
Sales Tax		\$0	5% of Equipment/Material Cost
Freight		\$0	5% of Equipment/Material Cost
<i>Total PEC</i>		\$0	
<b>Direct Installation Costs</b>			
Labor		\$0	Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding		\$0	2.5% of Labor
Mobilization / Demobilization		\$0	1.5% of Labor
<i>Labor Cost Due To Overtime Inefficiency</i>		\$0	5% of Labor
<i>Total Direct Installation Costs</i>		\$0	
Total Direct Costs (PEC + Direct Installation Costs)		\$0	
<b>Indirect Costs</b>			
Contractor's General and Administration Expense		\$0	10% of Total Direct Costs
Contractor's Profit		\$0	5% of Total Direct Costs
Engineering, Procurement, & Project Services		\$0	8% of Total Direct Costs
Construction Management/Field Engineering		\$0	4% of Total Direct Costs
S-U / Commissioning		\$0	1% of Total Direct Costs
Spare Parts		\$0	0.5% of Total Direct Costs
Owner's Cost		\$0	2% of Total Direct Costs
Total Indirect Costs		\$0	
<b>Contingency</b>		\$0	20% of Direct and Indirect Costs
<b>Total Capital Investment (TCI)</b>		\$0	sum of direct costs, indirect costs, and contingency
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$		0.0820	20 year life of equipment (years) @ 5.25% interest.
<b>Annualized Capital Costs (CRF x TCI)</b>		\$0	
<b>OPERATING COSTS</b>			
<b>Operating &amp; Maintenance Costs</b>			
<b>Variable O&amp;M Costs</b>			
Increased Waste Disposal Cost		\$233,000	Based on disposal rate of \$8.70 per ton.
Increased Limestone Cost		\$939,000	Based on limestone cost of \$57 per ton.
DBA Cost		\$0	Based on DBA cost of \$500 per ton.
Increased Auxiliary Power Cost		\$254,000	Based on auxiliary power cost of \$48.06 per MWh (Unit 1) and \$40.47 (Unit 2).
Increased Water Cost		\$13,000	Based on water cost of \$1.00 per 1000 gallons.
<i>Total Variable O&amp;M Costs</i>		\$1,439,000	



LOS Units 1 and 2

SO<sub>2</sub> Control Cost Evaluation

FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio and L/G Ratio

SO <sub>2</sub> Control Option Description	FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio and L/G Ratio	
	Unit 1	Unit 2
Baseline SO <sub>2</sub> Emissions, lb/MMBtu		0.09
Post Upgrade SO <sub>2</sub> Emissions, lb/MMBtu		0.075
Capacity Factor used of Cost Estimates (%)		69%

<b>Fixed O&amp;M Costs</b>			
Additional Operators per shift		0	Assume no additional operators
Operating Labor		\$0	N/A
Supervisor Labor		\$0	N/A
Maintenance Materials		\$0	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor		\$0	Included in cost for maintenance materials.
<i>Total Fixed O&amp;M Cost</i>		\$0	
<b>Indirect Operating Cost</b>			
Property Taxes		\$0	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance		\$0	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration		\$0	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
<i>Total Indirect Operating Cost</i>		\$0	
<b>Total Annual Operating Cost</b>		<b>\$1,439,000</b>	
<b>TOTAL ANNUAL COST</b>			
Annualized Capital Cost		\$0	
Annual Operating Cost		\$1,439,000	
<b>Total Annual Cost</b>		<b>\$1,439,000</b>	

LOS Units 1 and 2  
SO<sub>2</sub> Control Cost Evaluation  
FGD Upgrades - pH Buffer Addition

SO <sub>2</sub> Control Option Description	FGD Upgrades - pH Buffer Addition	
	Unit 1	Unit 2
Baseline SO <sub>2</sub> Emissions, lb/MMBtu	0.09	0.09
Post Upgrade SO <sub>2</sub> Emissions, lb/MMBtu	0.055	0.05
Capacity Factor used of Cost Estimates (%)	68%	69%

CAPITAL COSTS		Cost (2018\$)		Basis	
		Unit 1	Unit 2		
Direct Costs					
Purchased Equipment Costs (PEC)					
Equipment and Materials	\$2,878,000	\$4,027,000	Based on Sargent & Lundy's conceptual cost estimating system.		
Instrumentation	\$0	\$0	Included in equipment and materials cost		
Sales Tax	\$144,000	\$201,000	5% of Equipment/Material Cost		
Freight	\$144,000	\$201,000	5% of Equipment/Material Cost		
Total PEC	\$3,166,000	\$4,429,000			
Direct Installation Costs					
Labor	\$1,919,000	\$2,684,000	Based on Sargent & Lundy's conceptual cost estimating system.		
Scaffolding	\$48,000	\$67,000	2.5% of Labor		
Mobilization / Demobilization	\$29,000	\$40,000	1.5% of Labor		
Labor Cost Due To Overtime Inefficiency	\$96,000	\$134,000	5% of Labor		
Total Direct Installation Costs	\$2,092,000	\$2,925,000			
Total Direct Costs (PEC + Direct Installation Costs)	\$5,258,000	\$7,354,000			
Indirect Costs					
Contractor's General and Administration Expense	\$526,000	\$735,000	10% of Total Direct Costs		
Contractor's Profit	\$263,000	\$368,000	5% of Total Direct Costs		
Engineering, Procurement, & Project Services	\$421,000	\$588,000	8% of Total Direct Costs		
Construction Management/Field Engineering	\$210,000	\$294,000	4% of Total Direct Costs		
S-U / Commissioning	\$79,000	\$110,000	1.5% of Total Direct Costs		
Spare Parts	\$26,000	\$37,000	0.5% of Total Direct Costs		
Owner's Cost	\$105,000	\$147,000	2% of Total Direct Costs		
Total Indirect Costs	\$1,630,000	\$2,279,000			
Contingency	\$1,378,000	\$1,927,000	20% of Direct and Indirect Costs		
Total Capital Investment (TCI)	\$8,266,000	\$11,560,000	sum of direct capital costs, indirect capital costs, and contingency		
Capital Recovery Factor (CRF) = $i(1 + i)^n / (1 + i)^n - 1$	0.0820	0.0820	20 year life of equipment (years) @ 5.25% interest.		
Annualized Capital Costs (CRF x TCI)	\$677,000	\$947,000			
OPERATING COSTS					
Operating & Maintenance Costs					
Variable O&M Costs					
Increased Waste Disposal Cost	\$154,000	\$245,000	Based on disposal rate of \$8.70 per ton.		
Increased Limestone Cost	\$620,000	\$989,000	Based on limestone cost of \$57 per ton.		
DBA Cost	\$2,963,000	\$5,265,000	Based on DBA cost of \$500 per ton.		
Increased Auxiliary Power Cost	\$0	\$254,000	Based on auxiliary power cost of \$48.06 per MWh (Unit 1) and \$40.47 (Unit 2).		
Increased Water Cost	\$9,000	\$14,000	Based on water cost of \$1.00 per 1000 gallons.		
Total Variable O&M Costs	\$3,746,000	\$6,767,000			

LOS Units 1 and 2  
SO<sub>2</sub> Control Cost Evaluation  
FGD Upgrades - pH Buffer Addition

SO <sub>2</sub> Control Option Description	FGD Upgrades - pH Buffer Addition	
	Unit 1	Unit 2
Baseline SO <sub>2</sub> Emissions, lb/MMBtu	0.09	0.09
Post Upgrade SO <sub>2</sub> Emissions, lb/MMBtu	0.055	0.05
Capacity Factor used of Cost Estimates (%)	68%	69%

<b>Fixed O&amp;M Costs</b>			
Additional Operators per shift	0	0	Assume no additional operators
Operating Labor	\$0	\$0	N/A
Supervisor Labor	\$0	\$0	N/A
Maintenance Materials	\$79,000	\$110,000	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor	\$0	\$0	Included in cost for maintenance materials.
<i>Total Fixed O&amp;M Cost</i>	\$79,000	\$110,000	
<b>Indirect Operating Cost</b>			
Property Taxes	\$83,000	\$116,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	\$83,000	\$116,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	\$165,000	\$231,000	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
<i>Total Indirect Operating Cost</i>	\$331,000	\$463,000	
<b>Total Annual Operating Cost</b>	<b>\$4,156,000</b>	<b>\$7,340,000</b>	
<b>TOTAL ANNUAL COST</b>			
Annualized Capital Cost	\$677,000	\$947,000	
Annual Operating Cost	\$4,156,000	\$7,340,000	
<b>Total Annual Cost</b>	<b>\$4,833,000</b>	<b>\$8,287,000</b>	

LOS Units 1 and 2

SO<sub>2</sub> Control Cost Evaluation

FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio

SO <sub>2</sub> Control Option Description	FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio	
	Unit 1	Unit 2
Baseline SO <sub>2</sub> Emissions, lb/MMBtu	0.09	
Post Upgrade SO <sub>2</sub> Emissions, lb/MMBtu	0.08	
Capacity Factor used of Cost Estimates (%)	68%	

CAPITAL COSTS		Cost (2018\$)		Basis
	Unit 1	Unit 2		
<b>Direct Costs</b>				
<b>Purchased Equipment Costs (PEC)</b>				
Equipment and Materials	\$0			Based on Sargent & Lundy's conceptual cost estimating system.
Instrumentation	\$0			Included in equipment and materials cost
Sales Tax	\$0			5% of Equipment/Material Cost
Freight	\$0			5% of Equipment/Material Cost
<i>Total PEC</i>	\$0			
<b>Direct Installation Costs</b>				
Labor	\$0			Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding	\$0			2.5% of Labor
Mobilization / Demobilization	\$0			1.5% of Labor
<u>Labor Cost Due To Overtime Inefficiency</u>	\$0			5% of Labor
<i>Total Direct Installation Costs</i>	\$0			
Total Direct Costs (PEC + Direct Installation Costs)	\$0			
<b>Indirect Costs</b>				
Contractor's General and Administration Expense	\$0			10% of Total Direct Costs
Contractor's Profit	\$0			5% of Total Direct Costs
Engineering, Procurement, & Project Services	\$0			8% of Total Direct Costs
Construction Management/Field Engineering	\$0			4% of Total Direct Costs
S-U / Commissioning	\$0			1% of Total Direct Costs
Spare Parts	\$0			0.5% of Total Direct Costs
Owner's Cost	\$0			2% of Total Direct Costs
Total Indirect Costs	\$0			
<b>Contingency</b>	\$0			20% of Direct and Indirect Costs
<b>Total Capital Investment (TCI)</b>	\$0			sum of direct costs, indirect costs, and contingency
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$	0.0820			20 year life of equipment (years) @ 5.25% interest.
<b>Annualized Capital Costs (CRF x TCI)</b>	\$0			
<b>OPERATING COSTS</b>				
<b>Operating &amp; Maintenance Costs</b>				
<b>Variable O&amp;M Costs</b>				
Increased Waste Disposal Cost	\$148,000			Based on disposal rate of \$8.70 per ton.
Increased Limestone Cost	\$595,000			Based on limestone cost of \$57 per ton.
DBA Cost	\$0			Based on DBA cost of \$500 per ton.
Increased Auxiliary Power Cost	\$0			Based on auxiliary power cost of \$48.06 per MWh (Unit 1) and \$40.47 (Unit 2).
Increased Water Cost	\$9,000			Based on water cost of \$1.00 per 1000 gallons.
<i>Total Variable O&amp;M Costs</i>	\$752,000			

LOS Units 1 and 2

SO<sub>2</sub> Control Cost Evaluation

FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio

SO <sub>2</sub> Control Option Description	FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio	
	Unit 1	Unit 2
Baseline SO <sub>2</sub> Emissions, lb/MMBtu	0.09	
Post Upgrade SO <sub>2</sub> Emissions, lb/MMBtu	0.08	
Capacity Factor used of Cost Estimates (%)	68%	

<b>Fixed O&amp;M Costs</b>		
Additional Operators per shift	0	Assume no additional operators
Operating Labor	\$0	N/A
Supervisor Labor	\$0	N/A
Maintenance Materials	\$0	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor	\$0	Included in cost for maintenance materials.
<i>Total Fixed O&amp;M Cost</i>	\$0	
<b>Indirect Operating Cost</b>		
Property Taxes	\$0	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	\$0	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	\$0	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
<i>Total Indirect Operating Cost</i>	\$0	
<b>Total Annual Operating Cost</b>	<b>\$752,000</b>	
<b>TOTAL ANNUAL COST</b>		
Annualized Capital Cost	\$0	
Annual Operating Cost	\$752,000	
<b>Total Annual Cost</b>	<b>\$752,000</b>	

## SO<sub>2</sub> CONTROL COST EFFECTIVENESS ESTIMATES

### *100% CAPACITY FACTOR AND PROJECTED FUTURE MAXIMUM EMISSION RATES*

**Leland Olds Station Units 1 & 2  
SO<sub>2</sub> Control Summary**

**Table 1. LOS Units 1 & 2 Operating Parameters**

Parameter	Units	Unit 1	Unit 2	Notes
Nominal Power Output	MW	220	440	
Annual Heat Input	MMBtu/yr	22,968,720	44,938,800	- Unit 1: 24-month annual average for period February 2015 to January 2017 - Unit 2: 24-month annual average for period April 2016 to March 2018
Annual Capacity Factor	%	100%	100%	
Hourly Heat Input	MMBtu/hr	2,622	5,130	Permit No. T5-F73004

**Table 2. SO<sub>2</sub> Control Effectiveness**

Control Technology	Unit 1					Unit 2				
	Control Efficiency	Expected Emissions	Emission Rate	Emission Rate	Expected Emissions Reduction	Control Efficiency	Expected Emissions	Emission Rate	Emission Rate	Expected Emissions Reduction
	(%)	(ton/year)	(lb/hr)	(lb/MMBtu)	(ton/year)	(%)	(ton/year)	(lb/hr)	(lb/MMBtu)	(ton/year)
FGD Upgrades - pH Buffer Addition	98.5%	632	144	0.055	398	98.7%	1,123	257	0.05	865
FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio and L/G Ratio						98.0%	1,685	385	0.075	303
FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio	97.9%	919	210	0.08	111					
Baseline (WFGD)	97.6%	1,030	235	0.09		97.6%	1,989	454	0.09	
Uncontrolled SO <sub>2</sub>		42,838	9,780	3.73			83,813	19,135	3.73	

**Table 3. SO<sub>2</sub> Control Cost Effectiveness - Unit 1**

Control Technology	Emissions	Tons of SO <sub>2</sub> Removed	Total Capital Requirement	Annualized Capital Cost	Annualized Outage Cost	Total Annual Operating Costs	Total Annual Costs	Average Cost Effectiveness	Incremental Cost Effectiveness
	(tpy)	(tpy)	(\$)	(\$/year)	(\$/year)	(\$/year)	(\$)	(\$/ton)	(\$/ton)
FGD Upgrades - pH Buffer Addition	632	398	\$8,266,000	\$677,000	\$0	\$6,865,000	\$7,542,000	<b>\$18,948</b>	\$19,237
FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio	919	111	\$0	\$0	\$0	\$2,019,000	\$2,019,000	<b>\$18,200</b>	
Baseline Unit 1 (WFGD)	1,030								

**Table 4. SO<sub>2</sub> Control Cost Effectiveness - Unit 2**

Control Technology	Emissions	Tons of SO <sub>2</sub> Removed	Total Capital Requirement	Annualized Capital Cost	Annualized Outage Cost	Total Annual Operating Costs	Total Annual Costs	Average Cost Effectiveness	Incremental Cost Effectiveness
	(tpy)	(tpy)	(\$)	(\$/year)	(\$/year)	(\$/year)	(\$)	(\$/ton)	(\$/ton)
FGD Upgrades - pH Buffer Addition	1,123	865	\$11,560,000	\$947,000		\$12,429,000	\$13,376,000	<b>\$15,462</b>	\$16,552
FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio and L/G Ratio	1,685	303	\$0	\$0		\$4,078,000	\$4,078,000	<b>\$13,444</b>	
Baseline Unit 2 (WFGD)	1,989								

LOS Units 1 and 2

SO<sub>2</sub> Control Cost Evaluation

FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio

SO <sub>2</sub> Control Option Description	FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio	
	Unit 1	Unit 2
Baseline SO <sub>2</sub> Emissions, lb/MMBtu	0.09	
Post Upgrade SO <sub>2</sub> Emissions, lb/MMBtu	0.08	
Capacity Factor used of Cost Estimates (%)	100%	

CAPITAL COSTS	Cost (2018\$)		Basis
	Unit 1	Unit 2	
<b>Direct Costs</b>			
<b>Purchased Equipment Costs (PEC)</b>			
Equipment and Materials	\$0		Based on Sargent & Lundy's conceptual cost estimating system.
Instrumentation	\$0		Included in equipment and materials cost
Sales Tax	\$0		5% of Equipment/Material Cost
Freight	\$0		5% of Equipment/Material Cost
<b>Total PEC</b>	\$0		
<b>Direct Installation Costs</b>			
Labor	\$0		Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding	\$0		2.5% of Labor
Mobilization / Demobilization	\$0		1.5% of Labor
<b>Labor Cost Due To Overtime Inefficiency</b>	\$0		5% of Labor
<b>Total Direct Installation Costs</b>	\$0		
<b>Total Direct Costs (PEC + Direct Installation Costs)</b>	<b>\$0</b>		
<b>Indirect Costs</b>			
Contractor's General and Administration Expense	\$0		10% of Total Direct Costs
Contractor's Profit	\$0		5% of Total Direct Costs
Engineering, Procurement, & Project Services	\$0		8% of Total Direct Costs
Construction Management/Field Engineering	\$0		4% of Total Direct Costs
S-U / Commissioning	\$0		1% of Total Direct Costs
Spare Parts	\$0		0.5% of Total Direct Costs
<b>Owner's Cost</b>	\$0		2% of Total Direct Costs
<b>Total Indirect Costs</b>	\$0		
<b>Contingency</b>	\$0		20% of Direct and Indirect Costs
<b>Total Capital Investment (TCI)</b>	<b>\$0</b>		sum of direct costs, indirect costs, and contingency
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$	0.0820		20 year life of equipment (years) @ 5.25% interest.
<b>Annualized Capital Costs (CRF x TCI)</b>	<b>\$0</b>		
<b>OPERATING COSTS</b>			
<b>Operating &amp; Maintenance Costs</b>			
<b>Variable O&amp;M Costs</b>			
Increased Waste Disposal Cost	\$397,000		Based on disposal rate of \$8.70 per ton.
Increased Limestone Cost	\$1,599,000		Based on limestone cost of \$57 per ton.
DBA Cost	\$0		Based on DBA cost of \$500 per ton.
Increased Auxiliary Power Cost	\$0		Based on auxiliary power cost of \$48.06 per MWh (Unit 1) and \$40.47 (Unit 2).
Increased Water Cost	\$23,000		Based on water cost of \$1.00 per 1000 gallons.
<b>Total Variable O&amp;M Costs</b>	<b>\$2,019,000</b>		



LOS Units 1 and 2

SO<sub>2</sub> Control Cost Evaluation

FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio

SO <sub>2</sub> Control Option Description	FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio	
	Unit 1	Unit 2
Baseline SO <sub>2</sub> Emissions, lb/MMBtu	0.09	
Post Upgrade SO <sub>2</sub> Emissions, lb/MMBtu	0.08	
Capacity Factor used of Cost Estimates (%)	100%	

<b>Fixed O&amp;M Costs</b>			
Additional Operators per shift	0		Assume no additional operators
Operating Labor	\$0		N/A
Supervisor Labor	\$0		N/A
Maintenance Materials	\$0		Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor	\$0		Included in cost for maintenance materials.
<i>Total Fixed O&amp;M Cost</i>	\$0		
<b>Indirect Operating Cost</b>			
Property Taxes	\$0		1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	\$0		1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	\$0		2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
<i>Total Indirect Operating Cost</i>	\$0		
<b>Total Annual Operating Cost</b>	<b>\$2,019,000</b>		
<b>TOTAL ANNUAL COST</b>			
Annualized Capital Cost	\$0		
Annual Operating Cost	\$2,019,000		
<b>Total Annual Cost</b>	<b>\$2,019,000</b>		

LOS Units 1 and 2

SO<sub>2</sub> Control Cost Evaluation

FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio and L/G Ratio

SO <sub>2</sub> Control Option Description	FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio and L/G Ratio	
	Unit 1	Unit 2
Baseline SO <sub>2</sub> Emissions, lb/MMBtu		0.09
Post Upgrade SO <sub>2</sub> Emissions, lb/MMBtu		0.075
Capacity Factor used of Cost Estimates (%)		100%

CAPITAL COSTS	Cost (2018\$)		Basis
	Unit 1	Unit 2	
<b>Direct Costs</b>			
<b>Purchased Equipment Costs (PEC)</b>			
Equipment and Materials		\$0	Based on Sargent & Lundy's conceptual cost estimating system.
Instrumentation		\$0	Included in equipment and materials cost
Sales Tax		\$0	5% of Equipment/Material Cost
Freight		\$0	5% of Equipment/Material Cost
<i>Total PEC</i>		\$0	
<b>Direct Installation Costs</b>			
Labor		\$0	Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding		\$0	2.5% of Labor
Mobilization / Demobilization		\$0	1.5% of Labor
<i>Labor Cost Due To Overtime Inefficiency</i>		\$0	5% of Labor
<i>Total Direct Installation Costs</i>		\$0	
Total Direct Costs (PEC + Direct Installation Costs)		\$0	
<b>Indirect Costs</b>			
Contractor's General and Administration Expense		\$0	10% of Total Direct Costs
Contractor's Profit		\$0	5% of Total Direct Costs
Engineering, Procurement, & Project Services		\$0	8% of Total Direct Costs
Construction Management/Field Engineering		\$0	4% of Total Direct Costs
S-U / Commissioning		\$0	1% of Total Direct Costs
Spare Parts		\$0	0.5% of Total Direct Costs
Owner's Cost		\$0	2% of Total Direct Costs
Total Indirect Costs		\$0	
<b>Contingency</b>		\$0	20% of Direct and Indirect Costs
<b>Total Capital Investment (TCI)</b>		\$0	sum of direct costs, indirect costs, and contingency
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$		0.0820	20 year life of equipment (years) @ 5.25% interest.
<b>Annualized Capital Costs (CRF x TCI)</b>		\$0	
<b>OPERATING COSTS</b>			
<b>Operating &amp; Maintenance Costs</b>			
<b>Variable O&amp;M Costs</b>			
Increased Waste Disposal Cost		\$729,000	Based on disposal rate of \$8.70 per ton.
Increased Limestone Cost		\$2,938,000	Based on limestone cost of \$57 per ton.
DBA Cost		\$0	Based on DBA cost of \$500 per ton.
Increased Auxiliary Power Cost		\$370,000	Based on auxiliary power cost of \$48.06 per MWh (Unit 1) and \$40.47 (Unit 2).
Increased Water Cost		\$41,000	Based on water cost of \$1.00 per 1000 gallons.
<i>Total Variable O&amp;M Costs</i>		\$4,078,000	

LOS Units 1 and 2

SO<sub>2</sub> Control Cost Evaluation

FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio and L/G Ratio

SO <sub>2</sub> Control Option Description	FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio and L/G Ratio	
	Unit 1	Unit 2
Baseline SO <sub>2</sub> Emissions, lb/MMBtu		0.09
Post Upgrade SO <sub>2</sub> Emissions, lb/MMBtu		0.075
Capacity Factor used of Cost Estimates (%)		100%

<b>Fixed O&amp;M Costs</b>			
Additional Operators per shift		0	Assume no additional operators
Operating Labor		\$0	N/A
Supervisor Labor		\$0	N/A
Maintenance Materials		\$0	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor		\$0	Included in cost for maintenance materials.
<i>Total Fixed O&amp;M Cost</i>		\$0	
<b>Indirect Operating Cost</b>			
Property Taxes		\$0	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance		\$0	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration		\$0	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
<i>Total Indirect Operating Cost</i>		\$0	
<b>Total Annual Operating Cost</b>		<b>\$4,078,000</b>	
<b>TOTAL ANNUAL COST</b>			
Annualized Capital Cost		\$0	
Annual Operating Cost		\$4,078,000	
<b>Total Annual Cost</b>		<b>\$4,078,000</b>	

LOS Units 1 and 2  
SO<sub>2</sub> Control Cost Evaluation  
FGD Upgrades - pH Buffer Addition

SO <sub>2</sub> Control Option Description	FGD Upgrades - pH Buffer Addition	
	Unit 1	Unit 2
Baseline SO <sub>2</sub> Emissions, lb/MMBtu	0.09	0.09
Post Upgrade SO <sub>2</sub> Emissions, lb/MMBtu	0.055	0.05
Capacity Factor used of Cost Estimates (%)	100%	100%

CAPITAL COSTS		Cost (2018\$)		Basis
	Unit 1	Unit 2		
<b>Direct Costs</b>				
<b>Purchased Equipment Costs (PEC)</b>				
Equipment and Materials	\$2,878,000	\$4,027,000	Based on Sargent & Lundy's conceptual cost estimating system.	
Instrumentation	\$0	\$0	Included in equipment and materials cost	
Sales Tax	\$144,000	\$201,000	5% of Equipment/Material Cost	
Freight	\$144,000	\$201,000	5% of Equipment/Material Cost	
<b>Total PEC</b>	<b>\$3,166,000</b>	<b>\$4,429,000</b>		
<b>Direct Installation Costs</b>				
Labor	\$1,919,000	\$2,684,000	Based on Sargent & Lundy's conceptual cost estimating system.	
Scaffolding	\$48,000	\$67,000	2.5% of Labor	
Mobilization / Demobilization	\$29,000	\$40,000	1.5% of Labor	
Labor Cost Due To Overtime Inefficiency	\$96,000	\$134,000	5% of Labor	
<b>Total Direct Installation Costs</b>	<b>\$2,092,000</b>	<b>\$2,925,000</b>		
<b>Total Direct Costs (PEC + Direct Installation Costs)</b>	<b>\$5,258,000</b>	<b>\$7,354,000</b>		
<b>Indirect Costs</b>				
Contractor's General and Administration Expense	\$526,000	\$735,000	10% of Total Direct Costs	
Contractor's Profit	\$263,000	\$368,000	5% of Total Direct Costs	
Engineering, Procurement, & Project Services	\$421,000	\$588,000	8% of Total Direct Costs	
Construction Management/Field Engineering	\$210,000	\$294,000	4% of Total Direct Costs	
S-U / Commissioning	\$79,000	\$110,000	1.5% of Total Direct Costs	
Spare Parts	\$26,000	\$37,000	0.5% of Total Direct Costs	
Owner's Cost	\$105,000	\$147,000	2% of Total Direct Costs	
<b>Total Indirect Costs</b>	<b>\$1,630,000</b>	<b>\$2,279,000</b>		
<b>Contingency</b>	<b>\$1,378,000</b>	<b>\$1,927,000</b>	20% of Direct and Indirect Costs	
<b>Total Capital Investment (TCI)</b>	<b>\$8,266,000</b>	<b>\$11,560,000</b>	sum of direct capital costs, indirect capital costs, and contingency	
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$	0.0820	0.0820	20 year life of equipment (years) @ 5.25% interest.	
<b>Annualized Capital Costs (CRF x TCI)</b>	<b>\$677,000</b>	<b>\$947,000</b>		
<b>OPERATING COSTS</b>				
<b>Operating &amp; Maintenance Costs</b>				
<b>Variable O&amp;M Costs</b>				
Increased Waste Disposal Cost	\$408,000	\$751,000	Based on disposal rate of \$8.70 per ton.	
Increased Limestone Cost	\$1,644,000	\$3,027,000	Based on limestone cost of \$57 per ton.	
DBA Cost	\$4,380,000	\$7,665,000	Based on DBA cost of \$500 per ton.	
Increased Auxiliary Power Cost	\$0	\$370,000	Based on auxiliary power cost of \$48.06 per MWh (Unit 1) and \$40.47 (Unit 2).	
Increased Water Cost	\$23,000	\$43,000	Based on water cost of \$1.00 per 1000 gallons.	
<b>Total Variable O&amp;M Costs</b>	<b>\$6,455,000</b>	<b>\$11,856,000</b>		

LOS Units 1 and 2  
SO<sub>2</sub> Control Cost Evaluation  
FGD Upgrades - pH Buffer Addition

SO <sub>2</sub> Control Option Description	FGD Upgrades - pH Buffer Addition	
	Unit 1	Unit 2
Baseline SO <sub>2</sub> Emissions, lb/MMBtu	0.09	0.09
Post Upgrade SO <sub>2</sub> Emissions, lb/MMBtu	0.055	0.05
Capacity Factor used of Cost Estimates (%)	100%	100%

<b>Fixed O&amp;M Costs</b>			
Additional Operators per shift	0	0	Assume no additional operators
Operating Labor	\$0	\$0	N/A
Supervisor Labor	\$0	\$0	N/A
Maintenance Materials	\$79,000	\$110,000	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor	\$0	\$0	Included in cost for maintenance materials.
<i>Total Fixed O&amp;M Cost</i>	<i>\$79,000</i>	<i>\$110,000</i>	
<b>Indirect Operating Cost</b>			
Property Taxes	\$83,000	\$116,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	\$83,000	\$116,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	\$165,000	\$231,000	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
<i>Total Indirect Operating Cost</i>	<i>\$331,000</i>	<i>\$463,000</i>	
<b>Total Annual Operating Cost</b>	<b>\$6,865,000</b>	<b>\$12,429,000</b>	
<b>TOTAL ANNUAL COST</b>			
Annualized Capital Cost	\$677,000	\$947,000	
Annual Operating Cost	\$6,865,000	\$12,429,000	
<b>Total Annual Cost</b>	<b>\$7,542,000</b>	<b>\$13,376,000</b>	

## ***APPENDIX B***

### NO<sub>x</sub> CONTROL COST EFFECTIVENESS ESTIMATES

## NO<sub>x</sub> CONTROL COST EFFECTIVENESS ESTIMATES

### *BASILINE CAPACITY FACTORS/EMISSIONS AND PROJECTED ACTUAL EMISSION RATES*

**Leland Olds Station Units 1 & 2**  
**NO<sub>x</sub> Control Summary**

**Table 1. LOS Units 1 & 2 Operating Parameters**

Parameter	Units	Unit 1	Unit 2	Notes
Nominal Power Output	MW	220	440	
Annual Heat Input	MMBtu/yr	11,681,110	30,419,273	- Unit 1: Annual average for period July 2017 to June 2018 - Unit 2: Annual average for period April 2017 to March 2018
Annual Capacity Factor	%	51%	68%	- Capacity factor based on Design Hourly Heat Input (MMBtu/hr) and Annual Baseline Heat Input (MMBtu/yr)
Average Baseline Hourly Heat Input	MMBtu/hr	1,646	3,692	- Hourly emission rates based on Average Baseline Hourly Heat Input (MMBtu/hr)
Design Hourly Heat Input	MMBtu/hr	2,622	5,130	Permit No. T5-F73004

**Table 2. NO<sub>x</sub> Control Effectiveness**

Control Technology	Unit 1					Unit 2				
	Control Efficiency	Expected Emissions	Emission Rate	Emission Rate	Expected Emissions Reduction	Control Efficiency	Expected Emissions	Emission Rate	Emission Rate	Expected Emissions Reduction
	(%)	(ton/year)	(lb/hr)	(lb/MMBtu)	(ton/year)	(%)	(ton/year)	(lb/hr)	(lb/MMBtu)	(ton/year)
SCR - Tail-End Configuration	82.8%	292	82	0.05	613					
SNCR Optimization + RRI						67.2%	3,346	812	0.22	1,183
SNCR Optimization						59.7%	4,107	997	0.27	423
Baseline (Unit 1: LNB/ASOFA/SNCR, Unit 2: ASOFA/SNCR)	46.6%	905	255	0.15		55.6%	4,530	1,099	0.30	
Uncontrolled NO <sub>x</sub>		1,694	477	0.29			10,190	2,473	0.67	



Leland Olds Station Units 1 & 2  
NO<sub>x</sub> Control Summary

Table 3. NO<sub>x</sub> Control Cost Effectiveness - Unit 1

Control Technology	Emissions (tpy)	Tons of NO <sub>x</sub> Removed (tpy)	Total Capital Requirement (\$)	Annualized Capital Cost (\$/year)	Annualized Outage Cost (\$/year)	Total Annual Operating Costs (\$/year)	Total Annual Costs (\$)	Average Cost Effectiveness (\$/ton)	Incremental Cost Effectiveness (\$/ton)
SCR - Tail-End Configuration	292	613	\$227,717,000	\$18,662,000	\$0	\$14,809,000	\$33,471,000	<b>\$54,605</b>	
Baseline Unit 1	905								

Table 4. NO<sub>x</sub> Control Cost Effectiveness - Unit 2

Control Technology	Emissions (tpy)	Tons of NO <sub>x</sub> Removed (tpy)	Total Capital Requirement (\$)	Annualized Capital Cost (\$/year)	Annualized Outage Cost (\$/year)	Total Annual Operating Costs (\$/year)	Total Annual Costs (\$)	Average Cost Effectiveness (\$/ton)	Incremental Cost Effectiveness (\$/ton)
SNCR Optimization + RRI	3,346	1,183	\$11,342,000	\$930,000	\$0	\$4,355,000	\$5,285,000	<b>\$4,466</b>	\$5,757
SNCR Optimization	4,107	423	\$3,089,000	\$253,000	\$0	\$654,000	\$907,000	<b>\$2,144</b>	
Baseline Unit 2	4,530								

LOS Units 1 and 2  
NO<sub>x</sub> Control Cost Evaluation  
SNCR Optimization

NO <sub>x</sub> Control Option Description	SNCR Optimization	
	Unit 1	Unit 2
Baseline NO <sub>x</sub> Emissions, lb/MMBtu		0.30
Post Upgrade NO <sub>x</sub> Emissions, lb/MMBtu		0.27
Capacity Factor used of Cost Estimates (%)		68%

CAPITAL COSTS		Cost (2018\$)	Basis
	Unit 1	Unit 2	
<b>Direct Costs</b>			
<b>Purchased Equipment Costs (PEC)</b>			
Equipment and Materials		\$1,147,000	
Instrumentation		\$0	Included in equipment and materials cost
Sales Tax		\$57,000	5% of Equipment/Material Cost
Freight		\$57,000	5% of Equipment/Material Cost
<i>Total PEC</i>		\$1,261,000	
<b>Direct Installation Costs</b>			
Labor		\$646,000	Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding		\$16,000	2.5% of Labor
Mobilization / Demobilization		\$10,000	1.5% of Labor
Labor Cost Due To Overtime Inefficiency		\$32,000	5% of Labor
<i>Total Direct Installation Costs</i>		\$704,000	
Total Direct Costs (PEC + Direct Installation Costs)		<b>\$1,965,000</b>	
<b>Indirect Costs</b>			
Contractor's General and Administration Expense		\$197,000	10% of Total Direct Costs
Contractor's Profit		\$98,000	5% of Total Direct Costs
Engineering, Procurement, & Project Services		\$157,000	8% of Total Direct Costs
Construction Management/Field Engineering		\$79,000	4% of Total Direct Costs
S-U / Commissioning		\$29,000	1.5% of Total Direct Costs
Spare Parts		\$10,000	0.5% of Total Direct Costs
Owner's Cost		\$39,000	2% of Total Direct Costs
Total Indirect Costs		<b>\$609,000</b>	
Contingency		<b>\$515,000</b>	20% of Direct and Indirect Costs
<b>Total Capital Investment (TCI)</b>		<b>\$3,089,000</b>	sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$		0.0820	20 year life of equipment (years) @ 5.25% interest.
<b>Annualized Capital Costs (CRF x TCI)</b>		<b>\$253,000</b>	
<b>OPERATING COSTS</b>			<b>Basis</b>
<b>Operating &amp; Maintenance Costs</b>			
<b>Variable O&amp;M Costs</b>			
Dry Urea Reagent Cost		\$369,000	Based on dry urea reagent cost of \$354 per ton.
Ammonia Reagent Cost		\$0	Based on ammonia reagent cost of \$700 per ton.
Water Cost		\$8,000	Based on water cost of \$1.47 per 1,000 gallons.
Steam Cost		\$17,000	Based on steam cost of \$1.06 per MMBtu.
Hydrated Lime Cost		\$0	Based on hydrated lime cost of \$150 per ton.
Catalyst Replacement Cost		\$0	Based on catalyst cost of \$8,000 per m <sup>3</sup> and catalyst replacement cost of \$1,000 per m <sup>3</sup> .
Auxiliary Power Cost		\$2,000	Based on auxiliary power cost of \$48.06 per MWh (Unit 1) and \$40.47 (Unit 2).
Replacement Power Cost		\$105,000	Based on heat rate penalty of 0.22% and replacement coal cost of \$1.57/MMBtu.
<i>Total Variable O&amp;M Costs</i>		\$501,000	

LOS Units 1 and 2  
NO<sub>x</sub> Control Cost Evaluation  
SNCR Optimization

NO <sub>x</sub> Control Option Description	SNCR Optimization	
	Unit 1	Unit 2
Baseline NO <sub>x</sub> Emissions, lb/MMBtu		0.30
Post Upgrade NO <sub>x</sub> Emissions, lb/MMBtu		0.27
Capacity Factor used of Cost Estimates (%)		68%

<b>Fixed O&amp;M Costs</b>			
Additional Operators per shift		0	
Operating Labor		\$0	Assume \$49.5/hr for each additional operator
Supervisor Labor		\$0	N/A
Maintenance Materials		\$29,500	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor		\$0	Included in cost for maintenance materials.
<b>Total Fixed O&amp;M Cost</b>		\$29,500	
<b>Indirect Operating Cost</b>			
Property Taxes		\$30,900	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance		\$30,900	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration		\$61,800	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
<b>Total Indirect Operating Cost</b>		\$123,600	
<b>Total Annual Operating Cost</b>		<b>\$654,000</b>	
<b>TOTAL ANNUAL COST</b>			
Annualized Capital Cost		\$253,000	
Annual Operating Cost		\$654,000	
<b>Total Annual Cost</b>		<b>\$907,000</b>	

LOS Units 1 and 2  
NO<sub>x</sub> Control Cost Evaluation  
SNCR Optimization + RRI

NO <sub>x</sub> Control Option Description	SNCR Optimization + RRI	
	Unit 1	Unit 2
Baseline NO <sub>x</sub> Emissions, lb/MMBtu		0.30
Post Upgrade NO <sub>x</sub> Emissions, lb/MMBtu		0.22
Capacity Factor used of Cost Estimates (%)		68%

CAPITAL COSTS	Cost (2018\$)		Basis
	Unit 1	Unit 2	
<b>Direct Costs</b>			
<b>Purchased Equipment Costs (PEC)</b>			
Equipment and Materials		\$4,530,000	
Instrumentation		\$0	Included in equipment and materials cost
Sales Tax		\$227,000	5% of Equipment/Material Cost
Freight		\$227,000	5% of Equipment/Material Cost
<i>Total PEC</i>		\$4,984,000	
<b>Direct Installation Costs</b>			
Labor		\$2,047,000	Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding		\$51,000	2.5% of Labor
Mobilization / Demobilization		\$31,000	1.5% of Labor
Labor Cost Due To Overtime Inefficiency		\$102,000	5% of Labor
<i>Total Direct Installation Costs</i>		\$2,231,000	
<b>Total Direct Costs (PEC + Direct Installation Costs)</b>		<b>\$7,215,000</b>	
<b>Indirect Costs</b>			
Contractor's General and Administration Expense		\$722,000	10% of Total Direct Costs
Contractor's Profit		\$361,000	5% of Total Direct Costs
Engineering, Procurement, & Project Services		\$577,000	8% of Total Direct Costs
Construction Management/Field Engineering		\$289,000	4% of Total Direct Costs
S-U / Commissioning		\$108,000	1.5% of Total Direct Costs
Spare Parts		\$36,000	0.5% of Total Direct Costs
Owner's Cost		\$144,000	2% of Total Direct Costs
<b>Total Indirect Costs</b>		<b>\$2,237,000</b>	
Contingency		<b>\$1,890,000</b>	20% of Direct and Indirect Costs
<b>Total Capital Investment (TCI)</b>		<b>\$11,342,000</b>	sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$		0.0820	20 year life of equipment (years) @ 5.25% interest.
<b>Annualized Capital Costs (CRF x TCI)</b>		<b>\$930,000</b>	
<b>OPERATING COSTS</b>			<b>Basis</b>
<b>Operating &amp; Maintenance Costs</b>			
<b>Variable O&amp;M Costs</b>			
Dry Urea Reagent Cost		\$2,490,000	Based on dry urea reagent cost of \$354 per ton.
Ammonia Reagent Cost		\$0	Based on ammonia reagent cost of \$700 per ton.
Water Cost		\$57,000	Based on water cost of \$1.47 per 1,000 gallons.
Steam Cost		\$111,000	Based on steam cost of \$1.06 per MMBtu.
Hydrated Lime Cost		\$0	Based on hydrated lime cost of \$150 per ton.
Catalyst Replacement Cost		\$0	Based on catalyst cost of \$8,000 per m <sup>3</sup> and catalyst replacement cost of \$1,000 per m <sup>3</sup> .
Auxiliary Power Cost		\$39,000	Based on auxiliary power cost of \$48.06 per MWh (Unit 1) and \$40.47 (Unit 2).
Replacement Power Cost		\$598,000	Based on heat rate penalty of 1.25% and replacement coal cost of \$1.57/MMBtu.
<i>Total Variable O&amp;M Costs</i>		\$3,295,000	

LOS Units 1 and 2  
NO<sub>x</sub> Control Cost Evaluation  
SNCR Optimization + RRI

NO <sub>x</sub> Control Option Description	SNCR Optimization + RRI	
	Unit 1	Unit 2
Baseline NO <sub>x</sub> Emissions, lb/MMBtu		0.30
Post Upgrade NO <sub>x</sub> Emissions, lb/MMBtu		0.22
Capacity Factor used of Cost Estimates (%)		68%

<b>Fixed O&amp;M Costs</b>			
Additional Operators per shift		1	
Operating Labor		\$434,000	Assume \$49.5/hr for each additional operator
Supervisor Labor		\$65,000	N/A
Maintenance Materials		\$108,000	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor		\$0	Included in cost for maintenance materials.
<i>Total Fixed O&amp;M Cost</i>		\$607,000	
<b>Indirect Operating Cost</b>			
Property Taxes		\$113,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance		\$113,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration		\$227,000	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
<i>Total Indirect Operating Cost</i>		\$453,000	
<b>Total Annual Operating Cost</b>		<b>\$4,355,000</b>	
<b>TOTAL ANNUAL COST</b>			
Annualized Capital Cost		\$930,000	
Annual Operating Cost		\$4,355,000	
<b>Total Annual Cost</b>		<b>\$5,285,000</b>	

LOS Units 1 and 2  
NO<sub>x</sub> Control Cost Evaluation  
SCR - Tail-End Configuration

NO <sub>x</sub> Control Option Description	SCR - Tail-End Configuration	
	Unit 1	Unit 2
Baseline NO <sub>x</sub> Emissions, lb/MMBtu	0.15	
Post Upgrade NO <sub>x</sub> Emissions, lb/MMBtu	0.05	
Capacity Factor used of Cost Estimates (%)	51%	

CAPITAL COSTS		Cost (2018\$)	Basis
		Unit 1	
<b>Direct Costs</b>			
<b>Purchased Equipment Costs (PEC)</b>			
Equipment and Materials	\$76,672,000		\$0
Instrumentation	\$0		Included in equipment and materials cost
Sales Tax	\$3,834,000		5% of Equipment/Material Cost
Freight	\$3,834,000		5% of Equipment/Material Cost
Total PEC	\$84,340,000		
<b>Direct Installation Costs</b>			
Labor	\$55,521,000		Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding	\$1,388,000		2.5% of Labor
Mobilization / Demobilization	\$833,000		1.5% of Labor
Labor Cost Due To Overtime Inefficiency	\$2,776,000		5% of Labor
Total Direct Installation Costs	\$60,518,000		
Total Direct Costs (PEC + Direct Installation Costs)	\$144,858,000		
<b>Indirect Costs</b>			
Contractor's General and Administration Expense	\$14,486,000		10% of Total Direct Costs
Contractor's Profit	\$7,243,000		5% of Total Direct Costs
Engineering, Procurement, & Project Services	\$11,589,000		8% of Total Direct Costs
Construction Management/Field Engineering	\$5,794,000		4% of Total Direct Costs
S-U / Commissioning	\$2,173,000		1.5% of Total Direct Costs
Spare Parts	\$724,000		0.5% of Total Direct Costs
Owner's Cost	\$2,897,000		2% of Total Direct Costs
Total Indirect Costs	\$44,906,000		
Contingency	\$37,953,000		20% of Direct and Indirect Costs
Total Capital Investment (TCI)	\$227,717,000		sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$	0.0820		20 year life of equipment (years) @ 5.25% interest.
Annualized Capital Costs (CRF x TCI)	\$18,662,000		
<b>OPERATING COSTS</b>			
<b>Operating &amp; Maintenance Costs</b>			
<b>Variable O&amp;M Costs</b>			
Dry Urea Reagent Cost	-\$274,000		Based on dry urea reagent cost of \$354 per ton.
Ammonia Reagent Cost	\$242,000		Based on ammonia reagent cost of \$700 per ton.
RO Water Cost	-\$3,000		Based on water cost of \$1.47 per 1,000 gallons.
Steam Cost	\$181,000		Based on steam cost of \$1.06 per MMBtu.
Hydrated Lime Cost	\$97,000		Based on hydrated lime cost of \$150 per ton.
Catalyst Replacement and Disposal Cost	\$2,081,000		Based on catalyst cost of \$8,000 per m <sup>3</sup> and catalyst replacement cost of \$1,000 per m <sup>3</sup> .
Auxiliary Power Cost	\$705,000		Based on auxiliary power cost of \$48.06 per MWh (Unit 1) and \$40.47 (Unit 2).
Replacement Power Cost	\$0		Based on replacement coal cost of \$1.57/Mbtu.
Total Variable O&M Costs	\$3,029,000		

LOS Units 1 and 2  
NO<sub>x</sub> Control Cost Evaluation  
SCR - Tail-End Configuration

NO <sub>x</sub> Control Option Description	SCR - Tail-End Configuration	
	Unit 1	Unit 2
Baseline NO <sub>x</sub> Emissions, lb/MMBtu	0.15	
Post Upgrade NO <sub>x</sub> Emissions, lb/MMBtu	0.05	
Capacity Factor used of Cost Estimates (%)	51%	

<b>Fixed O&amp;M Costs</b>		
Additional Operators per Shift	1	
Operating Labor	\$434,000	Assume \$49.5/hr for each additional operator 15% of Operating Labor. EPA Cost Manual Section 1, Chapter 2, page 2-31.
Supervisor Labor	\$65,000	
Maintenance Materials	\$2,173,000	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor	\$0	Included in cost for maintenance materials.
<b>Total Fixed O&amp;M Cost</b>	<b>\$2,672,000</b>	
<b>Indirect Operating Cost</b>		
Property Taxes	\$2,277,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	\$2,277,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	\$4,554,000	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
<b>Total Indirect Operating Cost</b>	<b>\$9,108,000</b>	
<b>Total Annual Operating Cost</b>	<b>\$14,809,000</b>	
<b>TOTAL ANNUAL COST</b>		
Annualized Capital Cost	\$18,662,000	
Annual Operating Cost	\$14,809,000	
<b>Total Annual Cost</b>	<b>\$33,471,000</b>	

## NO<sub>x</sub> CONTROL COST EFFECTIVENESS ESTIMATES

### *100% CAPACITY FACTOR AND PROJECTED FUTURE MAXIMUM EMISSION RATES*



**Leland Olds Station Units 1 & 2**  
**NO<sub>x</sub> Control Summary**

**Table 1. LOS Units 1 & 2 Operating Parameters**

Parameter	Units	Unit 1	Unit 2	Notes
Nominal Power Output	MW	220	440	
Annual Heat Input	MMBtu/yr	22,968,720	44,938,800	- Unit 1: Annual average for period July 2017 to June 2018 - Unit 2: Annual average for period April 2017 to March 2018
Annual Capacity Factor	%	100%	100%	
Hourly Heat Input	MMBtu/hr	2,622	5,130	Permit No. T5-F73004

**Table 2. NO<sub>x</sub> Control Effectiveness**

Control Technology	Unit 1					Unit 2				
	Control Efficiency	Expected Emissions	Emission Rate	Emission Rate	Expected Emissions Reduction	Control Efficiency	Expected Emissions	Emission Rate	Emission Rate	Expected Emissions Reduction
	(%)	(ton/year)	(lb/hr)	(lb/MMBtu)	(ton/year)	(%)	(ton/year)	(lb/hr)	(lb/MMBtu)	(ton/year)
SCR - Tail-End Configuration	82.8%	574	131	0.05	1,205					
SNCR Optimization + RRI						67.2%	4,943	1,129	0.22	1,748
SNCR Optimization						59.7%	6,067	1,385	0.27	625
Baseline (Unit 1: LNB/ASOFA/SNCR, Unit 2: ASOFA/SNCR)	46.6%	1,779	406	0.15		55.6%	6,692	1,528	0.30	
Uncontrolled NO <sub>x</sub>		3,330	760	0.29			15,054	2,473	0.67	

Leland Olds Station Units 1 & 2  
NO<sub>x</sub> Control Summary

Table 3. NO<sub>x</sub> Control Cost Effectiveness - Unit 1

Control Technology	Emissions (tpy)	Tons of NO <sub>x</sub> Removed (tpy)	Total Capital Requirement (\$)	Annualized Capital Cost (\$/year)	Annualized Outage Cost (\$/year)	Total Annual Operating Costs (\$/year)	Total Annual Costs (\$)	Average Cost Effectiveness (\$/ton)	Incremental Cost Effectiveness (\$/ton)
SCR - Tail-End Configuration	574	1,205	\$227,717,000	\$18,662,000	\$0	\$15,722,000	\$34,384,000	<b>\$28,528</b>	
Baseline Unit 1	1,779								

Table 4. NO<sub>x</sub> Control Cost Effectiveness - Unit 2

Control Technology	Emissions (tpy)	Tons of NO <sub>x</sub> Removed (tpy)	Total Capital Requirement (\$)	Annualized Capital Cost (\$/year)	Annualized Outage Cost (\$/year)	Total Annual Operating Costs (\$/year)	Total Annual Costs (\$)	Average Cost Effectiveness (\$/ton)	Incremental Cost Effectiveness (\$/ton)
SNCR Optimization + RRI	4,943	1,748	\$11,342,000	\$930,000	\$0	\$5,927,000	\$6,857,000	<b>\$3,922</b>	\$5,082
SNCR Optimization	6,067	625	\$3,089,000	\$253,000	\$0	\$894,000	\$1,147,000	<b>\$1,836</b>	
Baseline Unit 2	6,692								

LOS Units 1 and 2  
NO<sub>x</sub> Control Cost Evaluation  
SNCR Optimization

NO <sub>x</sub> Control Option Description	SNCR Optimization	
	Unit 1	Unit 2
Baseline NO <sub>x</sub> Emissions, lb/MMBtu		0.30
Post Upgrade NO <sub>x</sub> Emissions, lb/MMBtu		0.27
Capacity Factor used of Cost Estimates (%)		100%

CAPITAL COSTS		Cost (2018\$)	Basis
		Unit 1      Unit 2	
<b>Direct Costs</b>			
<b>Purchased Equipment Costs (PEC)</b>			
Equipment and Materials		\$1,147,000	Based on Sargent & Lundy's conceptual cost estimating system.
Instrumentation		\$0	Included in equipment and materials cost
Sales Tax		\$57,000	5% of Equipment/Material Cost
Freight		\$57,000	5% of Equipment/Material Cost
<b>Total PEC</b>		<b>\$1,261,000</b>	
<b>Direct Installation Costs</b>			
Labor		\$646,000	Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding		\$16,000	2.5% of Labor
Mobilization / Demobilization		\$10,000	1.5% of Labor
Labor Cost Due To Overtime Inefficiency		\$32,000	5% of Labor
<b>Total Direct Installation Costs</b>		<b>\$704,000</b>	
<b>Total Direct Costs (PEC + Direct Installation Costs)</b>		<b>\$1,965,000</b>	
<b>Indirect Costs</b>			
Contractor's General and Administration Expense		\$197,000	10% of Total Direct Costs
Contractor's Profit		\$98,000	5% of Total Direct Costs
Engineering, Procurement, & Project Services		\$157,000	8% of Total Direct Costs
Construction Management/Field Engineering		\$79,000	4% of Total Direct Costs
S-U / Commissioning		\$29,000	1.5% of Total Direct Costs
Spare Parts		\$10,000	0.5% of Total Direct Costs
Owner's Cost		\$39,000	2% of Total Direct Costs
<b>Total Indirect Costs</b>		<b>\$609,000</b>	
Contingency		\$515,000	20% of Direct and Indirect Costs
<b>Total Capital Investment (TCI)</b>		<b>\$3,089,000</b>	sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$		0.0820	20 year life of equipment (years) @ 5.25% interest.
<b>Annualized Capital Costs (CRF x TCI)</b>		<b>\$253,000</b>	
<b>OPERATING COSTS</b>			<b>Basis</b>
<b>Operating &amp; Maintenance Costs</b>			
<b>Variable O&amp;M Costs</b>			
Dry Urea Reagent Cost		\$546,000	Based on dry urea reagent cost of \$354 per ton.
Ammonia Reagent Cost		\$0	Based on ammonia reagent cost of \$700 per ton.
Water Cost		\$13,000	Based on water cost of \$1.47 per 1,000 gallons.
Steam Cost		\$24,000	Based on steam cost of \$1.06 per MMBtu.
Hydrated Lime Cost		\$0	Based on hydrated lime cost of \$150 per ton.
Catalyst Replacement Cost		\$0	Based on catalyst cost of \$8,000 per m <sup>3</sup> and catalyst replacement cost of \$1,000 per m <sup>3</sup> .
Auxiliary Power Cost		\$3,000	Based on auxiliary power cost of \$48.06 per MWh (Unit 1) and \$40.47 (Unit 2).
Replacement Power Cost		\$155,000	Based on heat rate penalty of 0.22% and replacement coal cost of \$1.57/MMBtu.
<b>Total Variable O&amp;M Costs</b>		<b>\$741,000</b>	

LOS Units 1 and 2  
NO<sub>x</sub> Control Cost Evaluation  
SNCR Optimization

NO <sub>x</sub> Control Option Description	SNCR Optimization	
	Unit 1	Unit 2
Baseline NO <sub>x</sub> Emissions, lb/MMBtu		0.30
Post Upgrade NO <sub>x</sub> Emissions, lb/MMBtu		0.27
Capacity Factor used of Cost Estimates (%)		100%

<b>Fixed O&amp;M Costs</b>			
Additional Operators per shift		0	
Operating Labor		\$0	Assume \$49.5/hr for each additional operator
Supervisor Labor		\$0	N/A
Maintenance Materials		\$29,500	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor		\$0	Included in cost for maintenance materials.
<b>Total Fixed O&amp;M Cost</b>		\$29,500	
<b>Indirect Operating Cost</b>			
Property Taxes		\$30,900	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance		\$30,900	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration		\$61,800	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
<b>Total Indirect Operating Cost</b>		\$123,600	
<b>Total Annual Operating Cost</b>		<b>\$894,000</b>	
<b>TOTAL ANNUAL COST</b>			
Annualized Capital Cost		\$253,000	
Annual Operating Cost		\$894,000	
<b>Total Annual Cost</b>		<b>\$1,147,000</b>	

LOS Units 1 and 2  
NO<sub>x</sub> Control Cost Evaluation  
SNCR Optimization + RRI

NO <sub>x</sub> Control Option Description	SNCR Optimization + RRI	
	Unit 1	Unit 2
Baseline NO <sub>x</sub> Emissions, lb/MMBtu		0.30
Post Upgrade NO <sub>x</sub> Emissions, lb/MMBtu		0.22
Capacity Factor used of Cost Estimates (%)		100%

CAPITAL COSTS		Cost (2018\$)	Basis
		Unit 1      Unit 2	
<b>Direct Costs</b>			
<b>Purchased Equipment Costs (PEC)</b>			
Equipment and Materials		\$4,530,000	Based on Sargent & Lundy's conceptual cost estimating system.
Instrumentation		\$0	Included in equipment and materials cost
Sales Tax		\$227,000	5% of Equipment/Material Cost
Freight		\$227,000	5% of Equipment/Material Cost
<b>Total PEC</b>		<b>\$4,984,000</b>	
<b>Direct Installation Costs</b>			
Labor		\$2,047,000	Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding		\$51,000	2.5% of Labor
Mobilization / Demobilization		\$31,000	1.5% of Labor
Labor Cost Due To Overtime Inefficiency		\$102,000	5% of Labor
<b>Total Direct Installation Costs</b>		<b>\$2,231,000</b>	
<b>Total Direct Costs (PEC + Direct Installation Costs)</b>		<b>\$7,215,000</b>	
<b>Indirect Costs</b>			
Contractor's General and Administration Expense		\$722,000	10% of Total Direct Costs
Contractor's Profit		\$361,000	5% of Total Direct Costs
Engineering, Procurement, & Project Services		\$577,000	8% of Total Direct Costs
Construction Management/Field Engineering		\$289,000	4% of Total Direct Costs
S-U / Commissioning		\$108,000	1.5% of Total Direct Costs
Spare Parts		\$36,000	0.5% of Total Direct Costs
Owner's Cost		\$144,000	2% of Total Direct Costs
<b>Total Indirect Costs</b>		<b>\$2,237,000</b>	
<b>Contingency</b>		<b>\$1,890,000</b>	20% of Direct and Indirect Costs
<b>Total Capital Investment (TCI)</b>		<b>\$11,342,000</b>	sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$		0.0820	20 year life of equipment (years) @ 5.25% interest.
<b>Annualized Capital Costs (CRF x TCI)</b>		<b>\$930,000</b>	
<b>OPERATING COSTS</b>			<b>Basis</b>
<b>Operating &amp; Maintenance Costs</b>			
<b>Variable O&amp;M Costs</b>			
Dry Urea Reagent Cost		\$3,679,000	Based on dry urea reagent cost of \$354 per ton.
Ammonia Reagent Cost		\$0	Based on ammonia reagent cost of \$700 per ton.
Water Cost		\$84,000	Based on water cost of \$1.47 per 1,000 gallons.
Steam Cost		\$164,000	Based on steam cost of \$1.06 per MMBtu.
Hydrated Lime Cost		\$0	Based on hydrated lime cost of \$150 per ton.
Catalyst Replacement Cost		\$0	Based on catalyst cost of \$8,000 per m <sup>3</sup> and catalyst replacement cost of \$1,000 per m <sup>3</sup> .
Auxiliary Power Cost		\$57,000	Based on auxiliary power cost of \$48.06 per MWh (Unit 1) and \$40.47 (Unit 2).
Replacement Power Cost		\$883,000	Based on heat rate penalty of 1.25% and replacement coal cost of \$1.57/MMBtu.
<b>Total Variable O&amp;M Costs</b>		<b>\$4,867,000</b>	

LOS Units 1 and 2  
NO<sub>x</sub> Control Cost Evaluation  
SNCR Optimization + RRI

NO <sub>x</sub> Control Option Description	SNCR Optimization + RRI	
	Unit 1	Unit 2
Baseline NO <sub>x</sub> Emissions, lb/MMBtu		0.30
Post Upgrade NO <sub>x</sub> Emissions, lb/MMBtu		0.22
Capacity Factor used of Cost Estimates (%)		100%

<b>Fixed O&amp;M Costs</b>			
Additional Operators per shift		1	
Operating Labor		\$434,000	Assume \$49.5/hr for each additional operator
Supervisor Labor		\$65,000	N/A
Maintenance Materials		\$108,000	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor		\$0	Included in cost for maintenance materials.
<i>Total Fixed O&amp;M Cost</i>		\$607,000	
<b>Indirect Operating Cost</b>			
Property Taxes		\$113,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance		\$113,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration		\$227,000	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
<i>Total Indirect Operating Cost</i>		\$453,000	
<b>Total Annual Operating Cost</b>		<b>\$5,927,000</b>	
<b>TOTAL ANNUAL COST</b>			
Annualized Capital Cost		\$930,000	
Annual Operating Cost		\$5,927,000	
<b>Total Annual Cost</b>		<b>\$6,857,000</b>	

LOS Units 1 and 2  
NO<sub>x</sub> Control Cost Evaluation  
SCR - Tail-End Configuration

NO <sub>x</sub> Control Option Description	SCR - Tail-End Configuration	
	Unit 1	Unit 2
Baseline NO <sub>x</sub> Emissions, lb/MMBtu	0.15	
Post Upgrade NO <sub>x</sub> Emissions, lb/MMBtu	0.05	
Capacity Factor used of Cost Estimates (%)	100%	

CAPITAL COSTS		Cost (2018\$)	Basis
		Unit 1	
<b>Direct Costs</b>			
<b>Purchased Equipment Costs (PEC)</b>			
Equipment and Materials	\$76,672,000		Based on Sargent & Lundy's conceptual cost estimating system.
Instrumentation	\$0		Included in equipment and materials cost
Sales Tax	\$3,834,000		5% of Equipment/Material Cost
Freight	\$3,834,000		5% of Equipment/Material Cost
<b>Total PEC</b>	<b>\$84,340,000</b>		
<b>Direct Installation Costs</b>			
Labor	\$55,521,000		Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding	\$1,388,000		2.5% of Labor
Mobilization / Demobilization	\$833,000		1.5% of Labor
Labor Cost Due To Overtime Inefficiency	\$2,776,000		5% of Labor
<b>Total Direct Installation Costs</b>	<b>\$60,518,000</b>		
<b>Total Direct Costs (PEC + Direct Installation Costs)</b>	<b>\$144,858,000</b>		
<b>Indirect Costs</b>			
Contractor's General and Administration Expense	\$14,486,000		10% of Total Direct Costs
Contractor's Profit	\$7,243,000		5% of Total Direct Costs
Engineering, Procurement, & Project Services	\$11,589,000		8% of Total Direct Costs
Construction Management/Field Engineering	\$5,794,000		4% of Total Direct Costs
S-U / Commissioning	\$2,173,000		1.5% of Total Direct Costs
Spare Parts	\$724,000		0.5% of Total Direct Costs
Owner's Cost	\$2,897,000		2% of Total Direct Costs
<b>Total Indirect Costs</b>	<b>\$44,906,000</b>		
<b>Contingency</b>	<b>\$37,953,000</b>		20% of Direct and Indirect Costs
<b>Total Capital Investment (TCI)</b>	<b>\$227,717,000</b>		sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$	0.0820		20 year life of equipment (years) @ 5.25% interest.
<b>Annualized Capital Costs (CRF x TCI)</b>	<b>\$18,662,000</b>		
<b>OPERATING COSTS</b>			
<b>Operating &amp; Maintenance Costs</b>			
<b>Variable O&amp;M Costs</b>			
Dry Urea Reagent Cost	-\$540,000		Based on dry urea reagent cost of \$354 per ton.
Ammonia Reagent Cost	\$475,000		Based on ammonia reagent cost of \$700 per ton.
RO Water Cost	-\$7,000		Based on water cost of \$1.47 per 1,000 gallons.
Steam Cost	\$357,000		Based on steam cost of \$1.06 per MMBtu.
Hydrated Lime Cost	\$190,000		Based on hydrated lime cost of \$150 per ton.
Catalyst Replacement and Disposal Cost	\$2,081,000		Based on catalyst cost of \$8,000 per m <sup>3</sup> and catalyst replacement cost of \$1,000 per m <sup>3</sup> .
Auxiliary Power Cost	\$1,386,000		Based on auxiliary power cost of \$48.06 per MWh (Unit 1) and \$40.47 (Unit 2).
Replacement Power Cost	\$0		Based on replacement coal cost of \$1.57/MMBtu.
<b>Total Variable O&amp;M Costs</b>	<b>\$3,942,000</b>		

LOS Units 1 and 2  
NO<sub>x</sub> Control Cost Evaluation  
SCR - Tail-End Configuration

NO <sub>x</sub> Control Option Description	SCR - Tail-End Configuration	
	Unit 1	Unit 2
Baseline NO <sub>x</sub> Emissions, lb/MMBtu	0.15	
Post Upgrade NO <sub>x</sub> Emissions, lb/MMBtu	0.05	
Capacity Factor used of Cost Estimates (%)	100%	

<b>Fixed O&amp;M Costs</b>		
Additional Operators per Shift	1	
Operating Labor	\$434,000	Assume \$49.5/hr for each additional operator 15% of Operating Labor. EPA Cost Manual Section 1, Chapter 2, page 2-31.
Supervisor Labor	\$65,000	
Maintenance Materials	\$2,173,000	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor	\$0	Included in cost for maintenance materials.
<b>Total Fixed O&amp;M Cost</b>	<b>\$2,672,000</b>	
<b>Indirect Operating Cost</b>		
Property Taxes	\$2,277,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	\$2,277,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	\$4,554,000	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
<b>Total Indirect Operating Cost</b>	<b>\$9,108,000</b>	
<b>Total Annual Operating Cost</b>	<b>\$15,722,000</b>	
<b>TOTAL ANNUAL COST</b>		
Annualized Capital Cost	\$18,662,000	
Annual Operating Cost	\$15,722,000	
<b>Total Annual Cost</b>	<b>\$34,384,000</b>	



#### B.4 – GRE CCS

##### B.4.a – Department Request



May 2, 2018

**FILE**

Ms. Mary Jo Roth  
Great River Energy  
12300 Elm Creek Boulevard  
Maple Grove, MN 55369-4718

Re: Regional Haze  
Second Planning Period

Dear Ms. Roth:

The Department of Health (Department) has begun work on the second planning period (Round 2) State Implementation Plan (SIP) for regional haze. In Round 1 of the regional planning process, the emphasis was on Best Available Retrofit Technology (BART) and making reasonable progress towards the national visibility goal. In Round 2, there are no BART requirements; therefore, we will focus on making reasonable progress. The reasonable progress analysis will be made using the four factors in Section 169A(g)(1) of the Clean Air Act:

The four factors are:

1. The cost of compliance
2. The time necessary to achieve compliance
3. The energy and non-air quality environmental impact of compliance; and
4. The remaining useful life of any existing source subject to such requirements

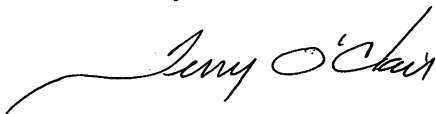
Guidance provided by the U.S. Environmental Protection Agency (Draft Guidance on Progress Tracking Metrics, Long Term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period at [https://www.epa.gov/sites/production/files/2016-07/documents/draft\\_regional\\_haze\\_guidance\\_july\\_2016.pdf](https://www.epa.gov/sites/production/files/2016-07/documents/draft_regional_haze_guidance_july_2016.pdf)) indicates the Department must address 80% of the visibility impairment caused by in-state sources. Data from the IMPROVE monitoring sites at Theodore Roosevelt National Park (TRNP) and Lostwood Wilderness Area (LWA) indicate that sulfates and nitrates continue to be the largest contributors to visibility impairment in these areas. The primary precursors of sulfates and nitrates are emissions of sulfur dioxide (SO<sub>2</sub>) and nitrogen oxides (NO<sub>x</sub>).

Coal-fired electrical generating units have been identified as one of the largest source of sulfur dioxide and nitrogen oxides in North Dakota. Therefore, the Department requests that you prepare a "four factors" analysis for your coal-fired electrical generating units. The analysis should be prepared using the draft EPA guidance noted above. The Department will identify other sources in North Dakota that will be required to submit a four factors analysis.

The Department will be working with the Western Regional Air Partnership (WRAP) to prepare the Round 2 SIP. WRAP will be conducting air quality modeling of regional emissions reductions in early 2019. The Department asks that your "four factors" analysis be submitted by January 31, 2019.

If you have any questions, please contact David Stroh of my staff at (701)328-5188.

Sincerely,

A handwritten signature in cursive script, reading "Terry O'Clair".

Terry L. O'Clair  
Director  
Division of Air Quality

TLO/TB:saj

#### B.4.b – Facility Response



12300 Elm Creek Boulevard  
Maple Grove, Minnesota 55369-4718  
763-445-5000  
greatriverenergy.com

September 12, 2019

Mr. James L. Semerad  
Director, Division of Air Quality  
North Dakota Department of Environmental Quality  
918 E. Divide Avenue, 2<sup>nd</sup> Floor  
Bismarck, ND 58501-1947

Dear Mr. Semerad:

Enclosed please find Great River Energy's *Coal Creek Station Units 1 and 2, Updated Best Available Retrofit Technology Analysis for NOx Emissions*.

Please let me know if you have any questions. I can be reached at 763-445-5212.

Sincerely,

A handwritten signature in black ink, appearing to read 'Mary Jo Roth', with a stylized flourish at the end.

Mary Jo Roth  
Manager, Environmental Services

c: David Stroh  
Tom Bachman  
Greg Archer  
Deb Nelson



## Coal Creek Station Units 1 and 2

### *Updated Best Available Retrofit Technology Analysis for NOx Emissions*

Prepared for  
Great River Energy

September 2019

# Coal Creek Station Units 1 and 2 Updated Best Available Retrofit Technology Analysis for NO<sub>x</sub> Emissions

September 2019

## Contents

1	Introduction .....	1
1.1	Overview of Steps and Factors for Conducting Case-by-Case BART .....	1
1.2	Proposed NO <sub>x</sub> BART Determination for Units 1 and 2 .....	3
2	BART Analysis Methodology .....	4
2.1	Current NO <sub>x</sub> Emissions Performance Levels for BART Analysis .....	4
2.1.1	Lignite Sodium Content Variability .....	7
2.1.2	Unit Load Variability .....	8
2.2	Identify and Rank Available and Technically Feasible Retrofit Emission Control Technologies .....	9
2.3	Factor #1 – Cost of Compliance .....	9
2.4	Factor #2 – Energy and Non-air Environmental Impacts .....	11
2.5	Factor #3 – Pollution Control Equipment at the Source .....	12
2.6	Factor #4 – Remaining Useful Life of the Source .....	12
2.7	Factor #5 – Visibility Impacts .....	12
3	Five-Factor BART NO <sub>x</sub> Analysis at Units 1 and 2 .....	14
3.1	Identification and Ranking of Technically Feasible Retrofit Controls .....	14
3.1.1	Identification of Available NO <sub>x</sub> Controls at Units 1 and 2 .....	14
3.1.2	SCR Technical Feasibility and Control Effectiveness Analysis .....	16
3.1.3	SNCR Technical Feasibility and Control Effectiveness Analysis .....	19
3.2	Factor #1 Evaluation – Costs of Compliance .....	21
3.2.1	SCR Cost Evaluation .....	21
3.2.2	SNCR Cost Evaluation .....	24
3.3	Factor #2 Evaluation – Energy and Non-Air Environmental Impacts .....	26
3.4	Factor #3 Evaluation – Pollution Control Equipment at the Source .....	27
3.5	Factor #4 Evaluation – Remaining Useful Life .....	27
3.6	Factor #5 Evaluation – Visibility Impacts .....	27
3.6.1	Determining 24-Hour Maximum Emission Rates for BART Emissions Control Scenarios .....	27
3.6.2	Modeled Results .....	30

3.7	Conclusion .....	34
-----	------------------	----

### List of Tables

Table 2-1: Annual Average Capacity Factors at Coal Creek Station Unit 1 and Unit 2.....	11
Table 3-1: Barr’s SCR Control Costs, per Unit Basis .....	22
Table 3-2: SCR Pollution Control Cost Effectiveness Summary, per Unit Basis .....	23
Table 3-3: Barr’s SNCR Control Costs, per Unit Basis.....	24
Table 3-4: SNCR Pollution Control Cost Effectiveness Summary, per Unit Basis.....	25
Table 3-3: BART Eligible Sources Screening Analysis Emission Rates .....	29
Table 3-4: BART Eligible Sources Screening Analysis Stack Parameters .....	30
Table 3-5: Year 2000 Visibility Modeling Results.....	31
Table 3-6: Year 2001 Visibility Modeling Results.....	32
Table 3-7: Year 2002 Visibility Modeling Results.....	33

### List of Figures

Figure 2-1: Unit 2 30-day Rolling NO <sub>x</sub> Emissions Performance (lb/MMBtu and ppm).....	6
Figure 2-2: Daily Lignite Ash Sodium Content (As-fired) from January 1, 2018 to July 31, 2019.....	8
Figure 3-1: NO <sub>x</sub> Emissions as a Function of Operating Load and Lignite Sodium Variability.....	35

### List of Attachments

Attachment A:	Report “Best Available Retrofit Technology for NO <sub>x</sub> Emissions from Coal Creek Unit 2 - 2019 Update” September 4, 2019; Black & Veatch
Attachment B:	Report “Cost Estimate for SNCR Impact to Fly Ash Disposal and Sales – Great River Energy – Coal Creek Station” March 1, 2019; Golder Associates Inc.
Attachment C:	Report “Ammonia Slip Mitigation for SNCR Impacted Ash at the Coal Creek Station” March 22, 2019; Boral Resources
Attachment D:	Letter “Coal Creek Station Unit 2 NO <sub>x</sub> Emissions” March 5, 2018 from GRE to the NDDEQ
Attachment E-1:	Report “Protocol for BART-Related Visibility Impairment Modeling Analysis – Great River Energy – Coal Creek Station” July 2019; Barr Engineering Company
Attachment E-2:	Approval Correspondence from US EPA Region 8 and NDDEQ for the BART Modeling Protocol; August 7 and 8, 2019



Attachment F:	EPA RBLC Database Tables
Attachment G:	EPA Control Cost Manual SCR and SNCR Spreadsheets for Units 1 and 2
Attachment H-1:	Report "Estimating Total Sulfuric Acid Emissions from Stationary Power Plants" 2018 Update; Electric Power Research Institute
Attachment H-2:	Sulfuric Acid Mist Emissions Calculations at Coal Creek Station Due to Selective Catalytic Reduction using EPRI Guidance

# 1 Introduction

Great River Energy (GRE) retained Barr Engineering Co. (Barr) to complete an updated analysis and evaluation of Best Available Retrofit Technology (BART) for NO<sub>x</sub> emissions at Coal Creek Station Units 1 and 2. Barr is an environmental and engineering consulting services firm with over 800 employees founded in 1966 with ten offices located in the United States and in Canada. Barr has provided environmental regulatory and technical services to GRE associated with the regional haze regulations at Coal Creek Station and at Stanton Station since 2005.<sup>1</sup> Specifically, Barr completed the BART evaluation and report in December 2007 for Coal Creek Station as well as supplemental analyses and updates through 2012 that are appended to the North Dakota Department of Environmental Quality's (NDDEQ's) State Implementation Plan (SIP) for regional haze.<sup>2</sup> Barr has also completed several other BART analyses for facilities in the power industry and other industrial sectors in North Dakota and other states.

The purpose of this case-by-case BART analysis of NO<sub>x</sub> emissions at Units 1 and 2 is to provide updated information to NDDEQ for the regional haze SIP record.

## 1.1 Overview of Steps and Factors for Conducting Case-by-Case BART

This case-by-case BART analysis for NO<sub>x</sub> emissions at Units 1 and 2 updates and readdresses the five basic steps described in EPA's "Guidelines for BART Determinations Under the Regional Haze Rule" (EPA BART Guidelines).<sup>3</sup>

Barr has completed a dispersion modeling analysis using the CALPUFF modeling platform to evaluate Step 5 in the BART analysis. The corresponding dispersion modeling protocol for Step 5 is provided in Attachment E to this report.

The five steps are summarized as follows:

### Step 1: Identify all Control Technologies

The first step in the analysis is to identify all available retrofit control technologies for each applicable emission unit.

---

<sup>1</sup> GRE has permanently ceased operations at Stanton Station, a 180 MW coal-fired power plant located just outside of Stanton, North Dakota. For informational purposes, Stanton Station's retirement results in an actual annual emissions reduction of 2,329 tpy SO<sub>2</sub> and 1,589 tpy NO<sub>x</sub> based on the average annual reported emissions for the last five calendar years of plant operation (2012 to 2016).

<sup>2</sup> North Dakota Department of Environmental Quality (formerly the North Dakota Department of Health), "North Dakota State Implementation Plan for Regional Haze," Adopted February 24, 2010 as supplemented and amended through December 20, 2012.

<sup>3</sup> 40 CFR 51, Appendix Y.

#### Step 2: Eliminate Technically Infeasible Options

In the second step, the technical feasibility of each control option identified in step one is evaluated with respect to source-specific factors. Technologies which are determined to be technically infeasible are eliminated from further consideration.

#### Step 3: Evaluate Control Effectiveness

In step three, the remaining controls are ranked based on the design control efficiency at the expected emission rate as compared to the emission rate before addition of controls.

#### Step 4: Evaluate Impacts and Document Results

The fourth step utilizes an engineering analysis to document the impacts of each remaining control technology option. The impacts analyses include: 1) costs of compliance, 2) energy impacts, 3) non-air quality environmental impacts, and 4) remaining useful life of the source.

#### Step 5: Evaluate Visibility Impacts

The fifth step simulates the degree of visibility improvement upon application of an additional emissions control technology. This study is conducted using the CALPUFF dispersion model.

Pursuant to the EPA BART Guidelines, application of the 5-step BART analysis *"identifies the best system of continuous emission reduction taking into account the following six factors:*

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

For purposes of consistency with the Black & Veatch technical report in Attachment A, Barr consolidates and orders the BART factors as follows:

Factor 1: Costs of compliance

Factor 2: Energy and non-air environmental impacts

Factor 3: Pollution control equipment in use at the source

Factor 4: Remaining useful life of the source

Factor 5: Visibility impacts

---

<sup>4</sup> 40 CFR 51, Subpart Y, subsection IV.A.

---

The methodology for analyzing these BART factors is described further in Section 2. The recommended BART, summarized in Section 1.2, is based on technical conclusions described in this report for these five factors.

## 1.2 Proposed NO<sub>x</sub> BART Determination for Units 1 and 2

In summary, based on our independent analysis and review of the attached third-party reports and the conservative nature of the cost analyses conducted for Factor #1, Barr concludes that potentially available additional NO<sub>x</sub> emissions control technologies do not represent BART for Units 1 and 2.

- Selective catalytic reduction (SCR) is neither technically feasible as a retrofit control technology at Coal Creek Station nor is it cost-effective. Additionally, the estimated increase in sulfuric acid mist emissions due to an SCR system at Units 1 and 2 offsets much of the modeled visibility improvement that would otherwise occur from a reduction in NO<sub>x</sub> emissions.
- Selective non-catalytic reduction (SNCR) is not cost-effective as well as potentially creates significant environmental impacts related to ammoniated fly ash.

Both SCR and SNCR pose serious risks that would need to be studied further through extensive pilot testing to determine if the technical concerns in Section 3.1.2 and 3.1.3 and adverse environmental impacts in Section 3.3 could be avoided or mitigated at Coal Creek Station.

Based on a review of recent emissions data with current emissions controls at Unit 2 and the anticipated completion of the same advanced combustion controls (LNC3+) for NO<sub>x</sub> to be installed at Unit 1 in the first half of 2020, Units 1 and 2 are expected to perform under anticipated normal operations at an annual average emissions rate of 0.13 pounds of NO<sub>x</sub> per million British thermal units heat input (lb NO<sub>x</sub>/MMBtu). Variability in NO<sub>x</sub> emissions during the year will continue to occur as a function of variable unit load (i.e., ramping in response to Midcontinent Independent System Operator or MISO) and the potential for low coal sodium concentrations (see Section 2.1). Taking into consideration these inherent variabilities affecting NO<sub>x</sub> emissions performance in order to determine the shorter-term average (i.e., 30-day rolling average) emissions rate impact on NO<sub>x</sub> performance, Barr recommends a BART emissions limit of 0.15 lb NO<sub>x</sub>/MMBtu with compliance demonstrated using the existing 40 CFR 75 certified continuous emissions monitoring systems (CEMS).

## 2 BART Analysis Methodology

Barr has conducted an updated examination of the five BART factors for Coal Creek Station Units 1 and 2. Barr's analysis of Factors #1 through #4 considers information developed in recently completed detailed evaluations and technical reports produced by third-party subject matter experts. These reports are provided as attachments. They represent work by Black & Veatch for a Unit 2 NO<sub>x</sub> BART evaluation of BART factors #1 through #4 in Attachment A and from Golder Associates (Golder) and Boral Resources (Boral) for impacts at Units 1 and 2 related to ammoniated fly ash in Attachments B and C, respectively. Section 3 of this report reviews and incorporates these analyses where relevant to the BART factors.

With respect to the Black & Veatch report, Barr provides additional analysis and context to their evaluation, where appropriate. For example, Black & Veatch estimated costs for available emissions control technologies using both the EPA Air Pollution Control Cost Manual<sup>5</sup> (EPA Control Cost Manual) methodology and a "site-specific methodology" incorporating actual costs from installation at another source that are scaled to Coal Creek Station. Barr has completed its own evaluation of costs for available controls also using the EPA Control Cost Manual.

Section 2.1 summarizes the anticipated NO<sub>x</sub> emissions rates from Unit 1 and 2 used to establish the anticipated annual emissions reduction from the application of additional emissions controls.

Sections 2.2 through 2.7 outline the approach to determining availability and technical feasibility of emissions controls and their corresponding impacts evaluated against the BART factors.

### 2.1 Current NO<sub>x</sub> Emissions Performance Levels for BART Analysis

The EPA BART Guidelines at 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."*

The initial BART evaluation used actual emission rates for the same time period used to determine the visibility baseline, which was a 3-year period of emission inventory data from 2000 to 2002. Due to the passage of time, this current BART analysis appropriately updates these emissions rates to reflect existing controls as well as updated operating conditions and emissions performance at Units 1 and 2. These updated NO<sub>x</sub> emissions levels shall take into consideration the DryFining™ technology<sup>6</sup> and any other

---

<sup>6</sup> DryFining™ is an innovative technology developed by GRE that reduces moisture and refines lignite coal, increasing the efficiency and performance of the fuel while reducing emissions. It became operational at Units 1 and 2 in 2010.

combustion controls.<sup>7</sup> 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 modeling conducted over a decade ago, Unit 2 installed larger registers;<sup>8</sup> this system of additional separated overfire air, closed-couple overfire air, and low NOx burners, are together referred to as LNC3+.

Unit 1 is scheduled to install the same LNC3+ technology in the first half of 2020. Therefore, Unit 1 and Unit 2 are assumed to be equivalent in their NOx emissions performance for purposes of estimating emissions reductions from the implementation of control technologies assessed in this BART analysis. Since these two units are of the same size and design, the five-factor BART analysis in Section 3 is the same for Unit 1 and Unit 2. Correspondingly, Barr’s analysis and the referenced work by Black & Veatch, Golder, and Boral apply to both units.<sup>9</sup>

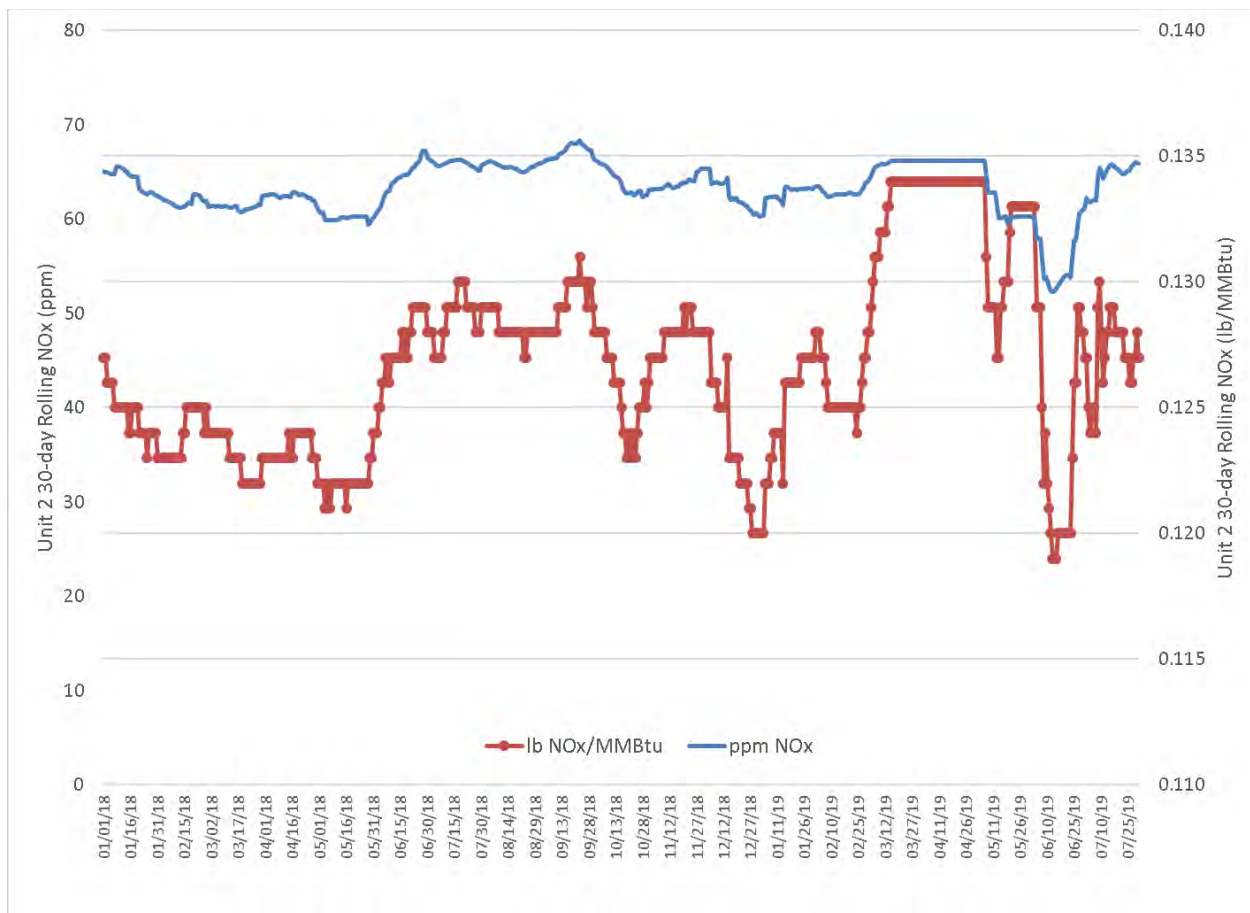
Unit 2’s annual NOx performance currently averages 0.13 pounds per million British thermal units (lb/MMBtu), which reflects an improvement in NOx emissions performance as compared to the time frame after LNC3+ was installed. Figure 2-1 illustrates 30-day rolling average NOx emissions levels on a parts per million (ppm) and lb/MMBtu basis at Unit 2 from January 1, 2018 to July 31, 2019. Actual NOx emissions during this time frame averaged 0.127 lb/MMBtu (rounded to 0.13 lb/MMBtu) with daily variability in NOx emissions between 0.10 and 0.19 lb/MMBtu. On a parts per million (ppm) concentration basis, the 30-day rolling average concentration varies from 52 to 68 ppm.

---

<sup>7</sup> See also Great River Energy’s February 10, 2012 report, “Coal Creek Station Units 1 and 2 Best Available Retrofit Technology Refined Analysis for NOx Emissions.” Section 2.2.

<sup>8</sup> Ibid. Larger registers allow for a greater ability to tune combustion staging and thus improve control of NOx emissions.

<sup>9</sup> Black and Veatch conducted their analysis on Unit 2 only as it currently operates with LNC3+ and is thus also representative of future operation at Unit 1, which is expected to operate with LNC3+ by mid-2020. Effectively, Black and Veatch’s analysis and conclusions for Unit 2 are applicable also to Unit 1.



**Figure 2-1: Unit 2 30-day Rolling NOx Emissions Performance (lb/MMBtu and ppm)**

Operation of these combustion controls at Unit 2 have been demonstrated to be in a well-tuned state for combustion-based pollutants like carbon monoxide (CO) and NOx. A study<sup>10</sup> was conducted by Alstom Power (now General Electric) in 2015 at Unit 2 to comply with the EPA’s Mercury Air Toxics Standards for Utilities (MATS) regulation. Alstom Power determined that the boiler with LNC3+ controls was found to be “well maintained and operated” and “well tuned for full load operation” while monitoring the flue gas for oxygen, NOx, and CO. Minor adjustments to oxygen levels had no effect on NOx emissions and any adjustments for the existing separated overfire air (SOFA) system settings resulted in increased NOx emissions. When Unit 1 is commissioned with LNC3+ controls next year, it also will be tuned to meet performance specifications, including for combustion pollutants. Barr recommends performing the commissioning and tuning process across the expected range of operating loads at Unit 1.

<sup>10</sup> See Attachment A at Appendix H for “Unit’s #1 and #2 MATS Tuning Executive Summary Report”, Alstom Power, June 2015.

In a March 5, 2018, letter to the NDDEQ (see Attachment D), GRE noted two key operational factors that were inhibiting additional reductions in NO<sub>x</sub> emissions at Unit 2:

- 1) Low sodium levels in the lignite provided by the nearby Falkirk Mine, and
- 2) Load variability when Coal Creek Station is required to ramp up and down based on demands from MISO, GRE's independent system operator.

An updated analysis of these factors, as applied to anticipated operations at Units 1 and 2, is provided in Sections 2.1.1 and 2.1.2.

Accounting for these operational factors and review of long-term actual NO<sub>x</sub> performance levels that have been achieved in recent years, the annual NO<sub>x</sub> emissions performance at Unit 2 (and at Unit 1 following LNC3+ installation in early 2020) is 0.13 lb/MMBtu for purposes of determining the emissions reduction effectiveness, costs, and other impacts of additional controls evaluated in Section 3.

### 2.1.1 Lignite Sodium Content Variability

There are two key variables that affect NO<sub>x</sub> performance. One of them is lignite sodium content. GRE notes in the March 5, 2018 letter that low-sodium coal has a *"pronounced impact on the amount of slagging; as sodium levels drop, less slagging occurs."* Reduced slagging creates *"greater heat absorption in the lower zone of the boiler and less heat reaches the upper reheat and superheat zones of the boiler. This lowers unit efficiency and raises the heat rate. As a result, CCS2 (Unit 2) must burn more coal to produce the same amount of electricity."*

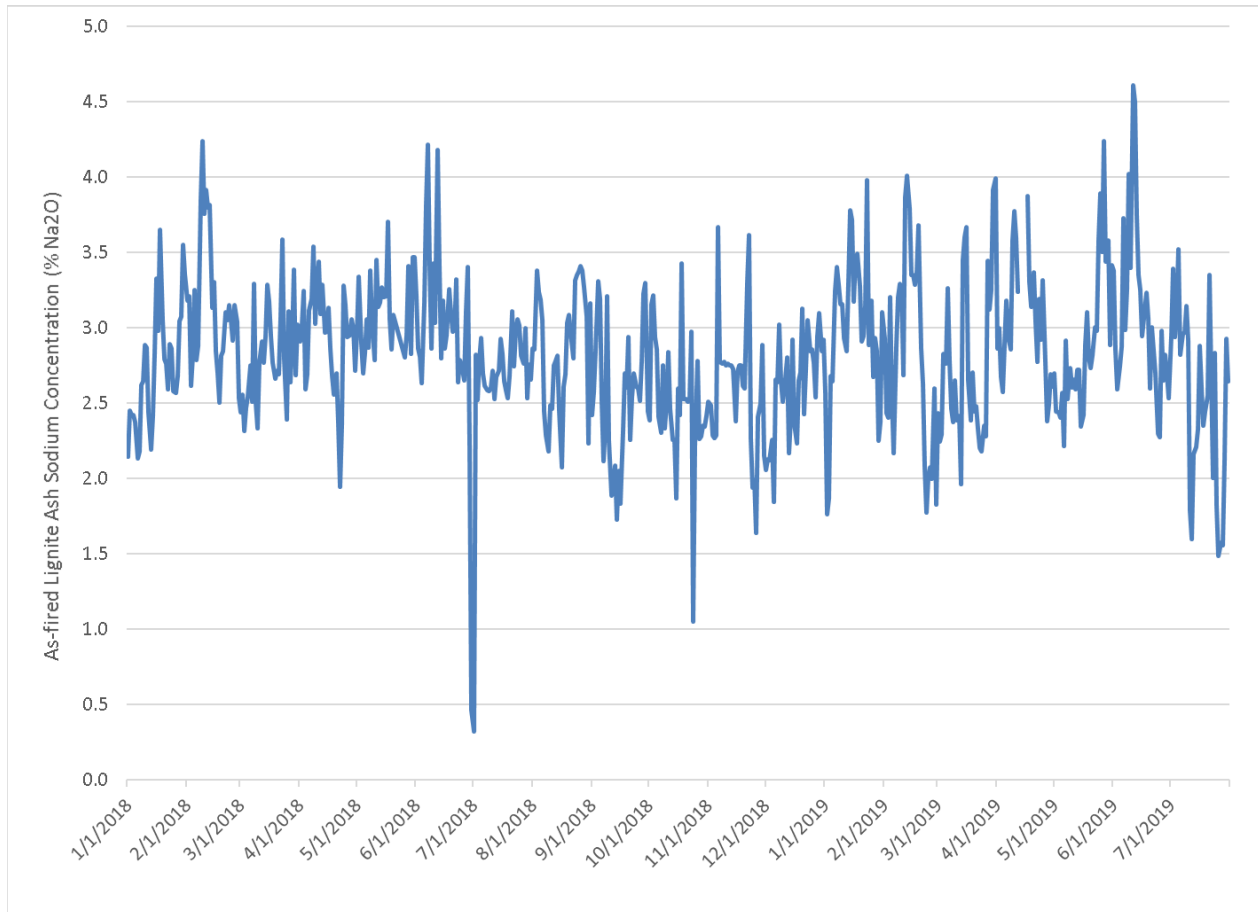
Since the time of this letter, GRE has been coordinating with the Falkirk Mine (Mine)<sup>11</sup> to help improve the minimum lignite sodium concentration to at least 2 percent sodium oxide (Na<sub>2</sub>O) in the ash. The Mine works to support this and other lignite characteristics (i.e., heat content, ash, and sulfur) by manually blending lignite from multiple piles at the mine site. Sodium in the lignite ash is highly variable at the Falkirk Mine. Core samples taken at areas of the Falkirk Mine representing future (20-year projection) mine activity show sodium content data that range from less than 1% to over 14%.<sup>12</sup>

---

<sup>11</sup> The Falkirk Mine is owned and operated by North American Coal Corporation. It is a separate stationary source from Coal Creek Station under the Clean Air Act permitting programs.

<sup>12</sup> See Attachment A at Appendix A.4 for a chart summarizing the mine core sample sodium data.





**Figure 2-2: Daily Lignite Ash Sodium Content (As-fired) from January 1, 2018 to July 31, 2019**

Improvements made to support a minimum sodium content have helped to address the heat absorption and unit efficiency issues, resulting in improved lb NO<sub>x</sub>/MMBtu performance. Figure 2-2 illustrates the daily as-fired sodium levels in the lignite ash at Coal Creek Station since 2018. However, sodium variability in the lignite fed to Units 1 and 2 will continue to occur based on Mine projections. At times, sodium levels are below 2 percent and at other times the levels are much higher than 2 percent, which creates other technical feasibility issues associated with add-on emissions controls. Specifically, higher sodium levels that will occur at times from the Falkirk Mine will cause ammonium bisulfate generation associated with SCR and corresponding deactivation of the SCR catalyst, as described in Section 3.1.2.

### 2.1.2 Unit Load Variability

The second key variable that affects NO<sub>x</sub> performance is load variability. In the May 5, 2018 letter, GRE describes that Coal Creek Station, which was designed as a baseload generation plant, experienced an increasing number of load-following events due to increased production of renewable energy and grid pricing signals. The impact of load shifts such as ramping up or down or operating at low-load, causes an increase in NO<sub>x</sub> emissions on a lb/MMBtu basis as compared to baseload operation.

---

More recently in 2018 and 2019, Units 1 and 2 have not been required to follow load as much, resulting in reduced cycling at night and corresponding reduced load variability. This, along with higher sodium levels in the lignite, have resulted in an improved NO<sub>x</sub> performance level of 0.13 lb/MMBtu on an annual average. However, with the continued growth and reduced costs of renewable energy supply, changes in energy demand, and other market factors, it is reasonable to assume that future load variability at Units 1 and 2 may increase from levels experienced recently.

In summary, unit load variability is expected to continue and will be a critical consideration in estimating NO<sub>x</sub> emissions levels with current emissions control technologies of DryFining™ and LNC3+ as well as for the technical feasibility of new emissions controls at Units 1 and 2.

## **2.2 Identify and Rank Available and Technically Feasible Retrofit Emission Control Technologies**

Consistent with Steps 1 through 3 of the BART analysis (summarized in Section 1.1) and prior to completing a five-factor analysis of each emissions control technology via Steps 4 and 5, commercially available and technically feasible emission control options for Units 1 and 2 must first be identified and ranked in order of control effectiveness. Potentially available emission control options include both add-on control equipment and process improvement applications. All control options identified as available and technically feasible are then evaluated against the five BART factors.

In order to be considered available and technically feasible, an emissions control must have been previously installed and operated successfully on a similar source under similar physical and operating conditions. Novel controls that have not been demonstrated on full-scale, coal-fired utilities are not considered as part of this analysis. Instead, this evaluation focuses on commercially demonstrated control options.

For purposes of this analysis, only those technologies that have the potential to achieve an overall NO<sub>x</sub> emissions less than 0.13 lb/MMBtu are considered. Importantly, the control effectiveness of a retrofit technology will generally not be as high for a unit that has relatively low NO<sub>x</sub> emissions, like Coal Creek, as it would be for a unit with higher emissions. In other words, standard percent reductions may not be applicable and site-specific design considerations should be used when practical.

## **2.3 Factor #1 – Cost of Compliance**

Factor #1 considers and estimates, as needed, the capital and annual operating and maintenance (O&M) costs of the control measure. Costs of emissions controls follow the accounting principles and methodologies in the EPA Control Cost Manual unless more refined site-specific estimates are available. Note that the methods in the EPA Control Cost Manual provide for a more simplified approach to estimate costs, but their application may not completely represent actual installation and operational costs due to site-specific considerations as described in this report. This is especially true for Coal Creek Station due to the location and operation of its unique DryFining™ and stack reheat systems, as described in Section 3.2.

Under Factor #1, the annualized cost of installation and operation, on a dollars per ton of pollutant removed (\$/ton) basis, of the control measure, referred to as “average cost effectiveness,” is compared to a cost effectiveness threshold that is determined by the NDDEQ. Generally, if the average cost effectiveness is greater than the threshold, the cost is considered to not be reasonable, pending an evaluation of other factors.

The cost of an emissions control measure is derived using capital and annual operation and maintenance (O&M) costs. Capital costs generally refer to the money required to design and build the system. This includes direct costs, such as equipment purchases, and installation costs. Indirect costs, such as engineering and construction field expenses and lost revenue due to additional unit downtime to install the additional control measure(s), are considered as part of the capital calculation. Annual O&M costs include labor, supplies, utilities, etc., as used to determine the annualized cost in the numerator of the cost effectiveness value. The denominator of the cost effectiveness value (tons of pollutant removed) is derived as the difference in: 1) anticipated annual emissions using the current emissions control measures (baseline emissions), as described in Section 2.1, in tons per year (tpy), and 2) expected annual emissions performance through installation of the additional retrofit control measure (controlled emissions), also in tpy.

For purposes of calculating baseline emissions at each unit, GRE uses the annual NO<sub>x</sub> performance level of 0.13 lb/MMBtu in conjunction with the maximum heat input capacity<sup>13</sup> and projected annual utilization (also called annual capacity factor or ACF)<sup>14</sup> of the unit to determine an annual tpy value. Over the past 10 years, Coal Creek Station averages 87% plant utilization, as shown in Table 2-1. GRE considers this value representative of projected operations for purposes of determining annualized emissions.

---

<sup>13</sup> The represented nominal heat input capacity in Coal Creek Station’s Title V Permit is 6,015 MMBtu/hr for Unit 1 and 6,022 MMBtu/hr for Unit 2, both of which are approximately equivalent to 605 MW nominal capacity at 10 MMBtu/MW (6,050 MMBtu/hr) that Barr uses in the cost analysis. At times, the short-term firing rate may exceed these values due to swings in lignite heat content and operating factors. These other values are reasonable for determining short-term (i.e., 24-hour) maximum actual emissions.

<sup>14</sup> Annual capacity factor is defined by EPA (40 CFR 60 Subpart Dc) as “... the ratio between the actual heat input to a steam generating unit from an individual fuel or combination of fuels during a period of 12 consecutive calendar months and the potential heat input to the steam generating unit from all fuels had the steam generating unit been operated for 8,760 hours during that 12-month period at the maximum design heat input capacity...”

Table 2-1: Annual Average Capacity Factors at Coal Creek Station Unit 1 and Unit 2

Year	Annual Capacity Factor	
	Unit 1	Unit 2
2009	94.2%	92.7%
2010	93.8%	79.6%
2011	81.6%	89.0%
2012	92.4%	90.9%
2013	92.4%	83.3%
2014	87.8%	88.2%
2015	89.3%	87.3%
2016	86.3%	72.9%
2017	70.8%	85.0%
2018	91.6%	90.5%
<b>10yr Average</b>	<b>88%</b>	<b>86%</b>
<b>Plant Average</b>	<b>87%</b>	

The calculated cost effectiveness value for each control measure is compared to a cost effectiveness threshold established by the NDDEQ. The NDDEQ's original BART cost thresholds were based on the "high cost" value of \$3,000 per ton listed in the June 1999 WRAP Annex to Grand Canyon Visibility Transport Commission (GCVTC) Report.<sup>15</sup> GRE scaled this 1999 value to today's dollars using the Chemical Engineering Plant Cost Index (CEPCI).<sup>16</sup> The CEPCI is an industrial plant index that is considered more representative for purposes of this analysis than general cost indices such as the Consumer Price Index (CPI). The average cost effectiveness threshold in current dollars is calculated to be \$4,630 per ton.<sup>17</sup>

## 2.4 Factor #2 – Energy and Non-air Environmental Impacts

Factor #2 involves consideration of the energy and non-air environmental impacts of each control measure. Non-air quality impacts may include solid (ash) or hazardous waste generation and

<sup>15</sup> Cited by EPA in the "Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations" proposed rule; 69 FR 25198; May 5, 2004.

<sup>16</sup> More information on CEPCI may be found at this link: <https://www.chemengonline.com/pci-home>. The CEPCI is accessible by subscription through "Chemical Engineering" magazine. The CEPCI scaling factors for this analysis compare 1999 values to December 2018 values.

<sup>17</sup> The NDDEQ also calculated an incremental cost effectiveness (cost effectiveness between two control measures) threshold in addition to the average cost effectiveness threshold for the BART evaluations. Barr does not use the incremental cost effectiveness criterion in the Factor #1 evaluation.

---

treatment/disposal, wastewater discharges from a control device, increased water consumption, and land use. The environmental impact analysis is conducted based on consideration of site-specific circumstances.

The energy impact analysis considers whether use of an emissions control technology results in any significant or unusual energy penalties or benefits. Energy use may be evaluated on an energy used per unit of production basis; energy used per ton of pollutant controlled or total annual energy use.

## **2.5 Factor #3 – Pollution Control Equipment at the Source**

Factor #3 considers pollution control equipment in use or anticipated to be used in the near future at the source when determining the availability and impacts of additional retrofit controls. Section 2.1 describes the DryFining™ and LNC3+ technologies at Units 1 and 2 that correspond to a NO<sub>x</sub> emissions performance of 0.13 lb/MMBtu. The evaluation of other control technologies shall consider the ongoing application of these technologies when determining if the additional control is effective in further reducing NO<sub>x</sub>.

Because the NO<sub>x</sub> emissions rate at Coal Creek Station of 0.13 lb/MMBtu is relatively low as compared to uncontrolled coal-fired units, the corresponding control efficiency for additional NO<sub>x</sub> controls applied at Coal Creek Station will inherently not be as high. In order to provide a clearer understanding of NO<sub>x</sub> emissions at the stack when evaluating additional controls in this evaluation, Barr examines the controlled emissions on a lb/MMBtu basis in relationship to the 0.13 lb/MMBtu value.

## **2.6 Factor #4 – Remaining Useful Life of the Source**

Factor #4 is the remaining useful life of the source, which is considered to be the difference between the date that additional emissions controls will be put in place and the date that the facility permanently ceases operation. Generally, the remaining useful life of the source is assumed to be longer than the useful life of the emissions control measure unless there is an enforceable cease-operation requirement. In the presence of an enforceable end date, the cost calculation can use a shorter period to amortize the capital cost.

For the purpose of this evaluation, the remaining useful life of both Unit 1 and Unit 2 is assumed to be longer than the useful life of the additional emission control measures. Therefore, the expected useful life of the control measure is used to calculate the emissions reductions, amortized costs, and the resulting cost per ton (\$/ton).

## **2.7 Factor #5 – Visibility Impacts**

The EPA BART Guidelines also require consideration of the degree of visibility improvement resulting from application of the retrofit technology when determining BART for an individual source. The CALPUFF program models how a pollutant contributes to visibility impairment with consideration for the background atmospheric ammonia, ozone and meteorological data. Additionally, the interactions between the visibility impairing pollutants NO<sub>x</sub>, SO<sub>2</sub> and PM<sub>10</sub> (and the speciated components of particulate matter) can play a large part in predicting impairment.

---

Barr and GRE communicated with EPA Region 8 and the NDDEQ air quality staff to develop the dispersion modeling protocol for evaluating Factor #5.<sup>18</sup> The dispersion modeling protocol and corresponding agency approval correspondence is contained in Attachment E-1 and E-2 to this report.

---

<sup>18</sup> US EPA Region 8 provided draft comments on GRE's March 5, 2019 draft protocol document in April 8, 2019 correspondence from Monica Morales to Jim Semerad of the NDDEQ. Great River Energy provided responses to the comments on May 3, 2019, followed by a May 13, 2019 teleconference between staff at US EPA Region 8, NDDEQ, Great River Energy, and Barr Engineering Company.

## 3 Five-Factor BART NO<sub>x</sub> Analysis at Units 1 and 2

Section 3.1 identifies NO<sub>x</sub> emissions control technologies and summarizes available and technically feasible controls at Units 1 and 2 using Steps 1 through 3 of the BART analysis. Sections 3.2 through 3.6 evaluate each of the five BART factors for the retrofit control technologies that are assumed to be technically feasible.

For purposes of not duplicating the narrative in the other technical reports in Attachments A, B, and C, Sections 3.1 through 3.5 refer to these reports and add additional context or information based on Barr's independent evaluation.

Section 3.7 summarizes conclusions of this updated NO<sub>x</sub> BART analysis.

### 3.1 Identification and Ranking of Technically Feasible Retrofit Controls

Barr has conducted a review of potentially available NO<sub>x</sub> control technologies and evaluated the technical feasibility of NO<sub>x</sub> retrofit controls at Units 1 and 2.

#### 3.1.1 Identification of Available NO<sub>x</sub> Controls at Units 1 and 2

In the 2007 BART Analysis<sup>19</sup> for Coal Creek Station, Barr identified several potentially available NO<sub>x</sub> control technologies and conducted a corresponding technical feasibility analysis. In this update, Barr has reviewed its previous BART analyses contained in the NDDEQ's regional haze SIP record as well as Black & Veatch's recent evaluation provided in Attachment A. From this review, a few additional types of NO<sub>x</sub> control technologies, which are additional forms of catalytic reduction, were identified:

- Tri-Mer® UltraCat ceramic filters with SCR catalyst incorporated into the ceramic filter matrix.
- Fabric filter bags with SCR catalyst incorporated into the filter bags. Manufacturers include Haldor Topsoe CataFlex™ and Gore® DeNO<sub>x</sub> Catalytic Filter Bags
- Use of mid-temperature range SCR catalyst; this catalyst is capable of NO<sub>x</sub> reduction down to 300°F, potentially available from IBIDEN CERAM and Shell.

A technical feasibility evaluation of each of these additional emissions controls is described below in this section. None of these emissions controls are considered technically feasible for Coal Creek Station.

---

<sup>19</sup> December 12, 2007, "Coal Creek Station Units 1 and 2 Best Available Retrofit Technology Analysis." This report is attached as Appendix C.2 to the NDDEQ's "North Dakota State Implementation Plan for Regional Haze", February 24, 2010.

In summary, consistent with Barr's findings in its earlier reports, the only available NO<sub>x</sub> control technologies that could reduce annual emissions less than the 0.13 lb/MMBtu level described in Section 2.1 and that are potentially applicable to Coal Creek Station, pending the technical feasibility evaluation, is SCR and SNCR.<sup>20</sup> The technical feasibility and control effectiveness evaluation for these two types of emissions controls is provided in Sections 3.1.2 and 3.1.3, respectively.

The 2007 BART Analysis noted that wet scrubbing NO<sub>x</sub> control technologies, such as Tri-NO<sub>x</sub> and low temperature oxidation (LoTO<sub>x</sub>™), were considered commercially available and were also presumed to be applicable (technically feasible) to a source type like Coal Creek Station. These technologies were not BART due to very high costs and significant environmental impacts (i.e., wastewater). Barr has since queried the EPA's RACT/BACT/LAER Clearinghouse (RBLC),<sup>21</sup> which shows no such installations on large (greater than 250 MMBtu/hr) coal fired boilers to date. Because no known installations of these control types have been completed on a source type that is of similar size and with similar characteristics as at Units 1 and 2, these technologies are not technically feasible for BART and are not evaluated further. If these technologies were to be assessed against the five BART factors, Barr expects that the same conclusions would be made with respect to substantial economic and non-air environmental impacts.

### **UltraCat**

The advantage of Ultra Cat is that the SCR catalyst is protected by being imbedded in the ceramic filter matrix. It is intended for high temperature applications such as glass manufacturing. Accordingly, it should be able to withstand the adverse effects of sodium in the boiler fly ash because the fly ash is filtered out before the flue gas can come in contact with the SCR catalyst particles. It is unknown at this time whether or not the sodium in the fly ash may cause plugging of the ceramic filter pores in the same way that sodium causes plugging in SCR catalyst pores.

UltraCat is not a viable retrofit option for Coal Creek Station, because it has not been implemented on a process that is close to the size of the Coal Creek Station boiler. Tri-Mer, UltraCat's manufacturer, indicates that the UltraCat modules are only capable of processing 30,000 actual cubic feet per minute (acfm) each and the maximum number of modules recommended per application is ten (300,000 acfm maximum). By comparison, the air flow rate out of the Coal Creek Station economizers exceeds 3,000,000 acfm at 830°F. Therefore, this technology is not feasible and is not further evaluated.

---

<sup>20</sup> The EPA BART Guidelines describe technical feasibility using two key concepts: "availability" (e.g., commercially demonstrated technology for sale) and "applicability." With respect to applicability, EPA describes the evaluation as follows: *"Generally, such a demonstration involves an evaluation of the characteristics of the pollutant-bearing gas stream and the capabilities of the technology. Alternatively, a demonstration of technical infeasibility may involve a showing that there are unresolvable technical difficulties with applying the control to the source (e.g., size of the unit, location of the proposed site, operating problems related to specific circumstances of the source, space constraints, reliability, and adverse side effects on the rest of the facility)."*

<sup>21</sup> EPA's RBLC is accessed at <https://cfpub.epa.gov/rblc/index.cfm?action=Home.Home>



---

### **Catalytic Filter Bags**

The advantage of catalytic filter bags is that the SCR catalyst is protected by enclosing the SCR catalyst inside a fabric filter bag. Catalytic filter bags are intended for multi-pollutant controls in applications where a fabric filter is used for particulate control. Thus, it should be able to withstand the adverse effects of sodium in the boiler fly ash because the fly ash is filtered out before the flue gas can come in contact with the catalyst.

Catalytic filter bags are not a technically feasible BART control for Coal Creek Station, because no known installations of this technology have been implemented on a process functionally comparable to the Coal Creek Station boilers. Additionally, Coal Creek Station uses electrostatic precipitators (ESPs) for particulate matter control instead of a baghouse, so this would require an entirely new baghouse complex with a corresponding extended several-month plant outage, which is impracticable and is thus not a viable retrofit option for further evaluation.

### **“Mid-Temperature” SCR Catalyst**

Shell-CRI SCR catalyst is rated from 280°F to 750°F. IBIDEN CERAM indicates its SCR catalyst may be effective to a certain degree from 300°F to 1,050°F. The outlet temperatures of the Units 1 and 2 air preheaters are approximately 350°F.

However, these control applications in practice are for very-low-sulfur fuel based exhaust only (e.g., natural gas, scrubbed refinery fuel gas). IBIDEN CERAM confirmed that sulfur levels at Units 1 and 2 downstream of the ESP are too high for installing an SCR, especially at lower operating temperatures (300°F to 400°F) where ammonium bisulfate generation causes catalyst deactivation and plugging.

Effectively, the SO<sub>2</sub>/SO<sub>3</sub> concentrations would need to be near 0 ppm for SCR to be viable for this option; otherwise, sulfuric acid would be formed as a side reaction on the SCR catalyst, ammonium bisulfate would form due to the reaction of ammonium and sulfuric acid, and catalyst plugging and deactivation would occur as a result. Therefore, this technology is not technically feasible at Units 1 and 2 and is not further evaluated.

### **3.1.2 SCR Technical Feasibility and Control Effectiveness Analysis**

An SCR system has two types of arrangements: “high-dust” (reactor is located upstream of the particulate control system) and “low-dust” (reactor is located downstream of the particulate control system). In the 2007 BART Analysis, Barr ascertained that a high-dust system was technically infeasible at Units 1 and 2 “due to the likelihood of catalyst surface plugging caused by high sodium concentrations,” and that “a low-dust SCR would require reheat to bring the stream temperature back to the effective range after it is cooled for particulate removal, but is a technical feasible option for NO<sub>x</sub> reduction.”

Barr’s conclusion that a low-dust SCR is technically feasible (i.e., it is available and applicable to the source type) is unchanged with this update. The particulate controls will capture most of the sodium-bearing fly ash particles, and thus may mitigate SCR catalyst deactivation that is expected to otherwise occur with a

high-dust SCR. However, in order for the SCR to be most effective at controlling NO<sub>x</sub> emissions from Units 1 and 2 that are already entering the system at a relatively low emissions rate (0.13 lb/MMBtu annualized), the exhaust gas from the outlet of the ESP must be reheated through a new fuel-fired reheat system to increase its temperature up to an SCR operating design of approximately 650°F. Subsequently, the gas leaving the SCR must then be cooled to the SO<sub>2</sub> scrubber inlet design temperature of 300°F. Designing and installing such reheating and cooling systems are expected to have significant economic impact and will have material environmental impacts due to associated air emissions from firing additional natural gas to reheat the exhaust. Barr believes that Black and Veatch's reported high-level cost estimate of the flue gas reheat and cooling systems at \$17 to \$20 million is reasonable, but actual installed costs may be higher than this when accounting for other site-specific factors. Therefore, a low-dust SCR will have a demonstrably higher economic impact than a high-dust SCR system, if the high-dust SCR system were determined to be technically feasible.

With respect to the technical feasibility of high-dust SCR, Barr's conclusion from 2007 that it is technically infeasible at Units 1 and 2 remains unchanged. Barr concurs with Black and Veatch's analysis and conclusion that an SCR catalyst supplier is unable to ensure reliable performance and catalyst life given significant concerns with potential plugging and catalyst deactivation unless extended trials (i.e., pilot testing with the exhaust characteristics of Units 1 and 2) are performed. The EPA generally does not consider a control technology to be technically feasible in this instance:<sup>22</sup>

*"Neither is it expected that an applicant would be required to experience extended trials to learn how to apply a technology on a totally new and dissimilar source type."*

Given that the physical characteristics of the coal burned at Coal Creek Station and the associated exhaust gas stream flow and characteristics are outside the realm of installed SCR systems and because pilot testing and extended trials would be required to assess operational risks associated with catalyst deactivation, SCR is not technically feasible.

Notwithstanding that a high-dust SCR at Units 1 and 2 is not technically feasible for BART, Barr conservatively carries forward SCR into the five-factor BART evaluation to assess the related costs and non-air quality impacts of applying this technology at Coal Creek Station. In doing so, the five-factor BART evaluation for high-dust SCR effectively also covers the impacts of a low-dust SCR, noting that the economic impact of a low-dust SCR will be higher than a high-dust SCR due to reheat and cooling systems, as described above.

Barr completed an independent search of the RBLC database for utility-sized coal-fired boilers for SCR systems and performance levels. Determinations for Best Available Control Technology (BACT) and Lowest Achievable Emissions Rate (LAER) are generally more stringent than that for BART. Accordingly, the RBLC data provides information consistent with the best controls on recently constructed new and modified coal-fired utility boilers. Please see Attachment F for the RBLC summary tables. The RBLC listings range

---

<sup>22</sup> USEPA, "Draft New Source Review Workshop Manual," October 1990, Page B.18.

from 0.05 to 0.25 lb/MMBtu with an average of 0.084 lb/MMBtu (9 listings). For comparison, Black and Veatch reports a SCR control effectiveness of 0.05 to 0.08 lb NO<sub>x</sub>/MMBtu from their review of actual SCR performance data recently collected from the Western Regional Air Partnership (WRAP) and EPA's Clean Air Markets Division (CAMD). The only empirical data available to represent the best performance to be expected is that of existing large power plants burning Texas lignite, which achieve 0.062 to 0.075 lb/MMBtu annual performance levels per Black and Veatch's review of the WRAP data.<sup>23</sup> As these units are most representative of the actual performance at lignite-fired units, a range of SCR catalyst performance levels at 0.06 and 0.08 lb NO<sub>x</sub>/MMBtu is established for purposes of the five-factor evaluation.

Actual SCR performance at Coal Creek Station is likely to not be as effective as at the Texas facilities based on the comparatively greater sodium content and other constituents of North Dakota lignite affecting the SCR catalyst as compared to that of Texas lignite. In the last two years, the as-fired lignite ash sodium content averaged 3% with variability generally of +/- 1% with deviation intermittently beyond these levels, as shown in Figure 2.2. The lignite ash sodium content has been and is expected, at times, to be greater than 4%, which is the maximum sodium percentage in IBIDEN CERAM's catalyst design.<sup>24</sup> Additionally, lignite ash sodium content data at the Falkirk mine, as summarized in Black and Veatch's report,<sup>25</sup> shows that 27% of all samples have a sodium content greater than 4% and that 9% of all samples were greater than 10% sodium content. By comparison, the sodium content in Texas lignite ash is consistently lower than that in North Dakota lignite ash. For example, one literature reference summarizes Texas lignite ash sodium levels between 0.59 and 1.67%, whereas North Dakota lignite ash sodium is shown as 5.8%.<sup>26</sup> In summary, the expected degradation and decreased performance of SCR catalyst in North Dakota lignite units is anticipated to be much more prevalent than at units firing lower sodium fuel like that in Texas.

Barr notes that the Black & Veatch report estimates the SCR control costs for a range of performance specifications at 0.04, 0.06, and 0.08 lb NO<sub>x</sub>/MMBtu. The estimated performance level of 0.04 lb NO<sub>x</sub>/MMBtu provided by the catalyst supplier was only for a one-time initial performance test. IBIDEN-Ceram, the SCR catalyst supplier, was uncertain of the degradation of catalyst performance over time in the presence of the high sodium content of the lignite coal burned at Coal Creek Station and required pilot testing to ascertain this critical design information during sustained operations. Correspondingly, Barr believes that 0.04 lb/MMBtu is not a demonstrable performance level for sustained operations at

---

<sup>23</sup> See Attachment A at Section 3.1 and Appendix F.

<sup>24</sup> See Attachment A at Appendix E.

<sup>25</sup> See Attachment A at Appendix A.4.

<sup>26</sup> The Babcock and Wilcox Company, "Steam: its generation and use," 41<sup>st</sup> Edition (2005), Chapter 9, Table 6 "Properties of U.S. Coals."

Coal Creek Station and that 0.06 lb/MMBtu is the best level of performance that can reasonably be expected based on established information to date.

Further, there are site-specific barriers to the installation of SCR at Coal Creek Station. The existing DryFinishing™ system and the stack reheat system<sup>27</sup> would need to be removed to tie SCR duct work into the boiler house and then be reconfigured, requiring an extended several-month outage, which is impracticable. Importantly, DryFinishing™ and stack reheat system are an integral part of the Coal Creek Station design to meet SO<sub>2</sub> BART requirements and must be preserved. DryFinishing™ also is used to remove moisture and improve the properties such as the heat content of lignite coal prior to combustion, thus improving NO<sub>x</sub> performance and the energy efficiency of the Coal Creek Station boilers.

Finally, Barr acknowledges the technical feasibility work at Coal Creek Station that was completed by Fuel Tech, a company that provides emissions control technologies for power plants and other sectors, as summarized in the Black and Veatch report.<sup>28</sup> In examining application of their ASCR® hybrid technology, Fuel Tech also noted process concerns with sodium levels causing significant catalyst deactivation. Because of this and other concerns (e.g., spatial limitations), Fuel Tech would not recommend using its ASCR technology at Coal Creek Station and, at a minimum, would need pilot testing to determine catalyst operation and performance. Therefore, this technology is not further evaluated.

### 3.1.3 SNCR Technical Feasibility and Control Effectiveness Analysis

In its 2007 BART Analysis, Barr ascertained that SNCR technology is available and is applicable to the source type with an estimated emissions performance level of 0.108 lb/MMBtu. Since the time of this report, NO<sub>x</sub> controls that have been (and will be) installed at Units 1 and 2, namely DryFinishing™ and LNC3+ combustion controls, will significantly decrease NO<sub>x</sub> emissions to an annual level of 0.13 lb/MMBtu, as compared to 0.22 lb/MMBtu evaluated in the 2007 BART Analysis. A NO<sub>x</sub> level of 0.13 lb/MMBtu at Unit 2 is generally equivalent to 65 ppm NO<sub>x</sub> depending on fuel and operating conditions. The EPA Control Cost Manual for SNCR denotes several concerns:

- *"Sources with stable temperatures of 1550°F to 1950°F, uncontrolled NO<sub>x</sub> emissions above 200 ppm, and residence times of 1 second are generally well suited to SNCR and attain the highest levels of NO<sub>x</sub> control."*

This reported NO<sub>x</sub> concentration is over three times the actual level at Coal Creek Station.

---

<sup>27</sup> The current Coal Creek Station exhaust stack is a dry stack and is not designed to accommodate water condensation in the stack. The reheat system is used to add sufficient heat to the stack to prevent water condensation for most operating conditions. Black and Veatch determined that the cost of replacing the existing stack with a new wet stack that could accommodate water condensation would cost at least \$16 million.

<sup>28</sup> See Attachment A at Section 2.2.13.

- *"Figure 1.8 shows an example of the NOx reduction efficiency that can be achieved for an uncontrolled NOx level of 120 parts per million (ppm) and various ammonia slip levels."*

In this figure, EPA shows that a high normalized stoichiometric ratio (NSR) is needed for the SNCR system to have a meaningful impact on NOx reductions at this uncontrolled concentration level, which is approximately twice that at Coal Creek Station.

A higher NSR results in increased ammonia slip. EPA notes several problems with ammonia slip, such as: *"Ammonia-sulfur salts can plug, foul, and corrode downstream equipment such as air heaters, ducts, and fans. Lastly, the ability to sell the fly ash as a secondary product is affected by its ammonia concentration."*

- *"Although there is significant scatter, Figure 1.1c shows a trend of increasing reductions with increasing baseline NOx levels for utility boilers. Specifically, the reductions range from 20 percent when the baseline NOx concentration is about 0.2 lb/MMBtu to 35 percent when the baseline NOx concentration is about 0.8 lb/MMBtu."*

Figure 1.1c for SNCR applied at coal-fired boilers shows no SNCR systems installed at boilers with an uncontrolled NOx level less than ~0.19 lb/MMBtu. By comparison, the current NOx performance level at Coal Creek Station is 0.13 lb/MMBtu. Even using the EPA-estimated 20 percent reduction from a 0.2 lb/MMBtu level results in controlled emissions that are higher than the current NOx performance level.

Barr completed an independent search of the RBLC database for utility-sized coal-fired boilers for SNCR systems and performance levels. Determinations for Best Available Control Technology (BACT) and Lowest Achievable Emissions Rate (LAER) are generally more stringent than that for BART, so the RBLC data provides information consistent with the best controls on recently constructed new and modified coal-fired utility boilers. Please see Attachment F for the RBLC summary tables. The RBLC listings range from 0.07 to 0.36 lb NOx/MMBtu (7 listings). However, five of these listings are for circulating fluidized bed (CFB) boilers, which are significantly different source type and exhaust characteristics that pulverized coal (PC) boilers like Unit 1 and 2. The two PC boilers with SNCR are shown with NOx performance levels of 0.35 and 0.36 lb/MMBtu.

For comparison, Black and Veatch reports a SNCR control effectiveness of 0.10 to 0.11 lb NOx/MMBtu from their review of Fuel Tech's site-specific assessment for SNCR at Unit 2. The SNCR proposal prepared by Fuel Tech is based on onsite testing of Unit 2 to collect data to prepare site-specific computational fluid dynamic (CFD) model and chemical kinetic model (CKM) of the boiler. Barr agrees with Black and Veatch's analysis and conclusion that SNCR NOx performance at Units 1 and 2 would be ~0.10 lb/MMBtu, at best, given that the chemical equilibrium of the SNCR reactions shifts and NOx re-formation rates make

it difficult to achieve further NO<sub>x</sub> emission reductions.<sup>29</sup> The EPA SNCR Control Cost Manual also notes this limitation.

SNCR control is highly dependent upon boiler operating conditions and the ability of the control system to inject reagent into the boiler at optimal rates in the appropriate locations and at expected temperature and residence times. The Fuel Tech proposal indicates that their SNCR control system can be integrated with the boiler's control system to be load-following, which is an anticipated operating condition at Units 1 and 2 (see Section 2.1.2). In theory, the proposed Fuel Tech SNCR system should be able to achieve the NO<sub>x</sub> reductions under routine variable loading, although they did not explicitly study it. As such, Barr considers the additional Multiple Nozzle Lances (MNL) option with its associated reagent injection rate and high stoichiometric ratio and ammonia slip from Fuel Tech as necessary elements for SNCR to address variable load conditions within the boiler.

## 3.2 Factor #1 Evaluation – Costs of Compliance

Barr has updated its cost evaluation from historical BART reports for high-dust SCR and for SNCR using the EPA Control Cost Manual methodology. Barr also has reviewed, for comparison, Black and Veatch's estimated costs for SCR and SNCR using both the general EPA Control Cost Manual methodology and a "site-specific methodology" incorporating actual costs from installation at another source that are scaled to Coal Creek Station. In summary, Barr's costs for high-dust SCR and for SNCR are comparable to Black and Veatch's estimates and would result in compliance costs that are much greater than the NDDEQ's cost effectiveness threshold.

### 3.2.1 SCR Cost Evaluation

Barr has populated the EPA SCR control cost spreadsheet with information relevant to Units 1 and 2. In doing so, it is noted that the EPA SCR control cost spreadsheets in this application will inherently underestimate the actual cost of SCR at Coal Creek Station. The EPA SCR cost correlations do not take into account the actual catalyst volume requirements, and resulting reactor size, for a specific application when calculating the cost of SCR. Based on the significant uncertainty of SCR catalyst performance and reliability under significant sodium variability conditions (see Section 2.1.1) at Coal Creek Station, IBIDEN CERAM's SCR catalyst proposal<sup>30</sup> and related communications with CERAM staff have identified that the specified catalyst volume is more than twice than that calculated in the EPA SCR Control Cost spreadsheet at a suggested performance level of 0.04 lb/MMBtu.<sup>31</sup> The EPA SCR control cost spreadsheet cannot

---

<sup>29</sup> See Attachment A at Section 2.2.12, page 2-18 and Section 4.1.2, page 4-14.

<sup>30</sup> See Attachment A at Appendix E for IBIDEN CERAM proposal.

<sup>31</sup> IBIDEN CERAM has requested that the actual catalyst volume be noted as business confidential but that it is at least twice the catalyst volume calculated in the EPA Control Cost Manual for reducing NO<sub>x</sub> emissions at a Coal Creek Station unit from 0.13 to 0.04 lb/MMBtu, which is 24,433 ft<sup>3</sup>. The catalyst volume calculated using the EPA spreadsheet at 0.06 and 0.08 lb/MMBtu levels is less than this value because the volume is a function of NO<sub>x</sub> emissions reduction.

readily be updated to accurately calculate the cost of SCR for CCS as it cannot account for the actual catalyst requirements recommended by the SCR catalyst supplier. Barr has not updated the spreadsheet to calculate the cost with catalyst volume and reactor size that reflects the IBIDEN CERAM's specification, and we note that the actual SCR cost is expected to be much higher than that calculated herein using the EPA spreadsheet.

As described in Section 3.1.2, Barr believes that a NO<sub>x</sub> control effectiveness range of 0.06 to 0.08 lb NO<sub>x</sub>/MMBtu on a sustained basis should be used in the control cost analysis due to the high potential for catalyst deactivation resulting from high sodium variability in the Falkirk lignite coal ash.

To be conservative (i.e., resulting in a lower estimated cost) in its estimate of catalyst replacement cost, Barr uses EPA Method 2 in the SCR Control Cost spreadsheet instead of EPA Method 1. Method 2 is an empirical correlation which estimates catalyst replacement costs based on industry experience. It relies on boiler capacity to estimate catalyst replacement costs. EPA Method 1 calculates the catalyst cost based on the anticipated catalyst replacement cycle. The EPA's recommended approach is to assume that one-third of the catalyst is replaced each year. However, the Coal Creek Station units normally operate on a 3-year maintenance outage cycle, so using the typical annual catalyst replacement cycle would not account for the costs and lost revenue of additional shutdowns for catalyst replacement. Following Method 1 assuming complete catalyst replacement at the end of the IBIDEN CERAM's estimated three-year life is consistent with Coal Creek Station's current operating practices, but results in a higher catalyst replacement cost. Method 2 is selected by Barr for determining catalyst replacement costs because it is generally representative of industry experience and results in a conservative (lower) estimated cost than the 3-year replacement cycle consistent with the IBIDEN-CERAM proposal.

Barr's estimates of control costs are summarized in Table 3-1.

**Table 3-1: Barr's SCR Control Costs, per Unit Basis**

NO <sub>x</sub> Performance Level	Installed Capital Cost (\$)	Annualized Capital Cost (\$/yr)	Annual Operating Costs (\$/yr)	Total Annualized Costs (\$/yr)	Annual Emissions Reduction (tpy)	Pollution Control Cost Effectiveness (\$/ton)
0.06 lb/MMBtu	\$192 million	\$12.8 million	\$3.9 million	\$16.7 million	1,614	\$10,351
0.08 lb/MMBtu	\$180 million	\$12.1 million	\$3.4 million	\$15.4 million	1,153	\$13,391

In comparing Barr's estimate to Black and Veatch's estimate using the EPA Control Cost spreadsheets, Barr notes three primary differences:

- 1) The SCR catalyst cost used in the EPA spreadsheet must include the purchase cost, installation cost, spent catalyst removal cost and spent catalyst disposal costs. The catalyst cost of \$118/ft<sup>3</sup> used in the Black & Veatch spreadsheets appears to include only the purchase cost and thus may underestimate actual costs. The EPA's default value of \$227/ft<sup>3</sup> is recommended as it considers the other necessary catalyst activities.

- 2) Barr uses the gross MW rating of each Coal Creek Station unit to calculate the associated heat input and annual emissions (at 87% capacity factor) that are used to estimate the emissions reduction, whereas Black and Veatch uses a lower estimate from EPRI's Vista model.
- 3) Barr's estimated range of sustained NOx performance is 0.06 and 0.08 lb/MMBtu as described above. Black and Veatch also considered a performance level of 0.04 lb/MMBtu.

These differences do not change the conclusion that both Barr's and Black and Veatch's cost estimates are much greater than the cost effectiveness threshold of \$4,630/ton NOx removed.

Barr believes that a low-dust SCR will be more costly than the high-dust SCR due to the required reheat and cooling system that would need to be designed and installed. Therefore, the cost for a low-dust SCR is also much greater than the cost effectiveness threshold.

Black and Veatch also prepared a cost estimate using "site-specific methodology" from another project. Barr does not have access to the underlying data used to scale project costs and thus has no comments on the accuracy of the analysis other than to note that using actual project costs generally should provide more accurate results than default assumptions in the EPA Control Cost spreadsheet. Black and Veatch's cost effectiveness results for SCR at 0.06 lb/MMBtu is \$11,233/ton,<sup>32</sup> which compares closely to Barr's estimate. Table 3-2 summarizes Barr's and Black and Veatch's results from the SCR cost effectiveness analyses.

**Table 3-2: SCR Pollution Control Cost Effectiveness Summary, per Unit Basis**

NOx Performance Level	Pollution Control Cost Effectiveness (\$/ton)		
	Barr Estimate using EPA Methodology	Black & Veatch Estimate using EPA Methodology	Black & Veatch Estimate using Site-specific Approach
0.04 lb/MMBtu	N/A	\$8,157	\$8,737
0.06 lb/MMBtu	\$10,351	N/A	\$11,233
0.08 lb/MMBtu	\$13,391	N/A	\$15,727

A critical physical complication with installation of SCR at Coal Creek Station that is not included in the cost effectiveness results above is the design of ductwork to accommodate the SCR. As described in the following points, both the existing DryFining™ system and the stack reheat system would need to be removed to tie SCR duct work into the boiler house and then be reconfigured, requiring an extended outage of 6 to 18 months as estimated by Black and Veatch.

- DryFining™ is used to remove moisture and improve the properties such as the heat content of lignite coal prior to combustion, thus improving NOx performance. This process also improves the

---

<sup>32</sup> See Attachment A at Table 4-5.



energy efficiency of the Coal Creek Station boilers and reduces SO<sub>2</sub>. DryFining™ is an integral part of the Coal Creek Station design to meet its SO<sub>2</sub> BART requirements. Therefore, this capability must be preserved. (See also Factor #3.)

- The current Coal Creek Station exhaust stack is a dry stack and is not designed to accommodate water condensation in the stack. The reheat system is used to add sufficient heat to the stack to prevent water condensation for certain operating conditions. For reference, Black & Veatch determined that the cost of replacing the existing stack with a new wet stack that could accommodate water condensation would cost at least \$16 million. This cost is not currently considered in the Table 3-1 estimate.

Effectively, these systems need to be removed and reconfigured in order to create space for installation of the SCR. Barr agrees with Black & Veatch's estimate that the plant outage would be approximately 6 to 18 months. The costs in lost revenue and in designing and implementing a reconfiguration of these systems are substantial and have not been included in the Table 3-1 estimate.

In summary, Barr believes that application of SCR is not cost effective for BART.

### 3.2.2 SNCR Cost Evaluation

Barr has examined the cost of an SNCR system by populating the EPA SNCR control cost spreadsheet with information relevant to Units 1 and 2. The EPA Control Cost Manual for SNCR and the associated spreadsheet estimate of the capital cost for SNCR are based primarily on size of the boiler and desired level of NO<sub>x</sub> control. In this case, Barr uses the 0.10 lb/MMBtu performance level specified by Fuel Tech, noting that the necessary additional costs for multiple nozzle lances (MNL) to achieve this performance level are not part of the EPA Control Cost spreadsheet or methodology.

Barr's estimate of SNCR control costs is summarized in Table 3-3.

**Table 3-3: Barr's SNCR Control Costs, per Unit Basis**

NO <sub>x</sub> Performance Level	Installed Capital Cost (\$)	Annualized Capital Cost (\$/yr)	Annual Operating Costs (\$/yr)	Total Annualized Costs (\$/yr)	Annual Emissions Reduction (tpy)	Pollution Control Cost Effectiveness (\$/ton)
0.10 lb/MMBtu	\$12.8 million	\$1.1 million	\$4.4 million	\$5.4 million	692	\$7,818

This cost effectiveness value aligns closely with that estimated by Black and Veatch using the EPA Control Cost spreadsheet and is more than 50% higher than the cost effectiveness threshold of \$4,630/ton NO<sub>x</sub> removed.

Because the correlations used in the Control Cost Manual do not include an option to account for advanced design features like multiple nozzle lances (MNL) that are described in Fuel Tech’s proposal,<sup>33</sup> the EPA spreadsheet underestimates the actual expected cost. This difference is apparent when comparing the cost in Table 3-2 to the cost estimate from Black & Veatch using the site-specific methodology, which results in a cost effectiveness value of \$8,899/ton NOx removed. Barr believes that this estimate based on Fuel Tech’s proposal is more accurate than that using the EPA methodology and results in a cost that is nearly twice the cost effectiveness threshold. Table 3-4 summarizes Barr’s and Black and Veatch’s results from the SNCR cost effectiveness analyses.

**Table 3-4: SNCR Pollution Control Cost Effectiveness Summary, per Unit Basis**

NOx Performance Level	Pollution Control Cost Effectiveness (\$/ton)		
	Barr Estimate using EPA Methodology	Black & Veatch Estimate using EPA Methodology	Black & Veatch Estimate using Site-specific Approach
0.10 lb/MMBtu	\$7,818	\$7,279	\$8,899
0.11 lb/MMBtu	N/A	\$11,082	\$11,145

An important consideration for cost and environmental impacts that is not directly included in Barr’s or Black and Veatch’s cost estimates is the effect of SNCR ammonia slip on lost fly ash sales and added ash disposal costs. GRE currently sells its fly ash as a raw material for concrete production. In order to meet a NOx control level of 0.10 lb NOx/MMBtu with SNCR, ammonia slip concentrations estimated by Fuel Tech are expected to be between 5 ppm and 10 ppm. This representation is also consistent with the EPA Control Cost Manual for SNCR. An ammonia slip rate of 10 ppm is highly probable due to load variability (see Section 2.1.2) and will thus adversely affect the chemistry of the fly ash.

GRE commissioned Golder Associates (Golder) and Boral Resources (Boral), in conjunction with the Fuel Tech report of expected ammonia slip from installation of SNCR, to evaluate the potential for adverse impacts of ammoniated fly ash. Golder’s report in Attachment B concludes that higher ammonia concentrations in fly ash caused by SNCR create material risk in the marketability and sale of fly ash. To mitigate this risk of fly ash disposal instead of beneficial reuse, installation of an ammonia slip mitigation (ASM) technology is prudent. Boral has developed an ASM technology, noting that the technology is no longer in use and has not yet been applied to a large, lignite-fired unit. Boral could not provide a guarantee on the successful application of the technology at Coal Creek Station. See Attachment C for the Boral document.

Golder developed a conceptual design of ASM at Coal Creek Station. They note that there are potential conditions under which the ammonia concentration of the produced fly ash may not be treatable with the ASM system. Golder predicts a reasonable future scenario wherein an additional 20% of fly ash produced

---

<sup>33</sup> See Attachment, Appendix E for Fuel Tech proposal.

annually cannot be treated to acceptable levels and will thus need to be disposed instead of beneficially reused. Golder provides a cost estimate associated with these reduced sales and the application of the ASM technology. Barr agrees with Golder that, for budgeting and cost estimate purposes, the application of SNCR will require application of ASM technology and will result in an increase in fly ash that needs to be disposed. These costs have not been directly included in the current cost estimate to be conservative.

In summary, Barr believes that application of SNCR is not cost effective for BART even without considering the expected mitigation and disposal costs associated with ammoniated fly ash.

### 3.3 Factor #2 Evaluation – Energy and Non-Air Environmental Impacts

Barr has evaluated the energy and non-air environmental impacts associated with implementation of SCR and SNCR. In conjunction with our evaluation, Barr has also reviewed Black & Veatch's analysis of these impacts associated with these technologies as well as Golder's report of impacts due to ammoniated fly ash from SNCR.

A key environmental impact from high-dust SCR is the production of sulfuric acid as a side reaction with the SCR process chemistry. Sulfuric acid, which is not captured within the boiler or associated downstream emission control, is released to the atmosphere as sulfuric acid mist (SAM). In addition to causing an unsightly "blue plume" from the exhaust stack, SAM is emitted as aerosol particles that contribute to visibility impairment. Therefore, the visibility impacts of SAM emissions must be considered in the analysis of visibility improvements from SCR, or the costs of controlling SAM emissions must be included in the SCR control cost analysis. Using the calculation procedures in a 2018 publication from Electric Power Research Institute,<sup>34</sup> SAM emissions of approximately 415 tons per year per unit are estimated as a result of the SCR catalyst with a 5% oxidation rate at Coal Creek Station.<sup>35</sup> Calculations of estimated SAM generation due to SCR at Units 1 and 2 are provided in Attachment H-2.

A low-dust SCR will require a fuel-fired reheat burner system, which will result in additional energy usage and collateral air emissions of NO<sub>x</sub> and other combustion pollutants.

Black & Veatch estimates the energy (due to auxiliary power consumption) and water consumption impacts of both technologies. The water demands for the SNCR system is estimated at 70 to 80 million gallons annually. Additionally, ammonia slip from these technologies will result in increased nitrogen in the scrubber that eventually is routed to the evaporation ponds. See Attachment A at Section 4.3 for a description of these impacts.

---

<sup>34</sup> See Attachment H-1. Electric Power Research Institute, "Estimating Total Sulfuric Acid Emissions from Stationary Power Plants," March 2018.

<sup>35</sup> The 5% oxidation rate was provided by IBIDEN CERAM and is referenced in Black and Veatch's report at Attachment A, Appendix E, Table 1.

---

Also for SNCR, Section 3.2.2 summarizes the risks due to increased fly ash disposal as a result of ammoniated fly ash. Golder estimates a scenario wherein an additional 92,000 tons annually of fly ash will need to be disposed in a landfill instead of beneficially reused, representing an 81 percent increase in the amount of fly ash disposed compared to current conditions.

In summary, the energy and environmental-related impacts from the application of SCR or SNCR at Units 1 and 2 are significant and support the conclusion that neither technology is BART.

### **3.4 Factor #3 Evaluation – Pollution Control Equipment at the Source**

Section 2.1 describes the use of DryFining™ and LNC3+ combustion controls that define the annual NO<sub>x</sub> performance level of 0.13 lb/MMBtu at Units 1 and 2 for purposes of determining emissions reductions due to additional retrofit controls. The current technologies are designed to be used for the foreseeable future.

### **3.5 Factor #4 Evaluation – Remaining Useful Life**

Since Coal Creek Station will continue to operate for the foreseeable future, the EPA defined defaults for useful life of the SCR (30 years) and SNCR (20 years) are used to calculate emission reductions, amortized costs, and cost effectiveness on a dollar per ton basis.

### **3.6 Factor #5 Evaluation – Visibility Impacts**

The visibility impairment contribution for different emission rate scenarios can be determined using the CALMET, CALPUFF, POSTUTIL, and CALPOST modeling tools. The modeling protocol at Attachment E-1 describes the emissions control scenarios to be evaluated and the CALPUFF model inputs, including the meteorological data set and background atmospheric ammonia and ozone concentrations along with the functions of the POSTUTIL and CALPOST post processing elements. The CALPOST output files provide two methods with which to assess the expected post-BART visibility improvement: the 98<sup>th</sup> percentile change in visibility, and the number of days on which a source exceeds an impairment threshold of 1.0 dV or 0.5 dV.

#### **3.6.1 Determining 24-Hour Maximum Emission Rates for BART Emissions Control Scenarios**

To be consistent with use of the highest daily emissions for pre-control visibility impacts, the emissions control scenarios reflecting the application of additional BART technologies to be used for the visibility impacts analysis should reflect the anticipated maximum 24-hour average basis. Emission rates and stack parameters for the emissions control scenarios used for visibility modeling are summarized in Table 3-3 and Table 3-4 and are described further in Attachment E-1. Note also that the generation of sulfuric acid

mist due to SCR is estimated in Attachment H-2 and is included in the modeled particulate matter emissions rate, consistent with EPA guidance.<sup>36</sup>

In summary, the emissions control scenarios are as follows:

- Scenarios #0 and #1 reflect historical emissions controls at Units 1 and 2 that have since been upgraded to those identified in Scenario #2;
- Scenario #2 reflects current/anticipated emissions performance with DryFinishing™ and LNC3+ controls;
- Scenario #3 reflects the addition of SNCR to Scenario #2 at a performance level of 0.10 lb/MMBtu, and
- Scenarios #4A and #4B reflect the addition of SCR to Scenario #2 at a performance level of 0.04 and 0.06 lb/MMBtu, respectively.

---

<sup>36</sup> April 8, 2019, correspondence from US EPA to the NDDEQ on the draft modeling protocol at Comment #19: *"If evaluating SCR, we recommend that PM10 emissions be adjusted to account for the associated increase in sulfuric acid emissions (as a subcomponent of PM). See Estimating Total Sulfuric Acid Emissions from Stationary Power Plants, 2018 Update, Electric Power Research Institute, March 2018."*

Table 3-5: BART Eligible Sources Screening Analysis Emission Rates

Emissions Control Scenario	Unit	Emissions Control Technologies	Stack Parameters (see Table 3-4)	PM10 <sup>(1)</sup> (lb/hr)	SO2 (lb/hr)	NOx (lb/hr)
#0 (2000 to 2002 Actual Emissions)	U1	LNC3	Pre SO <sub>2</sub> BART	249.2	5733.5	1772.3
	U2	LNC3	Pre SO <sub>2</sub> BART	216.1	4969.3	1822.4
#1	U2	LNC3, DryFining™, SO <sub>2</sub> BART	Post SO <sub>2</sub> BART	90.2	979	1233
	U2	LNC3, DryFining™, SO <sub>2</sub> BART	Post SO <sub>2</sub> BART	90.3	955	1233
#2	U1	LNC3+, DryFining™, SO <sub>2</sub> BART	Post SO <sub>2</sub> BART	90.2	979	898
	U2	LNC3+, DryFining™, SO <sub>2</sub> BART	Post SO <sub>2</sub> BART	90.3	955	898
#3	U1	LNC3+, DryFining™, SO <sub>2</sub> BART, SNCR	Post SO <sub>2</sub> BART	90.2	979	695
	U2	LNC3+, DryFining™, SO <sub>2</sub> BART, SNCR	Post SO <sub>2</sub> BART	90.3	955	695
#4A	U1	LNC3+, DryFining™, SO <sub>2</sub> BART, SCR@0.04	Post SO <sub>2</sub> BART	199.2	979	280
	U2	LNC3+, DryFining™, SO <sub>2</sub> BART, SCR@0.04	Post SO <sub>2</sub> BART	199.3	955	280
#4B	U1	LNC3+, DryFining™, SO <sub>2</sub> BART, SCR@0.06	Post SO <sub>2</sub> BART	199.2	979	415
	U2	LNC3+, DryFining™, SO <sub>2</sub> BART, SCR@0.06	Post SO <sub>2</sub> BART	199.3	955	415

Note(s):

Modeled particulate for all Emissions Control Scenarios except #4 is speciated into the following component percentages: coarse (PMC = 32.0%), fine (PMF = 33.9%), secondary organic aerosols (SOA = 6.6%), elemental carbon (EC = 1.3%), and sulfate (SO<sub>4</sub> = 26.3%), using particulate speciation profiles for coal fired boilers as recommended by the National Park Service (NPS). For Emissions Control Scenario #4, consideration of sulfuric acid formation from the application of SCR technology contributes 109 lb/hr to the particulate emissions, modeled as sulfate.

**Table 3-6: BART Eligible Sources Screening Analysis Stack Parameters**

Unit	X Coord. <sup>(1)</sup> (km)	Y Coord. <sup>(1)</sup> (km)	Stack Height (m)	Base Elevation (m)	Stack Diam. (m)	Exit Velocity (m/s)	Exit Temp. (K)
Coal Creek 1 – Pre SO <sub>2</sub> BART	63.387	376.062	201.0	602.0	6.7	25.9	358.5
Coal Creek 2 – Pre SO <sub>2</sub> BART	63.492	376.068	201.0	602.0	6.7	24.9	354.5
Coal Creek 1 – Post SO <sub>2</sub> BART	63.387	376.062	206.4	602.0	7.85	18.6	334
Coal Creek 2 – Post SO <sub>2</sub> BART	63.492	376.068	206.4	602.0	7.85	18.0	332

Note(s):

(1) Coordinates reflect North Dakota Lambert Projection

### 3.6.2 Modeled Results

Visibility impairment is modeled using the meteorological data for the years 2000, 2001, and 2002 for the historical, current/anticipated, and BART emission scenarios. Results for the 98th percentile impacts and number of days above 0.5 dV and 1.0 dV at Lostwood Wilderness Area (LWA) and Theodore Roosevelt National Park (TRNP) North, South and Elkhorn Ranch units are summarized in Table 3-5 through Table 3-7.

As illustrated by the modeled visibility impacts, the future expected performance reflected in Scenario #2 for anticipated emissions controls and corresponding NO<sub>x</sub> performance at Units 1 and 2 represents a significant improvement in facility-wide impacts from the original baseline. For example, the change in visibility impairment between Scenario #0 and Scenario #2 is generally between 1.0 to 2.0 Δ-dV on a 98th percentile comparison, depending on the Class I area and meteorological year.

The change in NO<sub>x</sub> emissions rate between Scenario #2 and those scenarios representing additional controls evaluated in this report, Scenario #3 (addition of SNCR) or #4 (SCR), results in an average change of only ~0.1 Δ-dV on a 98th percentile comparison, depending on the Class I area and meteorological year. We also note that the sulfuric acid mist generated due to SCR has an appreciable impact on visibility impairment such that it effectively offsets much of the improvement in visibility that would otherwise occur from a reduction in NO<sub>x</sub> emissions. In some cases, the visibility impairment is higher with SCR than with existing emissions controls modeled in Scenario #2.

Table 3-7: Year 2000 Visibility Modeling Results

Description		Visibility Impairment											
		TRNP South Unit			TRNP North Unit			TRNP Elkhorn Ranch			Lostwood Wilderness Area		
Emissions Control Scenario	Units	Days Above 0.5 $\Delta$ -dV	Days Above 1.0 $\Delta$ -dV	98th % $\Delta$ -dV	Days Above 0.5 $\Delta$ -dV	Days Above 1.0 $\Delta$ -dV	98th % $\Delta$ -dV	Days Above 0.5 $\Delta$ -dV	Days Above 1.0 $\Delta$ -dV	98th % $\Delta$ -dV	Days Above 0.5 $\Delta$ -dV	Days Above 1.0 $\Delta$ -dV	98th % $\Delta$ -dV
#0: LNC3	1 & 2	35	17	1.959	35	19	1.780	25	15	1.412	54	34	2.155
#1: LNC3, DryFining™, SO <sub>2</sub> BART	1 & 2	11	5	0.660	12	5	0.647	8	3	0.599	20	5	0.916
#2: LNC3+, DryFining™, SO <sub>2</sub> BART	1 & 2	10	4	0.552	10	4	0.540	8	1	0.501	19	4	0.729
#3: LNC3+, DryFining™, SO <sub>2</sub> BART, SNCR	1 & 2	8	3	0.506	7	3	0.476	4	1	0.440	15	4	0.637
#4A: LNC3+, DryFining™, SO <sub>2</sub> BART, SCR@0.04	1 & 2	8	2	0.558	8	4	0.518	4	1	0.416	21	4	0.775
#4B: LNC3+, DryFining™, SO <sub>2</sub> BART, SCR@0.06	1 & 2	9	3	0.596	13	4	0.557	5	1	0.461	24	4	0.852



Table 3-8: Year 2001 Visibility Modeling Results

Description		Visibility Impairment											
		TRNP South Unit			TRNP North Unit			TRNP Elkhorn Ranch			Lostwood Wilderness Area		
Emissions Control Scenario	Units	Days Above 0.5 $\Delta$ -dV	Days Above 1.0 $\Delta$ -dV	98th % $\Delta$ -dV	Days Above 0.5 $\Delta$ -dV	Days Above 1.0 $\Delta$ -dV	98th % $\Delta$ -dV	Days Above 0.5 $\Delta$ -dV	Days Above 1.0 $\Delta$ -dV	98th % $\Delta$ -dV	Days Above 0.5 $\Delta$ -dV	Days Above 1.0 $\Delta$ -dV	98th % $\Delta$ -dV
#0: LNC3	1 & 2	36	16	1.653	29	21	1.378	27	12	1.626	45	28	2.842
#1: LNC3, DryFinishing™, SO <sub>2</sub> BART	1 & 2	7	2	0.474	10	3	0.571	8	1	0.526	21	5	0.873
#2: LNC3+, DryFinishing™, SO <sub>2</sub> BART	1 & 2	7	2	0.416	8	3	0.502	6	1	0.443	19	4	0.745
#3: LNC3+, DryFinishing™, SO <sub>2</sub> BART, SNCR	1 & 2	4	2	0.394	6	2	0.422	3	1	0.392	15	4	0.713
#4A: LNC3+, DryFinishing™, SO <sub>2</sub> BART, SCR@0.04	1 & 2	6	2	0.462	8	2	0.529	4	1	0.451	19	7	0.967
#4B: LNC3+, DryFinishing™, SO <sub>2</sub> BART, SCR@0.06	1 & 2	7	2	0.492	8	2	0.557	6	1	0.491	22	7	0.992

Table 3-9: Year 2002 Visibility Modeling Results

Description		Visibility Impairment											
		TRNP South Unit			TRNP North Unit			TRNP Elkhorn Ranch			Lostwood Wilderness Area		
Emissions Control Scenario	Units	Days Above 0.5 $\Delta$ -dV	Days Above 1.0 $\Delta$ -dV	98th % $\Delta$ -dV	Days Above 0.5 $\Delta$ -dV	Days Above 1.0 $\Delta$ -dV	98th % $\Delta$ -dV	Days Above 0.5 $\Delta$ -dV	Days Above 1.0 $\Delta$ -dV	98th % $\Delta$ -dV	Days Above 0.5 $\Delta$ -dV	Days Above 1.0 $\Delta$ -dV	98th % $\Delta$ -dV
#0: LNC3	1 & 2	39	23	3.131	40	26	2.692	28	18	2.173	39	26	1.980
#1: LNC3, DryFinishing™, SO <sub>2</sub> BART	1 & 2	22	11	1.279	18	8	1.145	14	6	0.987	17	2	0.689
#2: LNC3+, DryFinishing™, SO <sub>2</sub> BART	1 & 2	20	9	1.048	15	6	0.970	10	5	0.806	12	0	0.566
#3: LNC3+, DryFinishing™, SO <sub>2</sub> BART, SNCR	1 & 2	18	6	0.911	15	5	0.841	9	3	0.706	8	0	0.504
#4A: LNC3+, DryFinishing™, SO <sub>2</sub> BART, SCR@0.04	1 & 2	19	8	1.011	16	7	0.796	12	4	0.746	16	0	0.670
#4B: LNC3+, DryFinishing™, SO <sub>2</sub> BART, SCR@0.06	1 & 2	20	8	1.052	17	7	0.842	12	4	0.825	16	0	0.704

### 3.7 Conclusion

After assessing and weighing the five BART factors and considering the conservative nature of the economic analysis performed, Barr concludes that additional NO<sub>x</sub> emissions control technologies applied to Units 1 and 2, namely selective catalytic reduction and selective non-catalytic reduction, are not BART.

High-dust selective catalytic reduction (SCR) is neither technically feasible as a retrofit control technology at Coal Creek Station nor is it cost-effective with an estimated total capital investment of nearly \$200 million and an annualized cost that is over twice the cost effectiveness threshold. Additionally, the estimated increase in sulfuric acid mist emissions due to an SCR system at Units 1 and 2 offsets much of the modeled visibility improvement that would otherwise occur from a reduction in NO<sub>x</sub> emissions. Low-dust SCR is also not cost-effective and has energy impacts and combustion emissions associated with a required fuel-fired reheat burner system.

Selective non-catalytic reduction (SNCR) is not cost-effective as well as potentially creates significant environmental impacts related to ammoniated fly ash.

Based on a review of recent emissions data at Unit 2 and the planned completion of installation of the same advanced combustion controls (LNC3+) for NO<sub>x</sub> at Unit 1 in the first half of 2020, Units 1 and 2 are expected to perform at an annual average emissions rate of 0.13 pounds of NO<sub>x</sub> per million British thermal units heat input (lb NO<sub>x</sub>/MMBtu) using DryFining™ and LNC3+ emissions controls.

Taking into consideration these inherent variabilities affecting NO<sub>x</sub> emissions performance and to determine the shorter-term average (i.e., 30-day rolling average) emissions rate impact on NO<sub>x</sub> performance on a heat input basis, Barr recommends a BART emissions limit of 0.15 lb NO<sub>x</sub>/MMBtu, which is less than the EPA's presumptive BART level of 0.17 lb/MMBtu on a 30-day rolling average.<sup>37</sup> This recommended limit is informed by actual NO<sub>x</sub> emissions levels that have occurred at Unit 2 during "high load high sodium," "low load high sodium," "high load low sodium," and "low load low sodium" conditions. For example, the average hourly Unit 2 NO<sub>x</sub> emissions at low load high sodium is 0.206 lb/MMBtu. Although GRE expects to operate primarily in high load high sodium, all of the other conditions are expected to occur at times in the future and will have an appreciable impact on the 30-day rolling average.

Figure 3-1 illustrates the effect of low load and low sodium on the 30-day rolling average. For example, an operating scenario may occur in the springtime (i.e., during mild weather) when Coal Creek Station is in a load-following mode for several days during a 30-day time frame. Considering the time for ramping up and ramping down and sustained low load conditions, it is reasonable to consider that a unit may operate in low load for several hours per day and for several days during the 30-day period. Based on the

---

<sup>37</sup> The EPA presumptive NO<sub>x</sub> emission limit of 0.17 lb/MMBtu is at 40 CFR 51, Appendix Y, Section IV.E.5, Table 1, for a tangential-fired unit firing lignite.

interpolation of NOx emissions at high load and low load conditions (assuming high sodium during the 30-day period), GRE would be able to operate in low load mode for approximately 6 hours per day for the 30-day period in order to meet the 0.15 lb/MMBtu limit.

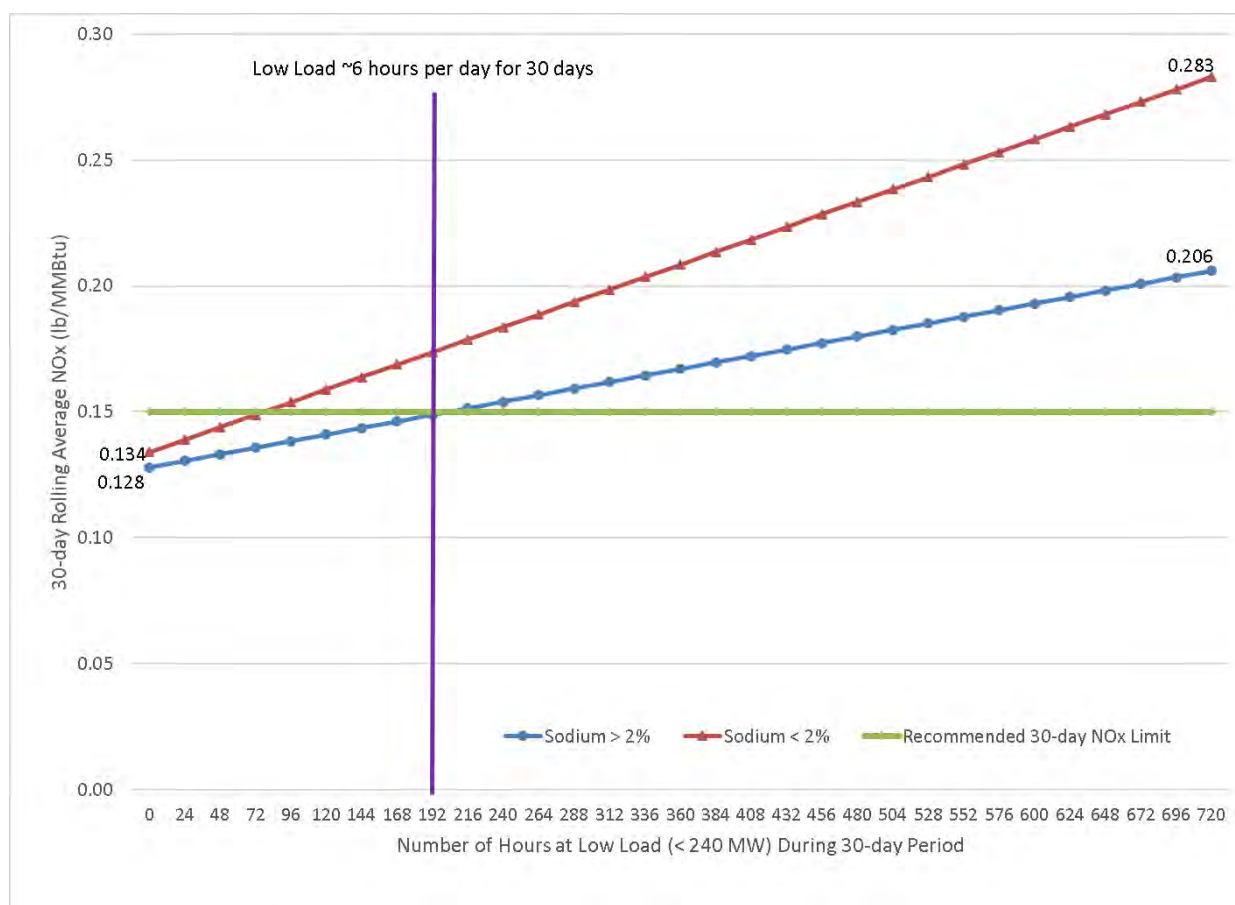


Figure 3-1: NOx Emissions as a Function of Operating Load and Lignite Sodium Variability



Attachments A through H-2

## **Coal Creek Station Units 1 and 2**

### ***Updated Best Available Retrofit Technology Analysis for NO<sub>x</sub> Emissions***

Prepared for  
Great River Energy

September 2019



## **Attachment A**

**Report "Best Available Retrofit Technology for NO<sub>x</sub> Emissions from Coal Creek Unit 2 - 2019 Update" September 4, 2019; Black & Veatch**





# BEST AVAILABLE RETROFIT TECHNOLOGY FOR NO<sub>x</sub> EMISSIONS FROM COAL CREEK UNIT 2

2019 Update

BLACK & VEATCH PROJECT NO. 400075  
BLACK & VEATCH FILE NO. 400075.1000

PREPARED FOR



Great River Energy

4 SEPTEMBER 2019



## Table of Contents

<b>1.0</b>	<b>Introduction &amp; Executive Summary .....</b>	<b>1-1</b>
1.1	Report Approach.....	1-2
1.2	Current Conditions at Coal Creek.....	1-4
<b>2.0</b>	<b>Initial Technology Screening .....</b>	<b>2-1</b>
2.1	Step 1 – Identify NO <sub>x</sub> Control Technologies.....	2-1
2.2	Step 2 – Eliminate Infeasible NO <sub>x</sub> Control Options.....	2-3
2.2.1	ECOTUBE .....	2-5
2.2.2	Flue Gas Recirculation.....	2-5
2.2.3	Low NO <sub>x</sub> Burners .....	2-6
2.2.4	LoTOX.....	2-6
2.2.5	Natural Gas Reburn.....	2-7
2.2.6	Neural Network Systems .....	2-8
2.2.7	NOXStar™ and NOXStar Plus™ .....	2-9
2.2.8	Overfire Air (OFA) System .....	2-10
2.2.9	Regenerative Selective Catalytic Reduction (RSCR).....	2-11
2.2.10	ROFA and ROTAMIX.....	2-12
2.2.11	Selective Catalytic Reduction (SCR) .....	2-12
2.2.12	Selective Non-Catalytic Reduction (SNCR).....	2-17
2.2.13	SNCR/SCR Hybrid.....	2-19
<b>3.0</b>	<b>Step 3 – Evaluate Control Effectiveness of Remaining Technologies .....</b>	<b>3-1</b>
3.1	SCR .....	3-1
3.2	SNCR.....	3-2
3.3	Summary of Control Effectiveness.....	3-2
<b>4.0</b>	<b>Step 4 – Evaluate Impacts and Document Results .....</b>	<b>4-1</b>
4.1	Cost of Compliance .....	4-1
4.1.1	SCR .....	4-2
4.1.1.1	EPA Cost Manual Spreadsheet Methodology .....	4-3
4.1.1.2	Site-Specific Methodology .....	4-3
4.1.2	SNCR.....	4-14
4.1.2.1	EPA Cost Manual Spreadsheet Methodology .....	4-14
4.1.2.2	Site-Specific Methodology .....	4-15
4.2	Cost Effectiveness .....	4-20
4.3	Energy and Non-Air Quality Environmental Impacts.....	4-22
4.3.1	SCR .....	4-23
4.3.2	SNCR.....	4-23
4.4	Pollution Control Equipment in Use/Existing at the Source.....	4-23
4.5	Remaining Useful Life of Any Potentially Affected Sources .....	4-24
<b>5.0</b>	<b>Conclusion.....</b>	<b>5-1</b>

<b>Appendix A.</b>	<b>Coal Creek VISTA Model Parameters .....</b>	<b>A-1</b>
<b>Appendix B.</b>	<b>Technical Discussion of Low-Dust SCR.....</b>	<b>B-1</b>
<b>Appendix C.</b>	<b>Discussions of Minor Line Items in Cost Estimates.....</b>	<b>C-1</b>
<b>Appendix D.</b>	<b>Site Specific Cost Estimate Summary Sheets .....</b>	<b>D-1</b>
<b>Appendix E.</b>	<b>Supporting Documentation for Cost Estimates.....</b>	<b>E-1</b>
<b>Appendix F.</b>	<b>Texas and WRAP Data .....</b>	<b>F-1</b>
<b>Appendix G.</b>	<b>EPA Cost Manual Cost Estimate Sheets.....</b>	<b>G-1</b>
<b>Appendix H.</b>	<b>Alstom Power MATS Tuning Report.....</b>	<b>H-1</b>

## LIST OF TABLES

Table 1-1	Technology Cost Estimates .....	1-2
Table 2-1	Overview of NO <sub>x</sub> Control Technologies' Initial Screening.....	2-2
Table 2-2	Evaluation to Eliminate Control Options .....	2-3
Table 3-1	WRAP and Texas Units with SCRs and Emissions <sup>(1)</sup> .....	3-1
Table 3-2	Ammonia Slip and Removal Efficiency.....	3-2
Table 3-3	Effectiveness of Remaining Control Technologies .....	3-3
Table 4-1	Cost of Compliance for Technologies (2018 dollars) Using EPA Spreadsheets.....	4-1
Table 4-2	Cost of Compliance for Technologies (2018 dollars) Using Site-Specific Approach .....	4-2
Table 4-3	Cost of Compliance for SCR Technologies (2018 dollars).....	4-2
Table 4-4	SCR Cost Summary Using Site-Specific Methodology .....	4-4
Table 4-5	SCR Cost with NO <sub>x</sub> Emissions Summary (2018 dollars) Using Site-Specific Methodology .....	4-5
Table 4-6	Cost of Compliance for SNCR Technologies (2018 dollars) .....	4-14
Table 4-7	SNCR Cost Summary Using Site-Specific Methodology .....	4-16
Table 4-8	Overall and Incremental Cost Effectiveness (2018 US Dollars) – Using EPA Spreadsheets.....	4-21
Table 4-9	Overall and Incremental Cost Effectiveness (2018 US Dollars) – Site Specific Methodology .....	4-21

## LIST OF FIGURES

Figure 2-1	Schematic Diagram of Typical SCR Reactor .....	2-14
Figure 2-2	Schematic of SNCR System with Multiple Injection Levels.....	2-18
Figure 4-1	General Sketch of SCR Location .....	4-6
Figure 4-2	Equipment in Boiler Building around ductwork tie-in at Coal Creek Unit 2.....	4-7
Figure 4-3	TAC vs Emissions Reduction .....	4-22

## 1.0 Introduction & Executive Summary

Great River Energy (GRE) contracted with Black & Veatch to assess four factors of the five-factor BART analysis of NO<sub>x</sub> reduction technologies for their Coal Creek Station's Unit 2 ("Coal Creek Unit 2").<sup>1</sup> This report describes the assessment and its results.

Coal Creek Station consists of two coal-fired electric generating units. Both boilers are tangentially-fired boilers manufactured by Combustion Engineering (CE, now a part of General Electric, or GE), and each unit produces about 605 MW (gross) of power. Coal Creek Station is a mine-mouth facility located near Underwood, North Dakota and burns lignite coal from the co-located Falkirk Mine. The facility's annual capacity factor is 87% based on a 10-year average, which includes planned outages. Unit 2 has a nominal rating of 605 MW, and it currently emits 0.13 lb/MMBtu of NO<sub>x</sub> as an annual average. The first generation of separated over-fired air registers were installed on Unit 2 in 1998. In 2007, GRE expanded the over-fired air registers on Unit 2 to be low NO<sub>x</sub> level 3 ("LNC3," referring to the combination of closed coupled overfired air, separated overfired air, and low NO<sub>x</sub> burners). In addition to LNC3, GRE installed and began operating its novel multi-pollutant reduction technology, "DryFining™" in 2010.<sup>2</sup> Together, the enlarged overfire air registers and DryFining™ technology are combined as "LNC3+" for NO<sub>x</sub> reductions.

Black & Veatch is an international engineering firm with vast experience within the power industry. Starting with scrubber designs in the 1960s, Black & Veatch has been involved with 87 air quality control (AQC) projects, with 17 of those related to NO<sub>x</sub> control technologies. This includes three NO<sub>x</sub> controls-related installations in last five years. Black & Veatch's role on these projects has varied from full engineering, procurement, and construction (EPC) to owner's engineer (OE). Black & Veatch has also provided many engineering services to power clients, including permitting support, risk analyses, and developing BART reports. Since 2006, Black & Veatch has helped numerous clients with fifteen BART analyses, and this does not include many more efforts related to requirements for Maximum Achievable Control Technology (MACT) and Lowest Achievable Emission Rate (LAER).

This report addresses four of the five BART factors: (1) costs of compliance, (2) certain energy and non-air quality environmental impacts of compliance,<sup>3</sup> (3) pollution control equipment in use or in existence at the source, and (4) the remaining useful life of the source. 42 U.S.C. § 7491(g)(2). The fifth BART factor, the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology, *see id.*, will be addressed in a separate report. Black & Veatch identified a number of technologies for NO<sub>x</sub> control at Coal Creek Unit 2. A number of these technologies were not carried forward for further analysis because they were not expected to provide substantial NO<sub>x</sub> reductions, were not commercially available, or specific circumstances

---

<sup>1</sup> A BART analysis for NO<sub>x</sub> controls at Unit 1 is contained in a separate report.

<sup>2</sup> As EPA has explained, DryFining™ is an innovative technology developed by GRE that reduces moisture and refines lignite coal, increasing the efficiency and performance of the fuel while reducing emissions. 83 Fed. Reg. 18248, 18251 (Apr. 26, 2018).

<sup>3</sup> The impacts to GRE's fly ash reuse program are addressed in a separate report.

preclude their application to Coal Creek Station. Black & Veatch ultimately analyzed selective noncatalytic reduction (SNCR) (with and without multi-level nozzle (MNL) enhancements) and selective catalytic reduction (SCR). SCR was determined to be likely infeasible, but it was analyzed to provide a conservative approach to this report.

Table 1-1 summarizes the cost estimates for the analyzed technologies, which show that none of the technologies are cost-effective. The prior North Dakota BART SIP considered cost effectiveness above \$3,650/ton to be excessive, which was adjusted for inflation to \$4,100/ton in the 2011/2012 NO<sub>x</sub> BART determination.<sup>4</sup> If adjusted to 2018 dollars using the Chemical Engineering Plant Cost Index, this value is \$4,630/ton. The assessed technologies are well above this threshold. In fact, the cost-effectiveness values of the technologies far exceed the values that other states and EPA have determined to be unreasonable in other BART determinations.

**Table 1-1 Technology Cost Estimates**

TECHNOLOGY	TOTAL CAPITAL INVESTMENT	TOTAL ANNUAL COST (\$/YR)	EFFECTIVENESS (\$/TON NO <sub>x</sub> )	INCREMENTAL COST (\$/TON)
SCR	\$190,920,000	\$17,590,000	\$8,737 <sup>5</sup>	\$8,652
SNCR w/ MNL	\$16,570,000	\$5,970,000	\$8,899	\$4,764
SNCR	\$12,740,000	\$4,860,000	\$11,145	NA

These cost-effectiveness values, along with the other three BART factors addressed in this report (energy and non-air quality environmental impacts, existing controls, and remaining useful life), indicate that none of the considered control technologies are likely to constitute BART.

## 1.1 REPORT APPROACH

This report follows the methodologies laid out in EPA's BART Guidelines, 40 CFR Part 51, Appendix Y. As described in the BART Guidelines, the first step of the BART analysis is to identify all available retrofit control technologies. These are defined as control technologies with "a practical potential for application to the emission unit." The second step is to eliminate technically infeasible options. A technology must be commercially available and demonstrated at sources under similar operating conditions to be considered technically feasible. The definition of technically feasible is considered the same as an "applicable" technology, per 40 CFR Part 51, Appendix Y. Per this definition, an applicable technology must be commercially available (i.e. it has

<sup>4</sup> Supporting Material, *North Dakota Supplemental NO<sub>x</sub> BART Determination for Coal Creek Station Supplement No. 2 to SIP for Regional Haze* at App. B.2.1, page 16 (Jan. 2, 2013), Docket ID EPA-R08-OAR-2010-0406-0428 (September 2012 Supplemental Evaluation of NO<sub>x</sub> BART Determination for CCS 1 and 2).

<sup>5</sup> The cost-effectiveness value SCR reflects a best-case scenario emission rate of 0.04 lb/MMBtu. For reasons discussed in Section 3.1, the achievable emission rate for Coal Creek Unit 2 is more likely in the range of 0.06-0.08 lb/MMBtu, which would result in even higher cost-effectiveness calculations.

sufficient pilot scale and existing commercial demonstrations to be installed at the facility of interest) and “reasonably be installed and operated on the source type under consideration.” The third step is the evaluation of the controls’ effectiveness, and the fourth step evaluates the impacts (i.e., costs, energy impacts, non-air quality environmental impacts, and remaining useful life) of the remaining control technologies.

This report assesses control costs using two separate methodologies, both of which are consistent with the BART Guidelines and the guidance in EPA’s Air Pollution Control Cost Manual (mentioned from hereon as the Cost Manual). First, this report utilizes EPA’s Cost Manual Excel spreadsheets to calculate the costs of SCR and SNCR. Second, this report also uses, where possible, costs from site-specific vendor quotes and costs based on recent Black & Veatch SCR and SNCR reference projects to provide a more accurate site-specific assessment of these technologies for Coal Creek Unit 2. The reference project costs used in this study come from very recent projects (within 5 years) of similar size (within 150 MW), in similar climates (e.g. severe winters). The line item costs from these projects were compared to the line item requirements for the assessed controls for Coal Creek Unit 2 and were adjusted as necessary (both upward and downward) to account for differences between the projects. As with the vendor quotes, the resulting line item cost estimates are tailored to Unit 2.

Both the BART Guidelines and the Cost Manual explicitly authorize the use of site-specific costs. The BART Guidelines instruct that “[t]he cost analysis should also take into account any site-specific design or other conditions . . . that affect the cost of a particular BART technology option.” 40 CFR Part 50, Appendix Y. Information for this site-specific assessment can come from “additional information” outside the Cost Manual, including information supplied by vendors that affects assumptions regarding purchased equipment costs, equipment life, replacement of major components, or any other element. *See id.*, n.15. As the Cost Manual notes, site-specific vendor quotes are *significantly* more accurate than the “study” estimate provided by the Cost Manual methodology.<sup>6</sup>

EPA has recognized the greater accuracy of site-specific cost estimates in its Regional Haze actions in other Region 8 states. In its partial Federal Implementation Plan (FIP) for Wyoming covering Basin Electric’s Laramie River Unit 1, EPA revised its cost analysis to incorporate site-specific cost estimates provided by Basin Electric, explaining, “Per EPA’s Control Cost Manual (CCM), use of site specific cost estimates is preferable to the use of generalized costs where those site specific costs can be supported and are appropriate.”<sup>7</sup> Similarly, in its partial FIP for Utah addressing Hunter Unit 1, EPA accepted both the catalyst volume and SCR design suggested by

---

<sup>6</sup> Cost Manual, Introduction, Chapter 2, Cost Estimation: Concepts and Methodology, at 6-7.

<sup>7</sup> *Approval, Disapproval and Promulgation of Implementation Plans; State of Wyoming; Regional Haze State Implementation Plan; Federal Implementation Plan for Regional Haze*, 79 Fed. Reg. 5032, 5039 (Jan. 30, 2014).

Sargent & Lundy for its BART determination.<sup>8</sup> EPA “acknowledge[d] that States (and EPA in promulgating a FIP) may deviate from the Control Cost Manual provided their analysis is reasonable and the deviations are documented.... Under the BART Guidelines, as explained above, we have the discretion to deviate (or not) from the CCM, so long as our analysis is reasonable and deviations are documented.”<sup>9</sup> EPA concluded that it “properly [took] into account additional (i.e. outside the CCM) information when it is warranted to use it in our cost estimates, and rejected additional information when it was not warranted to use it in our cost estimates.”<sup>10</sup>

## 1.2 CURRENT CONDITIONS AT COAL CREEK

A major limitation to controlling NO<sub>x</sub> is the load variability at Coal Creek Station. Historically, Coal Creek Station has been base-loaded with very infrequent load reductions over 30-day rolling periods. As more renewable resources have become available throughout the upper Midwest, Coal Creek increasingly has been required to reduce load or to vary load in response to these intermittent renewable resources. Coal Creek Station’s units are designed as base load units but are expected to respond more frequently to the transforming mix of renewable generation in MISO.

Coal Creek Unit 2 emitted ~0.13 lb/MMBtu of NO<sub>x</sub> as an annual average in 2017 and 2018, with occasional dips down to 0.12 lb/MMBtu as a 24-hour value during optimal conditions and increases to 0.17 lb/MMBtu in poor conditions. Due to coal sodium and load variability, these emission rates can increase. They are lower than what is commonly observed from other coal-fired electric generating units (EGUs) and indicate that Coal Creek Unit 2 has gone through extensive tuning procedures to optimize the combustion process. In a study performed by Alstom Power (now GE)<sup>11</sup> in 2015 to comply with the NESHAPs MATS rule, the boiler was found to be well tuned with limited adjustments possible for improving the emissions.

The baseline emission rate of 0.13 lb/MMBtu on an annual average was used for this report’s evaluation of control technologies. Combustion calculations were done using EPRI’s Vista model. Coal information used for the combustion calculations and as part of design considerations/modeling, can be found in Appendix A.

---

<sup>8</sup> *Approval, Disapproval and Promulgation of Air Quality Implementation Plans; Partial Approval and Partial Disapproval of Air Quality Implementation Plans and Federal Implementation Plan; Utah; Revisions to Regional Haze State Implementation Plan; Federal Implementation Plan for Regional Haze*, 81 Fed. Reg. 43894, 43917 (July 5, 2016).

<sup>9</sup> EPA, *Response to Comments for the Federal Register Notice for Air Quality State Implementation Plans; Approvals and Promulgations: Utah; Revisions to Regional Haze State Implementation Plan; Federal Implementation Plan for Regional Haze; Partial Approval and Partial Disapproval*, at 269. EPA Docket ID EPA-R08-OAR-2015-0463-0208.

<sup>10</sup> *Id.*

<sup>11</sup> See Appendix H.



## 2.0 Initial Technology Screening

There are many available methods to control NO<sub>x</sub> emissions but some are not applicable to Coal Creek Station due to their lack of operational experience on units of similar size or operating on similar fuels. It is therefore important to narrow down the list of NO<sub>x</sub> control technologies from those that are commercially available to those that are truly applicable for a retrofit installation at Coal Creek Station. Coal Creek Unit 2's baseline of 0.13 lb NO<sub>x</sub>/MMBtu, as an annual average, is below the presumptive BART limit of 0.17 lb/MMBtu.<sup>12</sup> Any NO<sub>x</sub> reductions must be considered within the context of Coal Creek Unit 2's already low emissions. Some technologies may generally claim NO<sub>x</sub> reductions over 40 percent, but these reductions are achieved only when the starting NO<sub>x</sub> emissions are much higher than Coal Creek Unit 2's. When the baseline NO<sub>x</sub> emissions are low, NO<sub>x</sub> removal is more difficult, and reduction capabilities of the technologies will be less. This is important, because a site-specific design is required to fully assess reduction capabilities given the low NO<sub>x</sub> baseline. Standard methods based on industry-wide, average data will lead to inaccurate inputs and conclusions. Steps 1 and 2 of the assessment delve deeper into this issue.

### 2.1 STEP 1 – IDENTIFY NO<sub>x</sub> CONTROL TECHNOLOGIES

There are two approaches to achieve a reduction in NO<sub>x</sub> emissions: combustion control and post-combustion control. Combustion control methods seek to suppress NO<sub>x</sub> formation during the combustion process by controlling the flame temperature and fuel/oxygen ratio. These methods include low NO<sub>x</sub> burners (LNBs), overfire air (OFA), and neural network combustion optimization systems. Post-combustion controls use chemical reactions with a reagent to remove NO<sub>x</sub> from the flue gas, such as selective non-catalytic reduction (SNCR) and selective catalytic reduction (SCR) systems. SNCR and SCR use either urea or ammonia as a reagent, with the SCR also utilizing catalyst (often multiple layers) to promote the chemical reactions with NO<sub>x</sub>.

The first step of a BART analysis is to identify all available retrofit control technologies that potentially could be applied to the facility. NO<sub>x</sub> control technologies that were identified as available for retrofit at Coal Creek Station are listed below with a short summary of each technology in the following sub-sections. The listed control technologies meet a minimum level of proven capabilities (e.g., the technologies have been implemented on coal-fired facilities, not just bench and pilot tests). While there may be additional technologies not covered here, their lack of demonstrated performance precludes them from evaluation in this study.

A summary of all identified NO<sub>x</sub> control technologies that meet a minimum amount of proven capabilities is provided in Table 2-1.

---

<sup>12</sup> 40 CFR Part 51, Appendix Y, Section IV.E.5 (Table 1).

**Table 2-1 Overview of NO<sub>x</sub> Control Technologies' Initial Screening**

TECHNOLOGY	REF SECTION	DESCRIPTION
ECOTUBE	2.2.1	Retractable lances inject air at a high velocity into the furnace above the primary burner zone.
Flue Gas Recirculation (IFGR or FGR)	2.2.2	A portion of the flue gas is extracted downstream of the economizer and re-injected at or near the burner combustion zone or within the existing combustion air ductwork. This location allows for a reduction in excess combustion air, which contributes more nitrogen that can form NO <sub>x</sub> . Recirculated flue gas can also lower NO <sub>x</sub> formation by lengthening the flame, which reduces maximum flame combustion temperature. This reduction in flame temperature reduces NO <sub>x</sub> formation, because NO <sub>x</sub> formation is increased at elevated temperatures.
Low NO <sub>x</sub> Burners (LNB)	2.2.3	Replace existing LNBS with the most technologically advanced LNBS on the market.
LoTO <sub>x</sub>	2.2.4	Injection of ozone to react with NO <sub>x</sub> to form N <sub>2</sub> O <sub>5</sub> , which is captured by a downstream WFGD.
Natural Gas Reburn	2.2.5	Provide a row of natural gas burners above the primary combustion zone in the furnace to complete combustion, creating CO <sub>2</sub> with oxygen from the NO <sub>x</sub> molecules, reducing NO <sub>x</sub> back to elemental N <sub>2</sub> and O <sub>2</sub> .
Neural Networks	2.2.6	Optimizing computer controls to maximize NO <sub>x</sub> reductions.
NO <sub>x</sub> Star™ and NO <sub>x</sub> Star Plus™	2.2.7	Ammonia and a hydrocarbon (natural gas) is injected into the flue gas when 1,600 – 1,800° F. The ammonia reduces NO <sub>x</sub> and the hydrocarbon reacts with ammonia slip, allowing higher ammonia injection rates.
Overfire Air	2.2.8	Works by reducing the excess air in the primary combustion (burner) zone, which enhances the combustion staging effect and further reduces NO <sub>x</sub> emissions. Any residual unburned fuel, such as CO and unburned carbon that escapes the main burner zone, is subsequently oxidized as the OFA is introduced.
Regenerative Selective Catalytic Reduction (RSCR)	2.2.9	Ammonia is injected into the flue gas stream downstream of all air quality control equipment, with a thermal oxidizer and duct burner providing the necessary heat input to allow the catalyst to promote NO <sub>x</sub> reduction by ammonia.
ROFA & ROTAMIX	2.2.10	OFA and SNCR combination using a rotating air system to maximize effectiveness.
Selective Catalytic Reduction (SCR)	2.2.11	Ammonia is injected into the flue gas stream upstream of a catalyst, which helps the ammonia reduce NO <sub>x</sub> into nitrogen and water. The catalyst is housed in a reactor in the ductwork, usually between the economizer and air heater.

TECHNOLOGY	REF SECTION	DESCRIPTION
Selective Non-Catalytic Reduction (SNCR)	2.2.12	The process involves injecting a urea (H <sub>2</sub> N - CO - NH <sub>2</sub> ) solution at multiple levels in the boiler, where the flue gas temperature ranges from 800 to 1100 °C (1500 to 2000 °F). The urea solution is pumped to the boiler and atomized with compressed air at the injection nozzles.
SNCR/SCR Hybrid	2.2.13	SNCR is used to reduce NO <sub>x</sub> from the furnace, and high ammonia slip is used by a single layer of catalyst to further reduce NO <sub>x</sub> .

## 2.2 STEP 2 – ELIMINATE INFEASIBLE NO<sub>x</sub> CONTROL OPTIONS

The second step is to eliminate technically infeasible control technologies. This requires determining whether “technical difficulties would preclude the successful use of the control option on the emissions unit under review” based on physical, chemical, or engineering principles. 40 CFR Part 51, Appendix Y, Section IV.D.2.2. Control technologies are technically feasible if either (1) they have been installed and operated successfully for the type of source under review under similar conditions, or (2) the technology could be applied to the source under review. *Id.* For a technology to be capable of being applied, it must be “available” and “applicable.” A technology is considered “available” if the source owner may obtain it through commercial channels, or it is otherwise available within the common sense meaning of the term. An available technology is “applicable” if it can reasonably be installed and operated on the source type under consideration. *Id.* EPA does “not expect a source owner to conduct extended trials to learn how to apply a technology on a total new and dissimilar source type. Consequently, you would not consider technologies in the pilot scale testing stages of development as ‘available’ for purposes of BART review.” *Id.*

The technologies identified in Table 2-1 are explained in greater detail in the subsequent sections. As a result of the analysis in this step, only the technologies that are expected to provide the highest NO<sub>x</sub> reductions and are considered technically feasible at Coal Creek Unit 2 are carried forward for further evaluation; technologies with nominal reductions or lack of demonstrations at units similar to Coal Creek Station are eliminated from consideration. Further, two technologies were carried forward despite one being determined to be technically infeasible and the other presenting significant concerns about feasibility, to be conservative in this report’s approach. An overview of the determination to eliminate the technologies is provided in Table 2-2.

**Table 2-2 Evaluation to Eliminate Control Options**

TECHNOLOGY	BEST ACHIEVED EMISSIONS REDUCTION	EXPECTED EMISSIONS REDUCTION AT UNIT 2	PROVEN ON SIMILAR FACILITIES?	EVALUATION
ECOTUBE	30-90% (per ECOMB)	Not available due to lack of experience	No	Technology not carried forward per discussion in Section 2.2.1

TECHNOLOGY	BEST ACHIEVED EMISSIONS REDUCTION	EXPECTED EMISSIONS REDUCTION AT UNIT 2	PROVEN ON SIMILAR FACILITIES?	EVALUATION
Flue Gas Recirculation (IFGR or FGR)	Up to 40-60% depending on level of FGR	10-15%, depending on level of FGR	Yes	Technology not carried forward due to high maintenance costs seen on previous systems, along with limited space for installation.
Low NO <sub>x</sub> Burners (LNB)	Up to 20%	0-5% (system already well tuned with LNBs)	Yes	Technology not carried forward due to currently installed burners being state of the art
LoTOx	30-95+% (per Linde)	Not available due to lack of experience, specifically at large units	No	Technology not carried forward per discussion in Section 2.2.4
Mobotec ROFA & ROTAMIX	Up to 75%	5-23%	No	ROFA is essentially the same as the existing Unit 2 (t-fired system with OFA); ROTAMIX essentially is an SNCR combined with the ROFA system so SNCR is carried forward.
Natural Gas Reburn	Up to 40-60% depending on baseline emissions	10-20%	No	Not carried forward because of lack of natural gas line, natural gas price volatility, limited experience at facilities of 600 MW, and minimal expected reductions at Coal Creek.
Neural Networks	Varied and nominal	0-5%	Yes	Not carried forward due to nominal NO <sub>x</sub> reductions.
NO <sub>x</sub> Star™ and NO <sub>x</sub> Star Plus™	Up to 50%	Not available due to lack of experience	No	Not carried forward due to lack of natural gas line and pilot testing required.
Overfire Air	Up to 40-50%	Already installed	Yes	Currently installed with limited room for improvement
Regenerative Selective Catalytic Reduction (RSCR)	Up to 85%	69%	No	Not carried forward due to lack of experience at units larger than 100 MW
Selective Catalytic Reduction (SCR)	Up to 90%	69%	Yes	Considered for further evaluation, despite feasibility concerns.

TECHNOLOGY	BEST ACHIEVED EMISSIONS REDUCTION	EXPECTED EMISSIONS REDUCTION AT UNIT 2	PROVEN ON SIMILAR FACILITIES?	EVALUATION
Selective Non-Catalytic Reduction (SNCR)	Up to 50%	15-23%	Yes	Considered for further evaluation.
SNCR/SCR Hybrid	Up to 50-60%	33%	Yes	Not carried forward due to technical infeasibility.

### 2.2.1 ECOTUBE

The ECOTUBE System, by ECOMB, is a boiler combustion improvement and NO<sub>x</sub> reduction technology. Retractable lance tubes that penetrate the boiler above the primary burner zone inject high-velocity air as well as reagents. The lance tubes work to create turbulent airflow and to increase the residence time for the air/fuel mixture. In principle, the OFA (see Section 2.2.8) and SNCR (see Section 2.1.12) control strategies are combined in this technology.

The water-cooled ECOTUBES are automatically retracted from the boiler on a regular basis and cleaned to remove layers of soot and other depositions. Additional benefits in terms of furnace combustion are increases in efficiency and reduced fuel usage and corrosion and erosion in the boiler and backend equipment. However, there are no existing installations on boilers of similar type or size as Coal Creek Station. Currently the largest installation is on two 270 MW coal-fired units in France while most of the installations are well under 100 MW and typically at municipal waste or biomass facilities. Scaling the technology up in size from the current largest installation to the size necessary at Coal Creek Station would present risk due to the need for significant technology development and design modifications and would make the system a first-of-its-kind for this size of unit and operation on this type of fuel. Even if ECOTUBE had more apt experience on a unit like Coal Creek Station, the technology combines two technologies that are also evaluated in this report: OFA (which is already installed at Coal Creek Station) and SNCR. For these reasons, ECOTUBE will not be carried forward in this study.

### 2.2.2 Flue Gas Recirculation

Injection of flue gas into the combustion air, known as Flue Gas Recirculation (FGR), is a proven method for controlling NO<sub>x</sub> production from gas-fired utility boilers.

FGR acts to reduce NO<sub>x</sub> formation by reducing peak flame temperatures. In conventional applications, the recirculated flue gas is typically extracted from the boiler outlet duct upstream of the air heater. The flue gas is then returned through a separate duct and hot gas fan to the combustion air duct that feeds the windbox. The recirculated flue gas is mixed with the combustion air via air foils or other mixing devices in the duct. At Coal Creek Station this technology would require installation of a separate hot gas fan to move flue gas from the boiler exit to the air supply

ducting at the windbox inlet, where mixing of the air and flue gas must be uniformly achieved by installation of appropriate mixing devices. However, experience has shown that this type of installation requires heavy maintenance due to the particulates in the flue gas eroding equipment as would be present with Falkirk Mine's lignite ash content. It is possible to take flue gas downstream of the particulate control device, but this would require more ductwork, requiring space that is limited around the Coal Creek Station boilers. Furthermore, FGR systems can cause maintenance problems that have led utilities to decommission their FGR systems. For these reasons, FGR will not be carried forward in this study.

### 2.2.3 Low NO<sub>x</sub> Burners

All low NO<sub>x</sub> burners (LNB) offered commercially for application to coal-fired boilers control the formation and emission of NO<sub>x</sub> through some form of staged combustion. The basic NO<sub>x</sub> reduction principles for LNBs are to control and balance the fuel and airflow to each burner, and to control the amount and position of secondary air in the burner zone so that fuel devolatilization and high temperature zones are not oxygen rich. In this process, the mixing of the fuel and the air by the burner is controlled in such a way that ignition and initial combustion of the coal takes place under oxygen deficient conditions, while the mixing of a portion of the combustion air is delayed along the length of the flame.

The objective of this process is to drive the fuel-bound nitrogen out of the coal as quickly as possible, under conditions where no oxygen is present, where it will be forced to form molecular nitrogen, rather than be oxidized to NO<sub>x</sub>. Any nitrogen escaping the initial fuel-rich region has a greater opportunity to be converted to NO<sub>x</sub> as the combustion process is completed. The net result of staged combustion is usually longer and/or wider flames, due to this delayed mixing process. This is also one of the main reasons why low NO<sub>x</sub> combustion is normally associated with the potential for increased carbon in ash and higher CO emissions, as the combustion process begins to encroach on cooled boiler surfaces.

Coal Creek Unit 2 currently uses LNBs. Any additional NO<sub>x</sub> reductions that could be achieved by changing burners would vary significantly by burner, as this largely depends on the age and type of LNB. Every major outage, the LNBs are inspected and refurbished, so only nominal upgrades to the existing LNBs are available. Since the Coal Creek Station units are operating at a low NO<sub>x</sub> emission rate, substantial reductions in NO<sub>x</sub> emissions are not expected from either refurbishing or installing new LNBs, so they will not be carried forward in this study.

### 2.2.4 LoTOX

The LoTOx technology is the low temperature gas-phase oxidation of NO<sub>x</sub> by ozone injection. In this method, ozone is injected into the flue gas upstream of a wet flue gas desulfurization (WFGD) system. The ozone reacts with the NO and NO<sub>2</sub> to form nitrogen pentoxide (N<sub>2</sub>O<sub>5</sub>). The nitrogen pentoxide formed is soluble in water and can be removed from the flue gas using the WFGD system. The nitrate production (gypsum wash water) from this technology is

captured in the FGD waste product. Most regulatory agencies are very strict about nitrate release into water systems, so Coal Creek Station's evaporation pond would need to be evaluated for potential changes to their chemistry. LoTOx also consumes significant amounts of power, resulting from the multiple ozone generators required to produce the ozone for the process. The power consumption is expected to be comparable to what is needed for a conventional FGD system, which is significantly higher than the power consumption from an SCR.

The LoTOx technology offers high NO<sub>x</sub> removal efficiency with a reported potential of 15 to 25 percent savings in capital cost over an SCR with no ammonia slip at small, non-EGU facilities. LoTOx has no commercial installations on coal-fired power plants according to AECOM, the exclusive licensee of the technology. There were some studies of LoTOx on coal-fired power plants in the early parts of the century, but some form of pilot testing would be mandatory before even a cost estimate could be provided for installing LoTOx at Coal Creek Station. Although LoTOx is technically commercially available through AECOM, it will not be carried forward in this study due to its lack of demonstrated performance.

### 2.2.5 Natural Gas Reburn

The natural gas reburning process employs three separate combustion zones to reduce NO<sub>x</sub> emissions. The first zone consists of the normal combustion zone in the lower furnace, which is formed by the existing burners. In this zone, 75 to 80 percent of the total fuel heat input is introduced. The first zone burners are operated with about 10 percent excess air (a 1:10 stoichiometric ratio). A second combustion zone (the reburn zone) is created above the lower furnace by operating a row of conventional natural gas burners at a stoichiometric ratio less than 1.0. This technology also has the potential for increased furnace corrosion (especially with higher sulfur fuels) due to the reducing atmosphere in the lower furnace.

The substoichiometric reburn zone causes NO<sub>x</sub> produced in the lower furnace to be reduced to molecular nitrogen and oxygen, because the oxygen stripped from the NO<sub>x</sub> molecules is combined with the more active carbon monoxide molecules to form carbon dioxide as combustion is completed in the upper furnace. Fuel burnout is completed in the third zone (the burnout zone) by the introduction of OFA. Sufficient OFA is introduced to complete combustion of the unburned materials in the upper furnace with an overall excess air rate for the boiler of 15 to 20 percent. Reburn technology has demonstrated NO<sub>x</sub> reduction of 40 to 65 percent. However, at Coal Creek Station, this is expected to be much less and more on the order of 10 to 20 percent due to the low NO<sub>x</sub> baseline.

Sufficient residence time (adequate furnace height) in the reburn and OFA zones is a key factor in determining whether the reburning technology can be applied. Successful retrofit of this technology requires space within the boiler to allow adequate residence time for both the additional burning zone (0.4 to 0.6 second) and the associated OFA burnout zone (0.6 to 0.9 second). When this space is available, reburning can be highly effective, but a low residence time will limit system performance.



Natural gas reburn was part of multiple pilot test programs in the 1990s, and while this led to some permanent installations, many have since been decommissioned or are not operating while still installed. Currently, natural gas reburn installations are scarce, and finding recent performance information about natural gas reburn is difficult, particularly for facilities comparable in size to Coal Creek Station. In Black & Veatch's discussions with other clients over the last several years regarding NO<sub>x</sub> controls, natural gas reburn has consistently been averted due to multiple reasons. These include the lack of natural gas at the facility, the volatile price of natural gas, the general inexperience within industry with natural gas reburn, uncertainty on what type of performance could be expected, and expected adverse impacts to overall plant performance.

All of these concerns apply to Coal Creek Station and serve as justification for not carrying natural gas reburn forward as a viable technology. Additionally, GRE currently does not have a supply of natural gas at Coal Creek Station, so a new line would need to be built. As of March 2019, the industry average price for installing natural gas lines is \$1-2 million/mile. There is a current natural gas line that runs parallel to Highway 83, approximately four miles away from the plant. This line would need to be expanded to accommodate delivery of natural gas sufficient for natural gas reburn. If the gas line along Highway 83 is not expanded, then the closest gas lines are currently in Minot (66 miles away) and Bismarck (50 miles away).

Furthermore, concrete evidence is not readily available that natural gas reburn can reduce NO<sub>x</sub> emissions by sufficient amounts at a unit the size of Coal Creek Station, especially with its low starting baseline emissions. While natural gas reburn has shown NO<sub>x</sub> reductions in excess of 40 percent, the performance is expected to exponentially decline as starting baseline emissions are lowered to the baseline emissions of Coal Creek Station. Overall plant performance will also suffer from installing natural gas reburn, because natural gas burns at lower temperatures than coal, though it is difficult to quantify the decrease in plant efficiency without more data. The lack of industry experience and uncertainties with natural gas reburn disqualifies this technology from further evaluation.

### 2.2.6 Neural Network Systems

Recent advances in computer hardware and software technology have enabled some power generation facilities to improve their competitive position by implementing cost-effective optimization solutions. This solution, commonly referred to as "boiler optimization" or "neural network systems," provides simultaneous improvements in both plant efficiency and emissions. Neural network computing differs from traditional computing in that engineering, statistical, and first-law principles have been replaced by complex, time varying, nonlinear relationships. Neural network systems use real-time operational data extracted from a plant Distributed Control System (DCS), to "learn" solutions from plant operational experience, and improve plant performance by continuously adapting to changes in plant operation.

Neural network systems also supplement other NO<sub>x</sub> reduction strategies. Some of these include LNB, OFA and post-combustion controls such as SCR and SNCR. These systems are also



used to help boiler manufacturers tune boilers with poor combustion characteristics, or after an LNB retrofit or other boiler modifications, such as OFA.

The amount of reduction in NO<sub>x</sub> emissions from neural networks is highly dependent on the facility's current operations, as units operating further away from their optimal efficiencies will benefit the most from neural networks. With respect to Coal Creek Station, Unit 2 already has achieved a low NO<sub>x</sub> emission rate. As mentioned, Alstom Power (now GE) conducted a study on Unit 2 as part of MATS NO<sub>x</sub>/CO optimization, and they concluded that Coal Creek Unit 2 was well tuned. In comparison to other NO<sub>x</sub> emission control technologies, neural networks are capable of achieving only minor reductions.

Coal Creek Station has experimented with a few forms of intelligent controls in the past (intelligent soot-blowers and coal-flow algorithm models), both of which did not work and have been since decommissioned in favor of their operators' ability to effectively control the unit. Space is also limited for installing any potential drives for the burners due to the existing layout of the burners in the unit, several of which are nearly adjacent, restricting the scope of a neural network. Considering that neural networks would have a limited, if any, impact on NO<sub>x</sub> emissions at Coal Creek Unit 2, and because there is limited physical space for additional installations, they will not be carried forward in this study for Coal Creek Station.

### 2.2.7 NOXStar™ and NOXStar Plus™

NOXStar™ is the trademarked name for a NO<sub>x</sub> control technology that involves the injection of ammonia and a hydrocarbon (typically natural gas) into the flue gas path of a coal-fired boiler at around 1,600 - 1,800° F. The ammonia reduces NO<sub>x</sub> through a selective non-catalytic reduction (SNCR) reaction, with the hydrocarbon minimizing the ammonia slip. This enables higher reagent injection rates for NO<sub>x</sub> reductions than achievable with a typical SNCR technology.

NOXStar™ eliminates the need for (1) installation of a catalyst reactor and the associated capital costs, (2) economizer modifications, and (3) major outages. By not requiring a catalyst layer the associated problems of chemical poisoning, physical plugging, and sintering due to temperature excursions, pressure drop requiring new ID fans, and disposal of a hazardous solid waste are avoided. The other advantage of the NOXStar™ system is that the conversion of SO<sub>2</sub> to SO<sub>3</sub> is said to be negligible, thus eliminating one of the main drawbacks of the SCR technology.

For installations where the NO<sub>x</sub> reduction requirements are greater than can be achieved with NOXStar™, the NOXStar™ Plus system incorporates a single layer of in-duct catalyst into the system. This arrangement is similar to a hybrid SCR/SNCR system with the addition of the hydrocarbon injection to minimize ammonia slip.

The major consideration for the NOXStar™ technology is that it currently has only one major installation in the US on a coal fired unit and may require the installation of a single layer of in-duct catalyst (NOXStar™ Plus) to achieve advertised levels of NO<sub>x</sub> reduction. Injecting reagent with lower catalyst volumes resembles an SNCR/SCR hybrid (ASCR), and, as described later, is a technology evaluated later in this report. Extensive research was done in an attempt to obtain

more information on these systems, but an organization representing NOXStar™ in the US has not been identified. Similarly, no performance information has been obtained. In addition, there is currently no supply of supplemental natural gas at the existing plant site.

Information and reports from the original equipment manufacturer (OEM) state that up to 50 percent reduction has been shown with NOXStar™. However, research has been unable to validate these results from any other sources. Therefore, pilot testing would be required to determine what level of NO<sub>x</sub> reductions could be achieved at Coal Creek Station. It is expected that due to Coal Creek Station's low baseline emissions, significantly fewer NO<sub>x</sub> reductions would be achieved with this technology. Given that pilot testing is needed, NOXStar™ and NOXStar™ Plus will not be carried forward as part of this study for Coal Creek Station.

### 2.2.8 Overfire Air (OFA) System

OFA works by reducing the excess air in the burner zone, thereby enhancing the combustion staging effect and further reducing NO<sub>x</sub> emissions. Any residual unburned material, such as CO and unburned carbon, which inevitably escapes the main burner zone, is subsequently oxidized as the OFA is added.

The performance that can be expected from a given OFA system depends upon a number of factors. As the amount of OFA is increased, the stoichiometry in the burner zone decreases and a point is reached at which CO emissions reach high levels and become uncontrollable. The point at which this occurs can be boiler- and coal-type specific, particularly if a fuel is in anyway difficult to burn, and will also depend upon the extent to which it is possible to balance flows between the individual cyclones or burners. As the OFA amount approaches 10 to 15 percent, the probability for individual burners operating under overall fuel-rich conditions increases, such that pockets of very high CO emissions and unburned carbon will be formed. Similarly, fuel rich operation at burners close to the water walls can begin to lead to local slag formation and increased tube wastage rates, particularly if slagging is an ongoing problem and the coals have a high sulfur content. A fairly high level of unburned material leaving the burner zone can be accommodated by proper overfire port design, where requirements call for rapid and complete mixing of the OFA with the boiler flue gases.

Aggressively staging combustion to reduce NO<sub>x</sub> emissions creates a reducing environment in the boiler and can damage the boiler water wall tubes. The reducing environment attacks the iron oxides in the tube metal and can lead to pin holes in the boiler tubes. This phenomenon is referred to as tube wastage. Poor staging in the boiler could lead to tube wastage resulting in an increase in the amount of maintenance and in the worst-case scenario may require a forced outage to repair the tubes.

OFA already exists at Coal Creek Unit 2. Increased circumferential cracking was experienced when the LNC3+ technology was first operated. Adjustments in the flame location and staging of the air in the furnace have reduced excessive circumferential cracking to a certain extent but have not completely eliminated the phenomenon. Operation of an OFA requires an extensive

level of tube repairs in the reduction zone during each major outage. Operators are now better at managing the LNC3+ for low NO<sub>x</sub> operations while minimizing slagging and circumferential cracking during baseload operation. As noted elsewhere in this report, coal sodium and load variability can exacerbate slagging and circumferential cracking due to changes in flame location, affecting low NO<sub>x</sub> operation.

The expected increase in NO<sub>x</sub> removal by optimizing the existing OFA ports is minimal, on the order of less than five (5) percent. Therefore, as a NO<sub>x</sub> reduction technology, OFA will not be carried forward in this study for Coal Creek Station.

### 2.2.9 Regenerative Selective Catalytic Reduction (RSCR)

Babcock Power provides a variation of the typical SCR (see Section 2.2.11), installing the SCR at the tail end of the air quality control (AQC) train, prior to the chimney. Termed as Regenerative Selective Catalytic Reduction (RSCR), the tail end SCRs are typically more costly than high-dust SCR's, mainly because the flue gas needs to be reheated from the FGD exit temperature of approximately 140° F to at least 450° F, and tail end SCRs consume a larger footprint due to a larger SCR box and the heat exchanger. RSCR typically is used for biomass applications where the exhaust gas poisons are too great for a high-dust SCR catalyst.

First, the reagent is injected into the flue gas. The flue gas then passes through a regenerative thermal oxidizer (RTO), which is a large ceramic bed that can absorb and release heat into the flue gas. The flue gas is heated up by the RTO and then passes through the first layer of SCR catalyst. After that, the flue gas passes a duct burner, which provides more heat to the flue gas, and then through the second layer of catalyst. Finally, it passes through another RTO. This time, the flue gas is used to heat up the second RTO. Once the flue gas has used up all the heat in the first RTO, the cycle is reversed, and the second RTO is used as the heat source. This cycle repeats itself again and again, as long as NO<sub>x</sub> control is required.

RSCRs generally have much less, if any, impact to the existing ductwork and boiler house structure, whereas the high dust arrangement would require many retrofit modifications. Fewer modifications result in shorter construction and tie-in schedules (e.g. 18-24 months from design to commercial operation of a high dust system, and less than 9 months for tail end). Additionally, less catalyst volume is needed for the tail end application, since the majority of the particulate and SO<sub>2</sub> (including the trace elements that poison the catalyst) have been removed. This also leads to longer catalyst life compared to high dust systems.

One major disadvantage of an RSCR system is an ammonia slip of ~3-4 ppm, which is higher than an SCR. Ammonia slip from an SCR is mostly removed by downstream FGD systems and particulate controls, but that is not the case with an RSCR system that is located immediately before the stack. Any ammonia slip will simply exit the stack as an emission. In addition to the ammonia slip, RSCRs achieve slightly less NO<sub>x</sub> removal rates than SCRs (>93 percent for high dust SCR and >85 percent for tail end RSCR), depending on the NO<sub>x</sub> baseline. For Coal Creek Station, the NO<sub>x</sub> removal rate is expected to be well below 85%, given its low NO<sub>x</sub> baseline.

RSCRs have not been installed at coal-fired facilities of Coal Creek Station's size. Babcock Power, the leading vendor of the technology, would not provide a budgetary quote for this effort based on the vendor's determination that this is not a good application for an RSCR. The technology has been installed at many facilities, but the largest to date is only 54 MW. Babcock Power limits the applications to units 100 MW and smaller due to concerns about increasing the reactor sizes. Therefore, while RSCR could be capable of providing NO<sub>x</sub> reductions for Coal Creek Station, it will not be carried forward due to an installation at Coal Creek Station being first of a kind for the technology and the unwillingness of the supplier to offer this technology for units of this size.

#### **2.2.10 ROFA and ROTAMIX**

AECOM provides a NO<sub>x</sub> reduction system that combines LNBs, OFA, and SNCR technologies into an integrated system. The system uses a modified OFA system with mixing characteristics achieved through implementing a rotation to the OFA. This system is called ROFA™ - Rotating Opposed Firing Air. In addition, ROTAMIX™ can be added to the system, which consists of adding urea or ammonia injection into the ROFA™ air nozzles. The extra mixing produced by combining the overfire air nozzles with the reagent injection, results in improved mixing and a more homogeneous temperature profile in the boiler. These technologies were formerly provided by Mobotec but is now currently commercially available through AECOM.

ROFA is effectively a tangential fired boiler with OFA ports. Because Coal Creek Unit 2 is comprised of a tangential fired boiler, meaningful NO<sub>x</sub> reductions are not expected from installing ROFA. Furthermore, ROTAMIX is essentially an SNCR with proprietary nozzles and injection system, and as explained later, SNCR is carried forward for further evaluation. Therefore, ROFA and ROTAMIX's benefit to Coal Creek Unit 2 are effectively captured elsewhere in this study. These specific technologies are not carried forward.

#### **2.2.11 Selective Catalytic Reduction (SCR)**

##### **2.2.11.1 Technical Background on SCR**

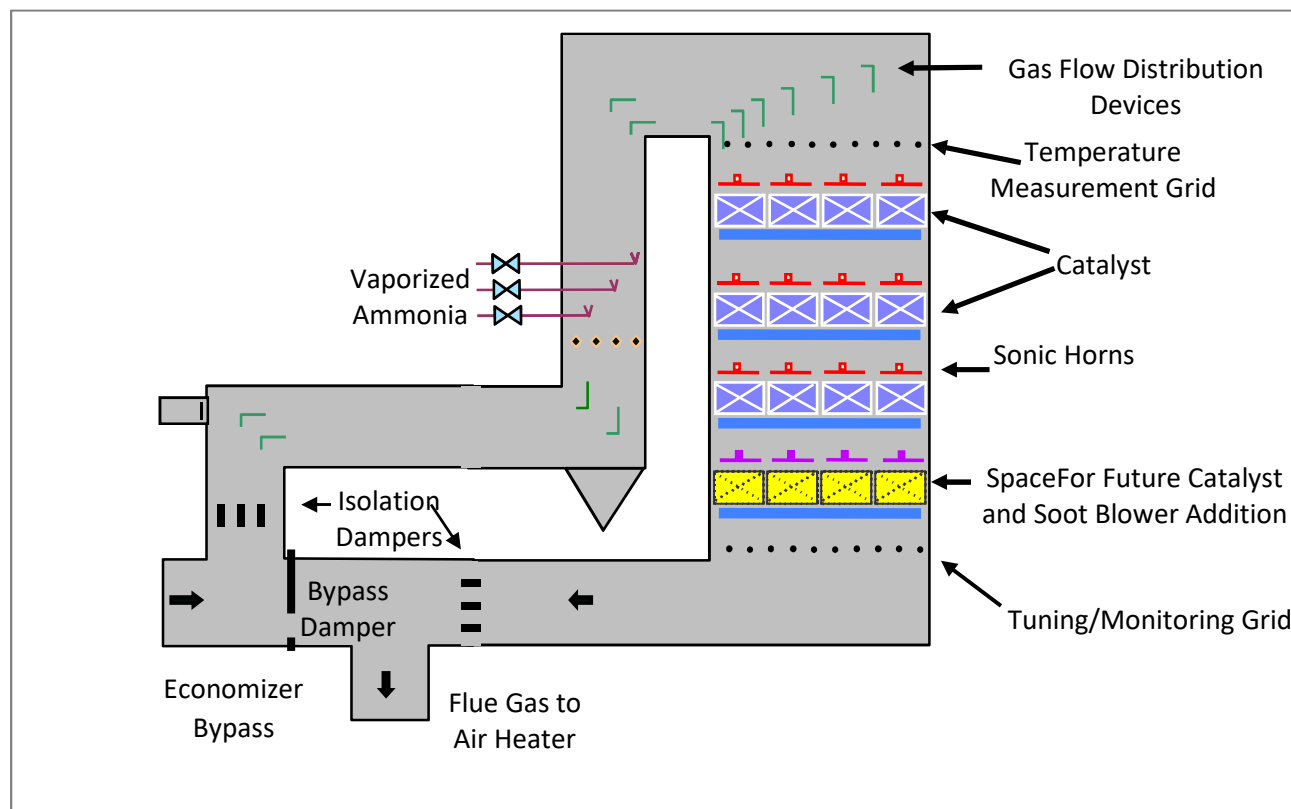
SCR systems are the most widely used post-combustion NO<sub>x</sub> control technology for achieving significant reductions in NO<sub>x</sub> emissions. In SCR systems, vaporized ammonia (NH<sub>3</sub>) injected into the flue gas stream acts as a reducing agent. Some large utility boiler SCR installations have been able to lower NO<sub>x</sub> emission to rates as low as 0.04 lb/MMBtu, but this is contingent on the unit's operating characteristics. Based on recent data from the Western Regional Air Partnership (WRAP) and EPA's Clean Air Markets Division (CAMD), SCRs on units of similar size as Coal Creek Unit 2 emit NO<sub>x</sub> at a rate of 0.05 to 0.08 lb/MMBtu on an annual average.<sup>13</sup> As will be discussed further in Section 3.1, the vendor quote was based on an emission rate of 0.04 lb/MMBtu, although the emission rate at Coal Creek Unit 2 likely would be higher based on the experience of other similar units.

---

<sup>13</sup> Based on information from <http://www.wrapair2.org/EGU.aspx> and <https://ampd.epa.gov/ampd/>.

NO<sub>x</sub> and ammonia reagent react to form nitrogen and water vapor. The reaction mechanisms are very efficient with a reagent stoichiometry of approximately 1.05 (on a NO<sub>x</sub> reduction basis) with very low ammonia slip (unreacted ammonia emissions). A simplified schematic diagram of a typical SCR reactor is illustrated in Figure 2-1. However, most modern SCR systems are built without a bypass systems and sonic horns are used in place of steam or air sootblowers.

The SCR reactor is the housing for the catalyst. The reactor is basically a widened section of ductwork modified by the addition of gas flow distribution devices, catalyst, catalyst support structures, access doors, and soot blowers. An ammonia injection grid is located upstream of the SCR reactor. The SCR reactor is typically elevated above and behind the air heater, and gas flow direction through the reactor is vertically downward for coal fired applications. There are two types of SCR arrangements: “high-dust” and “low-dust.” In a high-dust SCR arrangement, the reactor is located between the outlet of the economizer and the inlet of the air heater. The high-dust system is typically the most economical and preferred arrangement where physically possible. A low-dust arrangement would locate the SCR after the particulate control device to remove most of the dust from the flue gas stream. This arrangement is preferred when the fly ash contains a high level of catalyst poisons (sodium, arsenic, etc.), and removing most of the fly ash from the flue gas will prolong the catalyst life. Additional discussion of low-dust SCR arrangements in relation to Coal Creek Unit 2 are provided in Appendix B. This report focuses on discussion of high-dust arrangements, as a low-dust arrangement would be even more expensive than a high-dust SCR. Because a high-dust arrangement is determined to be not cost-effective as discussed in Section 4.1.1.2, a low-dust arrangement would be even less cost-effective.



**Figure 2-1 Schematic Diagram of Typical SCR Reactor**

The ammonia reagent for the SCR systems can be supplied by anhydrous ammonia, aqueous ammonia, or by conversion of urea to ammonia. Since the ammonia is vaporized prior to contact with the catalyst, the selection of ammonia type does not influence the catalyst performance. However, the selection of ammonia type does affect all other subsystem components, including reagent storage, vaporization, injection control, and balance-of-plant requirements. Anhydrous ammonia was assumed for this report, as it is the least expensive and most commonly used reagent.

SCR systems have a variety of interfacing system requirements to support operations. These impacts predominately relate to draft, auxiliary power, soot blowing steam, gas temperature, controls, ductwork, reactor footprint, and air heater. Dependent on arrangement and performance requirements, draft losses can range from 4 to 10 in. w.g. This can be compensated with the addition of ID booster fans. As needed, ductwork, and/or boiler box reinforcement need to be considered. In conjunction with the fan modification, the upgrade of the auxiliary power system might be necessary, which might also be triggered by ammonia supply system requirements.

The major impact of the SCR system can be seen at the air heater where there are two primary areas of concern. One is the formation and deposition of ammonium bisulfate (ABS) on the air heater surface. This will cause an increase in the pressure drop of the air heater and reduced heat transfer, negatively affecting unit efficiency. The other potential danger for the air heater is high concentrations of  $\text{SO}_3$  in the flue gas, which increase ahead of the air heater from SCR and  $\text{SO}_2$



interactions. Acid gas dewpoint is a function of the acid concentrations (such as SO<sub>3</sub>) in the flue gas, so the acid dew point of the flue gas increases after the SCR. This is an important consideration, because the flue gas temperatures significantly decrease after the air heater, potentially below the acid gas dewpoint. During low load operation and in the presence of air leakage, acid gases can condense in the air heater and lead to plugging and corrosion. Several measures can be taken to avoid or correct this situation. Most important is the right composition of the catalyst to minimize the SO<sub>2</sub> to SO<sub>3</sub> conversion rate. Another operational remedy is to change the boiler soot blowing program to shorter cycles. This will reduce the economizer outlet temperature and subsequently the conversion rate of SO<sub>2</sub> to SO<sub>3</sub> downstream of the SCR. Otherwise, modifications to the air heater and downstream equipment, or installation of an SO<sub>3</sub> mitigation system, is required to prevent corrosion.

#### **2.2.11.2 Technical Feasibility of SCR**

While SCR is an industry-proven NO<sub>x</sub> reduction technology, it has not been proven on units burning North Dakota lignite. There are two primary technical challenges with SCR and North Dakota lignite: catalyst plugging and catalyst fouling. In fact, the North Dakota Department of Health (NDDH) determined in 2009 that high-dust SCR is not technically feasible for units combusting North Dakota lignite due to these issues.<sup>14</sup> This determination was based heavily on the performance of a high-dust SCR pilot test at a lignite-fired boiler at Coyote Station.<sup>15</sup> There, plugging was observed at the catalyst inlet due to the high levels of alkalis, namely sodium (Na), in the fly ash, which can form alkali sulfates that deactivate catalyst and alkali oxides that physically blind catalyst surfaces.<sup>16</sup> Coal Creek Station would face similar challenges with the sodium content of its lignite coal. As shown in Appendix A, recent samples from the Falkirk Mine show a range of 0-14 percent sodium, approximately 27 percent of the samples are above four percent. While the fly ash analysis from GRE's coal has consistently been under four percent as an annual average, with the average Na<sub>2</sub>O weight percent being just above two percent, short term sodium spikes can be expected, increasing the operational risk of SCR catalysts and LNC3+ as discussed in this report.

Given that nearly a decade has passed since the NDDH determination, Black & Veatch conducted additional investigations into the feasibility of SCR at the Coal Creek Station to assess any technological advancements. Black & Veatch contacted three catalyst vendors to provide preliminary guarantees as part of a budgetary quote based on an average coal sodium content of 4 percent. Even at a 4 percent sodium level, one vendor did not provide a budgetary quote. Two vendors provided quotes, one of which requested to remain anonymous.<sup>17</sup> IBIDEN Ceram was the only vendor to provide a formal quote for purposes of the cost analysis in this Report. Their

---

<sup>14</sup> Best Available Retrofit Technology – Selective Catalytic Reduction, Technical Feasibility Analysis for North Dakota Lignite. Division of Air Quality, ND Department of Health. July/2009.

<sup>15</sup> *Id.*

<sup>16</sup> North Dakota RH SIP, Appendix C.2, Great River Energy, Coal Creek Stations, Units 1 and 2, BART Analysis, Revised December 12, 2007, Document ID EPA-R08-OAR-2010-0406-0006.

<sup>17</sup> Because this vendor requested to remain anonymous, its information cannot be relied upon for purposes of this analysis.

quotation and experience lists are included in Appendix E. IBIDEN Ceram considers the actual sodium range levels of North Dakota lignite (0-14 percent) to be potentially prohibitive and believes they cannot be addressed through catalyst pitch and design, without first performing a pilot test. Pitch refers to the width of the catalyst cell and the wall thickness, so catalysts with smaller pitches are more prone to experience plugging issues. The SCR catalyst used in the study at Coyote Station had a 6 mm pitch, but many current catalysts use a larger pitch. However, the upper end of the North Dakota lignite sodium content range is outside of Ceram's operating experience, and they expect that even a catalyst with a larger pitch would experience an impracticably high deactivation rate as a result of the sodium levels.<sup>18</sup> According to Ceram, because there is no direct experience in the industry with SCR catalyst installed on a unit firing ND lignite, it is difficult to determine with a high level of certainty what the long term impacts will be on the SCR catalyst. A pilot study would confirm the likely deactivation rate, and would require approximately 2,000 to 5,000 hours of operational data.

Ceram suggested that catalyst deactivation concerns could be addressed by the installation of the SCR in a tail-end arrangement (i.e., after all pollution control equipment). Tail-end SCRs, which are a type of low-dust SCR, are more expensive than high dust arrangements due to the need to reheat the flue gas prior to entering the SCR and the potential need to cool the flue gas prior to entering the stack. Flue gas exiting the scrubber is approximately 135° F; for the tail-end SCR to be effective the flue gas needs to be reheated to approximately 500° F. To provide this reheat, a natural gas line would need to be installed to Coal Creek. Additionally, the experience of tail-end SCR applications in the United States is minimal and is limited to small installations. Multiple manufacturers were approached for their experience list. Of these, only Babcock Power has installed tail-end SCR's in the United States, all of them at Oak Creek Power Station units ranging from 261 to 312 MW. Other manufacturers such as GE and Mitsubishi-Hitachi only have installations overseas at unit under 200 MW. Due to this lack of experience, and because the cost a tail-end SCR would be greater than the cost of a high dust SCR, only the high-dust SCR was carried forward for a cost analysis. See Appendix B for further explanation of the additional costs associated with low-dust SCRs, which would include tail-end SCRs.

The concerns about the impact of North Dakota lignite from the Falkirk Mine on the catalyst is shared by Fuel Tech, the vendor of the SCR/SNCR hybrid technology. Fuel Tech has concerns with catalyst erosion associated with the Falkirk Mine coal and would not provide any performance guarantees on the SCR portion of the hybrid technology, even if the sodium content could be guaranteed to remain below four percent, until more is known about the effects of North Dakota lignite ash on catalyst performance and deactivation. Like CERAM, Fuel Tech recommends that pilot scale testing be performed to obtain actual operational data to prove catalyst operation and performance.

---

<sup>18</sup> A trace element analysis was conducted, and IBIDEN Ceram did not have any concerns with the other poisons' concentrations.



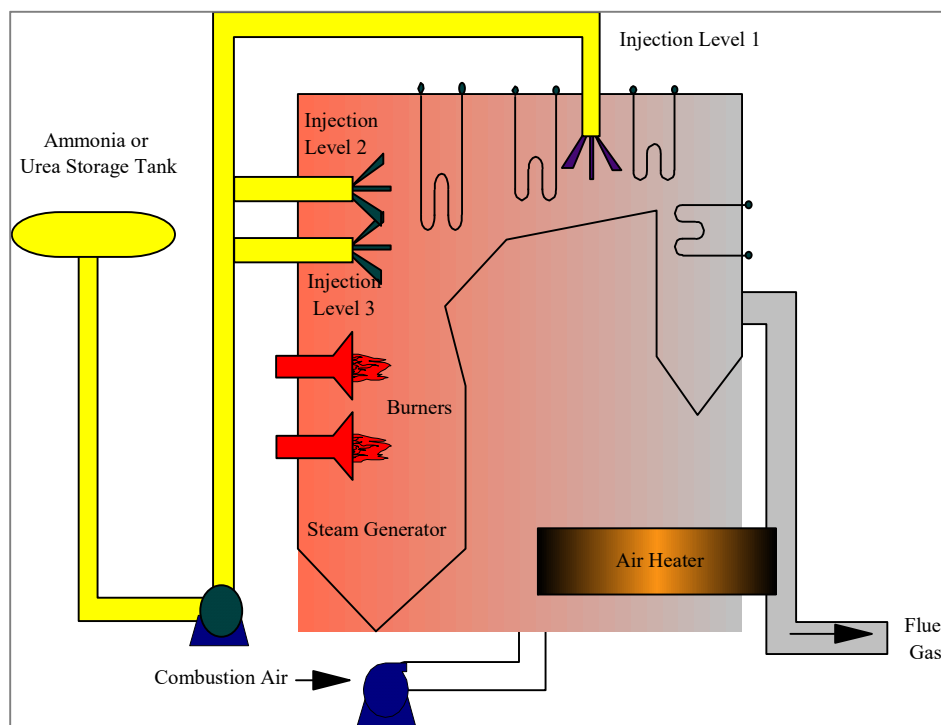
In light of NDDH's prior infeasibility determination, as well as the more recent information obtained by Black & Veatch, plugging and catalyst poisoning likely would render an SCR technically infeasible at Coal Creek Unit 2. Nevertheless, SCR is carried forward to Step 3 in order provide a conservative approach to this BART analysis.<sup>19</sup> In addition, because of the specific technical challenges associated with the installation of SCR at Coal Creek Station, it is critical that a site-specific design be considered when assessing costs.

### 2.2.12 Selective Non-Catalytic Reduction (SNCR)

Selective Non-Catalytic Reduction (SNCR) systems reduce NO<sub>x</sub> emissions by injecting a reagent at multiple levels in the steam generator as illustrated in Figure 2-2. SNCR systems rely solely on reagent injection rather than a catalyst. With respect to reagent injection, there are several critical variables: reagent injection temperature, reagent/gas mixing, and residence time for adequate reaction time to achieve NO<sub>x</sub> reductions. SNCR systems can use either ammonia or urea as the reagent. On coal-fired power plants, urea is the predominant reagent of choice. NO<sub>x</sub> reactions are delayed when using urea, because the urea must be converted to ammonia. This delay in reaction allows better reagent distribution in the boiler. Urea is injected above the burners and in the upper part of furnace, where the flue gas temperature ranges from 1,500 to 2,200° F. It is important to note that furnace temperatures of a pulverized coal fired boiler can range between 2,500 to 3,000° F. Therefore, the site-specific injection points are critical for maximizing NO<sub>x</sub> reductions.

---

<sup>19</sup> In addition to the concerns about coal sodium levels plugging and/or deactivating the catalyst, there is extremely limited installation space for an SCR. See Section 2.3.1 for further information.



**Figure 2-2 Schematic of SNCR System with Multiple Injection Levels**

SNCR systems are capable of achieving NO<sub>x</sub> emission reductions of 50 to 60 percent in optimum conditions (adequate reaction time, temperature, and reagent/ flue gas mixing, baseline NO<sub>x</sub> over 0.35 lb/MMBtu, multiple levels of injectors) with ammonia slip levels ranging from 5 to 50 ppmvd. Lower ammonia slip values are achieved with lower NO<sub>x</sub> reduction requirements. Typically, optimum conditions are difficult to consistently achieve, resulting in emission reduction levels of 20 to 40 percent over longer averaging periods. Potential performance is very site-specific and varies with fuel type, steam generator size, allowable ammonia slip, furnace CO concentrations, and steam generator heat transfer characteristics.

SNCR systems reduce NO<sub>x</sub> emissions using the same reduction reaction mechanism as SCRs, but without a catalyst. Most of the undesirable chemical reactions occur when reagent is injected at temperatures above or below the optimum range. At best, these undesired reactions consume reagent with no reduction in NO<sub>x</sub> emissions while. At worst, the oxidation of ammonia can generate more NO<sub>x</sub>. Accordingly, NO<sub>x</sub> reductions and overall reaction stoichiometry are very sensitive to the temperature of the flue gas at the reagent injection point. This is particularly complicated for SNCR applications on boilers larger than 100 MW.

Reagent injection lances are usually located between the boiler soot blowers in the pendent superheat section, and installation will require minor modifications to the water walls. Optimum injector location is mainly a function of temperature and residence time. To accommodate SNCR reaction temperature and boiler turndown requirements, multiple levels of injection lances are normally installed. A flue gas residence time of at least 0.3 second in the optimum temperature

range is desired to assure adequate SNCR performance. Residence times in excess of 1 second yield high NO<sub>x</sub> reduction levels even under less than ideal mixing conditions.

Computational Fluid Dynamics (CFD) and Chemical Kinetic Modeling (CKM) should be performed to establish the optimum ammonia injection locations and flow patterns for a specific boiler. The EPA Cost Manual Chapter 1, Section 1.2.5 states under Other Considerations under Computational Fluid Dynamics (CFD) and Chemical Kinetic Modeling (CKM), "Each boiler unit has a unique temperature and flow gradient with areas of high flow and stagnation. In addition, temperature and flow profiles vary according to the load capacity under which the boiler is operating. A mathematical model is developed to describe this stratification and variation of important species such as NO<sub>x</sub> and SO<sub>3</sub> in the flow stream. To develop the model, the flue gas temperature and velocity within the boiler are measured at many locations. These measurements are used in a CFD model for the convective passes of the boiler. The model predicts the temperature and gas flow within the boiler for various operating conditions and injection scenarios."

There is limit to overall reductions achievable by SNCR. Per the Institute of Clean Air Companies (ICAC), "As temperature increases, the 'critical' or equilibrium NO<sub>x</sub> concentration at a given oxygen concentration increases. At high enough temperatures, any reduction of NO<sub>x</sub> to below the critical level by SNCR or other means will be counteracted by the rapid oxidation of nitrogen to re-form NO<sub>x</sub>. For this reason, at sufficiently high temperatures and baseline NO<sub>x</sub> levels below the critical concentration, injection of ammonia or urea into the flue gas will result in increased NO<sub>x</sub> levels. If, however, the baseline NO<sub>x</sub> concentration is above the critical level, NO<sub>x</sub> reduction will result. For typical coal and oil-fired steam boilers, critical NO<sub>x</sub> levels are 70-90 ppm (ca. 0.1 lb/MMBtu) in the upper furnace."<sup>20</sup>

Coal Creek Unit 2 operates at NO<sub>x</sub> emissions near the critical point, as identified by the ICAC, of 0.1 lb/MMBtu. Even though minimal reductions are expected from an SNCR, it is still a well proven technology that can reduce Coal Creek Station's low NO<sub>x</sub> emissions. Therefore, SNCR is determined to be feasible and is carried forward in this analysis.

### 2.2.13 SNCR/SCR Hybrid

The SNCR/SCR hybrid system uses components and operating characteristics of both SNCR and SCR systems. The result is a NO<sub>x</sub> reduction alternative that is lower in capital cost than a full SCR but operating at a higher NO<sub>x</sub> reduction than just an SNCR system.

The SNCR component of the hybrid system is identical to the SNCR system described previously, except that the hybrid system may have more levels of multiple lance nozzles for reagent injection. This will increase the capital cost of the SNCR component of the hybrid system. During operation, the SNCR system would be allowed to inject higher amounts of reagent into the flue gas. This increased reagent flow has a twofold effect: NO<sub>x</sub> reduction within the boiler is

---

<sup>20</sup> Institute of Clean Air Companies (ICAC). *Selective Non-Catalytic Reduction (SNCR) for controlling NO<sub>x</sub> Emissions*. February 2008

increased while ammonia slip also increases. The ammonia that slips from the SNCR is then used as the reagent for the catalyst.

There are two design philosophies for using this excess ammonia slip. The most conservative hybrid systems use the catalyst as an ammonia slip “scrubber” with some nominal NO<sub>x</sub> reductions. As with in-duct systems, the flue gas velocity through the catalyst is an important factor in design. Operating ammonia in this mode allows maximum NO<sub>x</sub> reduction within the boiler by the SNCR while minimizing the catalyst volume requirement. This results in a relatively cheaper overall installation, but without maximum NO<sub>x</sub> reductions. The second philosophy uses a larger catalyst volume, albeit smaller than a full SCR, to obtain greater levels of additional NO<sub>x</sub> reduction within the space constraints of the boiler. The additional reduction is a function of the quantity of ammonia slip, catalyst volume, and distribution of ammonia to NO<sub>x</sub> within the flue gas.

Fuel Tech is the leading vendor of SNCR/SCR hybrid systems, termed ASCR®.<sup>21</sup> Fuel Tech has installed a hybrid on multiple coal-fired power plants, including one that is close in size to Coal Creek Station. Fuel Tech assessed Coal Creek Unit 2 and identified concerns with insufficient space available for an ASCR in the boiler building. Due to the existing DryFining™ and reheat systems, there is no room for installation of an ASCR. The system would be required to be installed outside the boiler house, which eliminates the benefits of an ASCR.

Fuel Tech also identified concerns with catalyst erosion associated with North Dakota lignite from the Falkirk Mine. Specifically, Fuel Tech states:

In addition to the spatial limitations, FTEK has several process concerns regarding the sodium (Na) levels in the fuel/ash and sulfur trioxide (SO<sub>3</sub>) levels in flue gas. SO<sub>3</sub> in the presence of ammonia (NH<sub>3</sub>), in the form of ammonia slip, from the SCR process could lead to ammonium bisulfate plugging in the air heater. Additionally, the SO<sub>3</sub> concentration in the flue gas may convert the Na in the solid phase to a gaseous phase which may cause significant catalyst deactivation. For these reasons, FTEK would not recommend the deployment of the ASCR technology on CCS Unit 2. We would not be willing to provide any performance guarantees on the SCR portion at this time until more is known about the effects of North Dakota lignite ash on catalyst performance and deactivation. FTEK would recommend that pilot scale testing should be performed to obtain actual operational data and learn more about North Dakota lignite and prove catalyst operation and performance.<sup>22</sup>

---

<sup>21</sup> Fuel Tech is a respected vendor of emission control technology for EGUs. In Region 8 alone, EPA has based final Regional Haze actions in part on data provided by Fuel Tech in Montana, 77 Fed. Reg. 57864, 57885 (Sept. 18, 2012) (relying on Fuel Tech control efficiency estimate); North Dakota, 77 Fed. Reg. 20894, 20897 (Apr. 6, 2012) (relying on SNCR capital costs derived from Fuel Tech budgetary proposal); Utah, 81 Fed. Reg. 43,894, 43,917 (July 5, 2016) (relying on subcontractor report that used Fuel Tech reagent and urea costs); and Wyoming, 79 Fed. Reg. 5032, 5144 (Jan. 30, 2014) (relying on Fuel Tech for utilization factor, urea costs, and emission reduction values).

<sup>22</sup> FuelTech Budgetary Quotation; January 21, 2019. Included in Appendix E.

For these reasons, Fuel Tech does not recommend the hybrid technology as feasible at Coal Creek Unit 2. Because the hybrid technology is technically infeasible for Coal Creek Station, it is not carried forward.

### 3.0 Step 3 – Evaluate Control Effectiveness of Remaining Technologies

For this step of the BART analysis, the SCR and SNCR are evaluated on their effectiveness in removing NO<sub>x</sub>. The metric used to determine control effectiveness is lb/MMBtu. This lb/MMBtu metric is eventually converted to a ton/year estimate based upon a projected annual capacity factor. For Coal Creek Station, the annual capacity factor is 87% based on a 10-year average.<sup>23</sup>

#### 3.1 SCR

As explained in Section 2.2.11, there are significant site-specific risks that make an SCR infeasible at Coal Creek Station, but the technology is carried forward for further analysis to be conservative. Industry experience has shown that SCRs are capable of achieving NO<sub>x</sub> emissions as low as 0.04 lb/MMBtu, with a range of 0.04 to 0.08 on units larger than 550MW. Table 3-1 shows units with SCRs located in Texas and within the WRAP states, along with their annual average emissions.<sup>24</sup>

**Table 3-1 WRAP and Texas Units with SCRs and Emissions<sup>(1)</sup>**

DESCRIPTION	COUNT IN DATA SET	ANNUAL AVERAGE EMISSIONS RANGE (LB/MMBTU)
Units with SCR	23	0.039 – 0.08
Units with SCR; > 550 MWg	11	0.039 – 0.08
Units with SCR; > 550 MWg; Burning Lignite	2	0.062 – 0.075
Total Units in Data Set	80 <sup>(2)</sup>	
Notes:		
1. Data obtained from the EPA Acid Rain Database and the Energy Information Administration.		
2. Number does not include units scheduled for retirement.		

Only ten (10) of twenty-three (23) units regularly emit 0.0499 lb/MMBtu NO<sub>x</sub> or less on an annual average basis, and none of these nine units burns lignite coal. It is important to highlight that large units with SCRs burning Texas lignite operate at higher emission rates of 0.062 to 0.075 lb/MMBtu as an annual average.

A range of 0.04 to 0.08 lb/MMBtu is assessed in this report based on industry experience at units of similar types and sizes as Coal Creek. Note that some installations at coal fired power plants are capable of reducing NO<sub>x</sub> emissions from baseline values by over 90 percent, but the

<sup>23</sup> See Section 1.0.

<sup>24</sup> Complete data is available in Appendix F.

percent removal rate expected at Coal Creek Station is lower due to the lower NO<sub>x</sub> baseline of 0.13 lb/MMBtu as an annual average.

### 3.2 SNCR

As an industry leading expert, Fuel Tech was contracted to perform a site-specific assessment for an SNCR's NO<sub>x</sub> reductions and associated costs for Coal Creek Unit 2. In October 2018, Fuel Tech mobilized a team to Coal Creek for gathering boiler and emissions data at various loads over a week's worth of tests. These data were then fed into Fuel Tech's proprietary CKM and CFD models to determine site-specific injection locations, urea injection rates, and associated NO<sub>x</sub> reductions across the load range of the Coal Creek Unit 2 boiler. The analysis resulted in an estimated reduction percentage of around 15 percent at baseload with a 10ppm slip using a basic SNCR system. Fuel Tech also evaluated an SNCR system using their proprietary multi-nozzle lances (MNL) to obtain better reagent distribution and NO<sub>x</sub> reduction. With the MNLs, Fuel Tech estimates a NO<sub>x</sub> reduction of 23 percent with a 10ppm slip at baseload.

Fuel Tech's NO<sub>x</sub> reduction estimates were lower with an ammonia slip guarantee of 5 ppm (10 and 18 percent with and without MNLs, respectively). Less ammonia injection equals less ammonia slip, which corresponds to lower NO<sub>x</sub> reductions. When SNCR vendors attempt to optimize injection, urea is injected in a much more limited fashion, leading to varying ammonia slip rates across the boiler. Due to uncertainty with the varying ammonia concentrations (e.g. stratification across the duct) and how a lower slip greatly restricts an SNCR's performance, Fuel Tech did not provide a 2 ppm ammonia slip guarantee. Table 3-2 shows the ammonia slip and reduction percentages expected with an SNCR. While NO<sub>x</sub> reduction percentages would be significantly lower at 2 ppm slip, the rate of decreased NO<sub>x</sub> reduction will increase as the ammonia slip decreases (e.g., removal at 2 ppm would be less than 10% when using MNLs).

**Table 3-2 Ammonia Slip and Removal Efficiency**

AMMONIA SLIP	REMOVAL % WITHOUT MNLS	REMOVAL % WITH MNLS
5 ppm	10	18
10 ppm	15	23

### 3.3 SUMMARY OF CONTROL EFFECTIVENESS

Table 3-3 summarizes the results of the technologies' control effectiveness.

**Table 3-3      Effectiveness of Remaining Control Technologies**

TECHNOLOGY	EXPECTED CONTROL EFFICIENCY (%)	EXPECTED GUARANTEED EMISSIONS (LB/MMBTU)
Selective Catalytic Reduction (SCR)	69	0.04
Selective Catalytic Reduction (SCR)	54	0.06
Selective Catalytic Reduction (SCR)	38	0.08
SNCR w/ Multi-Nozzle Lances	23	0.10
Selective Non-Catalytic Reduction (SNCR)	15	0.11



## 4.0 Step 4 – Evaluate Impacts and Document Results

Per Appendix Y to 40 CFR Part 51, the fourth step of a BART analysis is reviewing the impacts of each control technology in terms of four categories: the cost of compliance, energy impacts, non-air quality environmental impacts, and remaining useful life.

### 4.1 COST OF COMPLIANCE

Cost estimates for each of the remaining technologies were developed using two separate methodologies for Coal Creek Unit 2.

First, costs for SCR and SNCR were calculated using the EPA Cost Manual spreadsheets.

Second, site specific costs were developed for SCR and SNCR based on budgetary quotes from vendors and cost information from past Black & Veatch projects for similar retrofits. The cost of compliance was based on NO<sub>x</sub> baseline emissions of 0.13 lb/MMBtu as an annual average. The tons/year of NO<sub>x</sub> removed was calculated from this baseline and the projected annual capacity factor, which is 87 percent based on a 10-year average. Each technology was sized to achieve the highest practical emissions reductions for Coal Creek Station, and sensitivity analyses were run with both SCR and SNCR as discussed below.

The Cost Manual was followed for guidance on what line items to include, as well as sizing and cost estimating calculations for those line items. Again, Black & Veatch used site-specific information from vendors and its own recent SCR and SNCR projects, where appropriate, to make the cost estimates more accurate. Where required, equipment costs were scaled to account for the difference in expected size and performance, based on the on-site inspection of Coal Creek Unit 2 performed by Black & Veatch. Explanations of the cost estimates are provided in the subsections below.

The cost of compliance can be broken down into capital and annual costs. Capital costs generally refer to the money required to design and build the system. This includes direct costs, such as equipment purchases, and installation costs, such as foundations and installation of mechanical equipment. Indirect costs, such as engineering and construction field expenses, are also considered. All of these items sum up to provide the Total Capital Investment (TCI).

Annual costs include the ongoing expenditures to operate and maintain the system. Some noteworthy items are maintenance materials, yearly emissions testing, reagent consumption, utilities consumption (e.g. water and power), and disposal costs.

Table 4-4 and Table 4-5 summarize the costs and effectiveness of each of the technologies.

**Table 4-1 Cost of Compliance for Technologies (2018 dollars) Using EPA Spreadsheets**

TECHNOLOGY	TOTAL CAPITAL INVESTMENT	TOTAL ANNUAL COST (\$/YR)	EFFECTIVENESS (\$/TON NO <sub>x</sub> )
SCR	\$195,655,000	\$16,417,000	\$8,157
SNCR w/ MNL <sup>(1)</sup>	\$12,534,000	\$4,867,000	\$7,279
SNCR	\$12,179, 000	\$4,833,000	\$11,082

## Notes:

1. SNCR w/ MNL cost only changed the removal rate from 15 percent, which is expected from “typical” SNCR systems, and 23 percent, which Fuel Tech expects with their MNL package. Associated costs with the MNL package as described in the site-specific sections are not covered in the EPA spreadsheets.

**Table 4-2 Cost of Compliance for Technologies (2018 dollars) Using Site-Specific Approach**

TECHNOLOGY	TOTAL CAPITAL INVESTMENT	TOTAL ANNUAL COST (\$/YR)	EFFECTIVENESS (\$/TON NO <sub>x</sub> )
SCR <sup>(1)</sup>	\$190,920,000	\$17,590,000	\$8,737
SNCR w/ MNL	\$16,570,000	\$5,970,000	\$8,899
SNCR	\$12,740,000	\$4,860,000	\$11,145

## Notes:

1. The SCR cost is conservatively based on NO<sub>x</sub> emissions of 0.04 lb/MMBtu. See Table 4-5 for how the \$/ton changes with different emissions.

**4.1.1 SCR**

As discussed in Section 2.2.11, costs are assessed for SCR despite the fact that the technology appears infeasible for Coal Creek Station. The costs estimated using two methodological approaches (the EPA Cost Manual spreadsheet methodology and the site-specific methodology) are displayed in Table 4-3.

**Table 4-3 Cost of Compliance for SCR Technologies (2018 dollars)**

TECHNOLOGY	TOTAL CAPITAL INVESTMENT	TOTAL ANNUAL COST (\$/YR)	EFFECTIVENESS (\$/TON NO <sub>x</sub> )
SCR (EPA Spreadsheet)	\$195,655,000	\$16,417,000	\$8,157
SCR (Site-specific Approach)	\$190,920,000	\$17,590,000	\$8,737

## Notes:

1. The SCR costs are based on NO<sub>x</sub> emissions of 0.04 lb/MMBtu. See Table 4-5 for how the \$/ton changes with different emissions.
2. The EPA Spreadsheet Total Annual Cost and Effectiveness values were developed using the Method 2 calculation which is stated as being applicable to “coal-fired utility boilers” and does not reflect site specific catalyst volumes. The EPA Spreadsheet catalyst volume calculated is approximately half of the site-specific catalyst volume determined necessary by IBIDEN Ceram.

#### 4.1.1.1 EPA Cost Manual Spreadsheet Methodology

The EPA provides a spreadsheet for estimating SCR costs according to the Cost Manual. This spreadsheet uses key site variables such as unit MW, fuel type, NO<sub>x</sub> removal rate, and reagent use, and applies the EPA Cost Manual methodology and formulas to these site variables to calculate TCI and total annual costs, which are then used to derive an overall \$/ton cost effectiveness estimate. As shown in Appendix G, Coal Creek Unit 2 variables were added to this spreadsheet. Similar to the site-specific methodology outlined in Section 4.1.1.2, the most restrictive NO<sub>x</sub> reduction of 69 percent was used with the spreadsheet based on an annual emission rate of 0.04 lb/MMBtu.

The Cost Manual spreadsheet calculates a TCI of \$195.7 million, and a cost effectiveness of \$8,157/ton NO<sub>x</sub> removed, according to 2018 dollars. This value was calculated by using a retrofit factor of 1.0, but the congestion at Coal Creek Unit 2 would justify an increase to the retrofit factor. As observed by Black and Veatch engineers, and as is discussed in more detail below in Section 4.1.1.2, Coal Creek Unit 2's unique DryFining™ and reheat systems occupy the space that typically would be used for installation of an SCR. If the retrofit factor is increased to 1.25 (Cost Manual spreadsheet identifies a range of 1 to 1.5), then the TCI increases to \$244.6 million with a cost effectiveness of \$9,906/ton NO<sub>x</sub> removed.

The Total Annual Cost and Cost Effectiveness values were developed using the EPA Spreadsheet Method 2 calculation alternative which does not use site specific catalyst volumes. The spreadsheet does calculate an estimated catalyst volume that is approximately half the amount of the site-specific catalyst volume determined necessary by IBIDEN Ceram. The greater site specific catalyst volume would be expected to result in a higher Total Annual Cost and Effectiveness cost compared to the EPA Spreadsheet default volume.

#### 4.1.1.2 Site-Specific Methodology

A high-dust arrangement was selected for this study's assessment of costs, because low-dust configurations would be more expensive at Coal Creek Station, given the need for both flue gas reheat and cooling, as discussed in Appendix B. If the cost of the high-dust arrangement is deemed to be cost-prohibitive, it is reasonable to assume that a cost analysis for a low-dust arrangement would result in the same conclusion.

The SCR and ancillary equipment were sized based on the most restrictive emission rate of 0.04 lb/MMBtu as an annual average. Catalyst vendors were provided the plant's expected flue gas information downstream of the economizer, based on the ultimate coal analysis of the lignite burned at Coal Creek Station. Trace elemental analysis of the ash at Coal Creek Station was also evaluated for catalyst poisons (sodium, arsenic, etc.). For purposes of this site-specific cost analysis only, IBIDEN Ceram provided a budgetary proposal for their catalyst in a high-dust SCR arrangement, despite their recommendation against a high-dust SCR at Coal Creek Station due to the sodium content of the coal. This proposal assumes a NO<sub>x</sub> inlet rate of 0.13 lb/MMBtu (approximately 60 ppm).

The most recent SCR project Black & Veatch has executed was on a 450 MW facility that burns PRB in 2014/2015. Black & Veatch completed an SCR installation in 2009 on a unit similarly sized to Coal Creek Station, but this unit burned an eastern coal that is significantly different from North Dakota lignite. Therefore, the more recent 450 MW SCR project was used as a more appropriate reference case for Coal Creek Station. Escalation factors for differently sized equipment were used, with appropriate parameters used for comparing equipment (e.g. reactor housing was scaled according to the catalyst volume, rather than total flue gas flow rate or units' MW). Inflation from the Chemical Engineering Plant Cost Index (CEPCI) per year was also applied.

Certain items had an elevation factor applied to the costs. The referenced project was at an elevation well over 6,000 feet, and Coal Creek Station is located at 1,940 feet, resulting in a ratio of 0.849. As the atmospheric pressure increases, the volumetric flow rate decreases according to Boyle's Law, so this elevation factor was applied as a cost adjustment where applicable. The Cost Manual uses it as a straight multiplier in some of its equations (e.g., equation 2.41). So, for equipment related to air gas flow, a multiplier of 0.849 was applied.

Table 4-4 provides a summary of the costs for the SCR, with subsequent sections explaining the specific categories of costs used to develop the overall cost estimate. More specific SCR cost information can be found in Appendix C, with the cost sheets provided in Appendix D.

**Table 4-4 SCR Cost Summary Using Site-Specific Methodology**

CATEGORY	US DOLLARS (2018)
Purchased Equipment Cost (PEC)	\$49,830,000
Direct Installation Cost (DIC)	\$69,130,000
<i>Total Direct Cost (DC = PEC+DIC)</i>	<i>\$118,960,000</i>
Indirect Costs (IC)	\$71,960,000
<b>Total Capital Investment (TCI = DC + IC)</b>	<b>\$190,920,000</b>
Direct Annual Cost (DAC), no ash impacts	\$4,370,000
Indirect Annual Cost (IDAC)	\$13,220,000
<b>Total Annual Cost (TAC = DAC + IDAC)</b>	<b>\$17,590,000</b>
<b>\$/Ton NO<sub>x</sub> removed</b>	<b>\$8,737</b>

As discussed in Section 3.1, industry experience has shown that SCRs are capable of achieving NO<sub>x</sub> emissions as low as 0.04 lb/MMBtu, with a range of 0.04 to 0.08 on units larger than 550MW. For the purpose of this cost evaluation, the conservative emission rate of 0.04 lb/MMBtu will be used. However, the unique technical risks associated with North Dakota lignite, as described in this document, may drive this emission rate higher to be more consistent with larger installed SCR systems. In particular, large units with SCRs burning Texas lignite operate at higher emission rates of 0.062 to 0.075 lb/MMBtu as an annual average. If the costs for an SCR are assumed to be

the same across NO<sub>x</sub> emission rates, the sensitivity of \$/ton according to different NO<sub>x</sub> removal rates is provided in Table 4-5.

**Table 4-5 SCR Cost with NO<sub>x</sub> Emissions Summary (2018 dollars) Using Site-Specific Methodology**

NO <sub>x</sub> EMISSION	\$/TON
0.04	8,737
0.06	11,233
0.08	15,727

Figure 4-1 shows a general location of where the SCR would be located at Coal Creek Station (ducts and SCR box in red). The general congestion close by the boiler building and elevated construction are evident in the picture. Coal Creek Station installed a novel multipollutant reduction technology ("DryFining™") that processes and dries the lignite prior to combustion. Consequently, the back of the boiler has additional conveyors, processing equipment and DryFining™ baghouses, which are not present on other coal fired units. In addition, Coal Creek Station installed a reheat system in order to run wet scrubbers with a dry stack to meet BART SO<sub>2</sub> limits, as another unique feature, which further restricts available space in the back of the boiler where SCRs are traditionally located. As observed by Black & Veatch engineers, and as illustrated in Figure 4-2, the congestion from these systems preclude installation of an SCR in inside the boiler house. Rather, an SCR installation at Coal Creek Unit 2 must be customized for these unique constraints. Significant parts of DryFining™ and reheat systems would still need to be removed to make space for the SCR ductwork, and then reconfigured for re-installation. As discussed below, this report takes a conservative approach and does not include an estimate of the costs for the reconfiguration.



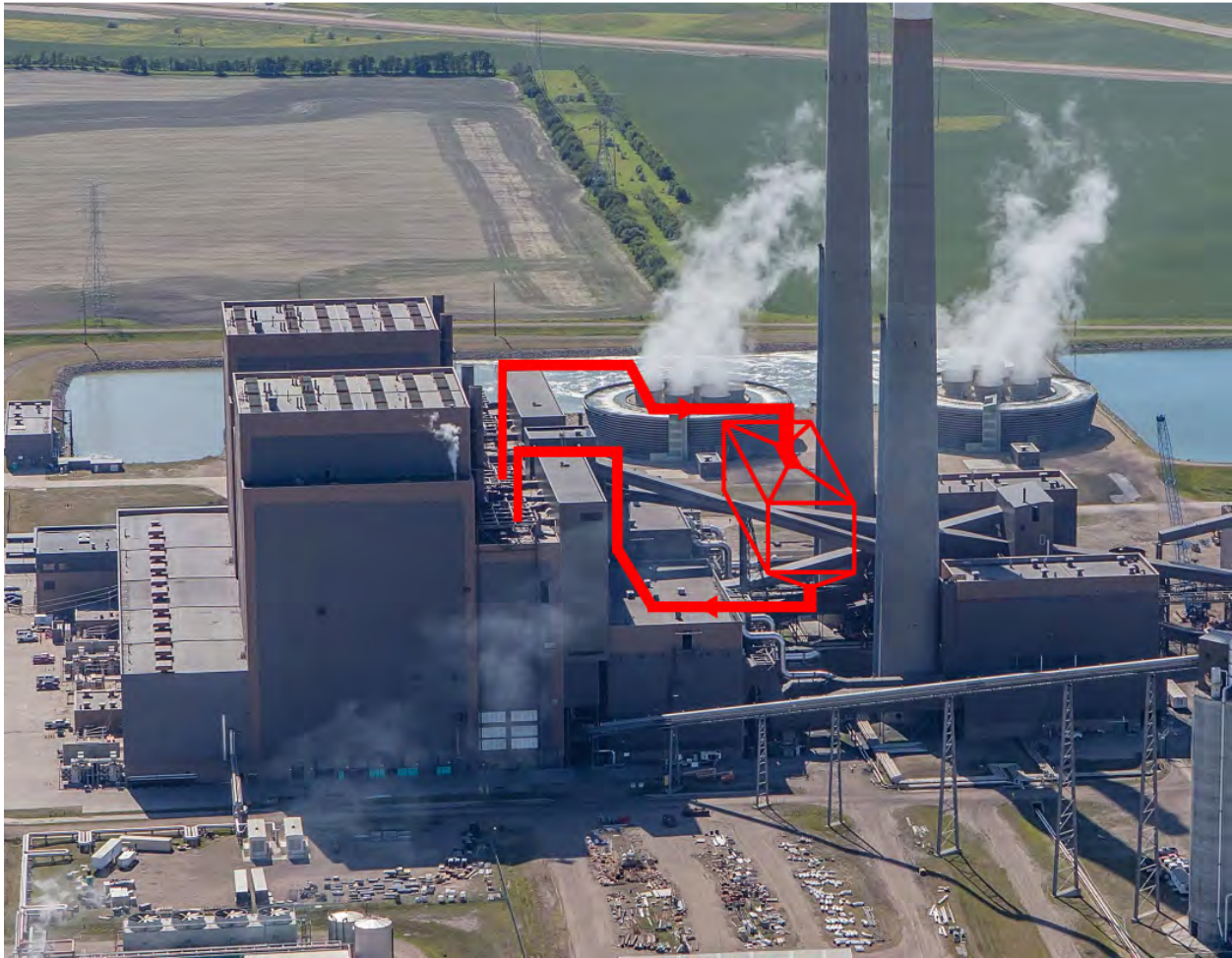
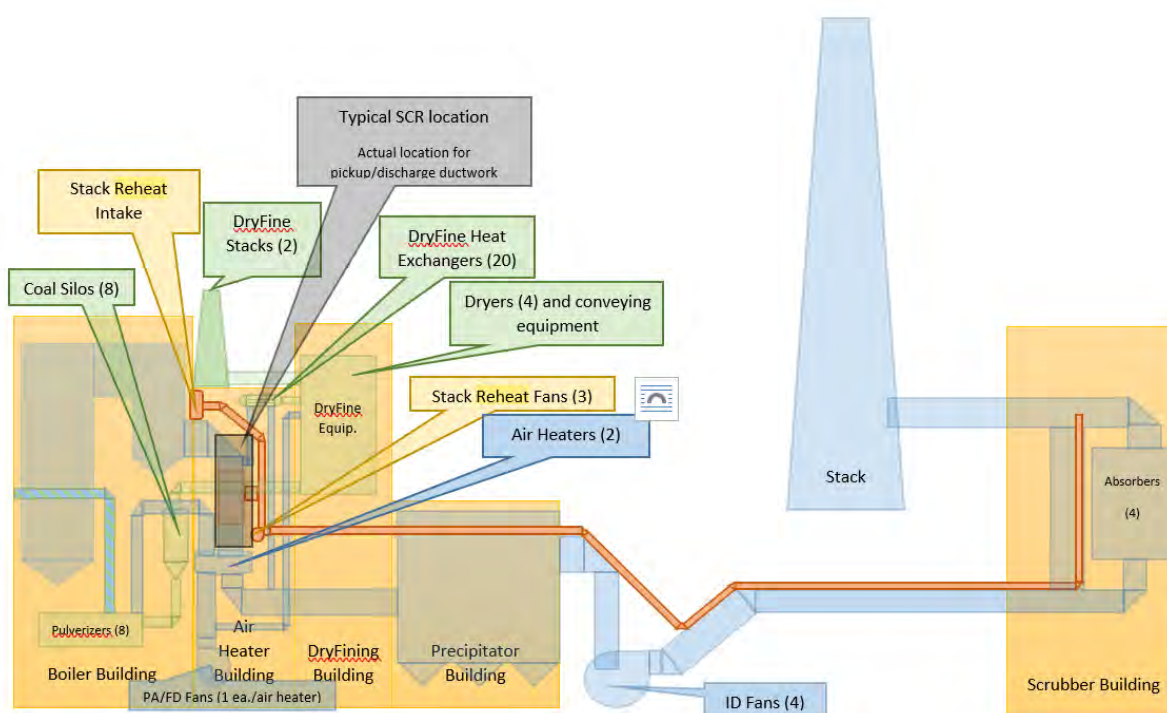


Figure 4-1 General Sketch of SCR Location



**Figure 4-2 Equipment in Boiler Building around ductwork tie-in at Coal Creek Unit 2**

#### 4.1.1.2.1 Purchased Equipment Costs

Purchased Equipment Costs (PEC) refers to the cost of purchasing equipment for the SCR from vendors. Significant site-specific costs generally exceeding \$1 million are described below, and explanations of the minor line items can be found in Appendix C. The total PEC for Coal Creek Station's SCR is \$49.83 million.

Figure 4-1 shows a general location of where the SCR would be located at Coal Creek Station (ducts and SCR box in red). The general congestion close by the boiler building and elevated construction are evident in the picture.

- **Reactor Housing** – New steel for the catalyst/reactor housing is required. This does not include new ductwork connecting the reactor to the existing ductwork. The price for this was escalated from the Black & Veatch SCR reference project based on the difference in its catalyst volume and the one provided by IBIDEN Ceram. The catalyst volume was calculated based on the actual volumetric flow rate. Therefore, an elevation adjustment factor was not applied to this cost. Total cost for reactor housing is estimated to be \$3.7 million.
- **Ammonia Injection Grid and Dilution Skid** – An ammonia injection grid is necessary to achieve optimal ammonia injection. A dilution skid is used to help deliver the anhydrous ammonia to the injection grid at a ratio of about 20:1 (air:ammonia). Since the size of the grid corresponds to the size of the reactor, the

difference in catalyst volume was also used to escalate the price. This cost is estimated to be \$2.3 million.

- **Initial Fill of Catalyst** –The catalyst quoted by IBIDEN Ceram is a honeycomb type with a makeup of about 80 percent titanium, 5-10 percent tungsten, and 0-3 percent vanadium. The balance of the catalyst is ceramic material. The volume of catalyst was selected based on having three layers, with a spare layer, and a 24,000 hour life span, consistent with plant outage schedules.<sup>25</sup>

Based on the coal type and flue gas characteristics IBIDEN Ceram calculated a catalyst volume approximately 2 times greater than the EPA spreadsheet estimate. Coal Creek Unit 2's higher temperature and potential poisons in North Dakota lignite resulted in IBIDEN Ceram calculating a higher volume than a "typical" installation for purposes of this cost assessment, although Ceram expects that this higher volume may be insufficient to address the deactivation rate likely to result from the high sodium levels in North Dakota lignite. This cost is estimated to be \$6.1 million.

- **Ductwork** – The cost of ductwork was escalated from the SCR reference project's costs based on the units' MW, because the ductwork at a coal fired units is reflective of the plant's overall size, not the SCR catalyst volume or ammonia consumption rate. Due to the congestion around the boiler building, the ductwork modifications and additions required to provide flue gas from the economizer to the SCR, and from the SCR to the air pre-heater, are complex. Black & Veatch's reference project used in this cost estimate had much more available space for installing an SCR. Therefore, the pricing was scaled to account for a more congested arrangement as well as difference in sizing requirements. This value is reasonable considering that the location of the SCR in this study is elevated above the ID fans due to limited real estate. There are also potential places beside Coal Creek Unit 2 and on the backside of Coal Creek Unit 1, but since there are complications with ductwork at any of the locations, above the ID fans was chosen. However, offsetting the cost increase from the higher exponent is an adjustment for elevation, or multiplying by the elevation factor of 0.849. This cost is estimated to be \$5.3 million.
- **Air Heater Modifications** – Modifications are necessary to bolster the air preheater from increased SO<sub>3</sub> in the flue gas from the catalyst converting SO<sub>2</sub>. Sulfuric acid is more likely to form with increased levels of SO<sub>3</sub>, resulting in corrosion problems of downstream equipment like the air preheater. This is particularly a concern with coals with higher sulfur content, as noted by IBIDEN Ceram. Due to the

---

<sup>25</sup> The catalyst costs estimated in this report are conservative. IBIDEN Ceram certifies its catalyst life for 24,000 hours or 36 months from date of delivery, whichever comes first. Because of ordering lead time, catalyst would be stored on-site for several months before installation during the next outage, decreasing the lifespan of that catalyst prior to the mandatory shipment of the next supply. This means that catalyst will be ordered more frequently than the lifespan guarantee, resulting in higher costs than are estimated here.



temperatures exiting the economizer (around 830° F), the catalyst best suited for the flue gas conditions at Coal Creek Unit 2 will oxidize about 5 percent of the SO<sub>2</sub>. The flue gas is expected to have around 831 ppm of SO<sub>2</sub>. If 5 percent is converted to SO<sub>3</sub>, this will result in over 40 ppm of SO<sub>3</sub>.

In addition to concerns about air heater corrosion, SO<sub>3</sub> is not readily captured by WFGD systems, resulting in noticeable blue plumes from the stack when the emissions exceed 10 ppm. One solution to the corrosion and blue plume issues is to install an SO<sub>3</sub> mitigation system (often termed SAM, or sulfuric acid mitigation). Current methods of reducing SO<sub>3</sub> in flue gas include injecting a sorbent such as hydrated lime, trona, sodium bicarbonate, or soda ash. Estimating a cost for this type of supplemental system is not part of this study, but based on past projects Black & Veatch would expect a minimum of \$10 million to fully engineer, procure, and construct this system.

The Cost Manual provides an equation (equation 2.43) to estimate the cost of air preheater modifications, and this equation resulted in ~ \$10.5 million.<sup>26</sup> Although the Cost Manual contemplates the application of air heater enhancements only for bituminous coal, B&V performed this calculation because of IBIDEN Ceram's concern about the economizer exit temperature and SO<sub>3</sub> creation across the catalyst. Some form of costs associated with increased SO<sub>3</sub> levels should be included, and the Cost Manual's value for air preheater modification was chosen instead of developing costs for a new SAM system.

- **Structural Steel** – In addition to the steel required for the reactor housing and ductwork, support steel must be purchased. This price was scaled up from the reference project based on the units' difference in MW. A significant portion of the steel is related to the ductwork that had an elevation adjustment factor applied to its cost. Therefore, the same adjustment is made to the steel. This cost is estimated to be \$10.6 million.

#### 4.1.1.2.2 Direct Installation Costs (DIC)

The DIC combines with the PEC to give the total direct costs (DC). As its name would imply, direct installation costs (DIC) refer to the costs directly associated with physically installing the SCR. Construction costs are often higher than the PEC, especially for retrofits. Coal Creek Station presents unique retrofit challenges because of existing reheat and DryFinishing™ equipment located on the back of the boiler. Therefore, site-specific design considerations are critical to deriving more accurate cost estimates. A general retrofit factor of some percentage was not universally applied. The following items were included in the DIC – see Appendix D for the values. The DIC was estimated using actual costs from the Black & Veatch reference project, which was also a retrofit.

<sup>26</sup> The EPA cost spreadsheet does not include a cost adder for air heater modifications when operating on lignite fuel. When bituminous fuel is selected an air heater modification price of approximately \$10,900,000 is shown.

- **Subsurface Construction** – Prior to installing any foundations or equipment, earth/soil/concrete must be moved along with any underground utility lines. Once this is done, all foundations, piles, ductbank, and embedments can be installed. This price was scaled up from the reference project based on the units' difference in MW. The previous project had more real estate for construction than Coal Creek Station. Therefore, these costs were adjusted by a slightly higher factor of 1.2 to account for physical constraints. This cost is estimated to be \$4.1 and \$1.1 million for earthwork/undergrounds and foundations, respectively.
- **Superstructure Construction** – In addition to the reactor and ductwork, a cost for installing a heated building around the SCR was included. Coal Creek Station experiences temperatures well below freezing, and to accommodate maintenance during the winter months, a heated enclosure is needed. The referenced SCR project by Black & Veatch was also located in an area with harsh winters. Consequently, the price of a heated building was used for this estimate. Since superstructures relate to equipment processing flue gas, the elevation adjustment factor was applied. Similar to the subsurface construction costs, costs were adjusted by factor of 1.2 to account for the congestion differences between the reference project and Coal Creek Station. This cost is estimated to be \$28.4 and \$15.2 million for the reactor/ductwork and the heated building, respectively. A significant portion of this cost is due to multiple large cranes required to build an elevated structure such as the SCR at Coal Creek Station.
- **Demolition and Rebuild** – Space inside and around the boiler building is very congested at Coal Creek Station. It will be extremely difficult to locate SCRs inside the boiler building. Based on Black & Veatch's initial assessment of the facility, including a site inspection and review of applicable engineering drawings, it was determined that, an SCR would have to be elevated and located above the ID fans, requiring more ductwork outside of the boiler house than typical installations. This is accounted for in the line item for ductwork and structural steel.

An additional line item was included to account for the rework inside the boiler house that will be required to tie-in the new ductwork connecting the new SCR to the old ducts. Inside the boiler building, there is a reheat system that takes in ambient air and is heated by the hot duct pantlegs entering the air preheater. As part of the SO<sub>2</sub> BART control strategy, this reheat gas is then directed to the stack, where it mixes with the flue gas leaving the WFGD and raises the overall exhaust gas temperature in order to maintain a dry stack. This reheat system is adjacent to the economizer outlet where SCR ductwork is typically connected. After the SCR duct tie-ins are made, the ductwork needs to exit the boiler building to the new SCR reactor. Due to existing equipment and steel inside the boiler building, the best option is routing the new duct work through the roof. However, GRE's DryFining™ system has ductwork and baghouse equipment in this area. Therefore, rework

would be needed to relocate or demo/rebuild the equipment that is in the way (See Figure 4-1). In brief, the reheat system, heat exchangers, and stacks would be removed in order to create space for installation of the SCR, and then reconfigured for reinstallation<sup>27</sup>. The removal of these systems would necessitate an outage of approximately 6 to 18 months depending on the final configuration and amount of demolition and relocation required. The cost for this lost revenue would be significant but is not accounted for in this analysis. Access to the SCR could be preserved for the necessary periodic catalyst replacement and other maintenance.

Given the unique congestion issues, site-specific cost estimates must be used for the demolition and rebuild of the reheat or DryFinishing™ ducts. If the reheat section is abandoned, then a wet chimney would be needed. The costs for new stacks are expensive. Based on a past project, a new, wet chimney at Coal Creek Station would cost at least \$16 million. Using past labor rates (manhours and wages) from Black & Veatch projects, the cost to demo and rebuild the reheat ductwork alone is estimated to be \$2.8 million based on the tonnage of Corten steel. This cost did not include the expenses to relocate/reroute significant parts of the DryFinishing™ and reheat equipment, which would require more detailed design work to accomplish. As such, it is viewed as more cost effective to retrofit the reheat duct work. Therefore, the wet chimney option was not incorporated into the cost estimate.

There is a large amount of steel and equipment associated with the DryFinishing™ system. Based on a high-level review of drawings, the cost to demolish and rebuild the DryFinishing™ equipment interfering with the new duct is estimated to be around \$5 million. The costs utilized in this analysis could increase as specific design requirements are analyzed.

- **Mechanical Construction** – This line item deals with installing the mechanical equipment (e.g. pumps, tanks, piping, catalyst layers, etc.). Once the foundations and structures are installed, the mechanical construction costs should be comparable to the referenced project, so the previous project's cost was escalated based on the units' difference in MW. This cost is estimated to be \$6.6 million.
- **Electrical Construction** – This line item deals with installing the electrical equipment. The previous project's cost was escalated based on the units' difference in MW. This cost is estimated to be \$4.4 million.

---

<sup>27</sup> The cost estimate for this study uses a conservative approach by basing re-installation of all equipment in a configuration similar to the current arrangement. It is expected that the re-installation will actually require significant re-design including potentially relocating equipment to a new building outside the existing boiler house.

#### 4.1.1.2.3 Indirect Costs

Indirect costs (IC) refer to those costs associated with executing a project that are not directly attributable to purchased equipment or installation. This includes the following:

- Engineering
- Construction and field expenses<sup>28</sup>
- Owner's cost
- Startup
- Performance tests
- Contingencies

The Cost Manual does not provide a specific equation for estimating IC. Rather, indirect costs are accounted for in their capital cost equations that comprise the total capital investment. Developing site-specific costs for Coal Creek Station allows the IC values to be explicitly estimated. The costs were calculated as a percentage of the direct costs, based on the reference project's final financials. This cost is estimated to be \$72 million.

#### 4.1.1.2.4 Total Capital Investment

Total Capital Investment (TCI) is the total sum of the DC, IC, and other project costs that must be paid to execute the project. This calculation of TCI does not include Allowable Funds Used During Construction (AFUDC), royalty allowances, preproduction cost, inventory capital, and initial catalyst and chemicals. These costs were provided in the 1998 and 2002 update of the Cost Manual, but then removed from the SCR chapter in the May 2016 update. Since these other costs are no longer part of the Cost Manual, they are not included in this cost analysis.

Using site-specific design information and costs from Black & Veatch's reference project, the TCI was calculated to be \$190,920,000. The reference project used by Black & Veatch in developing this cost estimate was ~450 MW unit, and the total in 2014/2015 dollars was ~\$175 million. The reference project included new ID fans. Some actual indirect and installation costs were unique to the reference project. Considering that Coal Creek Station does not need new ID fans, it saves nearly \$20 million in equipment and installation costs. However, Coal Creek Station is over 30 percent larger with a larger amount of demolition and rebuild required. These differences support the estimated TCI as an appropriate cost estimate. If the costs for DryFinishing™ and reheat systems' demolition and rebuild are excluded, the TCI is \$176,430,000, or very similar to the reference project.

#### 4.1.1.2.5 Direct Annual Costs

Direct annual costs include variable and fixed costs. Fixed annual costs are those that a plant owner will have to pay every year. The Cost Manual assumes that operating labor is 4 hours a day due to the SCR system, which equates to half a full-time employee. An annual salary of \$149,365 was used for this cost estimate based on GRE's cost for operators (based on an hourly

---

<sup>28</sup> Construction and field expenses include costs for crane and scaffolding.

cost of \$71.81/hr). There is also a cost associated with maintenance labor and materials, and the Cost Manual assumes this to be 0.5 percent of the TCI (former editions used 1.5 percent). Black & Veatch included a cost for testing the catalyst activity and fly ash based on past estimates.

In addition to fixed annual costs, variable annual costs exist due to the SCR system. A capacity factor of 0.87 (based on a ten-year average) was provided by GRE and applied to all variable costs. The Cost Manual's Equation 2.58 and 2.59 were used for calculating the cost of reagent consumption and power consumption. The reagent consumption was calculated using a stoichiometric ratio of 1.05, an outlet emission of 0.04 lb/MMBtu, and a 2 ppm ammonia slip. The cost of anhydrous ammonia was provided with delivery included to Bismarck<sup>29</sup> by truck. Equations 2.60 and 2.62 were used to calculate the cost from the SCR's power consumption. The cost of power was provided by GRE.

Another variable cost is for replacing catalyst. IBIDEN Ceram's catalyst volume was provided based on a 24,000 hour-lifespan, or three years from the date of delivery, whichever comes first. Coal Creek Unit 2 undergoes a planned major outage every three years, so catalyst replacement may or may not align with this schedule. The plan would be to replace all of the catalyst layers during the major outage. The cost of catalyst was taken from the vendor quote, and a future worth factor (FWF) was applied per the Cost Manual. The FWF "amortizes the catalyst cost over the years preceding the actual catalyst purchase." Since this cost would occur every three years, it was divided by three to determine the annual impact.

For each layer of catalyst that is replaced, the removed catalyst must be properly disposed. Therefore, a disposal cost was applied based on a \$10.50/ton rate provided by GRE. The total DAC is estimated to be \$4.4 million.

#### **4.1.1.2.6 Indirect Annual Costs**

Indirect annual costs include administrative costs, property taxes, insurance, overhead, and capital recovery. Insurance and property taxes were assumed to either be nominal or non-existent for the SCR. Overhead was assumed to be negligible since administrative costs comprise a significant portion of overhead costs. Equation 2.69 was used to calculate the administrative costs, and the capital recovery was calculated by the annuity formula based on 5.25 percent interest and a 30-year life. The interest rate was provided by the NDDH (from the EPA), and the 30-year life was taken from the Cost Manual. In general, the capital recovery can be understood as an equal payment over "n" years (in this case 30), so that the current value of the total payments is equivalent to the total capital investment at the specified interest rate. The total IDAC is estimated to be \$13.2 million.

---

<sup>29</sup> The anhydrous ammonia supplier stated that the material would be shipped from Minnesota, so the cost for delivery to Coal Creek Station in lieu of Bismarck is expected to be slightly higher (approximately 50 additional miles). To ensure a conservative estimate, this additional cost is not included.

#### 4.1.1.2.7 SCR Cost Effectiveness Sensitivity

Based on Equation 2.73, the cost effectiveness was calculated by dividing the total annual costs (the sum of direct and indirect costs) by the total tons of NO<sub>x</sub> removed per year. The removal rate was based on a conservative outlet emission of 0.04 lb/MMBtu, which as explained in Section 4.1.1, may be higher upon actual installation and operation. The cost effectiveness based on this emission rate is estimated to be \$8,737/ton NO<sub>x</sub> removed. The cost effectiveness is estimated to be \$11,233/ton NO<sub>x</sub> removed based on an emission rate of 0.06 lb/MMBtu, and \$15,727/ton NO<sub>x</sub> removed based on an emission rate of 0.08 lb/MMBtu.

#### 4.1.2 SNCR

Costs were calculated for SNCR using both EPA's cost manual spreadsheet methodology, and a site-specific approach, as summarized in Table 4-6. The high dollar cost per ton of NO<sub>x</sub> removed reflects the low baseline NO<sub>x</sub> emissions at Coal Creek Unit 2, and the limited additional reductions achievable through SNCR. The unit operates at NO<sub>x</sub> emissions near the critical point of 0.1 lb/MMBtu, at which the injection of ammonia or urea will actually result in *increased* NO<sub>x</sub> levels.

**Table 4-6 Cost of Compliance for SNCR Technologies (2018 dollars)**

TECHNOLOGY	TOTAL CAPITAL INVESTMENT	TOTAL ANNUAL COST (\$/YR)	EFFECTIVENESS (\$/TON NO <sub>x</sub> )
SNCR w/MNL (EPA Spreadsheet)	\$12,534,000	\$4,867,000	\$7,279
SNCR w/MNL (Site-specific Approach)	\$16,570,000	\$5,970,000	\$8,899
SNCR (EPA Spreadsheet)	\$12,179,000	\$4,833,000	\$11,082
SNCR (Site-specific Approach)	\$12,740,000	\$4,860,000	\$11,145

#### 4.1.2.1 EPA Cost Manual Spreadsheet Methodology

EPA provides a spreadsheet for estimating SNCR costs according to the Cost Manual. This spreadsheet uses key site variables such as baseline NO<sub>x</sub> emissions, and normalized stoichiometric ratio (NSR). The spreadsheet applies the EPA Cost Manual Methodology and formulas to these site variables to calculate screening level NO<sub>x</sub> reductions and associated TCI and total annual costs, which are then used to derive an overall \$/ton cost effectiveness estimate. As shown in Appendix G, Coal Creek Unit 2 variables were added to this spreadsheet. Similar to the site-specific methodology outlined in Section 4.1.2.2, Fuel Tech's site-specific NSR estimate was used in the spreadsheet calculations. For reasons discussed in this report, the Cost Manual prioritizes the use of vendor-specific NSR calculations where available.



The Cost Manual spreadsheet calculates a TCI for SNCR without MNL of \$12.2 million, and a cost effectiveness of \$11,082/ton NO<sub>x</sub> removed, according to 2018 dollars. This value was calculated by using a retrofit factor of 1.0. The Cost Manual spreadsheet calculates a TCI for SNCR with MNL of \$12.5 million, and a cost effectiveness of \$7,279/ton NO<sub>x</sub> removed, according to 2018 dollars. This value was calculated by using a retrofit factor of 1.0. The spreadsheet's calculation of MNL cost does not account for site-specific design considerations. Rather, it applies default stoichiometric ratios based on higher MNL percentage removal than would be achieved at CCS Unit 2, resulting in an underestimation of cost effectiveness.

#### 4.1.2.2 Site-Specific Methodology

This analysis provides a vendor-specific estimate by following the Cost Manual's Section 1.3.2 Design Parameters for Detailed/Performance Specifications in Chapter 1 for Selective Non-Catalytic Reduction (SNCR). A detailed analysis was conducted to design and calculate the performance of an SNCR specifically taking into consideration Coal Creek Station's unique boiler over its operational range. As stated in the EPA Pollution Control 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 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."<sup>30</sup>

This report contains cost quotations from Fuel Tech for the design and build of the SNCR system and engineering estimates from Black & Veatch for the installation and construction of the SNCR system. Two system costs were provided by Fuel Tech, one for a system with standard injection lances and another with additional Multiple Nozzle Lances (MNL). The MNL is a proprietary lance designed to provide optimal reagent coverage, particularly at high temperature locations. Fuel Tech estimated that using MNLs along with the standard wall lances provides an 8 percent further reduction in NO<sub>x</sub> at baseload. Table 4-7 provides a summary of these two system costs, with descriptions of the costs in following subsections. Refer to Appendix D for details of the individual items' costs. The site-specific cost calculations incorporate the NSR calculated by Fuel Tech.

As stated in the EPA Cost Manual, a system supplier can "more accurately predict the NSR for a given boiler" than the values calculated using the Cost Manuals simplified estimation procedure by accounting for the following factors:<sup>31</sup>

- Reaction temperature range available within the boiler superheater (radiative and convective section) and primary reheater (convective section or cavity) region. If the required temperature window occurs in the radiant section of the boiler, NSR

<sup>30</sup> EPA Cost Manual, Chapter 1: Selective Noncatalytic Reduction

<sup>31</sup> Chapter 1: Selective Noncatalytic Reduction, at 1-39.

could decrease. However, if the temperature window occurs in the convective section, NSR may increase.

- Residence time available in the desirable temperature range. The required NSR decreases as the available residence time increases.
- Degree of mixing between the injected chemical and the flue gases. NSR decreases as the degree of mixing increases.
- Ammonia slip vs. required NO<sub>x</sub> reduction. Tighter constraints on ammonia slip would dictate lower NSRs, thereby limiting the achievable NO<sub>x</sub> reduction.”

Fuel Tech’s NSR values were developed using proprietary CFD and CKM models that account for Coal Creek Unit 2’s low baseline NO<sub>x</sub> emissions among other variables, which are close to the critical NO<sub>x</sub> level of 0.1 lb/MMBtu. SNCR needs more reagent as it approaches the critical emissions level, increasing the NSR.

Although Fuel Tech observed NO<sub>x</sub> emissions of 0.12 lb/MMBtu and a heat input of 5,971 MMBtu/h during its field testing for the SNCR quote, they confirmed the reduction percentage would be the same for a nominally higher baseline (0.13 lb/MMBtu). Therefore urea usage rates were calculated using the same reduction percentage but based on the baseline value of 0.13 lb/MMBtu of NO<sub>x</sub> at a heat input of 6,022 MMBtu/h, which reflect the average conditions at Coal Creek Unit 2.

**Table 4-7 SNCR Cost Summary Using Site-Specific Methodology**

CATEGORY	US DOLLARS (2018) STANDARD LANCES	US DOLLARS (2018) MULTIPLE NOZZLE LANCE
Purchased Equipment Cost (PEC)	\$3,040,000	\$4,800,000
Direct Installation Cost (DIC)	\$6,690,000	\$7,860,000
<i>Total Direct Cost (DC = PEC+DIC)</i>	<i>\$9,730,000</i>	<i>\$12,660,000</i>
Indirect Costs (IC)	\$3,010,000	\$3,910,000
<b>Total Capital Investment (TCI = DC + IC)</b>	<b>\$12,740,000</b>	<b>\$16,570,000</b>
Direct Annual Cost (DAC), no ash impacts	\$3,820,000	\$4,610,000
Indirect Annual Cost (IDAC)	\$1,040,000	\$1,360,000
<b>Total Annual Cost (TAC = DAC + IDAC)</b>	<b>\$4,860,000</b>	<b>\$5,970,000</b>
<b>\$/Ton NO<sub>x</sub> removed</b>	<b>\$11,145</b>	<b>\$8,899</b>

#### 4.1.2.2.1 Purchased Equipment Costs

The PEC primarily consists of the SNCR system that is provided by a supplier/vendor. A budgetary quote from Fuel Tech was used for the PEC, as covering most line items. Costs that were



not covered, such as balance of plant piping and electrical, were included in the installation costs. The total PEC for Coal Creek Unit 2's SNCR was \$3 million with wall injectors only and \$4.8 million with the MNLs.

- **Vendor's Scope of Work** – Fuel Tech was contracted to gather field data and conduct CFD and CKM modeling to develop a budgetary proposal, due to their industry experience and expertise with SNCRs. Other vendor quotes were not solicited. Their quote included a urea storage tank, dilution water skid, injection nozzles, metering equipment, and miscellaneous components.

A 50 percent urea solution was assumed, which would be delivered by truck. An unloading panel is therefore required to transfer the solution from the truck to the holding tank. The trucks have an unloading pump, so the unloading panel solely functions as an indicator of the storage tank level to let the operator know when the truck can be unloaded. The urea storage tanks have a residence time of 30 days. Three storage tanks, each at 70,000 gallons, were included in the proposal from the vendor to meet the 30-day requirement. The storage tank is made of fiber reinforced plastic (FRP), and a typical 14-foot diameter was used for sizing.

Fuel Tech provided two options of injectors for Coal Creek Unit 2; one standard option with three different levels of wall injectors, and another option with the same wall injectors but with additional MNLs. The standard injectors (termed G-1) attach to newly installed ports, and are designed to provide the optimum reagent coverage per the CFD modeling done by Fuel Tech. Zone 1 of the three injection levels also comes with an automatic retract device for the lances in order to protect them when not in use.

The MNL option achieves lower NO<sub>x</sub> emissions than the standard wall injectors, because they are designed to provide better reagent coverage. Each MNL has nozzles spaced at various intervals along the whole length of the lance. Cooling water and atomizing air are fed throughout the lance. Each lance can be retracted from the boiler, similar to a soot blower. In addition to extra, larger ports for the MNLs, spools for cooling water are required, increasing the price for the MNL option. The total PEC for Coal Creek Unit 2's SNCR was \$3 million with wall injectors only and \$4.8 million with the MNLs.

#### 4.1.2.2.2 Direct Installation Costs

Various balance of plant items, such as foundations, piping, electrical, were not included in the PEC. These items are included in the direct installation costs similar to the reference SNCR project.

- **Subsurface Construction** – An SNCR system will need some foundational and subsurface work to install major system components, most notably the urea storage tanks. This price was scaled up from the SNCR reference project based on the units' difference in area of the installed equipment, with some reductions due to costs

associated with the reference project's firewater system. No adjustments to the firewater system were included for Coal Creek Station.

The MNLs allow better reagent coverage, so more chemical reactions occur in the flue gas. More reagent can therefore be injected while staying below the ammonia slip requirements, and this higher reagent flow rate results in a higher storage volume. The SNCR with MNLs therefore has a higher subsurface construction cost to account for the additional storage tank capacity. This cost is estimated to be \$1.9 million for the SNCR without MNLs, and \$2.1 million with the MNLs.

- **Superstructure Construction** – Similar to the SCR, an enclosure was provided for major pieces of equipment for the SNCR, such as the storage tanks. This is recommended for operations and maintenance at installations with severe weather conditions, like Coal Creek Station. The reference project was in an environment that endured harsh winters, and likewise had a heated enclosure for major pieces of equipment. No additional ductwork, piers, columns, or other superstructures are needed for an SNCR. Therefore, this line item solely deals with the heated enclosure. The circulation module is provided by Fuel Tech with an enclosure, so the difference in square footage of the remaining modules was used to escalate the costs from the reference project. This cost is estimated to be \$1.4 million, regardless of whether MNLs are included.
- **Mechanical Construction** – This line item deals with the cost of installing all the vendor supplied equipment, as well as procuring and installing balance of plant equipment. The estimated cost was escalated from the reference project based on the units' difference in reagent flow rate. This cost is estimated to be \$2.3 and \$2.8 million without and with the MNLs, respectively.

#### 4.1.2.2.3 Indirect Costs

Indirect costs (IC) refer to those costs associated with executing a project that are not directly attributable to purchased equipment or installation. This includes the following:

- Engineering
- Construction and field expenses
- Owner's cost
- Startup
- Performance tests
- Contingencies

The costs were calculated as a percentage of the direct costs, based on the reference project's final financials. This cost is estimated to be \$3 and \$3.9 million without and with the MNLs, respectively.

#### 4.1.2.2.4 Total Capital Investment

Total Capital Investment (TCI) is the total sum of the DC, IC, and other project costs that must be paid to execute the project. This calculation of TCI does not include Allowable Funds Used During Construction (AFUDC), royalty allowances, preproduction cost, and inventory capital, or initial catalyst and chemicals. These costs were removed from the SNCR chapter of the Cost Manual in the May 2016 update, so they are not included in the overall cost. This cost is estimated to be \$12.7 and \$16.6 million without and with the MNLs, respectively.

#### 4.1.2.2.5 Direct Annual Costs

The direct annual costs for an SNCR were calculated based on the Cost Manual's instructions. The fixed costs included zero additional costs for operating personnel, because the plant's existing operators should be able to incorporate the SNCR's relatively simple system into their current workload. A 1.5 percent cost against the TCI was applied for the annual maintenance and labor costs.

The variable costs for the SNCR were based on a 50 percent reagent solution as-received, with it being diluted to 10 percent prior to injection. The reagent, power, and water consumption rates were taken from the budgetary estimate from Fuel Tech. The reagent cost was provided by Cervantes-Delgado, as-delivered to Bismarck.<sup>32</sup> GRE provided the cost of power and water. Equation 1.47 of the Cost Manual was also used to account for additional fuel consumed to vaporize the reagent solution, and the price of coal was provided by GRE. This cost is estimated to be \$3.8 and \$4.6 million without and with the MNLs, respectively.

#### 4.1.2.2.6 Indirect Annual Costs

The indirect annual costs included administrative charges and the cost for capital recovery. The insurance, property taxes, and other indirect costs are assumed to be zero in the Cost Manual, so these costs were not included in this estimate. Equations 1.52 through 1.55 were used to calculate administrative charges and the cost for capital recovery (based on a 5.25 percent interest rate and a 20-year life per the Cost Manual). This cost is estimated to be \$1 and \$1.36 million without and with the MNLs, respectively.

#### 4.1.2.2.7 SNCR Cost Effectiveness

Based on Equation 2.73, the cost effectiveness was calculated by dividing the total annual costs (the sum of direct and indirect costs) by the total tons of NO<sub>x</sub> removed per year. The removal rate was based on the removal efficiencies provided by Fuel Tech: a 15% removal rate for the SNCR and a 23% removal rate for the SNCR with the MNLs. The cost effectiveness based on these removal rates are estimated to be \$11,145 and \$8,899 per ton of NO<sub>x</sub> removed without and with the MNLs.

---

<sup>32</sup> Cervantes-Delgado stated the urea would be shipped from North Dakota but did not provide an exact location. The differential cost for shipping to Coal Creek Station in lieu of Bismarck is expected to be minor enough as to not impact the calculated direct annual costs.

## 4.2 COST EFFECTIVENESS

The cost effectiveness of each of the technologies was calculated according to Equation 2.73 of the Cost Manual (SCR section) and 40 CFR 51, Appendix Y, Section IV, D. The cost effectiveness is a value that compares the annualized cost of the technology per ton of pollutant removed. There are two technologies to be considered for cost effectiveness: SCR and SNCR. SNCR was found to be the cheapest option on total annualized costs, but the SCR was the cheapest on a dollar per ton basis when assessed based on tons of NO<sub>x</sub> removed.

In addition to the total cost effectiveness, the incremental cost effectiveness was calculated according to 40 CFR 51, Appendix Y. The SNCR annualized cost was used as the basis. The SNCR with MNLs and the SCR were assessed on incremental cost effectiveness from the SNCR basis and adjusted by the difference in TAC and the tons of NO<sub>x</sub> removed. Table 4-8 and Table 4-9 shows the average cost effectiveness values in \$(TAC)/ton NO<sub>x</sub> removed (per annual basis). Figure 4-3 is a graph of total annualized costs versus emissions reductions. The high cost effectiveness for SNCR is due to Coal Creek's already low NO<sub>x</sub> emission rate. Unit 2 is emitting NO<sub>x</sub> near the critical value for SNCR systems, where further removal is not possible. This explains why the SNCR's removal capabilities are limited, driving the \$/ton value higher.

As can be seen, the cost effectiveness of all the considered technologies exceeds thresholds determined to be reasonable in other BART determinations, under both calculation methodologies. The North Dakota BART SIP considered cost effectiveness above \$3,650/ton to be excessive, which was adjusted for inflation to \$4,100/ton in the 2011/2012 NO<sub>x</sub> BART.<sup>33</sup> If adjusted to 2018 dollars, the NDDH cost effectiveness threshold is approximately \$4,630/ton. The cost-effectiveness of the technologies also exceeds the values that other states and EPA have determined to be unreasonable in other BART determinations, including Nevada, which determined controls to be not cost-effective at \$1,190/ton to \$2,102/ton in 2012.<sup>34</sup> Most recently, EPA has proposed to approve Arkansas's determination that controls are not cost-effective at \$5,387/ton to \$5,420/ton. 83 Fed. Reg. 62204, 62220-22 (Nov. 30, 2018).

<sup>33</sup> Supporting Material, *North Dakota Supplemental NO<sub>x</sub> BART Determination for Coal Creek Station Supplement No. 2 to SIP for Regional Haze* at App. B.2.1, page 16 (Jan. 2, 2013), Docket ID EPA-R08-OAR-2010-0406-0428 (September 2012 Supplemental Evaluation of NO<sub>x</sub> BART Determination for CCS 1 and 2).

<sup>34</sup> 77 Fed. Reg. 17334 (Mar. 26, 2012) (EPA approval); Nevada Dept. of Env'tl. Prot., Revised Nevada Division of Environmental Protection BART Determination Review of NV Energy's Fort Churchill Generating Station Units 1 and 2, at 5-7 (Oct. 15, 2009), EPA Docket No. EPA-R09-OAR-2011-0130-0004.

**Table 4-8 Overall and Incremental Cost Effectiveness (2018 US Dollars) – Using EPA Spreadsheets**

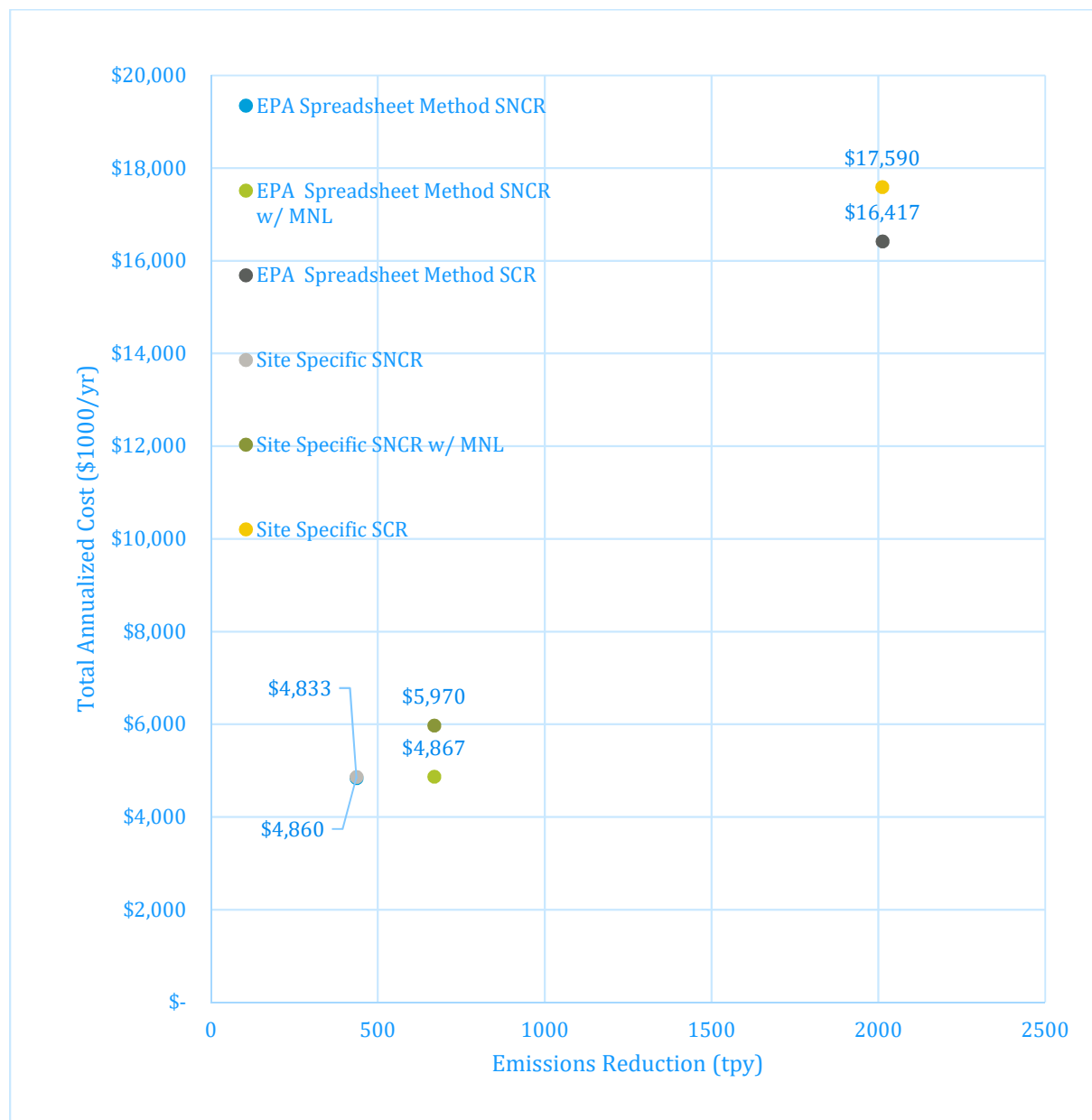
TECHNOLOGY	TAC	TON NO <sub>x</sub> REMOVED	EFFECTIVENESS (\$/TON NO <sub>x</sub> )	INCREMENTAL COST (\$/TON)
SNCR	\$4,833,000	436	\$11,082	--
SNCR w/ MNL	\$4,867,000	669	\$7,279	\$146
SCR <sup>35</sup>	\$16,417,000	2,013	\$8,157	\$8,594

**Table 4-9 Overall and Incremental Cost Effectiveness (2018 US Dollars) – Site Specific Methodology**

TECHNOLOGY	TAC	TON NO <sub>x</sub> REMOVED	EFFECTIVENESS (\$/TON NO <sub>x</sub> )	INCREMENTAL COST (\$/TON)
SNCR	\$4,860,000	436	\$11,145	--
SNCR w/ MNL	\$5,970,000	669	\$8,899	\$4,764
SCR <sup>36</sup>	\$17,590,000	2,012	\$8,737	\$8,652

<sup>35</sup> The calculations for SCR are based on an assumed emission rate of 0.04 lb/MMBtu, but as explained in Section 3.1, a range of 0.06-0.08 lb/MMBtu is more reasonable. If the higher emission rates are used, the cost effectiveness of SCR would be even higher.

<sup>36</sup> The calculations for SCR are based on an assumed emission rate of 0.04 lb/MMBtu, but as explained in Section 3.1, a range of 0.06-0.08 lb/MMBtu is more reasonable. If the higher emission rates are used, the cost effectiveness of SCR would be even higher.



**Figure 4-3 TAC vs Emissions Reduction**

### 4.3 ENERGY AND NON-AIR QUALITY ENVIRONMENTAL IMPACTS

SCR and SNCR have energy and water consumption impacts.<sup>37</sup> The energy impacts are primarily related to the auxiliary power consumption of the systems and were included in the cost estimates under the variable annual costs. Similarly, water costs were included as appropriate. Both technologies also would impact GRE's award-winning fly ash reuse program. These impacts

<sup>37</sup> All three technologies also would impact GRE's award-winning fly ash reuse program. These impacts are discussed in another report.

are discussed in another report. Please refer to the sheets in Appendix D for further information on the power and water demand of each technology.

#### 4.3.1 SCR

Energy demands from the SCR system are associated the power consumed by the additional pressure drop that the ID fans need to provide, the dilution air blowers, heaters, ammonia pumps, and other minor auxiliary loads. The Cost Manual's equation 2.60 was used for estimating the total power consumption for the SCR, which included increased ID fan loads and resulted in about 3.5 MW.

Ammonia slip will lead to increased nitrogen to the scrubber, which ultimately will be deposited in the evaporation ponds. This nitrogen will act as a nutrient to plants, potentially increasing future pond maintenance requirements and associated costs.

#### 4.3.2 SNCR

For SNCR, power consumption should be nominal, because there is an insignificant impact to the flue gas pressure drop. The urea pumps and dilution skid would be the main power consumers. The power consumption was provided by the SNCR vendor and was listed as 75 and 95 kW with and without MNLs, respectively. Other indirect energy impacts, such as the energy to produce reagents, were not considered in this study.

The SNCR also would consume water as part of the urea injection system, as the urea solution is reduced to 10 percent by weight prior to injection. The water demands are in the mid-100 gpm, which multiplied by an 87 percent capacity factor and 8,760 hours per year, results in about 70 to 80 million gallons per year. This additional water consumption could require an increase in the water appropriations permit.

Ammonia slip will lead to increased nitrogen to the scrubber, which ultimately will be deposited in the evaporation ponds. This nitrogen will act as a nutrient to plants, potentially increasing future pond maintenance requirements and associated costs.

### 4.4 POLLUTION CONTROL EQUIPMENT IN USE/EXISTING AT THE SOURCE

Coal Creek Unit 2 already has existing NO<sub>x</sub> controls in place that have yielded a low NO<sub>x</sub> emissions baseline. The facility uses LNBs, DryFining™, OFA, and tuning to achieve this low emission rate. DryFining™, in particular, is a unique technology developed by GRE that reduces moisture and refines lignite coal, increasing the efficiency and performance of the fuel while reducing emissions.<sup>38</sup> Coal Creek Unit 2 employs an electrostatic precipitator (ESP) for collecting particulate matter such as fly ash. After the ESP, flue gas passes through a wet flue gas desulfurization (WFGD) system that removes acid gas from the system.

---

<sup>38</sup> 83 Fed. Reg. 18248, 18251 (Apr. 26, 2018).

Coal Creek Unit 2 has a higher economizer temperature than many installations, and this elevated temperature will result in more SO<sub>2</sub>/SO<sub>3</sub> conversion across an SCR catalyst. Modifications due to SO<sub>3</sub> are discussed further in Section 2.2.11, most notably the air heater.

The WFGD's acid removal should not be adversely affected. Ammonia can act as a base or acid, and it will be absorbed in the WFGD solute. At the low concentrations of ammonia slip the technologies are designed for, ammonia should not adversely affect the solution's pH or chemistry.

#### **4.5 REMAINING USEFUL LIFE OF ANY POTENTIALLY AFFECTED SOURCES**

Consistent with GRE's resource plan, Coal Creek Station will continue to operate for at least 30 years. The facility is well managed and operated. Further, long term investments have been made in the plant (e.g. DryFinishing™ and HVDC converter replacements). Therefore, the lifetimes of the evaluated technologies were kept at the Cost Manual's values (30 years for SCR and 20 for SNCR), as opposed to lesser values based on a limited forecast of Coal Creek Unit 2's life.



## 5.0 Conclusion

The specific challenges associated with the combustion of North Dakota lignite, as well as the extremely limited space for the installation of controls in the boiler house, significantly limit the feasibility of NO<sub>x</sub> controls on Coal Creek Unit 2. There are significant concerns about the technical feasibility of SCR but the technology was carried forward for further review, along with SNCR, in order to provide a conservative approach to this BART analysis.

This further review revealed that neither of the controls are cost-effective, regardless of the cost assessment methodology employed. SCR and SNCR (both with and without MNL) far exceed the \$4,630/ton threshold (adjusted for inflation) that has been applied by NDDH in past BART determinations, as well as exceeding the values determined by other states and EPA to be unreasonable. These high cost-effectiveness values were calculated using both site-specific cost assessments and EPA's spreadsheet methodology. The high values reflect the low NO<sub>x</sub> emission rate of 0.13 lb/MMBtu, as an annual average, already achieved at Coal Creek Unit 2 through the implementation of LNC3+. This low NO<sub>x</sub> baseline limits the availability of further NO<sub>x</sub> reductions. For example, SNCR would achieve minimal reductions, as the facility operates near the critical point of 0.1 lb/MMBtu, after which the injection of ammonia or urea actually results in *increased* NO<sub>x</sub> emissions. In light of these cost effectiveness values, as well the low NO<sub>x</sub> baseline and the energy and non-air environmental impacts of the considered controls, none of the three technologies are determined to be BART.

## Appendix A. Coal Creek VISTA Model Parameters

### A.1 FUEL DATA

<b>Fuel Data</b>		
<b>Case Descriptor</b>		
Evaluation	Calibration 21 Aug	
Run Date	Oct 9 2018 1:43PM	
Case Number	0	
Unit	Coal Creek U2- 21 Aug	
Load Curve	21-Aug	
Fuel Description	Coal Creek	
Gas Cofire Percentage (Average)	0	
<b>Coal Properties</b>		
Description		
Higher Heating Value	6612.00	Btu/lbm
Higher Heating Value, Min	6446.70	Btu/lbm
Higher Heating Value, Max	6777.30	Btu/lbm
Lower Heating Value	6052.55	Btu/lbm
Lower Heating Value, Min	0.00	Btu/lbm
Lower Heating Value, Max	0.00	Btu/lbm
<b>Proximate Analysis</b>		
Basis	Wet	
Moisture	31.43	%
Moisture, Min	29.54	%
Moisture, Max	33.32	%
Ash	12.89	%
Ash, Min	9.93	%
Ash, Max	15.85	%
Volatile Matter	28.57	%
Fixed Carbon	27.11	%
<b>Ultimate Analysis</b>		
Basis	Wet	
Carbon	39.17	%
Carbon, Min	36.82	%
Carbon, Max	41.52	%
Hydrogen	2.58	%
Hydrogen, Min	2.43	%
Hydrogen, Max	2.73	%
Nitrogen	0.63	%
Nitrogen, Min	0.43	%
Nitrogen, Max	0.83	%
Sulfur	0.61	%
Sulfur, Min	0.43	%
Sulfur, Max	0.79	%

Chlorine	0.00 %
Chlorine, Min	0.00 %
Chlorine, Max	0.00 %
Oxygen (by difference)	12.69 %
<b>Ash Analysis</b>	
Silica (SiO <sub>2</sub> )	47.18 %
Alumina (Al <sub>2</sub> O <sub>3</sub> )	13.39 %
Titania (TiO <sub>2</sub> )	0.57 %
Iron Oxide (Fe <sub>2</sub> O <sub>3</sub> )	7.43 %
Lime (CaO)	12.13 %
Magnesia (MgO)	3.90 %
Potassium (K <sub>2</sub> O)	1.94 %
Sodium (Na <sub>2</sub> O)	3.02 %
Sulfur Trioxide (SO <sub>3</sub> )	10.30 %
Phosphorous (P <sub>2</sub> O <sub>5</sub> )	0.02 %
Strontium (SrO)	0.00 %
Barium (BaO)	0.00 %
Manganese (Mn <sub>3</sub> O <sub>4</sub> )	0.00 %
Undetermined	0.12 %
<b>Ash Temperatures</b>	
Initial Deformation (Reducing)	2108.00 F
Softening (Reducing)	2144.00 F
Hemispherical (Oxidizing)	2194.00 F
<b>Miscellaneous Properties</b>	
Hardgrove Grindability	37.00
Hardgrove Grindability, Min	31.45
Hardgrove Grindability, Max	42.55
T250	2405.00 F
T250, Min	2284.75 F
T250, Max	2525.25 F
Equilibrium Moisture	34.30 %
SO <sub>2</sub> Production	1.84 lbm/MBtu
Ash Production	19.49 lbm/MBtu
Hg Production	0.00 lbm/TBtu
<b>Alternate Solid Fuel Properties</b>	
Non-Coal Percent	0.00 %
Renewables Percent	0 %
<b>Trace Elements</b>	
Arsenic (As)	0 ppm
Lead (Pb)	0 ppm
Mercury (Hg)	0 ppm
<b>Gas Properties</b>	
Description	
Higher Heating Value (Mass Basis)	0.00 Btu/lbm

Higher Heating Value (Volume Basis)	0.00 Btu/in3
Lower Heating Value (Mass Basis)	0.00 Btu/lbm
Lower Heating Value (Volume Basis)	0.00 Btu/in3
Gas Density	0.00 lb/ft3
Gas Density, Min	0.00 lb/ft3
Gas Density, Max	0.00 lb/ft3
Moisture	0.00 %
<b>Oil Properties</b>	
Description	
Higher Heating Value (Mass Basis)	0.00 Btu/lbm
Higher Heating Value (Volume Basis)	0.00 Btu/in3
Lower Heating Value (Mass Basis)	0.00 Btu/lbm
Lower Heating Value (Volume Basis)	0.00 Btu/in3
Density	0.00 lb/ft3
Carbon	0.00 %
Hydrogen	0.00 %
Nitrogen	0.00 %
Sulfur	0.00 %
Moisture	0.00 %
Ash	0.00 %
Oxygen	0.00 %

## A.2 FULL LOAD UNIT PERFORMANCE

<b>Full Load Unit Performance</b>	
<b>Case Descriptor</b>	
Evaluation	Calibration 21 Aug
Run Date	Oct 9 2018 1:43PM
Case Number	0
Unit	Coal Creek U2- 21 Aug
Load Curve	21-Aug
Fuel Description	Coal Creek
<b>Full Load Unit Operation</b>	
Gross Power	602.57 MW
Net Power	563.42 MW
Boiler Efficiency, HHV Basis	80.27 %
Boiler Efficiency, LHV Basis	87.69 %
Net Turbine Heat Rate	7818.00 Btu/kWh
Net Unit Heat Rate, HHV Basis	10416.20 Btu/kWh
Net Unit Heat Rate, LHV Basis	9534.84 Btu/kWh
<b>Fuel Burn Rate</b>	
Total Heat Input, HHV Basis	5868.68 MBtu/hr

Total Heat Input, LHV Basis	5372.12	MBtu/hr
Coal Burn Rate, Mass Basis	443.79	ton/hr
Coal Burn Rate, HHV Basis	5868.68	MBtu/hr
Coal Burn Rate, LHV Basis	5372.12	MBtu/hr
Alt Solid Fuel Burn Rate, Mass Basis	0.00	ton/hr
Alt Solid Fuel Burn Rate, HHV Basis	0.00	MBtu/hr
Alt Solid Fuel Burn Rate, LHV Basis	0.00	MBtu/hr
Gas Burn Rate, Volumetric Basis	0.00	kcfm
Gas Burn Rate, HHV Basis	0.00	MBtu/hr
Gas Burn Rate, LHV Basis	0.00	MBtu/hr
Oil Burn Rate, Mass Basis	0.00	ton/hr
Oil Burn Rate, Volumetric Basis	0.00	gal/min
Oil Burn Rate, HHV Basis	0.00	MBtu/hr
Oil Burn Rate, LHV Basis	0.00	MBtu/hr
<b>Boiler Efficiency</b>		
<b>Higher Heating Value Basis</b>		
Latent	8.25	%
Sensible	7.81	%
Unburned Carbon	1.00	%
Radiation and Convection	0.40	%
Margin and Unaccounted	2.27	%
Total	80.27	%
<b>Lower Heating Value Basis</b>		
Latent	0.00	%
Sensible	8.38	%
Unburned Carbon	1.07	%
Radiation and Convection	0.43	%
Margin and Unaccounted	2.43	%
Total	87.69	%
<b>Net Turbine Heat Rate Adjustments</b>		
Base by Input	7818.00	Btu/kWh
Superheat Temperature/Spray	0.00	Btu/kWh
Reheat Temperature/Spray	0.00	Btu/kWh
Sootblowing Steam	0.00	Btu/kWh
Air Preheat Steam	0.00	Btu/kWh
Steam Driven Fans	0.00	Btu/kWh
SCR Reheat Steam	0.00	Btu/kWh
FGD Reheat Steam	0.00	Btu/kWh
Ambient Temperature	0.00	Btu/kWh
Ambient Relative Humidity	0.00	Btu/kWh
Circulating Water Inlet Temperature	0.00	Btu/kWh
Coal Cleaning/Drying Steam	0.00	Btu/kWh
Adjusted Net Turbine Heat Rate	7818.00	Btu/kWh

<b>Turbine Load Correction</b>	
Superheat Temp	0.00 kW
Superheat Spray	0.00 kW
Reheat Temp	0.00 kW
Reheat Spray	0.00 kW
Sec. Reheat Temp (Double Reheat)	0.00 kW
Sec. Reheat Spray (Double Reheat)	0.00 kW
Total Correction	0.00 kW
<b>Unburned Combustible Details</b>	
<b>Calculation Source</b>	
NOx LOI Predictor's LOI Prediction Used	No
NOx LOI Predictor's LOI Prediction	0.00 %
Vista's LOI Prediction	2.97 %
<b>LOI Results Used in Analysis</b>	
Total LOI	3.42 %
Fly Ash LOI	2.97 %
Bottom Ash LOI	4.46 %

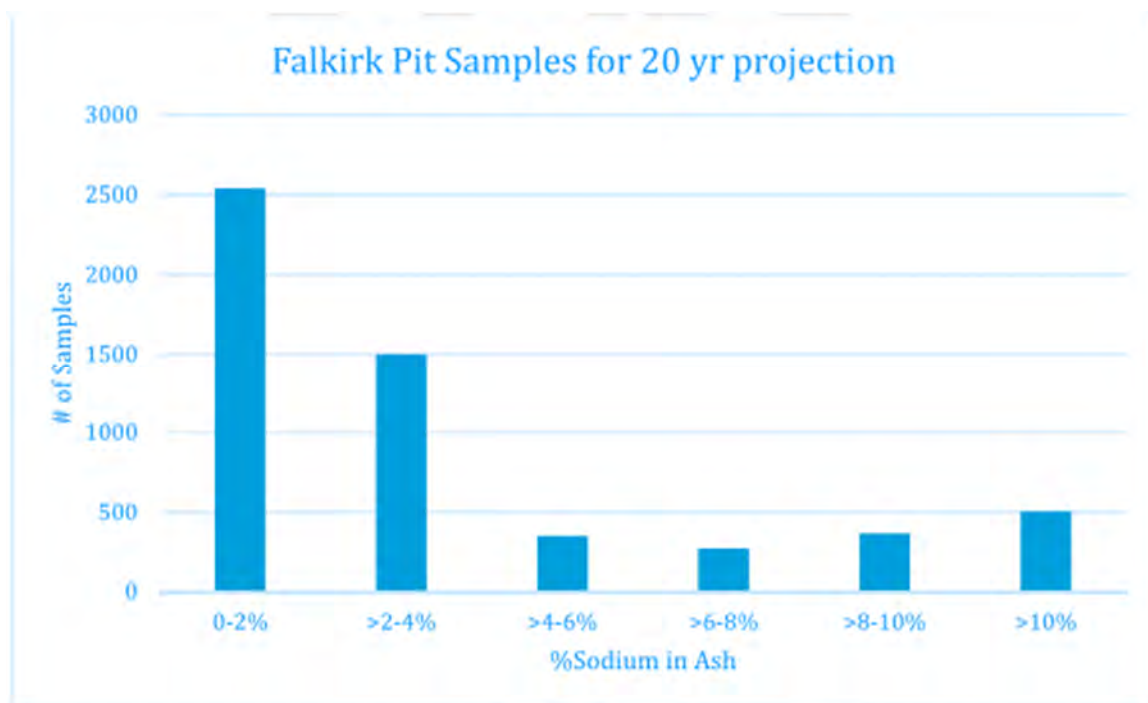
### A.3 COMBUSTION AIR-GAS COMPOSITION

<b>Combustion Air and Gas Composition</b>	
<b>Case Descriptor</b>	
Evaluation	Calibration 21 Aug
Run Date	Oct 9 2018 1:43PM
Case Number	0
Unit	Coal Creek U2- 21 Aug
Load Curve	21-Aug
Fuel Description	Coal Creek
<b>Combustion Air and Flue Gas Composition</b>	
Based on Air Heater Leakage	11.72 %
Based on Excess Air Percentage	17.11 %
Excess Oxygen Percentage	2.66 %
O2 Analyzer Type	Wet
O2 Measurement Basis	Mole Basis
Total Furnace Stoichiometry	5.73664
Total Furnace Stoichiometry, Including Air Inleakage	5.73664
<b>Air Entering PA Fans</b>	
Temperature	74.62 F
Pressure	0.00 inwg
Moisture	10008.23 lbm/hr
Oxygen	463291.81 lbm/hr
Nitrogen	1512820.50 lbm/hr
Argon	26470.99 lbm/hr

<b>Air Entering FD Fans</b>	
Temperature	74.62 F
Pressure	0.00 inwg
Moisture	18727.72 lbm/hr
Oxygen	866926.19 lbm/hr
Nitrogen	2830837.25 lbm/hr
Argon	49533.36 lbm/hr
<b>Gas Exiting Economizer</b>	
Temperature	830.75 F
Pressure	-5.50 inwg
Ash Flow Rate	82923.63 lbm/hr
Moisture	508931.47 lbm/hr
Oxygen	181628.98 lbm/hr
Nitrogen	3832362.00 lbm/hr
Argon	67252.06 lbm/hr
Sulfur Dioxide	10698.31 lbm/hr
Sulfur Trioxide	148.71 lbm/hr
Carbon Dioxide	1259058.88 lbm/hr
Chlorine	0.00 lbm/hr
Nitrogen Oxide <sup>39</sup>	1130.74 lbm/hr
Nitrogen Dioxide <sup>39</sup>	34.97 lbm/hr
Mercury	0.00 lbm/hr
<b>Gas at Air Heater Outlet</b>	
Temperature	347.90 F
Pressure	-12.54 inwg
Ash Flow Rate	83002.21 lbm/hr
Moisture	512332.81 lbm/hr
Oxygen	339748.94 lbm/hr
Nitrogen	4348683.00 lbm/hr
Argon	76286.52 lbm/hr
Sulfur Dioxide	10698.31 lbm/hr
Sulfur Trioxide	84.56 lbm/hr
Carbon Dioxide	1259058.88 lbm/hr
Chlorine	0.00 lbm/hr
Nitrogen Oxide	1130.74 lbm/hr
Nitrogen Dioxide	34.97 lbm/hr
Mercury	0.00 lbm/hr

<sup>39</sup> Nitrogen Oxide and Nitrogen Dioxide values shown are the VISTA model output values used to calculate the initial NOx emission rate of 126 ppm provided to IBIDEN Ceram in October 2018. Following this initial communication, the actual Unit 2 emission rate of 60 ppm was provided to IBIDEN Ceram. IBIDEN Ceram confirmed they are able to achieve 69% reduction for both inlet NOx values of 126 ppm and 60 ppm, as Case 1 and Case 2 respectively, (see quotation in Appendix D).

## A.4 FALKIRK PIT SAMPLES – 20 YEAR PROJECTION





## Appendix B. Technical Discussion of Low-Dust SCR

Although this BART analysis assesses high-dust SCR, low-dust SCR also was initially considered. Low-dust SCR was not assessed further because it would be more expensive than a high-dust SCR. Since a high-dust SCR was determined to be not cost-effective, there was no need to conduct a cost analysis for a low-dust SCR. The high costs of low-dust SCR are driven by two factors: (1) heating and cooling requirements, and (2) the potential need for a natural gas line. These factors would increase the costs of SCR *above* the high-dust SCR costs already assessed in the body of this report.

First, Coal Creek Station would be required to install a system for reheating the flue gas before it passes through the low-dust SCR, as well as a system for cooling down the flue gas after the SCR. The low dust arrangement is commonly installed after the air preheater, resulting in temperatures in the mid-300s°F, which is too low for a catalyst to work. Thus, the inlet temperature to the low-dust SCR must be increased. The flue gas temperature must then be reduced after passing through the low-dust SCR to accommodate the wet flue gas desulfurization (WFGD) system at Coal Creek Unit 2. There is very little temperature drop across the SCR, so flue gas leaving the SCR would be near 600° F. The WFGD is not designed with sufficient spray capacity to lower incoming flue gas from 600° F to its operating conditions. The WFGD mist eliminators are designed to 300° F, but the flue gas temperature would need to be dropped well below this due to performance considerations. The absorber vessels typically operate with the flue gas at 11 ft/s, and the plant operates to maintain the velocity below 18 ft/s to prevent carryover. As the flue gas temperature increases, the volume and velocity increase. Elevated temperatures and increased velocities will also have an adverse impact on the SO<sub>2</sub> removal percentage. Accordingly, the SCR outlet temperature would have to be lowered for the WFGD to operate as designed.

There are multiple ways to accomplish the cooling and heating methods, and two were examined as part of this study. The first method would be to install heating equipment that uses combustion for adding heat, such as a thermal oxidizer, and then a cooling system that uses some form of external heat reject to exchange heat with the flue gas, such as a fluid system (e.g. glycol or Dowtherm A) with coils inside the duct and fin fans outside. Based on a 2007 estimate for a thermal oxidizer and applying the general 6/10 rule of escalation for volume and temperature differences and a 3 percent inflation rate, a general equipment cost of \$1.43 million was calculated. Additional BOP equipment (e.g. structural steel) would be required, so a high-level factor of 2x can be used for the BOP equipment. Applying a 2x factor for installation then a high-level cost of \$5.7 million is obtained for the heater section. The cooling section is more complicated, as determining costs would require piping lengths, fans, coolant, etc. Glycol is not suitable for the temperature ranges, so Dowtherm A was identified as a heat exchange fluid. Using past quotes for air cooled heat exchangers and a budgetary quote from Dow Chemical, a cooling system was estimated to cost \$11.3 million. This includes a 2x factor for installation. Due to uncertainty with piping, this price

could be higher upon implementation. Combined with the heater, the total cost for this option is about \$17 million.

The second method would be using a gas/gas heat exchanger, similar to an air preheater. At a high level, Ljungstrom style of gas/gas heat exchangers (2x50 percent) would cost about \$17.1 million to install. This cost will likely be higher due to additional ductwork that needs to be installed, but without doing detailed engineering, a precise cost estimate cannot be determined.

If the selected heating system relies upon natural gas, there would be significant additional costs. Coal Creek Station does not have a natural gas line to supply natural gas burners, so one would need to be constructed. Generally, it costs about \$1-2 million per mile of installed natural gas line, as discussed in Section 2.2.5.

## Appendix C. Discussions of Minor Line Items in Cost Estimates

### C.1 SCR

#### C.1.1 Purchased Equipment Costs

- **Anhydrous Ammonia Tank** – This is based on 30 days of storage capacity. Due to the severe winter conditions and remote location of Coal Creek Station, 30 days of capacity is needed to provide ample reserves in case of road closures. This time frame was provided by GRE. The cost from the reference project's anhydrous ammonia tank was scaled down based on the tank's capacity.
- **Air Compressors** – GRE has stated that the existing air compressor system was recently upgraded, with a new, fourth compressor having been installed. New compressors were assumed not to be needed, but the cost of two new compressed air receivers (2 x 100%) were included. By not requiring new air compressors approximately \$150k was avoided in PEC.
- **Vaporizers** – Anhydrous ammonia is fully vaporized before being delivered to the dilution skid. The price of a vaporizer skid from the reference project was scaled down according to the differences in ammonia consumption rates.
- **Ammonia Unloading Skids** – Ammonia is assumed to come by trucks, so a method of unloading the ammonia and transferring it to the storage tank is required. The price from the reference SCR project was used without any scaling, because the number of deliveries and size of trucks were expected to be similar.
- **Ammonia Supply Pump Skid** – Pumps are required to feed the ammonia to the SCR, and the reference project's price was scaled down according to the differences in ammonia consumption rates.
- **Miscellaneous Ammonia Handling and Injection Equipment** – This line item includes general miscellaneous items not covered above, such as piping, a mixing chamber, etc. The overall cost of all purchased equipment for the ammonia handling and injection contract, minus the equipment specifically identified, was used for this cost and adjusted based on the difference in MW between Coal Creek Station and the referenced project. The ammonia consumption rate was not used, because the amount of miscellaneous equipment is more related to the overall size of the units. Piping for example will have larger spans to traverse on a larger boiler, so even if the ammonia consumption rate is lower, the total piping material will be more.

- **Ash Handling Modifications** – Fly ash will separate out from the flue gas stream as it passes through the SCR reactor and catalyst layers. The fly ash is collected in a hopper at the bottom of the SCR, and this needs to be connected to the existing fly ash system. The cost for this was scaled from the reference project's costs based on the units' size difference in MW.
- **Electrical Equipment** – This covers the costs for electrical equipment (e.g. transformers, cabling, etc.) that are required for an SCR. This price was scaled up from the reference project based on the units' difference in MW.
- **Induced Draft or Booster Fans** – No costs were included for new ID fans or booster fans. Black & Veatch's reference project installed new ID fans, and if those costs are applied to Unit 2, nearly 20 million dollars (including installation) would have been added to the overall capital cost. The pressure drop across the catalyst layers is expected to be anywhere from 2.1 to 2.60 inches w.g. (according to IBDIEN Ceram), and including the ductwork, LPA screen, and mixing devices, over 6 inches w.g. of pressure drop can be expected. Coal Creek Unit 2 has four, identical ID fans with VFDs, and all of them normally operate at a speed around 640 rpm. The fan curve shows that at 705 rpm, the fans provide about 19 inches w.g. of pressure rise, and at 880 rpm, the fans provide about 37.5 inches of pressure rise. These readings are taken at 2.1 million lb/h of flue gas, which was calculated from the results of a stack test in 2017, here near 8.4 million lb/h of flue gas was measured. Considering where the fans are currently operating, there is enough margin available in the fans' capabilities to overcome the pressure losses from a new SCR.
- **Sonic Horns** – There are two traditional ways of cleaning SCR catalysts from various deposits that can plug up catalyst, soot blowing and sonic horns. Both have been shown to work, but prices for sonic horns were readily available when developing the cost estimates for this report. Therefore, sonic horns were used in the cost estimate. A change to soot blowers would not significantly increase the overall SCR price. An elevation adjustment factor was applied after escalating the cost from the reference facility based on MW.
- **LPA Screens** – A screen is placed upstream of the SCR catalyst to collect large particle ash (LPA). This price was scaled up based on the units' difference in catalyst volume, and the cost was adjusted according to the elevation.
- **Flow Modeling** – Physical models at 1/12 of the actual scale are often used when designing and building an SCR, because CFD models often are not precise in predicting ash flow patterns. The price from the reference project was used without any adjustment, because the price difference is expected to be nominal.

- **Instruments and Controls** – As with any system, instrumentation will be needed to provide process data for operators. SCRs do not require as much instrumentation as other control systems, like a flue gas desulfurization (FGD) system, but costs for additional instruments are required. Based on the reference project, a general 2 percent of the total capital costs is applied.
- **NO<sub>x</sub> Monitoring** – NO<sub>x</sub> analyzers and associated equipment are provided as a process control. This is separate from a continuous emissions monitoring system (CEMS), as there is already a NO<sub>x</sub> CEMS at Coal Creek Station. The price from the reference project was used without any adjustment, because the cost of analyzers and the associated equipment should be nearly constant. This cost is estimated to be \$1.3 million.
- **Taxes and Freight** – A general 7 percent tax (confirmed by GRE) and 5 percent freight charge are applied against the total capital costs. These numbers can fluctuate, but neither will have a significant impact on the overall price. This cost is estimated to be \$3 and \$2.2 million for taxes and freight, respectively.

### C.1.2 Direct Installation Costs

- **Spare Parts, Training, Technical Assistance** – When installing a system, it is routine to have a set number of spare parts in the warehouse for startup and for turning over to the owner. Training and technical assistance from vendors is also necessary to properly install and startup the equipment. The previous project's cost was escalated based on the units' difference in MW.

## C.2 SNCR

### C.2.1 Purchased Equipment Costs

- **Vendor's Scope of Work** – Solutions such as urea must be continuously agitated to ensure the solids stay in solution, so a circulation module was included in Fuel Tech's quote. The circulation module includes two pumps and a strainer, with appropriate instrumentation, connected to the storage tank and metering module. Due to the cold temperatures at Coal Creek Station, a weather enclosure for the circulation module was included by Fuel Tech.

Prior to being injected into the furnace, the urea solution is diluted with water (to 10 percent in Fuel Tech's design), which is provided by the plant. Fuel Tech has provided a strainer/pump system to account for the SNCR's pressure and flow requirements. In addition to the dilution module, a metering module is in Fuel Tech's scope of supply. The metering module regulates the flow and pressure of diluted solution to each injection zone, and due to its criticality, some form of weather protection is necessary. This was not included in Fuel Tech's scope of

supply though, but rather it is in the Balance of Plant's scope, described in the subsection below.

After the metering modules, distribution modules mix the reagent with atomizing air. Compressed instrument air was assumed to be provided by the plant, because there is sufficient capacity in the existing compressed air system. The distribution modules are located near the injectors.

- **Air Compressors** – A cost for two receivers was included in the cost estimate. Coal Creek Station's instrument air system has sufficient capacity. By not requiring new air compressors approximately \$150k was avoided in PEC.
- **Monitoring Equipment** – The existing CEMS may be used for monitoring but to minimize ammonia consumption, individual monitors will be required in each furnace. The monitors will provide the necessary process control to allow operational control of each furnace, minimizing ammonia costs. The value included for the monitors was minimal and has no significant impact on the total project cost.
- **Taxes and Freight** – A general 7 percent tax (confirmed by GRE) and 5 percent freight charge are applied against the total capital costs. These numbers can fluctuate, but neither will have a significant impact on the overall price.

### C.2.2 Direct Installation Costs

- **Electrical Construction** – This line item deals with installing the electrical equipment. The previous project's cost was escalated based on the units' difference in reagent flow rate.
- **Boiler Modifications** – New ports for the injection lances will be required, so new boiler penetrations will be needed. Babcock Power was contacted to obtain a general, high level cost for providing seal boxes and penetrations to be installed on site by GRE. GRE's labor costs and past experience, on the time required to install boiler penetrations, were used to calculate a general cost for the new ports. This is higher for the system with MNLs, because the MNLs are additional penetrations that are larger than traditional wall injectors.
- **Spare Parts, Training, Technical Assistance** – When installing a system, it is routine to have a set number of spare parts in the warehouse for startup and for turning over to the owner. Training and technical assistance from vendors is also necessary to properly install and startup the equipment. The previous project's cost was escalated based on the units' difference in reagent flow rate.

## Appendix D. Site Specific Cost Estimate Summary Sheets

## GRE Coal Creek - Cost Analysis

Technology: Selective Catalytic ReductionDate: 3/4/2019

Cost Item	2018 \$	Remarks/Cost Basis		
<b>CAPITAL COST</b>				
<b>Direct Costs</b>				
Purchased equipment costs				
Reactor housing	\$3,690,000			Engineering estimate based on past project
Ammonia handling and injection				
Ammonia Injection Grid & dilution skid	\$2,260,000			Engineering estimate based on past project
Anhydrous ammonia tank	\$520,000			Engineering estimate based on past project
Air Compressors (plant's existing has spare capacity)	\$20,000			Plant's existing compressor have spare capacity, receivers only
Vaporizers	\$380,000			Engineering estimate based on past project
Ammonia unloading skids	\$530,000			Engineering estimate based on past project
Ammonia supply pump skid	\$200,000			Engineering estimate based on past project
Miscellaneous equipment/components	\$160,000			Engineering estimate based on past project
Mixing Chamber (included)	---			Included as part of the dilution skid
Piping (ammonia supply, etc)	---			Included in Mechanical Construction
Initial catalyst (Ceram)	\$6,100,000			Quote from catalyst supplier
Flue gas handling: ductwork	\$5,270,000			Engineering estimate based on past project
Air heater modifications	\$10,500,000			Per Cost Manual Equation 2.43
ASH handling (e.g. conveyors)	\$670,000			Engineering estimate based on past project
Electrical equipment	\$250,000			Engineering estimate based on past project
Structural steel	\$10,600,000			Engineering estimate based on past project
ID Fan (no upgrade or new required)	---			Fan curves indicate sufficient capacity for additional pressure drop
Misc. equipment				
Sonic horns	\$290,000			Engineering estimate based on past project
LPA screens / rappers	\$760,000			Engineering estimate based on past project
NOx/NH3 monitoring	\$1,340,000			Engineering estimate based on past project Added \$20k for another monitor without emit
Flow modeling	\$190,000			Engineering estimate based on past project
Subtotal capital cost (CC)	\$43,710,000			
Instruments and controls	\$870,000	(CC) X	2.0%	
Taxes	\$3,060,000	(CC) X	7.0%	
Freight	\$2,190,000	(CC) X	5.0%	
Total purchased equipment cost (PEC)	\$49,830,000			
<b>Direct installation costs</b>				
Subsurface construction				
Earthwork, underground utilities, etc.	\$4,070,000			Engineering estimate based on past project
Foundations (including embedments)	\$1,120,000			Engineering estimate based on past project
Superstructures construction				
Reactor housing, ductwork, etc.	\$28,380,000			Engineering estimate based on past project
Heated building	\$15,230,000			Engineering estimate based on past project
Demo and Rebuild	\$9,030,000			
Mechanical construction	\$6,600,000			Engineering estimate based on past project
Electrical construction	\$4,350,000			Engineering estimate based on past project
Spare parts, training, TA	\$350,000			Engineering estimate based on past project
Total direct installation costs (DIC)	\$69,130,000			
Total direct costs (DC) = (PEC) + (DIC)	\$118,960,000			
<b>Indirect Costs</b>				
Engineering	\$8,330,000	(DC) X	7.0%	Engineering estimate based on past project
Construction and field expenses	\$35,680,000	(DC) X	30.0%	Engineering estimate based on past project
Start-up	\$3,570,000	(DC) X	3.0%	Engineering estimate based on past project
Performance test	\$590,000	(DC) X	0.5%	Engineering estimate based on past project
Contingencies	\$23,790,000	(DC) X	20.0%	Engineering estimate based on past project
Total indirect costs (IC)	\$71,960,000			
Total Capital Investment (TCI) = (DC) + (IC) + (AFDC)	\$190,920,000			
	\$316	\$/KW		



**ANNUAL COST****Direct Annual Costs****Fixed annual costs**

Operating labor	\$70,000	0.5 FTE and	149,365 \$/year	Estimated manpower level
Maintenance labor & materials	\$960,000	(TCI) X 0.5%		
Catalyst activity testing	\$10,000	Engineering estimate		
Fly ash sampling and analysis	\$20,000	Engineering estimate		
Total fixed annual costs	<u>\$1,060,000</u>			

**Variable annual costs**

Reagent	\$490,000	213 lb/yr and	604 \$/ton	Vendor quotes
Auxiliary and ID fan power	\$880,000	3517.84 KW and	0.03291 \$/kWh	Vendor quote and GRE cost
Catalyst replacement	\$1,930,000	1,463 m3 and	4,171 \$/m3	3 yr catalyst replacement rate
Catalyst disposal	\$10,000	1,326,626 lb and	10.5 \$/ton	3 yr catalyst replacement rate
Total variable annual costs	<u>\$3,310,000</u>			

**Total direct annual costs (DAC)****\$4,370,000****Indirect Annual Costs**

Administrative charges	\$450,000	3% of Operator/Labor + 40% of Maintenance (per Cost Manual)		
Cost for capital recovery	\$12,770,000	(TCI) X 6.69%	CRF at 5.25% interest & 30 year life	
Total indirect annual costs (IDAC)	<u>\$13,220,000</u>			

**Total Annual Cost (TAC) = (DAC) + (IDAC)****\$17,590,000****\$8,737**

\$/ton NOx

## GRE Coal Creek - Cost Analysis

Technology: Selective Non-Catalytic ReductionDate: 3/4/2019

Cost Item	2018 \$	Remarks/Cost Basis			
<b>CAPITAL COST</b>					
<b>Direct Costs</b>					
Purchased equipment costs	\$2,640,000	Vendor Quote			
Reagent storage, handling, injection & controls					
Urea Unloading Skid (included)	---	Included with vendor quote			
Urea Storage Tank and Circulation Module	---	Included with vendor quote			
Dilution Water, Injection Nozzles, and Metering	---	Included with vendor quote			
Miscellaneous SNCR system equipment/components	---	Included with vendor quote			
Air Compressors (plant's existing has spare capacity)	\$20,000	Plant's existing compressor have spare capacity, receivers only			
Piping (included and part of mechanical installation)	---	Included in mechanical construction costs			
Foundations	---	Included in subsurface construction costs			
Instrumentation and Controls (included)	---	Included in electrical construction costs			
Monitoring Equipment (use existing CEMS; new NH3)	\$50,000	Engineering estimate for two TDLs			
Electrical	---	Included in electrical construction costs			
Enclosure(s)	---	Included in superstructures construction costs			
Initial urea inventory	---	Included in Direct Installation Costs			
Subtotal capital cost (CC)	\$2,710,000				
Taxes	\$190,000	(CC) X	7.0%		
Freight	\$140,000	(CC) X	5.0%		
Total purchased equipment cost (PEC)	\$3,040,000				
<b>Direct Installation costs</b>					
Subsurface construction	\$1,880,000	Engineering estimate based on past project			
Superstructures construction	\$1,430,000	Engineering estimate based on past project			
Demo and rebuild	\$0	None expected			
Mechanical construction	\$2,330,000	Engineering estimate based on past project			
Electrical construction	\$730,000	Engineering estimate based on past project			
Boiler modifications (injection ports, included)	\$50,000	Estimate from vendor and site labor			
Miscellaneous	\$80,000	Engineering estimate based on past project			
Spare parts, training, TA	\$190,000	Engineering estimate based on past project			
Total direct installation costs (DIC)	\$6,690,000				
Total direct costs (DC) = (PEC) + (DIC)	\$9,730,000				
<b>Indirect Costs</b>					
Engineering and Home Office	\$680,000	(DC) X	7.0%	Engineering estimate based on past project	
Construction and field expense (e.g. facilities)	\$970,000	(DC) X	10.0%	Engineering estimate based on past project	
Start-up	\$290,000	(DC) X	3.0%	Engineering estimate based on past project	
Performance test	\$100,000			Engineering estimate based on past project	
Contingencies	\$970,000	(DC) X	10.0%	Engineering estimate based on past project	
Total indirect costs (IC)	\$3,010,000				
Total Capital Investment (TCI) = (DC) + (IC) + (AFDC)	\$12,740,000				
	\$21.05	\$/KW			
<b>ANNUAL COST</b>					
<b>Direct Annual Costs</b>					
Fixed annual costs					
Operating labor	\$0		0 FTE and	149,365 \$/yr	Estimated manpower level
Maintenance labor and materials	\$190,000	(TCI) X	1.5%		
Total fixed annual costs	\$190,000				
Variable annual costs					
Reagent	\$3,000,000	292 gph and	1.35 \$/gallon	Vendor quotes	
Auxiliary and ID fan power	\$20,000	75 kW and	0.03291 \$/kWh	Vendor quote and GRE cost	
Water	\$280,000	165 gpm and	3.7 \$/1,000 gal	Vendor quote and GRE cost	
Fuel (additional to vaporize solution)	\$320,000	23 MMBtu/hr &	1.85 \$/MMBtu	Cost Manual and GRE cost	
Ash disposal (additional due to more coal burned)	\$10,000	359 lb/hr and	10.5 \$/ton	Cost Manual and GRE cost	
Total variable annual costs	\$3,630,000				
Total direct annual costs (DAC)	\$3,820,000				
<b>Indirect Annual Costs</b>					
Administrative charges	\$6,000	3 %	of annual maintenance cost (per Cost Manual)		
Cost for capital recovery	\$1,040,000	(TCI) X	8.20%	CRF at 5.25% interest & 20 year life	
Total indirect annual costs (IDAC)	\$1,040,000				
Total Annual Cost (TAC) = (DAC) + (IDAC)	\$4,860,000				
	\$11.145	\$/ton NOx			

## GRE Coal Creek - Cost Analysis

Technology: Selective Non-Catalytic Reduction w/ MNLs

Date: 3/4/2019

Cost Item	2018 \$	Remarks/Cost Basis			
<b>CAPITAL COST</b>					
<b>Direct Costs</b>					
Purchased equipment costs	\$4,215,000	Vendor Quote			
Reagent storage, handling, injection & controls	---	Included with vendor quote			
Urea Unloading Skid (included)	---	Included with vendor quote			
Urea Storage Tank and Circulation Module	---	Included with vendor quote			
Dilution Water, Injection Nozzles, and Metering	---	Included with vendor quote			
Miscellaneous SNCR system equipment/components	---	Included with vendor quote			
Air Compressors (plant's existing has spare capacity)	\$20,000	Plant's existing compressor have spare capacity, receivers only			
Piping (included and part of mechanical installation)	---	Included in mechanical construction costs			
Foundations	---	Included in subsurface construction costs			
Instrumentation and Controls (included)	---	Included in electrical construction costs			
Monitoring Equipment (use existing CEMS; new NH3)	\$50,000	Engineering estimate based on past project			
Electrical	---	Included in electrical construction costs			
Enclosure(s)	---	Included in superstructures construction costs			
Initial urea inventory	---	Included in Direct Installation Costs			
Subtotal capital cost (CC)	\$4,290,000				
Taxes	\$300,000	(CC) X	7.0%		
Freight	\$210,000	(CC) X	5.0%		
Total purchased equipment cost (PEC)	\$4,800,000				
<b>Direct installation costs</b>					
Subsurface construction	\$2,110,000	Engineering estimate based on past project			
Superstructures construction	\$1,430,000	Engineering estimate based on past project			
Demo and rebuild	\$0	None expected			
Mechanical construction	\$2,760,000	Engineering estimate based on past project w/ additional cost for MNLs			
Electrical construction	\$950,000	Engineering estimate based on past project w/ additional cost for MNLs			
Boiler modifications (injection ports, included)	\$60,000	Estimate from vendor and site labor			
Miscellaneous	\$210,000	Engineering estimate based on past project w/ additional cost for MNLs			
Spare parts, training, TA	\$340,000	Engineering estimate based on past project w/ additional cost for MNLs			
Total direct installation costs (DIC)	\$7,860,000				
Total direct costs (DC) = (PEC) + (DIC)	\$12,660,000				
<b>Indirect Costs</b>					
Engineering and Home Office	\$890,000	(DC) X	7.0%	Engineering estimate based on past project	
Construction and field expense (e.g. facilities)	\$1,270,000	(DC) X	10.0%	Engineering estimate based on past project	
Start-up	\$380,000	(DC) X	3.0%	Engineering estimate based on past project	
Performance test	\$100,000	Engineering estimate based on past project			
Contingencies	\$1,270,000	(DC) X	10.0%	Engineering estimate based on past project	
Total indirect costs (IC)	\$3,910,000				
Allowance for Funds Used During Construction (AFDC)	\$0	[(DC)+(IC)] X		0.00%	1 years (project time length)
Royalty Allowance	\$0	Per Cost Manual			
Preproduction Cost (\$290,000)	\$0	Per Cost Manual			
Inventory Capital (TBD, 280,000)	\$0	Per Cost Manual			
Initial Catalyst and Chemicals	\$0	Per Cost Manual			
Total Capital Investment (TCI) = (DC) + (IC) + (AFDC)	\$16,570,000				
	\$27.38	\$/KW			
<b>ANNUAL COST</b>					
<b>Direct Annual Costs</b>					
Fixed annual costs					
Operating labor	\$0	0 FTE and		149,365 \$/yr	Estimated manpower level
Maintenance labor and materials	\$250,000	(TCI) X	1.5%		
Total fixed annual costs	\$250,000				
Variable annual costs					
Reagent	\$3,680,000	358 gph and	1.35 \$/gallon	Vendor quotes	
Auxiliary and ID fan power	\$20,000	95 kW and	0.03291 \$/kWh	Vendor quote and GRE cost	
Water	\$250,000	145 gpm and	3.7 \$/1,000 gal	Vendor quote and GRE cost	
Fuel (additional to vaporize solution)	\$390,000	28 MMBtu/hr	1.85 \$/MMBtu	Cost Manual and GRE cost	
Ash disposal (additional due to more coal burned)	\$20,000	430 lb/hr and	10.5 \$/ton	Cost Manual and GRE cost	
Total variable annual costs	\$4,360,000				
Total direct annual costs (DAC)	\$4,610,000				
<b>Indirect Annual Costs</b>					
Administrative charges	\$8,000	3 %	of annual maintenance cost (per Cost Manual)		
Cost for capital recovery	\$1,360,000	(TCI) X	8.20%	CRF at 5.25% interest & 20 year life	
Total indirect annual costs (IDAC)	\$1,368,000				
Total Annual Cost (TAC) = (DAC) + (IDAC)	\$5,978,000				
	\$8.899	\$/ton NOx			

## Appendix E. Supporting Documentation for Cost Estimates



**Black & Veatch**

Attn. Mr. Mark Dittus  
11401 Lamar Ave  
Overland Park, Kansas 66211

June 18, 2019

**Budgetary Catalyst Proposal for GRE Coal Creek SCR Project**

**B&V No. 400075.60.1000**

CERAM Proposal No. GH190617-1 - Confidential

Dear Mr. Dittus:

With reference to your request for a budgetary quotation from the June 13, 2019 conference call, IBIDEN CERAM, Inc. (CERAM) is pleased to provide Black & Veatch (B&V) with our budgetary proposal for supplying selective catalytic reduction (SCR) catalyst for the Great River Energy (GRE) Coal Creek SCR Project. We have based our catalyst design on the design data e-mailed by B&V on October 9, 2018 and further correspondence provided in both May and June 2019. Our proposal described herein is based on supplying honeycomb catalyst manufactured at our production plant located in Frauental, Austria. Since 1985, CERAM has produced over 180,000 m<sup>3</sup> of SCR homogeneous honeycomb and plate type catalyst for over 1,600 applications and is a world leader in the supply of this product. CERAM has proposed using our [REDACTED] pitch honeycomb catalyst for this application due to the high temperature and required specific surface area.

B&V specified that the catalyst would be in a high dust arrangement or immediately downstream of the economizer boiler section. There were no design constraints on the size or number of SCR reactors or catalyst layers required to meet the DeNOx demand (e.g., 69% NOx reduction and 2 ppmvdc ammonia slip for 24,000 hours). The design information indicated the fuel to be North Dakota (ND) lignite. CERAM does not have direct experience with ND lignite, but we have developed a wide portfolio of experience and have mainly focused on "dirty" gas applications. While not every application has the exact same design basis, we do have experience with other lignite and brown coal fired applications using both of our honeycomb and plate catalysts. However, the high levels of sodium oxide (Na<sub>2</sub>O) (>4%) in the ash for the ND lignite are not commonly found in sub-bituminous, bituminous and other lignite coals based on our supplied experience. Moreover, the ND coal analysis indicates there are high levels of various other catalyst poisons (arsenic, potassium, etc.) and masking agents (calcium sulfate, etc.) that must be taken into consideration in an SCR catalyst design. Table 1 summarizes our budgetary catalyst design for the project. Additional design details are provided in Attachment A. Table 2 summarizes the scope of supply, delivery, and budgetary pricing regarding this offering.

**IBIDEN CERAM, Inc.**

7304 W. 130<sup>th</sup> Street Suite 140 • Overland Park, Kansas 66213

Tel: (913) 239-9896 • Fax: (913) 239-9821

Table 1. GRE Coal Creek SCR Catalyst Design Summary <sup>(1)</sup>		
Catalyst Design:		
Catalyst Pitch / Element Length, mm	[REDACTED] / [REDACTED]	
No. of Reactors / Initial Layers Installed	2 / 3	
Module Arrangement per Layer	13 x 9	
Catalyst Volume/Reactor, m <sup>3</sup>	[REDACTED]	
Performance: <sup>(2),(3)</sup>	Case 1	Case 2
Inlet NOx, ppmvd act. O <sub>2</sub>	126	60
Outlet NOx, ppmvd act. O <sub>2</sub>	39 (69% reduction)	18.6 (69% reduction)
Initial Pressure Drop, in. w.g.	2.1 (clean) / 2.6 (dirty)	
Initial Ammonia Slip, ppmvd ref. O <sub>2</sub>	2	
Initial SO <sub>2</sub> to SO <sub>3</sub> Oxidation Rate, %	5	
Guarantee Life, (hours)	24,000 (or 36 months from delivery); Dependent on Pilot Scale Test Results	
Notes:		
1. Reference Attachment A (CERAM data sheet) for further information.		
2. SO <sub>2</sub> to SO <sub>3</sub> oxidation design for ammonia on conditions ( $\alpha = 1$ ).		
3. Guarantees for NOx reduction, ammonia slip, pressure drop and SO <sub>2</sub> to SO <sub>3</sub> oxidation for Test A only (reference proposal for further information).		

Table 2 – GRE Coal Creek Catalyst Scope of Supply and Budgetary Pricing	
<b>Scope of Supply:</b> Production Testing and Documentation Catalyst with Steel Module Frames Module-to-Module and Module-to-Reactor Wall Seals 50% of the Frames with 1 Removable Full Size Test Element 20 Replacement Test Elements Cover Grates for Each Module Four Lifting Frames Operation & Maintenance Manuals & Required Performance Curves Catalyst Module, Lifting Frame and Seal Drawings (6 weeks after receipt of order) Protective Crating to the Site Freight to Jobsite (DDP to site; Assume delivery 1 <sup>st</sup> quarter 2021)	
<b>Budgetary Pricing:</b> (Validity is 60 Days)	
Base Design: [REDACTED] Pitch Catalyst ([REDACTED])	\$6,100,000
Note: (1) CERAM is willing to work with GRE and B&V with regards to payment terms in order to meet the project requirements. We understand that at this point in the project the main commercial driver is the performance guarantees and budgetary catalyst scope of supply pricing.	

### Catalyst Deactivation

CERAM's experience with sodium levels greater than 4% has shown that catalyst deactivation would be higher than a typical bituminous or sub-bituminous coal fired application. Figure 1 shows the percentages of sodium from the Falkirk mine based on 5,531 samples. Our catalyst design was based on a maximum sodium percentage of 4% (12% ash). The data indicates that for approximately 27% of the samples the sodium percentage would be greater than 4%. While CERAM does not have direct experience with firing North Dakota lignite, we based our current design on our biomass experience (e.g., wood, switch grass, etc.) where there are also high alkalis, such as potassium and sodium. However, the upper range of sodium shown in the ND lignite data set is outside our operating experience. Therefore, we expect the catalyst deactivation to be accelerated due to the higher levels of sodium (>4%).

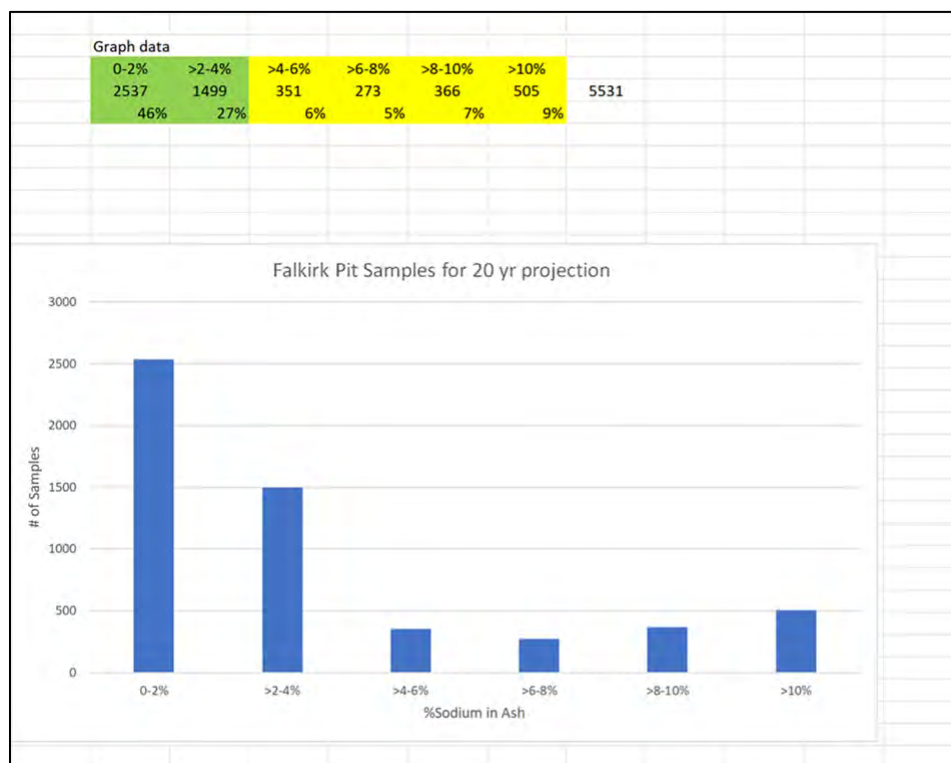


Figure 1. Sodium in ash percentages from the Falkirk Pit samples based on 20 year projections provided by GRE/B&V.

CERAM's experience with biomass applications in a high dust arrangement were successful because we were able to take advantage of the lower flame temperature (e.g., less oxidized poisons) with using a bubbling fluidized bed (BFB) boiler and the nature of a BFB where there is available sorbent (e.g., limestone) that can absorb a portion of the catalyst poisons and a large portion of the ash is entrained. Pulverized coal (PC) boilers in a high dust arrangement can lead to an increase in deactivation due to the higher local flame temperature and areas of incomplete combustion that both can lead to a severe increase in oxidized poisons, such as sodium oxide, arsenic trioxide, etc.

Catalyst deactivation due to the high sodium levels will occur based on normal operations from the formation of sodium aerosols and from poisoning that would occur during outages. The effects of sodium in the particulate form can be controlled by maintaining warm and dry conditions on the catalyst at all times during layup conditions of the SCR reactor. However, if there are moist conditions on the catalyst, such as condensation during an outage then the particulate bound sodium will leach into the pore structure of the catalyst where catalyst poisoning will occur. Small aerosol particles will penetrate and neutralize active catalyst sites even in dry conditions; however the effect is much worse when moisture is present. The current catalyst management plan from GRE and B&V would be to replace all of the catalyst every three years due to Coal Creeks expected three year outage cycle. CERAM agrees this would eliminate the effects of deactivation during scheduled outages, since all six levels of catalyst would be replaced, however the forced outages must also be taken into consideration. There must be no moisture in the SCR reactor during layup or when the SCR is isolated for example during an unexpected boiler outage. In this regard, maintaining temperatures greater than or equal to 300 F would be recommended. Prior to short term isolation the catalyst layers should be air purged with dry acid free air to prevent condensation of moisture on the catalyst surface and never isolate the reactor with flue gas. Startups and the time needed to put the SCR in surface would need to be minimized/optimized to reduce the effects of deactivation. Due to the possibility of high sodium concentrations, CERAM would recommend a full SCR bypass system be installed. During lay-up periods the catalyst would need to remain warm and dry perhaps by using an air drying or dehumidification system.

### **Catalyst Performance Guarantees**

Catalyst deactivates due to the exposure of flue gas. It is known in the industry that catalyst deactivation is a result of the operating conditions and fuels fired, and is independent of catalyst type or manufacturer. The goal of properly designing catalyst is to accurately predict the rate of catalyst deactivation for a given project. Since there is no direct experience in the industry with SCR catalyst installed on a unit firing ND lignite, it is difficult to determine with a high level of certainty what the long term impacts will be on the SCR catalyst. As such, it is very risky and difficult to provide life guarantees for this application until further field testing is performed to fully assess the long term impacts.

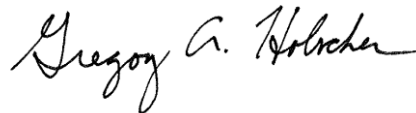
Based on the budgetary catalyst design included herein, CERAM would be willing to provide initial (Test A) performance guarantees which would include NO<sub>x</sub> reduction, ammonia slip, SO<sub>2</sub> to SO<sub>3</sub> conversion rate, pressure drop and ammonia slip. Additional, data that would be very useful would be to understand the concentrations and particle size distribution of the probable catalyst poisons from firing ND lignite. The most critical information is how the small particles which are present in the flue gas stream will affect the catalyst by either poisoning or fouling mechanisms. CERAM believes that with additional field testing information that catalyst life guarantees could also be provided. The budgetary design presented is for a 24,000 hour or 3 year period to reflect the planned outage schedule at Coal Creek, however CERAM is unable to offer end of life performance guarantees given the potential for high sodium levels without additional field information. CERAM would recommend a pilot test using CERAM's CoPilot<sup>®</sup> Test Reactor, or a similar device to develop long term trends associated with catalyst deactivation.



The pilot test program would involve flue gas exposure of one to several catalyst elements under conditions that would replicate the actual SCR system. CERAM recommends at least 2,000 hours of exposure per catalyst sample. As many as 5,000 hours of exposure would be preferred. Based on participation in such a pilot test program, CERAM would be able to provide 24,000 hour life guarantees for this project. In this situation, CERAM would prefer to work in an “open book” manner to design the catalyst with direct input from B&V and GRE with regards to catalyst design and sizing margin.

We hope this proposal meets your expectations. Please contact John Cochran ([john.cochran@ceram-usa.com](mailto:john.cochran@ceram-usa.com)) or myself ([greg.holscher@ceram-usa.com](mailto:greg.holscher@ceram-usa.com)) at 913-239-9896 should you have any questions or need any further information.

Yours sincerely,  
IBIDEN CERAM, Inc.



Gregory A. Holscher, Ph.D.  
Senior Applications Engineer

cc: Mr. Paul Lee (B&V)  
Mr. John Cochran (CERAM)  
Mr. Kurt Orehovsky (CERAM)

Enclosures

1. Attachment A – CERAM Data Sheets

Curr.No.	Project	Client	End user / Engineering company	Plant location	Application	Fuel	Configuration	Shipped quantity	Delivery date
1.	KW Dürnrohr	EVN	EVN	AUT	Steam Power Plant	Bituminous Coal	High Dust	2 m³	2010
2.	KW Mehrum	Kraftwerk Mehrum	Kraftwerk Mehrum	DEU	Steam Power Plant	Bituminous Coal	High Dust	165 m³	2011
3.	Laziska Unit 12	Strabag	PKE S.A. Laziska Power Plant	POL	Steam Power Plant	Bituminous Coal	High Dust	295 m³	2011
4.	China Steel Unit # 7	Fuel Tech	China Steel Corp.	TWN	Steam Power Plant	Bituminous Coal	High Dust	25 m³	2012
5.	Laziska Unit 11	Strabag	PKE S.A. Laziska Power Plant	POL	Steam Power Plant	Bituminous Coal	High Dust	295 m³	2012
6.	Kozienice Unit 6	Termokimik	Elektrownia "Kozienice" S.A	POL	Steam Power Plant	Bituminous Coal	High Dust	379 m³	2012
7.	KS 1/2	Strabag	Formosa Plastics Corporation (FPG)	TWN	Steam Power Plant	Bituminous Coal	High Dust	92 m³	2012
8.	JH 1	Strabag	FPG	TWN	Steam Power Plant	Bituminous Coal	High Dust	54 m³	2012
9.	LP1	Strabag	FPG	TWN	Steam Power Plant	Bituminous Coal	High Dust	54 m³	2012
10.	JH 1 Spare Layer	Strabag	FPG	TWN	Steam Power Plant	Bituminous Coal	High Dust	29 m³	2012
11.	Samkwang Glass	Haelim Eng. Co.	Samkwang Glass Co.	KOR	Glass Trough	Natural Gas	Low Dust	12 m³	2012
12.	KCC GF #1	Hae Cheon Industrial Co. Ltd	Kumkang Korea Chemical Co, Ltd	KOR	Glass Trough	Natural Gas	Low Dust	15 m³	2012
13.	JP1 Spare Layer	FPG	FPG	TWN	Steam Power Plant	Bituminous Coal	High Dust	37 m³	2012
14.	Yushe Unit 3	Huaneng	Huaneng	CHN	Steam Power Plant	Bituminous Coal	High Dust	425 m³	2012
15.	Maasvlakte Unit 1	E.ON	E.ON	NDL	Steam Power Plant	Bituminous Coal	High Dust	265 m³	2012
16.	Yonghung #4	KOSEP	KOSEP	KOR	Steam Power Plant	Bituminous Coal	High Dust	445 m³	2013
17.	Polaniec	Termokimik	GDF Suez	POL	Steam Power Plant	Bituminous Coal	High Dust	255 m³	2013
18.	Maasvlakte Unit 2	E.ON	E.ON	NDL	Steam Power Plant	Bituminous Coal	High Dust	265 m³	2013
19.	Elm Road Unit 2	WE Energies	WE Energies	USA	Steam Power Plant	PRB/Sub-bituminous	High Dust	295 m³	2013
20.	Yushe Unit 4	Huaneng	Huaneng	CHN	Steam Power Plant	Bituminous Coal	High Dust	425 m³	2013
21.	KS 3	Strabag	FPG	TWN	Steam Power Plant	Bituminous Coal	High Dust	77 m³	2013
22.	KP 1	Strabag	FPG	TWN	Steam Power Plant	Bituminous Coal	High Dust	61 m³	2013
23.	Laziska Unit 10	Strabag	PKE S.A. Laziska Power Plant	POL	Steam Power Plant	Bituminous Coal	High Dust	295 m³	2013
24.	Kozienice Unit 7	Termokimik	Elektrownia "Kozienice" S.A	POL	Steam Power Plant	Bituminous Coal	High Dust	379 m³	2013
25.	China Steel Unit # 6	Fuel Tech	China Steel Corp.	TWN	Steam Power Plant	Bituminous Coal	High Dust	51 m³	2013

## Reference List

for plate catalyst projects as of July 2018

Curr.No.	Project	Client	End user / Engineering company	Plant location	Application	Fuel	Configuration	Shipped quantity	Delivery date
26.	Nexen Tire	Haelim Eng. Co.	Nexen Tire Co. Ltd.	KOR	Industrial Plant	Pet Coke	High Dust	10 m <sup>3</sup>	2013
27.	TYC	Strabag	Ta-Yuan Cogeneration Co., Ltd.	TWN	Steam Power Plant	Bituminous Coal	High Dust	51 m <sup>3</sup>	2013
28.	Hadong #8 Replacement	KOSPO	KOSPO	KOR	Steam Power Plant	Bituminous Coal	High Dust	93 m <sup>3</sup>	2013
29.	China Steel Unit # 8	Fuel Tech	China Steel Corp.	TWN	Steam Power Plant	Bituminous Coal	High Dust	51 m <sup>3</sup>	2013
30.	Nantong Fiber 8&9	Jiangsu Sunco Boiler Co. Ltd.	Nantong Cellulose Fibers Co.	CHN	Steam Power Plant	Bituminous Coal	High Dust	92 m <sup>3</sup>	2013
31.	Boryeong TPP # 6	KOMIPO	KOMIPO	KOR	Steam Power Plant	Bituminous Coal	High Dust	223 m <sup>3</sup>	2013
32.	HanFeng #1	Huaneng	Huaneng	CHN	Steam Power Plant	Bituminous Coal	High Dust	890 m <sup>3</sup>	2013
33.	Pleasant Prairie Unit 1	WE Energies		USA	Steam Power Plant	PRB/Sub-bituminous	High Dust	404 m <sup>3</sup>	2014
34.	HanFeng #2	Huaneng	Huaneng	CHN	Steam Power Plant	Bituminous Coal	High Dust	890 m <sup>3</sup>	2014
35.	Pleasant Prairie Unit 2	WE Energies		USA	Steam Power Plant	Bituminous Coal	High Dust	404 m <sup>3</sup>	2014
36.	Laziska Unit 9	Strabag	PKE S.A. Laziska Power Plant	POL	Steam Power Plant	Bituminous Coal	High Dust	295 m <sup>3</sup>	2014
37.	Kozienice Unit 5	Termokimik	Elektrownia "Kozienice" S.A	POL	Steam Power Plant	Bituminous Coal	High Dust	379 m <sup>3</sup>	2014
38.	Nanyang Tianyi Unit 4	Dongfang Boiler Group Co. Ltd.	Nanyang Tianyi Power Generation Co.,Ltd.	CHN	Steam Power Plant	Bituminous Coal	High Dust	736 m <sup>3</sup>	2014
39.	Nantong Fiber 6	Jiangsu Sunco Boiler Co. Ltd.	Nantong Cellulose Fibers Co.	CHN	Steam Power Plant	Bituminous Coal	High Dust	38 m <sup>3</sup>	2014
40.	Nanyang Yahekou #1	Tongfang Environment Co. Ltd.	Nanyang Yahekou Power Generation Co.,Ltd.	CHN	Steam Power Plant	Bituminous Coal	High Dust	453 m <sup>3</sup>	2014
41.	Torrevaldaliga L1	ENEL		ITA	Steam Power Plant	Bituminous Coal	High Dust	216 m <sup>3</sup>	2014
42.	Sostanj Unit 6	ALSTOM Boiler Deutschland GmbH	TES Termoelektrana Sostanj	SLO	Steam Power Plant	Lignite Coal	High Dust	584 m <sup>3</sup>	2014
43.	Taeon #6	Korea Western Power Co.	Korea Western Power Co.	KOR	Steam Power Plant	Bituminous Coal	High Dust	556 m <sup>3</sup>	2014
44.	Detmarovice 3&4	Strabag	CEZ	CZE	Steam Power Plant	Bituminous Coal	High Dust	429 m <sup>3</sup>	2014
45.	Rybnik 7&8	Strabag	EDF Poland	POL	Steam Power Plant	Bituminous Coal	High Dust	604 m <sup>3</sup>	2014
46.	Nantong Fiber 2nd supply	Nantong Sanpu Electrical&Mechanical	Nantong Cellulose Fibers Co.	CHN	Steam Power Plant	Bituminous Coal	High Dust	38 m <sup>3</sup>	2014
47.	KS1 Spare Layer	Strabag	Formosa Plastics Corporation (FPG)	TWN	Steam Power Plant	Bituminous Coal	High Dust	19 m <sup>3</sup>	2014
48.	Nantong Fiber 7	Jiangsu Sunco Boiler Co. Ltd.	Nantong Cellulose Fibers Co.	CHN	Steam Power Plant	Bituminous Coal	High Dust	38 m <sup>3</sup>	2014
49.	Ningbo 2	Strabag	Formosa Chemicals & Fibre Corporation Co., Ltd.	CHN	Steam Power Plant	Bituminous Coal	High Dust	165 m <sup>3</sup>	2014
50.	KCC GF #7	Hae Cheon Industrial Co. Ltd	Kumkang Korea Chemical Co, Ltd	KOR	Glass Trough	Natural Gas	Low Dust	77 m <sup>3</sup>	2014

## Reference List

for plate catalyst projects as of July 2018

Curr.No.	Project	Client	End user / Engineering company	Plant location	Application	Fuel	Configuration	Shipped quantity	Delivery date
51.	SK3	Strabag		TWN	Steam Power Plant	Bituminous Coal	High Dust	153 m <sup>3</sup>	2014
52.	Laziska Unit 12	Strabag	PKE S.A. Laziska Power Plant	POL	Steam Power Plant	Bituminous Coal	High Dust	26 m <sup>3</sup>	2014
53.	Bialystok Boiler K7+K8	Strabag	Elektrociepownia Bialystok	POL	Steam Power Plant	Bituminous Coal	High Dust	212 m <sup>3</sup>	2014/2015
54.	Torrevaldaliga L2	ENEL		ITA	Steam Power Plant	Bituminous Coal	High Dust	216 m <sup>3</sup>	2015
55.	Torrevaldaliga L3	ENEL		ITA	Steam Power Plant	Bituminous Coal	High Dust	216 m <sup>3</sup>	2015
56.	Hawthorn Unit 5 - Layer 1	KCP&L	GPES	USA	Steam Power Plant	PRB/Sub-bituminous	High Dust	278 m <sup>3</sup>	2015
57.	Nantong Fiber #5	Nantong Sanpu Electrical&Mechanical	Nantong Cellulose Fibers Co.	CHN	Steam Power Plant	Bituminous Coal	High Dust	38 m <sup>3</sup>	2015
58.	KS2 Spare Layer	Strabag	FPG	TWN	Steam Power Plant	Bituminous Coal	High Dust	38 m <sup>3</sup>	2015
59.	Oak Grove	Luminant		USA		Lignite Coal		36 m <sup>3</sup>	2015
60.	Amos Unit 1	AEP	AEP	USA	Steam Power Plant	Bituminous Coal	High Dust	472 m <sup>3</sup>	2015
61.	Kozienice Unit 4	Termokimik	Elektrownia "Kozienice" S.A	POL	Steam Power Plant	Bituminous Coal	High Dust	379 m <sup>3</sup>	2015
62.	KW Heyden	E.ON	E.ON	DEU	Steam Power Plant	Bituminous Coal	High Dust	439 m <sup>3</sup>	2015
63.	Laziska Unit 11	Strabag	PKE S.A. Laziska Power Plant	POL	Steam Power Plant	Bituminous Coal	High Dust	13 m <sup>3</sup>	2015
64.	La Cygne Unit 1	KCP&L	GPES	USA	Steam Power Plant	PRB/Sub-bituminous	High Dust	491 m <sup>3</sup>	2015
65.	TREA Breisgau	EEW Energy from Waste Saarbrücken GmbH		DEU	Steam Power Plant	Municipal Waste	Low Dust	34 m <sup>3</sup>	2015
66.	Nantong Fiber #6 Spare	Nantong Cellulose Fibers Co.		CHN	Steam Power Plant	Bituminous Coal	High Dust	19 m <sup>3</sup>	2015
67.	Brown Unit 3	Kentucky Utilities		USA	Steam Power Plant	Bituminous Coal	High Dust	340 m <sup>3</sup>	2015
68.	BASF Yeosu Plant	BASF		KOR	Steam Power Plant	Bituminous Coal	High Dust	24 m <sup>3</sup>	2015
69.	Nantong Fiber Unit 10 & 11	Nantong Cellulose Fibers Co.		CHN	Steam Power Plant	Bituminous Coal	High Dust	57 m <sup>3</sup>	2015
70.	Ostroleka K2 + K3	Termokimik		POL	Steam Power Plant	Bituminous Coal	High Dust	455 m <sup>3</sup>	2015
71.	Laziska Unit 12 repl. 2015	Strabag	PKE S.A. Laziska Power Plant	POL	Steam Power Plant	Bituminous Coal	High Dust	117 m <sup>3</sup>	2015
72.	Laziska Unit 12	Strabag	PKE S.A. Laziska Power Plant	POL	Steam Power Plant	Bituminous Coal	High Dust	117 m <sup>3</sup>	2015
73.	Duke Gibson Unit 5	Duke Energy		USA	Steam Power Plant	Bituminous Coal	High Dust	101 m <sup>3</sup>	2015
74.	Nantong Fiber Phase 3	Nantong Sanpu Electrical and Mechanical Technology		CHN	Steam Power Plant	Bituminous Coal	High Dust	28 m <sup>3</sup>	2015
75.	Hawthorn Unit 5 - Layer 2	KCP&L	GPES	USA	Steam Power Plant	PRB/Sub-bituminous	High Dust	278 m <sup>3</sup>	2016

## Reference List

for plate catalyst projects as of July 2018

Curr.No.	Project	Client	End user / Engineering company	Plant location	Application	Fuel	Configuration	Shipped quantity	Delivery date
76.	Kozienice Unit 8	Termokimik	Elektrownia "Kozienice" S.A	POL	Steam Power Plant	Bituminous Coal	High Dust	379 m <sup>3</sup>	2016
77.	Kyger Creek Unit 1-5	AEP	AEP	USA	Steam Power Plant	PRB & Bituminous Coal	High Dust	630 m <sup>3</sup>	2016
78.	Pleasant Prairie Unit 1 + 2	WE Energies		USA	Steam Power Plant	PRB/Sub-bituminous	High Dust	906 m <sup>3</sup>	2016
79.	Campbell Unit 3	Consumers Energy		USA	Steam Power Plant	PRB/Sub-bituminous	High Dust	1011 m <sup>3</sup>	2016
80.	Sikierki K2	Andritz AG		POL	Steam Power Plant	Bituminous Coal	High Dust	88 m <sup>3</sup>	2016
81.	Yonghung #4 RP	KOSEP		KOR	Steam Power Plant	Bituminous Coal	High Dust	142 m <sup>3</sup>	2016
82.	KS-1 2nd Spare Layer	Yara Taiwan		CHN	Steam Power Plant	Bituminous Coal	High Dust	15 m <sup>3</sup>	2016
83.	TREA Breisgau	EEW Energy		DEU	Steam Power Plant	Municipal Waste	Low Dust	27 m <sup>3</sup>	2016
84.	LongChen Hubei	Yara		CHN	Steam Power Plant	Bituminous Coal	High Dust	106 m <sup>3</sup>	2016
85.	Laziska Unit 12	Yara	PKE S.A. Laziska Power Plant	PL	Steam Power Plant	Bituminous Coal	High Dust	6 m <sup>3</sup>	2016
86.	FP1	Yara Taiwan		TWN	Steam Power Plant	Bituminous Coal	High Dust	133 m <sup>3</sup>	2016
87.	Detmarovice K3	Strabag/Yara		CZE	Steam Power Plant	Bituminous Coal	High Dust	56 m <sup>3</sup>	2016
88.	Boswell Unit 3	Minnesota Power		USA	Steam Power Plant	PRB/Sub-bituminous	High Dust	211 m <sup>3</sup>	2016
89.	Yahekou #1	JiangHe Mechanical		CHN	Steam Power Plant	Bituminous Coal	High Dust	227 m <sup>3</sup>	2016
90.	Gheco One	Laborelec		THA	Steam Power Plant	Bituminous Coal	High Dust	307 m <sup>3</sup>	2016
91.	Iatan Unit 2	KCP&L		USA	Steam Power Plant	PRB/Sub-bituminous	High Dust	472 m <sup>3</sup>	2016
92.	Sibley Unit 3	KCP&L		USA	Steam Power Plant	PRB/Sub-bituminous	High Dust	227 m <sup>3</sup>	2016
93.	LongChen Hubei	Yara Taiwan	Long Chen Paper Corporation	CHN	Steam Power Plant	Bituminous Coal	High Dust	106 m <sup>3</sup>	2016
94.	Bowen Unit 2	Southern Company		USA	Steam Power Plant	Bituminous Coal	High Dust	330 m <sup>3</sup>	2016
95.	Scherer Unit 2	Southern Company		USA	Steam Power Plant	PRB/Sub-bituminous	High Dust	642 m <sup>3</sup>	2016
96.	Crist Unit 7	Southern Company		USA	Steam Power Plant	Bituminous Coal	High Dust	295 m <sup>3</sup>	2016
97.	FP1	Yara Taiwan	Mai-Liao Power Corporation	Taiwan	Steam Power Plant	Bituminous Coal	High Dust	133 m <sup>3</sup>	2016
98.	EWB Bern	Energie Wasser Bern		CH	Steam Power Plant	Municipal Waste	Low Dust	41 m <sup>3</sup>	2016
99.	HP5	Yara Taiwan	Formosa Petrochemical Corp.	TWN	Steam Power Plant	Bituminous Coal	High Dust	165 m <sup>3</sup>	2016
100.	HP1	Yara Taiwan	Formosa Petrochemical Corp.	TWN	Steam Power Plant	Bituminous Coal	High Dust	74 m <sup>3</sup>	2016

## Reference List

for plate catalyst projects as of July 2018

Curr.No.	Project	Client	End user / Engineering company	Plant location	Application	Fuel	Configuration	Shipped quantity	Delivery date
101.	Tianyi	JiangHe Mechanical		CHN	Steam Power Plant	Bituminous Coal	High Dust	368 m <sup>3</sup>	2016
102.	Hadong #8	KOSPO		KOR	Steam Power Plant	Bituminous Coal	High Dust	46 m <sup>3</sup>	2016
103.	KY1	Yara Taiwan		TWN	Steam Power Plant	Bituminous Coal	High Dust	21 m <sup>3</sup>	2016
104.	KY2 + KY3	Yara Taiwan		TWN	Steam Power Plant	Bituminous Coal	High Dust	42 m <sup>3</sup>	2016
105.	Nantong Fiber	Nantong Sanpu		CHN	Steam Power Plant	Bituminous Coal	High Dust	28 m <sup>3</sup>	2016
106.	Opole Unit 5 + 6	GE Boiler Deutschland	PGE Górnictwo i Energetyka Konwencjonalna S.A.	PL	Steam Power Plant	Bituminous Coal	High Dust	2064 m <sup>3</sup>	2016/2017
107.	Mill Creek Unit 3+4	LG&E / Kentucky Uti.	LG&E / Kentucky Uti.	USA	Steam Power Plant	Bituminous Coal	High Dust	566 m <sup>3</sup>	2016/2017
108.	Duyen Hai 3	Babcock & Wilcox		VIE	Steam Power Plant	Bituminous Coal	High Dust	675 m <sup>3</sup>	2017
109.	Four Corners Unit 4+5	Babcock Power Inc.		USA	Steam Power Plant	Bituminous Coal	High Dust	3171 m <sup>3</sup>	2017
110.	Sibley Unit 3	KCP&L		USA	Steam Power Plant	PRB/Sub-bituminous	High Dust	453 m <sup>3</sup>	2017
111.	Taiwan PJT	JGC C&C		TWN	Steam Power Plant	Bituminous Coal	High Dust	30 m <sup>3</sup>	2017
112.	Barry 5	Southern Company		USA	Steam Power Plant	Bituminous Coal	High Dust	400 m <sup>3</sup>	2017
113.	Gorgas Unit 10	Southern Company		USA	Steam Power Plant	Bituminous Coal	High Dust	413 m <sup>3</sup>	2017
114.	Polaniec Unit #7	Engie Energia Polska		PL	Steam Power Plant	Bituminous Coal	High Dust	256 m <sup>3</sup>	2017
115.	Scherer Unit 3	Southern Company		USA	Steam Power Plant	PRB/Sub-bituminous	High Dust	642 m <sup>3</sup>	2017
116.	TREA Breisgau	EEW Energy from Waste Saarbrücken GmbH		DE	Steam Power Plant	Municipal Waste	Low Dust	54 m <sup>3</sup>	2017
117.	Laziska Unit 10	Strabag	PKE S.A. Laziska Power Plant	PL	Steam Power Plant	Bituminous Coal	High Dust	51 m <sup>3</sup>	2017
118.	KCC GF #3 & #6	Haecheon		KOR	Glass trough	Natural Gas	Low Dust	16 m <sup>3</sup>	2017
119.	Bowen Unit 4	Southern Company	Southern Company	USA	Steam Power Plant	Bituminous Coal	High Dust	8 m <sup>3</sup>	2017
120.	Iatan Unit 1	KCP&L	KCP&L	USA	Steam Power Plant	PRB/Sub-bituminous	High Dust	493 m <sup>3</sup>	2017
121.	Nantong Fiber			CN	Steam Power Plant	Bituminous Coal	High Dust	33 m <sup>3</sup>	2017
122.	EWB Bern	Energie Wasser Bern	Energie Wasser Bern	CH	Steam Power Plant	Municipal Waste	Low Dust	14 m <sup>3</sup>	2017
123.	Kollenbach Platte	Yara	Yara	D	Cement Plant	Fossile Fuels + Additional Fuels	High Dust	3 m <sup>3</sup>	2017
124.	Sostanj	TES Termoelektrana Sostanj		SLO	Steam Power Plant	Lignite Coal	High Dust	292 m <sup>3</sup>	2017
125.	Ostroleka K1	Termokimik	Termokimik	PL	Steam Power Plant	Bituminous Coal	High Dust	228 m <sup>3</sup>	2018

## Reference List

for plate catalyst projects as of July 2018

Curr.No.	Project	Client	End user / Engineering company	Plant location	Application	Fuel	Configuration	Shipped quantity	Delivery date
126.	Ottumwa Unit 1	BPI/Alliant Energy	Alliant Energy	USA	Steam Power Plant	PRB/Sub-bituminous	High Dust	1246 m <sup>3</sup>	2018
127.	Crist Unit 7	Southern Company	Southern Company	USA	Steam Power Plant	Bituminous Coal	High Dust	590 m <sup>3</sup>	2018
128.	Kyger Creek Unit 1-5	AEP	AEP	USA	Steam Power Plant	PRB & Bituminous Coal	High Dust	630 m <sup>3</sup>	2018
129.	Sibley 3	KCP&L	KCP&L	USA	Steam Power Plant	PRB/Sub-bituminous	High Dust	38 m <sup>3</sup>	2018
130.	Bowen Unit 1	Southern Company	Georgia Power Company	USA	Steam Power Plant	Bituminous Coal	High Dust	727 m <sup>3</sup>	2018
131.	Laziska Unit 9	Strabag	PKE S.A. Laziska Power Plant	PL	Steam Power Plant	Bituminous Coal	High Dust	46 m <sup>3</sup>	2018
132.	TREA Breisgau	EEW Energy from Waste Saarbrücken GmbH		DEU	Steam Power Plant	Municipal Waste	Low Dust	34 m <sup>3</sup>	2015
133.	KCC GF #3	Hae Cheon Industrial Co. Ltd		KOR	Glass Trough	Natural Gas	Low Dust	11 m <sup>3</sup>	2018
134.	Uvelia Herstal	Laborelec		BE	Steam Power Plant	Municipal Waste	Low Dust	53 m <sup>3</sup>	2018
135.	Han Glass	Hacheon Industry		KOR	Glass Trough	Natural Gas	Low Dust	21 m <sup>3</sup>	2018
136.	Gheco One	Laborelec		THA	Steam Power Plant	Bituminous Coal	High Dust	307 m <sup>3</sup>	2018
137.	Nantong Fiber	Nantong Sanpu		CHN	Steam Power Plant	Bituminous Coal	High Dust	38 m <sup>3</sup>	2018
138.	Boswell Unit 3	Minnesota Power	Boswell Energy Center	USA	Steam Power Plant	PRB/Sub-bituminous	High Dust	169 m <sup>3</sup>	2018
139.	Hitachinaka	TEPCO		JPN	Steam Power Plant	Bituminous Coal	High Dust	833 m <sup>3</sup>	2018
140.	Parish Unit 7	NRG		USA	Steam Power Plant	PRB/Sub-bituminous	High Dust	455 m <sup>3</sup>	2019
141.	Parish Unit 5	NRG		USA	Steam Power Plant	PRB/Sub-bituminous	High Dust	769 m <sup>3</sup>	2019
142.	Opole Unit 5	GE Boiler Deutschland	PGE Górnictwo i Energetyka Konwencyjna S.A.	PL	Steam Power Plant	Bituminous Coal	High Dust	258 m <sup>3</sup>	2019
<b>Total</b>								<b>40321 m<sup>3</sup></b>	

Curr.No.	Project	Client	End user / Engineering company	Plant location	Application	Shipped quantity	Delivery date
1.	FHKW Mellach	SGP	STEWEAG	AUT	Bituminous Coal, High Dust	287 m <sup>3</sup>	1986
2.	Altbach	Steinmüller	EnBW	DEU	Coal / Oil	132 m <sup>3</sup>	1987 / 88
3.	Wedel I/II	Steinmüller	HEW	DEU	Coal, High Dust	370 m <sup>3</sup>	1987
4.	FHKW Mellach 4. Lage	SGP	STEWEAG	AUT	Bituminous Coal, High Dust	94 m <sup>3</sup>	1988
5.	Karlsruhe	DBA	EnBW	DEU	Coal, Tail End	60 m <sup>3</sup>	1988
6.	Bexbach	EVT	SaarEnergie	DEU	Coal, High Dust	858 m <sup>3</sup>	1988
7.	Herne 1, 2, 3	KWH	STEAG	DEU	Coal, Tail End	501 m <sup>3</sup>	1989
8.	Voerde West I/II	KWH	STEAG	DEU	Coal, Tail End	535 m <sup>3</sup>	1989
9.	Lünen 11	KWH	STEAG	DEU	Coal, Tail End	243 m <sup>3</sup>	1989
10.	Lünen 10	KWH	STEAG	DEU	Coal, Tail End	94 m <sup>3</sup>	1989
11.	Weiher 3	Steinmüller	SaarEnergie	DEU	Coal, High Dust	617 m <sup>3</sup>	1990
12.	BHKW Voitsberg 3	SGP	Österr. Draukraftwerke	AUT	Brown Coal, High Dust	405 m <sup>3</sup>	1990
13.	STEAG Repl., 1 layer	STEAG	STEAG	DEU	Coal, Tail End	46 m <sup>3</sup>	1991
14.	Tiefstack	Steinmüller		DEU	Coal	212 m <sup>3</sup>	1992
15.	Bexbach	Saarbergwerke AG		DEU	Coal, High Dust	286 m <sup>3</sup>	1992
16.	BHKW Voitsberg 3	SGP	Österr. Draukraftwerke	AUT	Brown Coal, High Dust, Additional Delivery	60 m <sup>3</sup>	1992
17.	RDK7	BASF	EnBW	DEU	Coal, High Dust	182 m <sup>3</sup>	1993
18.	Fiume Santo	IDRECO	ENEL	ITA	Coal / Oil	602 m <sup>3</sup>	1994 / 96
19.	Bremen Block 5	BASF	Stadtwerke Bremen	DEU	Coal, High Dust	46 m <sup>3</sup>	1994
20.	Mannheim	BASF	GKW Mannheim	DEU	Coal, High Dust	168 m <sup>3</sup>	1994
21.	Lünen 11	BASF	STEAG	DEU	Coal, Tail End	80 m <sup>3</sup>	1994
22.	Ibbenbüren	BASF	Preussag / RWE	DEU	Coal, Tail End	143 m <sup>3</sup>	1994
23.	SW Bremen Block 6	BASF	Stadtwerke Bremen	DEU	Coal	124 m <sup>3</sup>	1995
24.	Tiefstack	BASF		DEU	Coal	86 m <sup>3</sup>	1995
25.	FHKW Mellach	AEE	STEWEAG	AUT	Bituminous Coal, High Dust, Additional Delivery	95 m <sup>3</sup>	1995
26.	RDK7	BASF	EnBW	DEU	Coal, Additional Delivery	182 m <sup>3</sup>	1995
27.	Vado Ligure	Termokimik	ENEL	ITA	Coal, High Dust	560 m <sup>3</sup>	1997 / 98
28.	SW Bremen KW Hafen 5	BASF	Stadtwerke Bremen	DEU	Coal, Additional Delivery	59 m <sup>3</sup>	1997



Curr.No.	Project	Client	End user / Engineering company	Plant location	Application	Shipped quantity	Delivery date
29.	SW Bremen KW Hafen 6	BASF	Stadtwerke Bremen	DEU	Coal, Additional Delivery	125 m <sup>3</sup>	1997
30.	SW Bremen HKW Hastedt	BASF	Stadtwerke Bremen	DEU	Coal, Additional Delivery	47 m <sup>3</sup>	1997
31.	SW Bremen KW Hafen 6	BASF	Stadtwerke Bremen	DEU	Coal, Additional Delivery	60 m <sup>3</sup>	1997
32.	SW Bremen	BASF	Stadtwerke Bremen	DEU	Coal	37 m <sup>3</sup>	1998
33.	GKM Mannheim Block 7	BASF	GKW Mannheim	DEU	Coal, Additional Delivery	168 m <sup>3</sup>	1998
34.	GKM Mannheim Block 8	BASF	GKW Mannheim	DEU	Coal, Additional Delivery	195 m <sup>3</sup>	1998
35.	Sulcis 3	ENEL	ENEL	ITA	Coal / Oil, Tail End	127 m <sup>3</sup>	1999
36.	SW Bremen HKW Hastedt	BASF	Stadtwerke Bremen	DEU	Coal, High Dust, Additional Delivery	48 m <sup>3</sup>	1999
37.	La Spezia	ENEL	ENEL	ITA	Coal, High Dust	525 m <sup>3</sup>	2000
38.	Homer City Unit 1, 2, 3	BASF	ABB	USA	Coal, High Dust	1913 m <sup>3</sup>	2000
39.	Stuart Unit 1, 2, 3, 4	Black & Veatch	Dayton Power & Light	USA	Coal, High Dust	2792 m <sup>3</sup>	2001/2/3
40.	KW Bexbach	BASF	Saarenergie	DEU	Coal, High Dust, Additional Delivery	6 m <sup>3</sup>	2001
41.	KW Weiher 3	BASF	Saarenergie	DEU	Coal, High Dust, Additional Delivery	369 m <sup>3</sup>	2001
42.	RDK 7	BASF	EnBW	DEU	Coal, High Dust, Additional Delivery	198 m <sup>3</sup>	2001
43.	Vado Ligure	ENEL	Tirreno Power	ITA	Coal, High Dust, Additional Delivery	87 m <sup>3</sup>	2001
44.	Dallman Station Unit 31, 32, 33	Black & Veatch	City of Springfield	USA	Bituminous Coal, High Dust	498 m <sup>3</sup>	2002/3
45.	Coffeen Unit 2	HRC	Ameren Energy / Sargent & Lundy	USA	Coal, High Dust	711 m <sup>3</sup>	2002
46.	Killen	Black & Veatch	Dayton Power & Light	USA	Coal, Low Dust	326 m <sup>3</sup>	2002
47.	Michigan City Unit 12	Black & Veatch	NIPSCO	USA	Coal, High Dust	583 m <sup>3</sup>	2002
48.	KW Weiher 3	BASF	Saarenergie	DEU	Coal, High Dust, Additional Delivery	369 m <sup>3</sup>	2002
49.	HKW 1 Kraftwerk Altbach	BASF	Neckarwerke	DEU	Coal, High Dust, Additional Delivery	132 m <sup>3</sup>	2002
50.	Homer City	BASF	Midwest Generation / ALSTOM POWER	USA	Coal, High Dust, Additional Delivery	196 m <sup>3</sup>	2002
51.	Vado Ligure	Interpower	Interpower	ITA	Coal, High Dust, Additional Delivery	88 m <sup>3</sup>	2002
52.	Coffeen Unit 1	HRC	Ameren Energy / Sargent & Lundy	USA	Coal, High Dust	438 m <sup>3</sup>	2003
53.	Culley Unit 3	Black & Veatch	Sigeco	USA	Coal, High Dust	304 m <sup>3</sup>	2003
54.	Schahfer Unit 14	Black & Veatch	NIPSCO	USA	Coal, High Dust	583 m <sup>3</sup>	2003
55.	Edwards Station Unit 3	LLNA	AES / Cilco	USA	Coal, High Dust	434 m <sup>3</sup>	2003
56.	Bailly 8	Black & Veatch	NIPSCO	USA	Coal, High Dust	531 m <sup>3</sup>	2003

Curr.No.	Project	Client	End user / Engineering company	Plant location	Application	Shipped quantity	Delivery date
57.	Duck Creek Unit 1	LLNA	AES / Cilco	USA	Coal, High Dust	555 m <sup>3</sup>	2003
58.	Cheswick Station # 1	Babcock & Wilcox	Orion Power Midwest	USA	Coal, High Dust	861 m <sup>3</sup>	2003
59.	Coffeen Unit 1	HRC	Ameren Energy / Sargent & Lundy	USA	Coal, High Dust, Additional Delivery	219 m <sup>3</sup>	2003
60.	HKW Wedel I	BASF	HEW	DEU	Coal, High Dust, Additional Delivery	59 m <sup>3</sup>	2003
61.	FUSINA	ENEL	ENEL	ITA	Coal, High Dust	104 m <sup>3</sup>	2003
62.	Vado Ligure		Interpower	ITA	Coal, High Dust, Additional Delivery	11 m <sup>3</sup>	2003
63.	HKW Wedel I, 2nd layer	BASF	HEW	DEU	Coal, High Dust, Additional Delivery	60 m <sup>3</sup>	2004
64.	Brindisi Nord Unit 3 & 4	Termokimik	Edipower	ITA	Coal, High Dust	660 m <sup>3</sup>	2004
65.	Warrick Unit 4	Black & Veatch	Sigeco	USA	Coal, High Dust	354 m <sup>3</sup>	2004
66.	Brown Unit 1, 2	Black & Veatch	Sigeco	USA	Coal, High Dust	708 m <sup>3</sup>	2004
67.	KW Bexbach	BASF	Saarenergie	DEU	Coal, High Dust, Additional Delivery	286 m <sup>3</sup>	2004
68.	Voerde Block A	BASF	STEAG	DEU	Coal, High Dust, Additional Delivery	350 m <sup>3</sup>	2004
69.	Scholven E	BASF	E.ON	DEU	Coal, High Dust, Additional Delivery	193 m <sup>3</sup>	2004
70.	Homer City Unit 3	Midwest Generation	Midwest Generation / ALSTOM POWER	USA	Coal, High Dust, Additional Delivery	246 m <sup>3</sup>	2004
71.	Samcheonpo TPP # 3 & 4	Halla	KOSEP	KOR	Coal, High Dust	904 m <sup>3</sup>	2004
72.	Vado Ligure		Interpower	ITA	Coal, High Dust, Additional Delivery	22 m <sup>3</sup>	2004
73.	Scholven B	BASF	E.ON	DEU	Coal, High Dust, Additional Delivery	193 m <sup>3</sup>	2004
74.	Voerde Block B	BASF	STEAG	DEU	Coal, High Dust, Additional Delivery	350 m <sup>3</sup>	2004
75.	Brown Unit 1	Black & Veatch	Sigeco	USA	Coal, High Dust, Additional Delivery	152 m <sup>3</sup>	2005
76.	Warrick Unit 4	Black & Veatch	Sigeco	USA	Coal, High Dust, Additional Delivery	177 m <sup>3</sup>	2005
77.	Stuart Unit 4	Dayton Power & Light	Dayton Power & Light	USA	Coal, High Dust, Additional Delivery	473 m <sup>3</sup>	2005
78.	Scholven C	BASF	E.ON	DEU	Coal, High Dust, Additional Delivery	193 m <sup>3</sup>	2005
79.	Edwards Station Unit 3	Ameren Energy	Ameren Energy	USA	Coal, High Dust, Additional Delivery	203 m <sup>3</sup>	2005
80.	Coffeen Unit 1	Ameren Energy	Ameren Energy	USA	Coal, High Dust, Additional Delivery	219 m <sup>3</sup>	2005
81.	Scholven D	BASF	E.ON	DEU	Coal, High Dust, Additional Delivery	193 m <sup>3</sup>	2005
82.	FHKW Mellach	VERBUND	VERBUND	AUT	Coal, High Dust, Additional Delivery	94 m <sup>3</sup>	2005
83.	Vado Ligure	Tirreno Power	Tirreno Power	ITA	Coal, High Dust, Additional Delivery	87 m <sup>3</sup>	2005
84.	GKK Kiel	BASF	E.ON	DEU	Coal, High Dust	185 m <sup>3</sup>	2005

Curr.No.	Project	Client	End user / Engineering company	Plant location	Application	Shipped quantity	Delivery date
85.	Scholven C	BASF	E.ON	DEU	Coal, High Dust, Additional Delivery	193 m <sup>3</sup>	2005
86.	La Spezia 3&4	ENEL Produzione	ENEL	ITA	Coal, High Dust, Additional Delivery	179 m <sup>3</sup>	2005
87.	Duck Creek Unit 1	Ameren Energy	Ameren Energy	USA	Coal, High Dust, Additional Delivery	203 m <sup>3</sup>	2005
88.	Yonghung Unit 4	HHI	KOSEP	KOR	Coal, High Dust	369 m <sup>3</sup>	2005
89.	HKW Heilbronn, Block 7	BASF	EnBW	DEU	Coal, High Dust	141 m <sup>3</sup>	2005
90.	KW Münster, K25	BASF	EnBW	DEU	Coal, High Dust	38 m <sup>3</sup>	2005
91.	Ruilen Unit 3, 4, 5	Termokimik	Electrabel / Tractebel	BEL	Coal, High Dust	642 m <sup>3</sup>	2006/07/08
92.	Fusina 1&2	Termokimik	Enelpower SpA	ITA	Coal, High Dust	320 m <sup>3</sup>	2006
93.	A.B. Brown Unit 2	VECTREN	VECTREN	USA	Coal, High Dust, Additional Delivery	152 m <sup>3</sup>	2006
94.	Vado Ligure	Tirreno Power	Tirreno Power	ITA	Coal, High Dust, Additional Delivery	174 m <sup>3</sup>	2006
95.	Wushashan Unit 4	Tsinghua Tongfang Ltd.	Datang International Co.	CHN	Coal, High Dust	308 m <sup>3</sup>	2006
96.	Voerde Block B	BASF	STEAG	DEU	Coal, High Dust, Additional Delivery	350 m <sup>3</sup>	2006
97.	Dallman Unit 31	City of Springfield	City of Springfield	USA	Coal, High Dust Replacement	47 m <sup>3</sup>	2007
98.	Michigan City Unit 12	NIPSCO	NIPSCO	USA	Coal, High Dust, Additional Delivery	278 m <sup>3</sup>	2007
99.	Thomas Hill Unit 3	Associated Electric Coop.	Associated Electric Coop.	USA	Coal, High Dust	802 m <sup>3</sup>	2007
100.	Coffeen Unit 2	Ameren Energy	Ameren Energy	USA	Coal, High Dust, Additional Delivery	357 m <sup>3</sup>	2007
101.	Duck Creek Unit 1	Ameren Energy	Ameren Energy	USA	Coal, High Dust Replacement	202 m <sup>3</sup>	2007
102.	Fusina	ENEL	ENEL	ITA	Coal, High Dust Replacement	104 m <sup>3</sup>	2007
103.	Gaobeidian 1+4	Tongfang	Huaneng Beijing	CHN	Coal, High Dust	461 m <sup>3</sup>	2007
104.	Edwards Unit 3	Ameren Energy	Ameren Energy	USA	Coal, High Dust, Additional Delivery	203 m <sup>3</sup>	2007
105.	Schahfer Unit 14	NIPSCO	NIPSCO	USA	Coal, High Dust, Additional Delivery	278 m <sup>3</sup>	2007
106.	Vado Ligure	Tirreno Power	Tirreno Power	ITA	Coal, High Dust, Additional Delivery	340 m <sup>3</sup>	2008/2009
107.	SJRPP Unit 1+2	JEA	JEA	USA	Coal, High Dust	1540 m <sup>3</sup>	2008/2009
108.	Dallman Unit 4	Foster Wheeler	City of Springfield	USA	Coal, High Dust, Additional Delivery	198 m <sup>3</sup>	2008
109.	Thomas Hill Unit 1-2	Associated Electric Coop.	Associated Electric Coop.	USA	Coal, High Dust	656 m <sup>3</sup>	2008
110.	Coffeen Unit 1	Ameren Energy	Ameren Energy	USA	Coal, High Dust, Additional Delivery	450 m <sup>3</sup>	2008
111.	Mannheim Block 8	BASF	GKM Mannheim	DEU	Coal, High Dust Additional Delivery	195 m <sup>3</sup>	2008
112.	Coffeen Unit 2	Ameren Energy	Ameren Energy	USA	Coal, High Dust, Additional Delivery	366 m <sup>3</sup>	2008

Curr.No.	Project	Client	End user / Engineering company	Plant location	Application	Shipped quantity	Delivery date
113.	Duck Creek Unit 1	Ameren Energy	Ameren Energy	USA	Coal, High Dust, Additional Delivery	405 m <sup>3</sup>	2008
114.	Fusina 3+4	ENEL	ENEL	ITA	Coal, High Dust, Additional Delivery	52 m <sup>3</sup>	2008
115.	Springfield Missouri Unit 1	Babcock & Wilcox	CUSMO	USA	Coal, High Dust	236 m <sup>3</sup>	2008
116.	Bailly Unit 7	NIPSCO	NIPSCO	USA	Coal, High Dust	304 m <sup>3</sup>	2008
117.	Sibley Unit 3	Babcock Power	Aquilla	USA	Coal, High Dust, Additional Delivery	405 m <sup>3</sup>	2008
118.	Killen Unit 2	Dayton Power & Light	Dayton Power & Light	USA	Coal, Low Dust, Additional Delivery	164 m <sup>3</sup>	2008
119.	KW Bergkamen Block A	BASF	Evonic	DEU	Coal, High Dust, Additional Delivery	262 m <sup>3</sup>	2008
120.	Mannheim Block 7	BASF	GKM Mannheim	DEU	Coal, High Dust, Additional Delivery	195 m <sup>3</sup>	2008
121.	Michigan 12	NIPSCO	NIPSCO	USA	Coal High Dust Additional Delivery	236 m <sup>3</sup>	2008
122.	Bailly 8	NIPSCO	NIPSCO	USA	Coal High Dust Additional Delivery	178 m <sup>3</sup>	2008
123.	Tiefstack	BASF		DEU	Coal, Hight Dust, Additional Delivery	53 m <sup>3</sup>	2008
124.	Coffeen Unit 2	Ameren Energy	Ameren Energy	USA	Coal, High Dust, Additional Delivery	366 m <sup>3</sup>	2009
125.	SJRPP Spare Layer 1	JEA	JEA	USA	Coal, High Dust, Additional Delivery	257 m <sup>3</sup>	2009
126.	Crystal River Unit 5	Babcock & Wilcox	Progress Energy	USA	Coal, High Dust	759 m <sup>3</sup>	2009
127.	SJRPP Additional Layer 2	JEA	JEA	USA	Coal, High Dust	257 m <sup>3</sup>	2009
128.	Ameren Spare Layer	Ameren Energy	Ameren Energy	USA	Coal, High Dust, Additional Delivery	366 m <sup>3</sup>	2009
129.	Amos Unit 2	AEP	AEP	USA	Coal, High Dust	34 m <sup>3</sup>	2009
130.	Nanticoke Unit 7 + 8	OPG	OPG	CAN	Coal, High Dust	410 m <sup>3</sup>	2009
131.	Fusina 3+4	ENEL	ENEL	ITA	Coal, High Dust, Additional Delivery	52 m <sup>3</sup>	2009
132.	Scholven	BASF	E.ON	DEU	Coal, High Dust, Additional Delivery	193 m <sup>3</sup>	2009
133.	Mannheim Block 6	BASF	GKM Mannheim	DEU	Coal, High Dust, Additional Delivery	120 m <sup>3</sup>	2009
134.	KP-R Project	JGC C&C	IHI	JPN	Coal, High Dust	182 m <sup>3</sup>	2009
135.	Stuart	Dayton Power & Light	Dayton Power & Light	USA	Coal, High Dust, Additional Delivery	540 m <sup>3</sup>	2009
136.	Bruce Mansfield	First Energy	First Energy	USA	Coal, High Dust	704 m <sup>3</sup>	2009
137.	Big Sandy 2	AEP	AEP	USA	Coal, High Dust	38 m <sup>3</sup>	2009
138.	Shidongkou Unit 1+2	Huaneng	Huaneng	CHN	Coal, High Dust	880 m <sup>3</sup>	2009
139.	Vado Ligure	Tirreno Power	Tirreno Power	ITA	Coal, High Dust, Additional Delivery	113 m <sup>3</sup>	2009
140.	Wygen 3 - Unit 5	Babcock & Wilcox	Babcock & Wilcox	USA	Coal, High Dust	152 m <sup>3</sup>	2009

Curr.No.	Project	Client	End user / Engineering company	Plant location	Application	Shipped quantity	Delivery date
141.	Yingkou Unit 1+2	Huaneng	Huaneng / Harbin Boiler	CHN	Coal, High Dust	631 m <sup>3</sup>	2009
142.	Yuhuan Unit 4	Huaneng	Huaneng / Harbin Boiler	CHN	Coal, High Dust	818 m <sup>3</sup>	2009
143.	Jinling Unit 1+2	Huaneng	Huaneng / Harbin Boiler	CHN	Coal, High Dust	1300 m <sup>3</sup>	2009
144.	Pingliang Unit 1+2	Huaneng	Huaneng / Harbin Boiler	CHN	Coal, High Dust	710 m <sup>3</sup>	2009
145.	Fuzhou Phase 3 - Unit 1+2	Huaneng	Huaneng	CHN	Coal, High Dust	860 m <sup>3</sup>	2009
146.	Fuzhou Phase 1+2 - Unit 1	Huaneng	Huaneng / Tongfang	CHN	Coal, High Dust	264 m <sup>3</sup>	2009
147.	Brindisi Sud	ENEL	ENEL	ITA	Coal, High Dust	531 m <sup>3</sup>	2009
148.	Shinta PS3	Envirgy Taiwan		TWN	Coal, High Dust	48 m <sup>3</sup>	2009
149.	GHECO - One	Doosan		THA	Coal, High Dust	454 m <sup>3</sup>	2010
150.	Yuhuan Unit 1, 2 + 3	Huaneng	Huaneng Beijing	CHN	Coal, High Dust	2453 m <sup>3</sup>	2010
151.	Dallman Station Unit 33	Black & Veatch	City of Springfield	USA	Bituminous Coal, High Dust, Additional Delivery	86 m <sup>3</sup>	2010
152.	Sines Power Plant Unit 1-4	Alstom	EDP	PRT	Coal, High Dust, Wood pellets, High Temp.	1460 m <sup>3</sup>	2010
153.	CUSMO Springfield Unit 2	Foster Wheeler	CUSMO	USA	Coal, High Dust	304 m <sup>3</sup>	2010
154.	Crystal River Unit 4	Babcock & Wilcox	Progress Energy	USA	Coal, High Dust	759 m <sup>3</sup>	2010
155.	Fuzhou Phase I+II Unit 2, 3, 4	Huaneng	Huaneng	CHN	Coal, High Dust	793 m <sup>3</sup>	2010
156.	Haimen Unit 3	Huaneng		CHN	Coal High Dust	649 m <sup>3</sup>	2010
157.	Yueyang Unit #5 + Unit #6	Huaneng		CHN	Coal High Dust	1002 m <sup>3</sup>	2010
158.	Lamamora Brescia	Termokimik	A2A	ITA	Coal High Dust	78 m <sup>3</sup>	2010
159.	Fusina 3+4	ENEL	ENEL	ITA	Coal, High Dust, Additional Delivery	46 m <sup>3</sup>	2010
160.	Roxboro Unit 4	Progress Energy	Progress Energy	USA	Coal Low Dust	396 m <sup>3</sup>	2010
161.	Vado Ligure	Tirreno Power	Tirreno Power	ITA	Coal, High Dust, Additional Delivery	114 m <sup>3</sup>	2010
162.	Ciuden	Integral	Ciuden Ciudad de la Energia	ESP	Coal High Dust	16 m <sup>3</sup>	2010
163.	King Plant	Xcel Energy Service	Xcel Energy Service	USA	Coal High Dust	302 m <sup>3</sup>	2011
164.	Yeosu Cogeneration	Hyundai	HDEC	KOR	Coal High Dust, CFBC-Boiler	160 m <sup>3</sup>	2011
165.	Sibley Unit 3	KCP&L	KCP&L	USA	Coal High Dust Additional Delivery	203 m <sup>3</sup>	2011
166.	Bailly Unit 3	Black & Veatch	NIPSCO	USA	Coal, High Dust	178 m <sup>3</sup>	2011
167.	Brindisi Sud	ENEL	ENEL	ITA	Coal, High Dust	531 m <sup>3</sup>	2011
168.	Schahfer Unit 14	NIPSCO	NIPSCO	USA	Coal, High Dust, Additional Delivery	236 m <sup>3</sup>	2011

Curr.No.	Project	Client	End user / Engineering company	Plant location	Application	Shipped quantity	Delivery date
169.	Roxboro Unit 2	Progress Energy	Progress Energy	USA	Coal High Dust	371 m <sup>3</sup>	2011
170.	Mayo Unit 1	Progress Energy	Progress Energy	USA	Coal Low Dust	385 m <sup>3</sup>	2011
171.	La Cygne Unit 1	KCP&L	KCP&L	USA	Coal High Dust	422 m <sup>3</sup>	2011
172.	Nebraska City Unit 2	OPPD	OPPD	USA	Coal, High Dust	260 m <sup>3</sup>	2011
173.	Thomas Hill Unit 2	AECI	AECI	USA	Coal, High Dust, Additional Delivery	148 m <sup>3</sup>	2011
174.	Dallman Unit 33	CWLP	CWLP	USA	Coal, High Dust, Additional Delivery	104 m <sup>3</sup>	2011
175.	Bailly Unit 7	NIPSCO	NIPSCO	USA	Coal, High Dust Additional Delivery	108 m <sup>3</sup>	2011
176.	La Cygne Unit 1	KCP&L	KCP&L	USA	Coal, High Dust, Additional Delivery	474 m <sup>3</sup>	2011
177.	Asheville Unit 1 - Layer 1&2	Progress Energy	Progress Energy	USA	Coal, High Dust	293 m <sup>3</sup>	2011
178.	Cardinal Unit 3 - part 1	AEP	AEP	USA	Coal, High Dust	298 m <sup>3</sup>	2011
179.	CUSMO Unit 1	Cusmo	Cusmo	USA	Coal, High Dust, Additional Delivery	119 m <sup>3</sup>	2011
180.	Michigan City Unit 12	NIPSCO	NIPSCO	USA	Coal, High Dust, Additional Delivery	236 m <sup>3</sup>	2011
181.	KW Bergkamen - Bock A	BASF	STEAG	DEU	Coal, High Dust, Additional Delivery	262 m <sup>3</sup>	2011
182.	HKW Wedel - Block 2	BASF	Vattenfall	DEU	Coal, High Dust, Additional Delivery	53 m <sup>3</sup>	2011
183.	Asheville Unit 2 - Layer 2	Progress Energy	Progress Energy	USA	Coal, High Dust	106 m <sup>3</sup>	2011
184.	Cardinal Unit 3	AEP	AEP	USA	Coal, Low Dust	424 m <sup>3</sup>	2011/2013
185.	Westfalen Block D+E	BASF	RWE	DEU	Coal High Dust	1960 m <sup>3</sup>	2012
186.	Edgewater Unit 5	Babcock Power		USA	Coal High Dust	708 m <sup>3</sup>	2012
187.	Brown Unit 3	Babcock Power		USA	Coal High Dust	607 m <sup>3</sup>	2012
188.	Bailly Unit 8 - Repl. 2012	NIPSCO	NIPSCO	USA	Coal, High Dust Additional Delivery	178 m <sup>3</sup>	2012
189.	Bailly Unit 7 - Repl. 2012	NIPSCO	NIPSCO	USA	Coal, High Dust Additional Delivery	6 m <sup>3</sup>	2012
190.	Dallman Unit 33	CWLP	CWLP	USA	Coal, High Dust Additional Delivery	78 m <sup>3</sup>	2012
191.	Brindisi Sud Unit 4	Termokimik	ENEL	ITA	Coal, High Dust	956 m <sup>3</sup>	2012
192.	King Plant	Xcel Energy " Utility Repl"	Xcel Energy " Utility Repl"	USA	Coal, High Dust Additional Delivery	301 m <sup>3</sup>	2012
193.	Roxboro Unit 1	Progress Energy	Progress Energy	USA	Coal, High Dust	209 m <sup>3</sup>	2012
194.	Schahfer Unit 14	NIPSCO	NIPSCO	USA	Coal, High Dust, Additional Delivery	236 m <sup>3</sup>	2012
195.	Brindisi Sud	ENEL	ENEL	ITA	Coal, High Dust	319 m <sup>3</sup>	2012
196.	Crystal River Unit 5	Babcock & Wilcox	Progress Energy	USA	Coal, High Dust, Additional Delivery	379 m <sup>3</sup>	2012

Curr.No.	Project	Client	End user / Engineering company	Plant location	Application	Shipped quantity	Delivery date
197.	Dallman Unit 4	City of Springfield	City of Springfield	USA	Bituminous Coal, High Dust, Additional Delivery	103 m <sup>3</sup>	2012
198.	HKW Wedel - Block 1	BASF	Vattenfall	DEU	Coal, High Dust, Additional Delivery	54 m <sup>3</sup>	2012
199.	Pingliang Unit 1+2 Spare Layer	Huaneng	Huaneng Pingliang	CHN	Coal High Dust, Additional Delivery	452 m <sup>3</sup>	2012
200.	Eemshaven Block A+B	BASF	RWE	DEU	Coal High Dust	1960 m <sup>3</sup>	2012/2013
201.	Project KR	JGC C&C	IHI	JPN	Coal fired Boiler	273 m <sup>3</sup>	2013
202.	Roxboro Unit 3	Progress Energy	Progress Energy	USA	Coal, High Dust, Additional Delivery	371 m <sup>3</sup>	2013
203.	Michigan City Unit 12	NIPSCO	NIPSCO	USA	Coal, High Dust, Additional Delivery	236 m <sup>3</sup>	2013
204.	Crystal River Unit 4	Progress Energy		USA	Coal High Dust, Additional Delivery	379 m <sup>3</sup>	2013
205.	Sibley Unit 3	KCP&L	KCP&L	USA	Coal High Dust Additional Delivery	202 m <sup>3</sup>	2013
206.	Iatan Unit 1	KCP&L	KCP&L	USA	Coal High Dust	465 m <sup>3</sup>	2013
207.	GKM Block 9	BASF	Alstom / GKM Mannheim	DEU	Coal, High Dust	619 m <sup>3</sup>	2013
208.	Nebraska City Unit 2	OPPD	OPPD	USA	Coal, High Dust, Additional Delivery	584 m <sup>3</sup>	2013
209.	Asheville Unit 1	Progress Energy	Progress Energy	USA	Coal, High Dust, Additional Delivery	93 m <sup>3</sup>	2013
210.	Shidongkou Spare Layer #1+2	Huaneng	Huaneng	CHN	Coal, High Dust, Additional Delivery	438 m <sup>3</sup>	2013
211.	Bailly Unit 7 + Unit 8	NIPSCO	NIPSCO	USA	Coal High Dust Additional Delivery	279 m <sup>3</sup>	2013
212.	Schahfer Unit 14	NIPSCO	NIPSCO	USA	Coal, High Dust, Additional Delivery	236 m <sup>3</sup>	2013
213.	Nantong Fiber TPP #10&11	Jiangsu Kehang		CHN	Coal High Dust, SNCR & SCR Hybrid	51 m <sup>3</sup>	2013
214.	Qinbei 1st and 2nd batch	Huaneng	Huaneng	CHN	Coal fired Boiler	549 m <sup>3</sup>	2013
215.	Shidongkou Phase 1 Unit #3	Huaneng	Huaneng	CHN	Coal fired Boiler	296 m <sup>3</sup>	2013
216.	Shidongkou Phase 1 Unit 4	Huaneng	Huaneng	CHN	Coal High Dust	296 m <sup>3</sup>	2013
217.	Dummy Eemshaven Block A+B	BASF	RWE / Alstom	DEU	Coal High Dust	163 m <sup>3</sup>	2013
218.	Mannheim Block 7	BASF	GKM Mannheim	DEU	Coal High Dust	21 m <sup>3</sup>	2013
219.	Yudong #1 + #2	Beijing Longdian	Huadian	CHN	Coal High Dust	572 m <sup>3</sup>	2013
220.	Pingliang Phase 1 Unit #1 + #2	Huaneng	Huaneng	CHN	Coal High Dust	525 m <sup>3</sup>	2013
221.	Gheco One Spare	Doosan	Gheco One Co. Ltd.	THA	Coal High Dust, Additional Delivery	114 m <sup>3</sup>	2013
222.	Sichuan Vinylon #1 + #2	Beijing Bozhi Weide Env. Tech. Co. Ltd.		CHN	Coal fired Boiler	405 m <sup>3</sup>	2013
223.	Yingkou Phase 1 Unit 1+2	Huaneng	Huaneng	CHN	Coal High Dust	569 m <sup>3</sup>	2013
224.	Gaobeidian Spare Layer	Huaneng	Huaneng	CHN	Coal High Dust	77 m <sup>3</sup>	2013

Curr.No.	Project	Client	End user / Engineering company	Plant location	Application	Shipped quantity	Delivery date
225.	Eerduosi Unit 4	Dongfang Boiler Group		CHN	Coal High Dust	359 m <sup>3</sup>	2013
226.	Tiefstack NR	Vattenfall	Vattenfall	DEU	Coal High Dust	35 m <sup>3</sup>	2013
227.	JTEC Unit 2 3rd Layer Addition	Cusmo		USA	Coal High Dust	152 m <sup>3</sup>	2014
228.	Springs	BASF		DEU	Coal High Dust	21 m <sup>3</sup>	2014
229.	La Spezia	ENEL	ENEL	ITA	Coal High Dust, Additional Delivery	163 m <sup>3</sup>	2014
230.	Dummy Module Sostanj Unit 6	Alstom		SVN	Brown Coal, High Dust	111 m <sup>3</sup>	2014
231.	Fusina L1	ENEL	ENEL	ITA	Coal High Dust	91 m <sup>3</sup>	2014
232.	Cardinal Unit 3	AEP	AEP	USA	Coal High Dust, Additional Delivery	287 m <sup>3</sup>	2014
233.	Mannheim Block 7	BASF	GKM Mannheim	DEU	Coal, Additional Delivery	63 m <sup>3</sup>	2014
234.	Dallmann U 31,32,33	City of Springfield	City of Springfield	USA	Coal High Dust, Additional Delivery	203 m <sup>3</sup>	2014
235.	Pingliang Phase 1 Unit #3 + #4	Huaneng	Huaneng	CHN	Coal fired Boiler	523 m <sup>3</sup>	2014
236.	King Plant	Xcel Energy	Xcel Energy	USA	Coal High Dust, Additional Delivery	301 m <sup>3</sup>	2014
237.	Stanton Unit 1	Black & Veatch	Orlando Utilities Commission	USA	Coal, High Dust	586 m <sup>3</sup>	2014
238.	Teko 4N	Effeleon		SVK	Coal High Dust	43 m <sup>3</sup>	2014
239.	Guacolda Unit 1	ANDRITZ Energy & Environment	Empresa Guacolda Energia	CHL	Coal High Dust	207 m <sup>3</sup>	2014
240.	Yichang #1&2	Beijing Bozhi Weide Environment	Sinopec	CHN	Coal High Dust	172 m <sup>3</sup>	2014
241.	Yichang #3	Beijing Bozhi Weide Environment	Sinopec	CHN	Coal High Dust	85 m <sup>3</sup>	2014
242.	Voerde Block A&B	STEAG Aktiengesellschaft	STEAG Aktiengesellschaft	DEU	Coal High Dust, Additional Delivery	700 m <sup>3</sup>	2014
243.	Shidongkou #2 Partial Repl.	Huaneng Shanghai Shidongkou	Huaneng Shanghai Shidongkou	CHN	Coal fired Boiler Additional Delivery	175 m <sup>3</sup>	2014
244.	Iatan Unit 2	KCP&L	KCP&L	USA	Coal High Dust	445 m <sup>3</sup>	2014
245.	Lansing Unit 4	Alliant Energy	Alliant Energy	USA	Coal High Dust	169 m <sup>3</sup>	2015
246.	Fusina L2	ENEL	ENEL	ITA	Coal High Dust	91 m <sup>3</sup>	2015
247.	Kumho Petrochemical	Pure Tech Korea Corp.	Kumho	KOR	Coal, Tail End	231 m <sup>3</sup>	2015
248.	OPPD Nebraska	OPPD	OPPD	USA	Coal, High Dust, Additional Delivery	351 m <sup>3</sup>	2015
249.	Los Barrios	Termokimik Corp.	E.ON	ES	Coal High Dust	524 m <sup>3</sup>	2015
250.	Monfalcone Unit 1	Termokimik Corp.	A2A	ITA	Coal High Dust	235 m <sup>3</sup>	2015
251.	Monfalcone Unit 2	Termokimik Corp.	A2A	ITA	Coal High Dust	235 m <sup>3</sup>	2015
252.	ZAK Kedzierzyn	Termokimik Corp.	ZAK S.A.	PL	Coal High Dust	59 m <sup>3</sup>	2015



Curr.No.	Project	Client	End user / Engineering company	Plant location	Application	Shipped quantity	Delivery date
253.	Litoral Unit 2	Termokimik Corp.	ENEL	ES	Coal High Dust	465 m <sup>3</sup>	2015
254.	Teko 4S	Effeleon		SVK	Coal High Dust	64 m <sup>3</sup>	2015
255.	La Spezia	ENEL	ENEL	ITA	Coal High Dust, Additional Delivery	280 m <sup>3</sup>	2015
256.	USS K7	Effeleon		SVK	Coal High Dust	94 m <sup>3</sup>	2015
257.	Mannheim Block 7	BASF	GKM Mannheim	DEU	Coal High Dust, Additional Delivery	62 m <sup>3</sup>	2015
258.	JP Madgett Dairyland	DPC	DPC	USA	Coal High Dust	391 m <sup>3</sup>	2015
259.	Brown Unit 3	Kentucky Utilities	Kentucky Utilities	USA	Coal High Dust; Additional Delivery	303 m <sup>3</sup>	2015
260.	Tiefstack NR 2015	Vattenfall Wärme Hamburg GmbH	Vattenfall Wärme Hamburg GmbH	DEU	Coal High Dust, Additional Delivery	71 m <sup>3</sup>	2015
261.	Crystal River Unit 5	Babcock & Wilcox	Progress Energy Florida Inc.	USA	Coal High Dust, Additional Delivery	379 m <sup>3</sup>	2015
262.	GK Kiel	E.ON Kraftwerke GmbH	E.ON Kraftwerke GmbH	DEU	Coal high dust, Additional Delivery	186 m <sup>3</sup>	2015
263.	Dallmann U 31-32	CWLP	CWLP	USA	Coal high dust, Additional Delivery	71 m <sup>3</sup>	2015
264.	Bailly Unit 7	Nipsco		USA	Coal high dust, Additional Delivery	102 m <sup>3</sup>	2015
265.	Michigan City Unit 12	Nipsco		USA	Coal high dust, Additional Delivery	279 m <sup>3</sup>	2015
266.	Schahfer Unit 14	Nipsco		USA	Coal high dust, Additional Delivery	279 m <sup>3</sup>	2015
267.	GHECO One Spare Layer	Laborelec	Glow Energy PCL	THA	Coal High Dust	114 m <sup>3</sup>	2015
268.	Quanlin #1-#3	Beijing Chinsuny Environmental Prot.		CHN	Coal fired boiler	492 m <sup>3</sup>	2016/2017
269.	Sines Repl. A-D	EDP	Energias de Portugal	PRT	Coal High Dust + Wood Pellets High Temperature	1802 m <sup>3</sup>	2016/2017
270.	Litoral Unit 1	Termokimik Corp.	ENEL	ES	Coal High Dust	403 m <sup>3</sup>	2016
271.	USS K6	Effeleon		SVK	Coal High Dust	94 m <sup>3</sup>	2016
272.	Maizuru Unit 1	Kansai Electricity Power Company		JPN	Coal High Dust, additional Delivery	263 m <sup>3</sup>	2016
273.	Ostroleka K3	Termokimik Corp.	Energa Ostroleka	PL	Coal / Biomass high dust	223 m <sup>3</sup>	2016
274.	Mannheim Block 7	BASF	GKM Mannheim	DEU	Coal High Dust; Additional Delivery	167 m <sup>3</sup>	2016
275.	Maasvlakte	Envirotherm	UNIPER	NL	Coal High Dust	250 m <sup>3</sup>	2016
276.	Litoral Unit 2 Exchange Modules	Termokimik Corp.	ENEL	IT	Coal high dust; Additional Delivery	4 m <sup>3</sup>	2016
277.	Litoral Unit 1 Exchange Modules	Termokimik Corp.	ENEL	IT	Coal high dust; Additional Delivery	3 m <sup>3</sup>	2016
278.	Brindisi Sud	ENEL	ENEL	IT	Coal high dust	320 m <sup>3</sup>	2016
279.	Litoral Unit 1 Layer 3	Termokimik Corp.	ENEL	IT	Coal high dust	201 m <sup>3</sup>	2016
280.	Litoral Unit 2 Layer 3	Termokimik Corp.	ENEL	IT	Coal high dust	233 m <sup>3</sup>	2016

Curr.No.	Project	Client	End user / Engineering company	Plant location	Application	Shipped quantity	Delivery date
281.	<b>Teko 4S</b>	Effeleon GmbH	Energyco S.r.o.	CZE	Coal high dust, Additional Delivery	9 m <sup>3</sup>	2016
282.	<b>Teko 4N Spare Layer</b>	Effeleon		SK	Coal high dust; Additional Delivery	22 m <sup>3</sup>	2016
283.	<b>Maizuru Repair Elements</b>	The Kansai Electric Power Co. Inc.	The Kansai Electric Power Co. Inc.	JPN	Coal fired boiler	18 m <sup>3</sup>	2016
284.	<b>Plomin 2</b>	Alstom Italy	TE Plomin d.o.o.	HRV	Coal High Dust	222 m <sup>3</sup>	2017
285.	<b>Nebraska Unit 2</b>	ODDP		USA	Coal High Dust; Additional Delivery	351 m <sup>3</sup>	2017
286.	<b>Fusina 2017</b>	ENEL	ENEL	IT	Coal high dust	314 m <sup>3</sup>	2017
287.	<b>Lansing Unit 4 RP 2017</b>	Alliant Energy		USA	Coal high dust	175 m <sup>3</sup>	2017
288.	<b>Columbia Unit 2</b>	Andritz	Alliant Energy	USA	Coal high dust	759 m <sup>3</sup>	2017
289.	<b>Michigan City Unit 12</b>	Nipsco	Nipsco	USA	Coal high dust; Additional Delivery	236 m <sup>3</sup>	2017
290.	<b>Dallman Unit 31/32/33</b>	CWLP	CWLP	USA	Coal high dust; Additional Delivery	139 m <sup>3</sup>	2017
291.	<b>Dallman Unit 4</b>	CWLP	CWLP	USA	Coal high dust; Additional Delivery	9 m <sup>3</sup>	2017
292.	<b>Dummy Module Opole Unit 5</b>	GE Boiler Deutschland	PGE	PL	Coal high dust	175 m <sup>3</sup>	2017
293.	<b>Hammond Unit 4</b>	Southern Company	Southern Company	USA	Coal high dust	219 m <sup>3</sup>	2017
294.	<b>King Station</b>		Xcel Energy	USA	Coal, High Dust, Additional Delivery	302 m <sup>3</sup>	2017
295.	<b>Luoyuan 1 + 2</b>	Fujian Longking	Huaneng	CHN	Coal fired boiler	981 m <sup>3</sup>	2017
296.	<b>GKM Block 9</b>	BASF	Grosskraftwerk Mannheim AG	DEU	Coal high dust; Additional Delivery	309 m <sup>3</sup>	2017
297.	<b>Sulcis</b>	ENEL Produzione S.p.A.	ENEL Produzione S.p.A.	IT	Coal tail end	137 m <sup>3</sup>	2017
298.	<b>Nordjyllandsvaerket</b>	Envirotherm	Nordjyllandsvaerket	DEU	Coal high dust	19 m <sup>3</sup>	2017
299.	<b>Los Barrios</b>	Termokimik Corp.		IT	Coal high dust, Additional Delivery	262 m <sup>3</sup>	2017
300.	<b>ZW Nowa</b>	GE Power Schweden AB	TAMEH Tauron ArcelorMittal Energy Holding	PL	Coal tail end	175 m <sup>3</sup>	2017
301.	<b>Long Phu 1 TTP</b>	Termokimik Corp.	Consortium: Russia Power Machines, Slovakia BTG Holding and PetroVietnam	VNM	Bituminous Coal high dust	1200 m <sup>3</sup>	2017
302.	<b>Plomin 2</b>	Alstom Power Italia S.p.A.	Alstom Italien	KR	Coal High Dust; Additional Delivery	111 m <sup>3</sup>	2017
303.	<b>Heilbronn Block 7</b>	EnBW Energie Baden-Württemberg AG	EnBW Energie Baden-Württemberg AG	DEU	Coal High Dust; Additional Delivery	283 m <sup>3</sup>	2017
304.	<b>Hassyan #1,#2,#3,#4</b>	GE Power Inc.		UAE	Coal High Dust	1963 m <sup>3</sup>	2017/2018/2019/2020
305.	<b>RDK 8</b>	EnBW Energie Baden-Württemberg AG	EnBW Energie Baden-Württemberg AG	DEU	Coal, High Dust	321 m <sup>3</sup>	2018
306.	<b>Sugözü Unit 10 + 20</b>	Termokimik Corp.	ISKEN (Steag + OYAK)	TUR	Bituminous Coal High Dust	1320 m <sup>3</sup>	2018
307.	<b>Fusina 3+4</b>	ENEL	ENEL	ITA	Coal, High Dust, Additional Delivery	226 m <sup>3</sup>	2018
308.	<b>Fusina 3+4</b>	ENEL	ENEL	ITA	Coal, High Dust, Additional Delivery	244 m <sup>3</sup>	2018

Curr.No.	Project	Client	End user / Engineering company	Plant location	Application	Shipped quantity	Delivery date
309.	Dallman Unit 31/32/33	CWLP	CWLP	USA	Coal high dust; Additional Delivery	109 m <sup>3</sup>	2018
310.	JP Madgett Unit 6 - Third Layer	DPC	DPC	USA	Coal, High Dust, Additional Delivery	253 m <sup>3</sup>	2018
311.	Karita PS	Kyushu		JPN	Coal High Dust	155 m <sup>3</sup>	2018
312.	Gaston	Alabama Power	APC - Gaston Plant	USA	Coal High Dust	472 m <sup>3</sup>	2018
313.	Schahfer Unit 14	Nipsco		USA	Coal High Dust, Additional Delivery	236 m <sup>3</sup>	2018
314.	Tsuruga Unit #1	Hokuriku Electric Power		JPN	Coal High Dust, Additional Delivery	140 m <sup>3</sup>	2018
315.	Hirono #5 (part 1+part 2)	Tepco		JPN	Coal High Dust, Additional Delivery	165 m <sup>3</sup>	2018
316.	Brindisi Sud - Unit 2	ENEL		ITA	Coal High Dust, Additional Delivery	863 m <sup>3</sup>	2018
317.	YES Replacement	Yokkaichi Energy Service		JPN	Coal High Dust, Additional Delivery	21 m <sup>3</sup>	2018
318.	Michigan City Unit 12	Nipsco		USA	Coal High Dust, Additional Delivery	236 m <sup>3</sup>	2018
319.	Nebraska City Unit 2	OPPD	OPPD	USA	Coal High Dust, Additional Delivery	351 m <sup>3</sup>	2019
320.	Dallman Unit 4 Spare Modules	CWLP	CWLP	USA	Coal high dust; Additional Delivery	9 m <sup>3</sup>	2019
321.	Dallman Unit 31, 32, 33	CWLP	CWLP	USA	Coal high dust; Additional Delivery	109 m <sup>3</sup>	2019
<b>Total</b>						<b>156151 m<sup>3</sup></b>	



Dale Pfaff  
Regional Sales Manager  
January 21, 2019

Ms. Megan Berge  
Baker Botts LLP  
1299 Pennsylvania Ave, NW  
Washington, D.C. 20004  
P: (202) 639-1308

**SUBJECT: GREAT RIVER ENERGY – REQUEST FOR PROPOSAL**

**COAL CREEK STATION UNIT 2 NOxOUT® SNCR SYSTEM  
FUEL TECH BUDGETARY PROPOSAL NO. 18-B-064, REVISION 2 – REDACTED**

Dear Ms. Berge:

Fuel Tech, Inc. (FTEK) is pleased to submit our preliminary and budgetary Proposal 18-B-064, Revision 2, to Great River Energy (GRE) for the Coal Creek Station (CCS) Unit 2. The following proposal provides the technical, performance, and commercial details for the FTEK Selective Non-Catalytic Reduction (SNCR) system for CCS Unit 2 located in Underwood, ND.

FTEK's scope includes the design and supply of the SNCR system including reagent storage, forwarding, metering, distribution, and injection equipment including field startup and optimization services. The reagent storage has been sized for thirty (30) days of storage and the system will be controlled via the Plant's Honeywell DCS System.

The process performance provided in this budgetary proposal is based on the furnace mapping information measured during the week of October 22, 2018. We have provided NOx reduction performance for 5 and 10 ppm ammonia slip cases. This revision includes the addition of four (4) additional wall injectors and one (1) 4-pack Distribution Module on Zone 2. There is no change to performance.

FTEK's SNCR reduction system is designed to cover a boiler load range of 185 – 600 MWg (~31 – 100% MCR). If the load range was decreased to 50 – 100% MCR, the Zone 1 Injectors (lowest level in the furnace) may be eliminated. FTEK could investigate the scope, cost, and utility consumption impacts of this change upon request.

We trust the information provided in the Offering meets your needs. In the meantime, please do not hesitate to contact me if there are any questions or comments.

Sincerely,

Dale Pfaff  
Regional Sales Manager

cc:

Mary Jo Roth, GRE  
Greg Heinz, GRE  
Paul Lee, B&V  
Mark Dittus, B&V

William Cummings, FTEK  
Kevin Dougherty, FTEK  
Terry Brown, FTEK  
Bob Mazzone, FTEK



**Great River Energy  
Budgetary Request for Quotation  
NOxOUT® Selective Non-Catalytic Reduction  
System for Coal Creek Station Unit 2**

**REDACTED VERSION**

## Table of Contents

<b>1.</b>	<b>EXECUTIVE SUMMARY .....</b>	<b>1</b>
1.1.	Introduction .....	1
1.2.	Unit Description .....	1
1.3.	Proposal Summary .....	2
<b>2.</b>	<b>FUEL TECH SNCR PROCESS DESCRIPTION.....</b>	<b>4</b>
<b>3.</b>	<b>PROCESS DESIGN TABLE (PARTIALLY REDACTED) .....</b>	<b>6</b>
<b>4.</b>	<b>FUEL TECH SCOPE OF SUPPLY .....</b>	<b>8</b>
4.1.	Base Equipment Scope of Supply Summary .....	8
4.2.	Detailed Equipment Descriptions (REDACTED).....	9
4.3.	Fuel Tech Standard Manufacturer's List (REDACTED) .....	10
4.4.	System and Equipment Engineering Services .....	10
<b>5.</b>	<b>PROPOSAL DRAWINGS (PARTIALLY REDACTED).....</b>	<b>11</b>
<b>6.</b>	<b>SCOPE OF SUPPLY BY OTHERS .....</b>	<b>12</b>
<b>7.</b>	<b>UREA AND DILUTION WATER INFORMATION.....</b>	<b>13</b>
7.1.	Specifications for Urea and Dilution Water .....	13
7.2.	Urea Supplier Information .....	14
<b>8.</b>	<b>TYPICAL FTEK SNCR PROJECT SCHEDULE .....</b>	<b>15</b>
<b>9.</b>	<b>PRICING AND PAYMENT TERMS .....</b>	<b>16</b>
9.1.	Pricing (REDACTED) .....	16
9.2.	Payment Terms.....	16
<b>10.</b>	<b>EXHIBIT C1 – FUEL TECH FIELD SERVICE PRICING (REDACTED).....</b>	<b>17</b>
<b>11.</b>	<b>FTEK EXHIBIT C3 – COMMERCIAL TERMS AND CONDITIONS (REDACTED) .....</b>	<b>18</b>
<b>12.</b>	<b>FUEL TECH PARTIAL EXPERIENCE LISTS (REDACTED).....</b>	<b>19</b>

## List of Figures

Figure 1 - GRE Coal Creek Unit 2.....	1
Figure 2 - Typical System Isometric.....	11



## 1. EXECUTIVE SUMMARY

### 1.1. Introduction

In response to Great River Energy (GRE) and the Request for Quotation, Fuel Tech, Inc. (FTEK) is providing this preliminary and budgetary Proposal for our NOxOUT® Selective Non-Catalytic NOx Reduction (SNCR) system for the Coal Creek Station Unit 2. FTEK's scope of supply includes the design, supply, and commissioning of our NOx reduction technologies applied to the 600 MWg tangential fired boiler located in Underwood, ND.

### 1.2. Unit Description

Coal Creek Station Unit 2 is a 600 MWg Combustion Engineering tangential fired boiler with eight corners and a divided furnace. The boiler fires 100% ND lignite coal with a permitted heat input of 6,022 MMBTU/hr. A maximum heat input of 5,971 MMBTU/hr was recorded at full load during the testing period and is used in FTEK's evaluation.

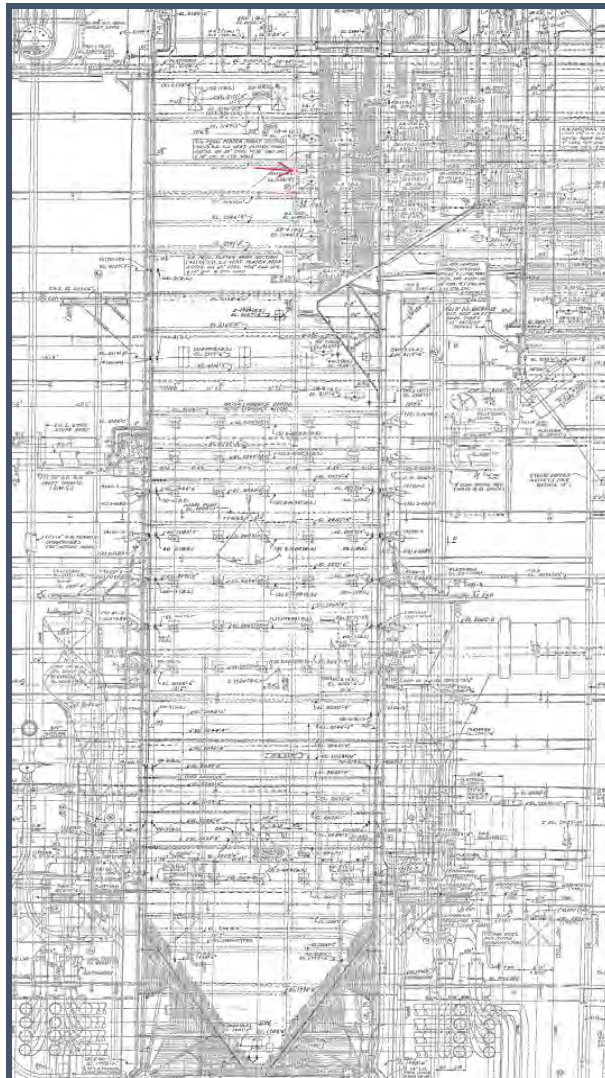


Figure 1 - GRE Coal Creek Unit 2

The Unit has Foster Wheeler Low NOx Combustion System with close coupled over fire air (CCOFA) and separated over fire air (SOFA) systems. The NOx baseline concentration of 0.121 lb/MMBtu used in FTEK's evaluation corresponds to the average emissions measured during the temperature mapping tests performed under full load conditions. For this proposal effort, the SNCR reduction system is designed to cover a load range of 185 – 600 MWg (~31 – 100% MCR). If the load range was decreased to 50 – 100% MCR, the Zone 1 Injectors (lowest level in the furnace) may be eliminated.

### **1.3. Proposal Summary**

FTEK has evaluated our SNCR process at 5 ppm and 10 ppm ammonia slip levels for GRE's consideration. The process design tables are broken down by 1) Wall Injectors only and Wall Injectors plus Multiple Nozzle Lances (MNLs) at 5 ppm slip and, 2) Wall Injectors only and Wall Injectors plus MNLs at 10 ppm ammonia slip. This proposal scope focuses on the 10 ppm ammonia slip scenarios. The NOxOUT SNCR process description and expected NOx reduction performance results of the SNCR system are detailed in Sections 2 and 3, respectively.

The equipment and engineering scope of supply summary is provided in Section 4 of this Proposal. FTEK utilized the urea flow rate at full load for thirty (30) days of 50% aqueous urea storage based on the 10 ppm ammonia slip case. Therefore, FTEK has included four (4) 70,000-gallon FRP tank with a circulation module. The reagent storage tanks include heat pads and insulation while the circulation module includes a pre-fabricated building to be located outdoors near the tank. All other modules must be located indoors for freeze protection.

The FTEK modules will include NEMA 4 junction boxes that will be controlled via the Owner's DCS System. At this writing, our scope of supply is based on our standard equipment specifications and manufacturers. Our scope of supply and drawings are provided in Sections 4 and 5, respectively.

FTEK will provide SAMA Logic diagrams and functional descriptions for programming by others. BOP engineering, air compressors, and water systems required for the SNCR systems shall be provided by others. The scope of supply by others and utility requirements are detailed in Section 6.

The NOxOUT aqueous urea and dilution water specifications are provided in Section 7. FTEK will review the Owner's water sources to help determine the best water source for dilution of the urea for injection. The engineering, equipment fabrication, and delivery milestone schedule has been detailed in Section 8.

The budgetary and preliminary pricing and payment terms are provided in Section 9. FTEK has provided pricing, expected utility demands, and other information based on the following scope definitions:

- Case 1 – Wall Injectors plus MNLs, 10 ppm Ammonia Slip
- Case 2 – Wall Injectors Only, 10 ppm Ammonia Slip



Pricing includes start up and optimization field services with travel and daily expenses included. Should additional mandays be required above and beyond what was specified in the FTEK Offering, Appendix C1, FTEK Field Service Rates, has been included in Section 10. Fuel Tech has based our commercial offering on our Exhibit C3 – FTEK Commercial Terms and Conditions included in Section 11. As always, FTEK will review and negotiate in good faith once the GRE commercial terms and conditions are provided.

FTEK is the world's leading supplier of combustion and post combustion NOx reduction technologies. These include low NOx Burners, over-fire air systems, urea based SNCR, advanced SCR, and the ULTRA Conversion system for SCR reagent feed. Fuel Tech's commercial experience includes over (108) LNB and OFA systems, (650+) NOxOUT® SNCR/advanced SCR systems, (132) ULTRA® Systems, and 50,000 MW of SCR experience.

FTEK has engineered SNCR systems for a variety of boiler configurations, loads, and process requirements. Our experience encompasses unique challenges including large units with difficult boiler geometry and high temperature furnace conditions, fuel variations and blends, wide operating load ranges, and non-optimal injection locations, all while providing our customers with the maximum, repeatable, and long-term NOx reduction performance expectations and guarantees. A few examples of FTEK's commercial and confidential SNCR experience on large, tangentially fired, coal boilers with low NOx baselines include:

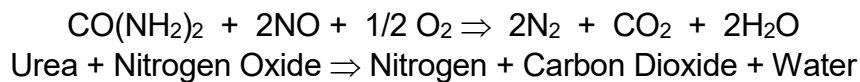
- Confidential Client Names REDACTED

FTEK has more installed SNCR applications than any other firm and the longest-running applications on very large utility furnaces. The total installed base includes more than 590 units firing all types of fossil, biomass, and industrial fuels. More than 50 of these applications are on coal fired units larger than 400MW, and several which are larger than 600MW. A partial experience list is provided for review in Section 12.

## 2. FUEL TECH SNCR PROCESS DESCRIPTION

Fuel Tech's urea-based selective non-catalytic reduction (SNCR) Process is a post-combustion NOx reduction method that reduces NOx through a controlled injection of an aqueous urea solution into the combustion gas path of fossil-fired and waste-fired boilers, furnaces, incinerators, or heaters. The most commonly used reagent consists of a 50% urea solution plus a small amount of additives for scale and corrosion control. This reagent is readily available and requires no special safety precautions for handling.

The predominant overall reaction is described as:



Fuel Tech has enhanced the basic SNCR technology by developing chemical injection hardware, widening the applicable temperature range, and process control expertise required for commercial applications. Fuel Tech's urea based SNCR technology is the NOxOUT® process. In addition to NOxOUT which utilizes low energy, air atomized injectors, Fuel Tech is also offering High Energy Reagent Technology (HERT™) which utilizes mechanically atomized injectors and carrier air for injection into the furnace.

Two key parameters that affect the process performance are flue gas temperature and the reagent distribution. The NOx reducing reaction is temperature sensitive; by-product emissions become significant at lower than the optimum temperature range while chemical utilization and NOx reduction decrease at higher than the optimum. This optimum temperature range is specific to each application. The reagent needs to be distributed within this optimum temperature zone to obtain the best performance. Typically, the distribution is more difficult for large units and for units with high flue gas velocity.

Fuel Tech's SNCR Processes are designed with the aid of Computational Fluid Dynamics (CFD) and Chemical Kinetic Model (CKM) in addition to results from field tests. The CFD model simulates flue gas flows and temperature inside a unit while the CKM calculates the reaction between urea and NOx based on temperature and flow information from CFD. A combination of these two models determines the optimum temperature region and the optimum injection strategy to distribute the reagent. With an ability to estimate NOx reduction, a model study can be performed to determine if an application is a right fit for the process.

Chemical injectors developed by Fuel Tech facilitate the reagent distribution. The NOxOUT injection system utilizes air-atomized injectors which direct the urea solution into the combustion gas path. The droplet size distribution and spray coverage developed by the injectors promote efficient contact between the chemical and the NOx in the flue gas.

The Multiple Nozzle Lance is designed to provide chemical coverage in high temperature locations where the wall injectors cannot be installed due to concerns of urea impinging on the convective surfaces. MNLs are added to the injection strategy if high levels of reduction are required, if the temperature window is very narrow due to low baseline NOx, or if the upper furnace flue gas temperature and CO concentration are excessive. Each MNL is supplied with

a retract mechanism to remove the lance from the boiler cavity when the lance is not in use, or if loss of cooling water flow, high cooling water temperature or loss of atomization air flow occurs.

Fuel Tech's SNCR Processes provide effective boiler load following capabilities. Through the computer modeling, an injection strategy is developed that makes use of multilevel injection, control of reagent concentration, droplet size and spray patterns, as well as jet penetration.

Several years of field-testing indicate that NOxOUT systems are applicable on various types of units firing many different fuels. The process was successfully proven on units fired with coal, oil, gas, wood or municipal solid or hazardous waste. These units varied in size and type: package boilers, process heaters, incinerators, circulating or bubbling fluidized beds, waste heat boilers, utility boilers. By being a post-combustion process, unit size and type and fuel type have some, but not a major effect on the process.

There are substantial benefits gained from the application of NOxOUT systems compared to first generation NOx control technologies, such as ammonia injection. These benefits are briefly summarized below:

- Use of non-toxic, non-hazardous chemicals.
- Potentially lower capital cost due to the lack of large system compressors and elimination of anhydrous ammonia storage, handling, and safety equipment.
- Lower operating costs resulting primarily from minimization of gas (steam or compressed air) requirements.
- Inherently more effective control of chemical distribution for better mixing with the use of liquid rather than gas-based reagents, thereby resulting in better chemical utilization.

### 3. PROCESS DESIGN TABLE (PARTIALLY REDACTED)

Unit Identification	Unit 2
Type of Unit	600 MW CE T-Fired, Eight (8) Corner, Divided Furnace
Type of Fuel	North Dakota Lignite
Load Range	30 – 100% MCR

Type of Fuel	U/M	Lignite (10/23/18 avg. fuel analysis)	Lignite (10/24/18 avg. fuel analysis)	Lignite (from CUS)	Lignite (10/23/18 avg. fuel analysis)
Load		Full Load, 600 MW	Mid Load, 350 MW	Low Load, 185 MW	Full Load, 600 MW
GHI	(MMBtu/hr)	5971	3461	2019	5971
Baseline NOx	(lb/hr)	722.4	494.9	450.2	722.4
Measured Baseline NOx	(lb/MMBtu)	0.121	0.143	0.223	0.121
Controlled NOx at Stack	(lb/MMBtu)	0.109	0.097	0.134	0.099
Guaranteed NOx Reduction from Baseline Above	(%)	10	32	40	18
<b>Average NH3 Slip @ Economizer Outlet, Guaranteed</b>	<b>(ppmd)</b>	<b>5</b>			
REDACTED					
50% Aqueous Urea Flow Rate, Expected	(gph)	REDACTED			
50% Aqueous Urea Flow Rate, Guaranteed	(gph)	239	62	71	336
No. of Injectors per Level (Retracts = Y/N		REDACTED			REDACTED

Type of Fuel	U/M	Lignite (10/23/18 avg. fuel analysis)	Lignite (10/24/18 avg. fuel analysis)	Lignite (from CUS)	Lignite (10/23/18 avg. fuel analysis)
Load		Full Load, 600 MW	Mid Load, 350 MW	Low Load, 185 MW	Full Load, 600 MW
GHI	(MMBtu/hr)	5971	3461	2019	5971
Baseline NOx	(lb/hr)	722.4	494.9	450.2	722.4
Measured Baseline NOx	(lb/MMBtu)	0.121	0.143	0.223	0.121
Controlled NOx at Stack	(lb/MMBtu)	0.103	0.090	0.123	0.093
Guaranteed NOx Reduction from Baseline Above	(%)	15	37	45	23
<b>Average NH3 Slip @ Economizer Outlet, Guaranteed</b>	<b>(ppmd)</b>	<b>10</b>			
REDACTED					
50% Aqueous Urea Flow Rate, Expected	(gph)	REDACTED			
50% Aqueous Urea Flow Rate, Guaranteed	(gph)	343	86	93	411
No. of Injectors per Level (Retracts = Y/N		REDACTED			REDACTED

Process Notes:

1. The FTEK guarantees the NOx reduction, ammonia slip, and urea flow values stated above provided that the final system is designed to the strict adherence to the model results, the baseline NOx is not higher than what is indicated on the process design table, the installation of injection ports are per FTEK's guidance, and the use of FTEK's metering and injection equipment. The performance guarantee results would be transferred to commercial performance guarantee language in the final commercial sale of equipment agreement of the SNCR System.
2. Ammonium bisulfate formation is not expected to be a concern since the S content is less than 1%.
3. For this proposal effort, the SNCR reduction system is designed to cover a load range of 185 – 600 MWg (~31 – 100% MCR). If the load range was decreased to 50 – 100% MCR, the Zone 1 Injectors (lowest level in the furnace) may be eliminated.

#### 4. FUEL TECH SCOPE OF SUPPLY

##### 4.1. Base Equipment Scope of Supply Summary

###### Equipment Summary Case 1 – Wall Injector plus MNL 10 ppm Ammonia Slip:

Equipment Description	Quantity
<b>Reagent Storage and Circulation Module</b>	
Aqueous Urea Truck Unloading Panel	One (1)
NOxOUT Reagent FRP Storage Tanks, Single Wall, Heat Traced and Insulated, Thirty (30) Days Storage	Four (4) 70,000 Gallon
Circulation Module, Two (2) 100% Redundant Pumps with Enclosure for outdoor placement and Return Pressure Control Station. Junction Box for Control by DCS.	One (1)
<b>Metering, Distribution, and Injection – Indoor Placement,</b>	
Dilution Water Module w/ Two (2) 100% Redundant Pumps. Junction Box for Control by DCS.	One (1)
Metering Module (s) w/ Junction Box for Control by DCS.	One (1) MM-HF-3Z for Wall Injectors One (1) MM-HF-1Z for MNLs
Distribution Module (s)	Eight (8) DM NX 5 Four (4) DM NX 6 One (1) DM NX 4
Injectors – NOxOUT Air Atomized Injectors	Sixty-eight (68) – NOxOUT
Automatic Retracts for Zone 1 Wall Injectors	Twenty-four (24)
Distribution Module, MNL	Two (2) – DM-MNL -2M
MNL Injectors w/Retracts, 26' Inserted Length	Four (4)
MNL cooling water Supply/Return Spool Pieces	One (1) Lot
<b>Engineering and Field Services</b>	
Process and Project Engineering	Included
SAMA Logic Diagrams and Functional Descriptions	Included
Field Start Up, Optimization, and Training Services	Included

###### Equipment Summary Case 2 – Wall Injectors Only 10 ppm Ammonia Slip:

Equipment Description	Quantity
<b>Reagent Storage and Circulation Module</b>	
Aqueous Urea Truck Unloading Panel	One (1)
NOxOUT Reagent FRP Storage Tanks, Single Wall, Heat Traced and Insulated, Thirty (30) Days Storage	Three (3) 70,000 Gallon
Circulation Module, Two (2) 100% Redundant Pumps with Enclosure for outdoor placement and Return Pressure Control Station. Junction Box for Control by DCS.	One (1)

Equipment Description	Quantity
<b>Metering, Distribution, and Injection – Indoor Placement</b>	
Dilution Water Module w/ Two (2) 100% Redundant Pumps. Junction Box for Control by DCS.	One (1)
Metering Module (s) w/ Junction Box for Control by DCS.	One (1) MM-HF-3Z for Wall Injectors
Distribution Module (s)	Eight (8) DM NX 5 Four (4) DM NX 6 One (1) DM NX 4
Injectors – NOxOUT Air Atomized Injectors	Sixty-eight (68) – NOxOUT
Automatic Retracts for Zone 1 Wall Injectors	Twenty-four (24)
<b>Engineering and Field Services</b>	
Process and Project Engineering	Included
SAMA Logic Diagrams and Functional Descriptions	Included
Field Start Up, Optimization, and Training Services	Included

**4.2. Detailed Equipment Descriptions (REDACTED)**  
**REDACTED**

**4.3. Fuel Tech Standard Manufacturer's List (REDACTED)**

**REDACTED**

**4.4. System and Equipment Engineering Services**

**Engineering** - Fuel Tech will provide Project and Process Engineering and the following drawings:

- Process Flow Diagrams (PFDs)
- P&IDs
- Module General Arrangement Drawings
- Foundation Dead Loads
- Injector Locations
- Electrical Schematics and Bill of Materials
- Electrical Panel Layout Drawings
- Interconnection Diagrams
- SAMA Logic Diagrams and Functional Descriptions

FTEK will provide three (3) drawing submittal cycles as follows:

1. Drawings submitted for review and comment.
2. Drawings submitted for Fabrication
3. As-built Drawings as Needed

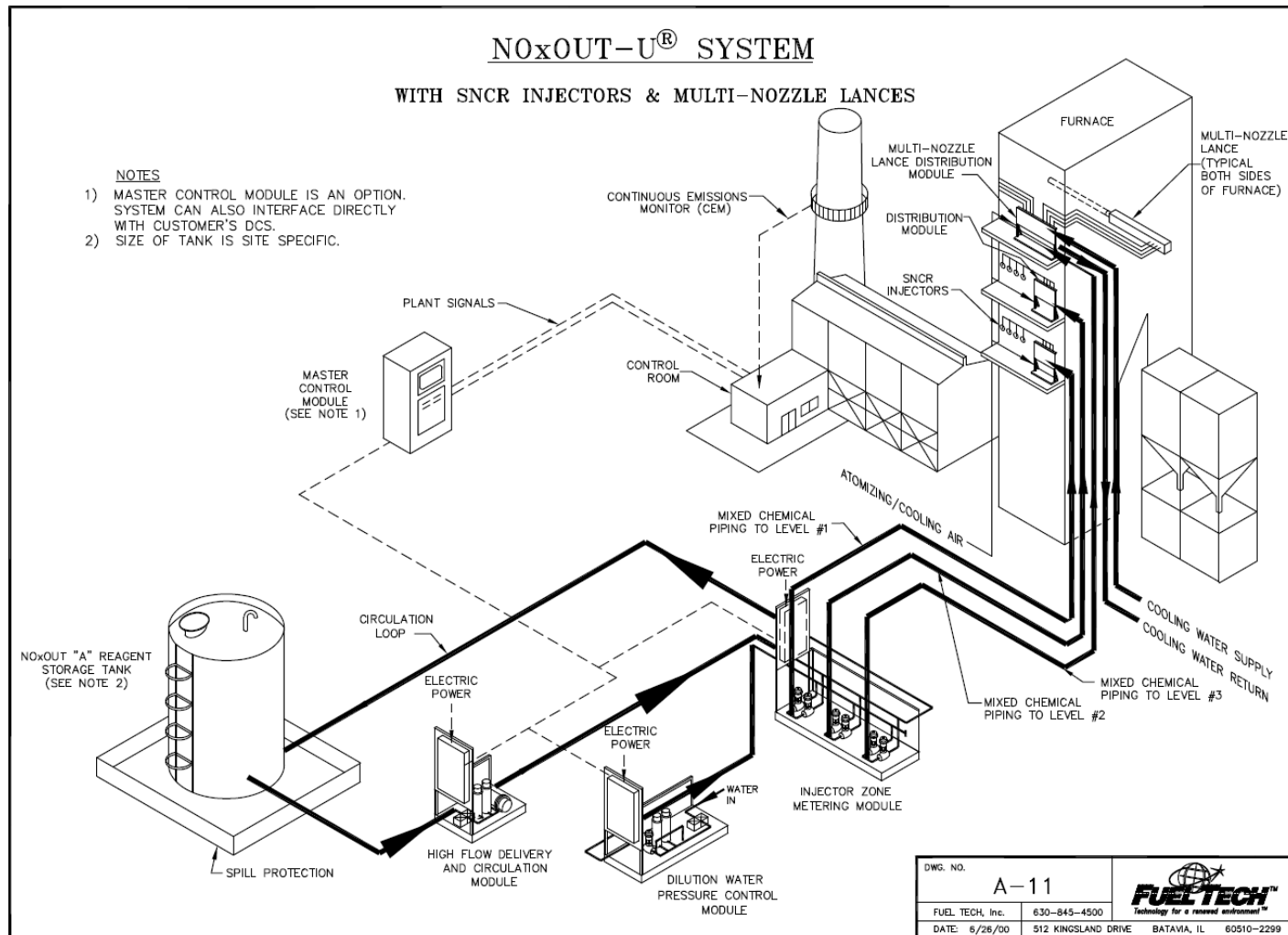
**Engineering Services**

- Process and Project Engineering
- Project Engineering and Project Management
- Engineering Kickoff Meeting/Bi-Weekly Update Conference Call/Webinar Meetings as Required
- Field Installation Support, Start-up, and Optimization Services
- Training Services and Training Manuals,
  - One (1) Electronic Version
  - Ten (10) hard copies
- Operation and Maintenance Manuals
  - One (1) Electronic Version
  - Four (4) Hard Copies



## 5. PROPOSAL DRAWINGS (PARTIALLY REDACTED)

The following proposal drawings are preliminary in nature and are intended to provide general reference to the equipment offering. Actual dimensions and weights will be provided during the design phase of the Project.



**Figure 2 - Typical System Isometric**

## 6. SCOPE OF SUPPLY BY OTHERS

1. Offloading of All Fuel Tech Supplied Equipment
2. Installation Labor and Materials for Fuel Tech, Inc. Supplied Equipment.
3. BOP and Installation Engineering, Installation Project Management
4. Interconnecting Piping and Wiring of Fuel Tech, Inc. Supplied Equipment.
5. No Costs were included for Performance or Bid Bonding
6. Professional Engineering Stamps if required
7. Implement Control Logic Schemes into Plant DCS (as required).
  - a. Procurement of DCS Hardware (as required)
  - b. Graphic Screens Development and Programming
  - c. SNCR-related Distributed Control System Programming
8. Air Compressors.
9. Chemical Supply: Licensed Quality or Industrial Grade urea (50% Solution).
10. Plant service water (NOxOUT® reagent) or demineralized water (unstabilized urea).
11. NOx, Ammonia, and CO Monitoring Equipment, if Required.
12. Boiler Penetrations, wall boxes, and water wall tube modifications for Injectors.
13. Boiler Scaffolding as needed
14. Tank Foundation and Structural Support for System Modules.
15. Appropriate Indoor Location/Building and Freeze Protection for FTEK Equipment as Required.
16. Permits as Required
17. Taxes as Required
18. Asbestos and Lead Paint Abatement, if Required
19. System Performance Testing
20. Spare Parts
21. Estimated System Utilities per Unit:

Description - Total	Instrument Air, SCFM (80 PSIG 70 °F)	Atomizing Air, SCFM (100 PSIG, Clean)	Dilution Water, GPM (60 PSIG/60 °F)	MNL Cooling Water, GPM (Clean, Inlet ≤ 120 °F, ≥ 150 PSIG)	Power, kW (480 or 120 VAC)
Case 1 - SNCR System w/Wall Injectors Plus MNLs	40, intermittent	1,010	145	300	95
Case 2 - SNCR System w/Wall Injectors Only	30, intermittent	720	165	N/A	75

## 7. UREA AND DILUTION WATER INFORMATION

### 7.1. Specifications for Urea and Dilution Water

Depending on the quality of water available for urea dilution at the Metering Module, either a licensed reagent (NOxOUT A or HP identified below) or unstabilized urea may be used. If an unstabilized urea of any concentration is used, the water quality requirements are much more stringent. The urea and dilution water specifications for SNCR operation with stabilized and unstabilized urea are provided below:

Quality Specifications for Aqueous Urea			
Description	NOxOUT® A	NOxOUT® HP	Unstabilized Urea
	Modified 50% Aqueous Solution of Urea	Modified 50% Aqueous Solution of Urea	50% Aqueous Solution of Urea
Density (g/ml @ 25° C)	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
Appearance	Light Yellow, Clear to Slightly Hazy	Light Yellow, Clear to Slightly Hazy	Light Yellow, Clear to Slightly Hazy
Salt Out Freeze Point	64 degrees F (18 degrees C)	64 degrees F (18 degrees C)	64 degrees F (18 degrees C)
Foam	Foam Lasts > 15 seconds after bottle is shaken	Foam Lasts > 15 seconds after bottle is shaken	Not Applicable
Free NH3	< 5000 ppm	< 5000 ppm	< 5000 ppm
Biuret Content	< 5000 ppm	< 5000 ppm	< 5000 ppm
Organic Phosphate	55 – 85 ppm as PO4	22 -40 ppm as PO4	Not Applicable
Orthophosphate	< 6 ppm as PO4	<6 ppm as PO4	<2 ppm as PO4
Total Suspended Solids	< 10 ppm	<10 ppm	<10 ppm
Urea Makeup Water	Total Hardness as CaCO <sub>3</sub> ≤ 300 ppm	Total Hardness as CaCO <sub>3</sub> ≤ 150 ppm	Total Hardness as CaCO <sub>3</sub> ≤ 20 ppm

Quality Specifications for Dilution Water			
Parameter	NOxOUT® A	NOxOUT® HP	Unstabilized Urea
Total Hardness as CaCO <sub>3</sub> (ppm)	<450	<150	<20
M" Alkalinity as CaCO <sub>3</sub> " (ppm)	<300	<100	<100
Conductivity (µmho)	>5 and <2500	>5 and <1000	>5 and <1000
Silica as SiO <sub>2</sub> (ppm)	<60	<60	<60
Iron as Fe (ppm)	<1	<1	<1
Manganese as Mn (ppm)	<0.3	<0.3	<0.3
Phosphate as P (ppm)	<1	<1	<1
Sulfate as SO <sub>4</sub> (ppm)	<200	<200	<200
Turbidity & Suspended Solids (NTU)	<10 NTU	<10 NTU	<10 NTU
pH	<8.3	<8.3	<8.3

GRE Coal Creek Station  
Unit 2 Budgetary RFQ  
SNCR System

January 21, 2019  
Proposal 18-B-064, Rev 2, **REDACTED**  
Page 14

## 7.2. Urea Supplier Information

Licensee	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	714.990.3940 714.329.2281 (cell) 714.990.4073 (fax)
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		
QLF	328 Bucklin Street Suite 200 LaSalle, IL 61301	Randy Saini	815.224.1553 815.228.5711 (cell)
Distribution Points	–La Salle, IL – Dunlap, IA – Wellsville, OH – Menomonie, WI		
PCS Nitrogen, Inc	1101 Skokie Blvd Northbrook, IL 60062	Jennifer A. Zagorski	847.849.4377 847.612.5301 847.849.4489
Distribution Points	– Augusta, GA - Lima, OH		
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		
The Andersons, Inc.	480 W. Dussel Drive P.O. Box 119 Maumee, OH 43537	Rod Erny	419.897.3687
Distribution Points	– Logansport, IN – Maumee, OH		
Colonial Chemical Co.	78 Carranza Rd Tabernacle, NJ 08088	Eric Wegelius	609.268.1200 x 112 609.268.2117 (fax)
Distribution Points	– Frederick, MD – Tabernacle, NJ – Monroe, LA – Hempstead, TX – Webberville, MI – Raeford, NC – Morrisville, PA – St. Paul, MN – Shakopee, MN		
Information Needed by Licensees:			
▪ Company Name		▪ If rail delivery- specify railroad	
▪ Location		▪ NOxOUT® Reagent Type Required (A,HP,LT)	
▪ Scheduled Start-Up Date		▪ NOxOUT® Reagent Usage Rate	
		▪ NOxOUT® Reagent Storage Tank Size	

## 8. TYPICAL FTEK SNCR PROJECT SCHEDULE

The schedule below is typical of SNCR projects with MNLs and of similar size and scope.

EVENT	RESPONSIBILITY	WEEKS FROM ORDER DATE
Receipt of Order	Customer	0
Begin Project Design	Fuel Tech	1
Submit Preliminary P&ID and PFD Drawings	Fuel Tech	6
Customer PFD/P&ID Drawing Comments Received	Customer	8
Submit Mechanical General Arrangement Drawings	Fuel Tech	10
Customer Drawing Comments Received/Release for Procurement and Fabrication	Customer	14
Submit Electrical Drawings	Fuel Tech	14
Submit SAMAs and Functional Descriptions	Fuel Tech	20
Begin Equipment Fabrication	Fuel Tech	20
Equipment Testing and FAT	Fuel Tech/Customer	40
Equipment Shipment	Fuel Tech	44
Equipment Delivery	Fuel Tech	46
Complete Equipment Installation	Customer	TBD
Begin Start-Up & Testing	Fuel Tech	1-2 weeks after completion of installation
Begin Optimization	Fuel Tech	2-4 weeks
Compliance Testing	Customer	TBD

### Notes

- Dates and durations subject to change based on contract release date and turnaround times for drawing approvals. FTEK's schedule is based on clients review and comment period of two (2) weeks or less.
- FTEK will provide three (3) drawing submittal cycles as follows:
  - Drawings submitted for review and comment.
  - Drawings submitted for Fabrication
  - As-built Drawings as Needed
- Additional drawing submittals may be provided as a cost adder.
- A more accurate schedule may be provided during a commercial proposal phase.

## **9. PRICING AND PAYMENT TERMS**

### **9.1. Pricing (**REDACTED**)**

For the design, supply, and field services for the SNCR system defined in this Proposal, FTEK quotes the preliminary and budgetary pricing of:

**REDACTED**

The installation shall be by others. Should additional field time be required beyond what is provided, the mandays and expenses will be invoiced per Appendix C-1, Field Service Rates. The current offering is based on FTEK standard equipment specifications and commercial terms and conditions.

### **9.2. Payment Terms**

- 10% Upon receipt of Letter of Intent, Purchase Order, or Contract
- 40% Upon Release of fabrication by the Buyer
- 40% Upon date of shipment of equipment, or thirty days after notification to buyer that equipment is ready to ship, whichever occurs first.
- 10% After successful completion of acceptance test or six (6) months after receipt of equipment, whichever occurs first.



GRE Coal Creek Station  
Unit 2 Budgetary RFQ  
SNCR System

January 21, 2019  
Proposal 18-B-064, Rev 2, REDACTED  
Page 17

**10. EXHIBIT C1 – FUEL TECH FIELD SERVICE PRICING (REDACTED)**

GRE Coal Creek Station  
Unit 2 Budgetary RFQ  
SNCR System

January 21, 2019  
Proposal 18-B-064, Rev 2, **REDACTED**  
Page 18

**11.FTEK EXHIBIT C3 – COMMERCIAL TERMS AND CONDITIONS (REDACTED)**



GRE Coal Creek Station  
Unit 2 Budgetary RFQ  
SNCR System

January 21, 2019  
Proposal 18-B-064, Rev 2, REDACTED  
Page 19

**12. FUEL TECH PARTIAL EXPERIENCE LISTS (REDACTED)**

SNCR Partial Experience List – U.S. Tangential Fired Units, Coal (REDACTED)

**Lee, Paul (Denver)**

---

**From:** Carlos Cervantes <cac@cervantes-delgado.com>  
**Sent:** Tuesday, October 23, 2018 12:03 PM  
**To:** Lee, Paul (Denver)  
**Subject:** 50% High Purity Urea Solution

Hello Paul,

I have some budgetary numbers for you on the subject material delivered to Bismarck, ND.

We have a supply facility about an hour away that can provide the highest purity urea available which would alleviate any impurity issues within the Nox system.

50% High Purity Urea Solution FOB delivered to Bismarck, ND  
\$1.35/gallon  
Full Truck Load quantities are 5000 gallons

Please let me know if there's any information you require.

Best regards,

**Carlos Cervantes**

Cervantes-Delgado, Inc.

AirBlueFluids, Inc.

Cell: 562) 505-2171

Fax: 714) 990-4073

E-mail: [cac@cervantes-delgado.com](mailto:cac@cervantes-delgado.com)

[www.cervantes-delgado.com](http://www.cervantes-delgado.com)

[www.airbluefluids.com](http://www.airbluefluids.com)

**Black and Veatch**  
**Attention: Paul Lee**

Paul

Below is your request for budgetary pricing for Anhydrous Ammonia delivered to Bismarck, ND.

Product: Commercial Grade Anhydrous Ammonia 99.5%  
Delivery: Bulk truck and driver  
Quantity: 34,000 to 36,000 pounds  
Product Price: \$0.2885, per pound, delivered  
Freight: Included in product price  
Fuel Surcharge: \$450  
Hazmat Fee: Waived

Product: Premium Grade Anhydrous Ammonia 99.995%  
Delivery: Bulk truck and driver  
Quantity: 34,000 to 36,000 pounds  
Product Price: \$0.60, per pound, delivered  
Freight: Included in product price  
Fuel Surcharge: \$450 estimated  
Hazmat Fee: Waived

This quote is good for 60 days.

Deliveries are typically made during weekdays with four (4) hours of unloading time. Weekend and holiday deliveries are available for an additional charge. Additional unloading time will be billed at an additional \$100 per hour.

If you have any other questions please contact me.

Thank you

## Lee, Paul (Denver)

---

**From:** Jay Guyton <jguyton@centralsteelservice.com>  
**Sent:** Thursday, December 27, 2018 1:07 PM  
**To:** Lee, Paul (Denver)  
**Subject:** RE: Corten Pricing

Hi Paul,

CW indicates a Per Hundred Pound measurement, often referred to as "Per Hundred Weight" pricing or "CWT", our system does not allow 3 letters in that field. If you changed to "\$.6950" as mentioned below, that would become the Price Per Pound. I hope this helps, the prices & totals on our quote is accurate, let me know if you have any other questions.

Best Regards,

Jay Guyton  
Central Steel Service, Inc.  
2764 Welborn Street  
Pelham, AL 35124  
(P) 800-868-6798  
(F) 205-663-3391



---

**From:** Lee, Paul (Denver) <LeeP@bv.com>  
**Sent:** Thursday, December 27, 2018 2:00 PM  
**To:** Jay Guyton <jguyton@centralsteelservice.com>  
**Subject:** FW: Corten Pricing

Jay,

Mack Van Eaton has been helping me with some estimates for steel. Your name was on the attached quote I received from them, so I figured it'd be best to ask you questions directly. The cost of coten plate is listed at 69.5 "CW", at 81,680 lbs. Multiplying the two results in 5,676,760, but your quote lists 56,767.60. Can you confirm what CW means, and that the "69.50" is actually \$0.6950?

Thank you,

**Paul Lee, P.E.\***

Boiler and Air Quality Group, Energy

\*Licensed in CO

Black & Veatch

4600 South Syracuse Street, Suite 800, Denver, CO 80237

o +1 720-834-4303

e [LeeP@BV.com](mailto:LeeP@BV.com)

## Lee, Paul (Denver)

---

**From:** Elliott, Carl <CElliott@babcockpower.com>  
**Sent:** Friday, November 30, 2018 3:12 PM  
**To:** Lee, Paul (Denver)  
**Cc:** Dittus, M. H. (Mark); Pauly, Josh S.  
**Subject:** Re: 470005.60.1000 181129 Budgetary Quote for Boiler Wall Penetrations

We do have erection capabilities in house via TEI Construction. They are open shop/ non union so they will have a significantly different price than union. Will this site accept non union?

**Carl P. Elliott**  
Babcock Power Inc.  
Sr. Account Executive  
[3805 SW Sandstone Dr.](#)  
[Lees Summit, MO 64082](#)

Mobile: [816.527.7590](tel:816.527.7590)

[CElliott@babcockpower.com](mailto:CElliott@babcockpower.com)  
<http://www.babcockpower.com>

Sent from my iPhone

On Nov 30, 2018, at 2:00 PM, Lee, Paul (Denver) <[LeeP@bv.com](mailto:LeeP@bv.com)> wrote:

This message is from OUTSIDE THE COMPANY - be CAUTIOUS, particularly with links and attachments.

Thanks a lot Carl. I have a few outstanding questions.

I have a cost estimate for installing boiler penetrations, but it's old and likely specific to this particular client. With that said, does Babcock offer installation services, and if yes, what would it cost to install these?

Additionally, I know I didn't provide the refractory material, but since it's a general consumable during construction, would you have any idea how much a generic refractory would cost on a sq ft or tonnage basis?

Thank you,

**Paul Lee, P.E.\***  
Boiler and Air Quality Group, Energy  
\*Licensed in CO  
Black & Veatch  
4600 South Syracuse Street, Suite 800, Denver, CO 80237  
☎ +1 720-834-4303  
✉ [LeeP@BV.com](mailto:LeeP@BV.com)

**Building a World of Difference.®**

**Please consider the environment before printing my email**

Please note that the information and attachments in this email are intended for the exclusive use of the addressee and may contain confidential or privileged information. If you are not the intended recipient, please do not forward, copy or print the message or its attachments. Notify me at the above address, and delete this message and any attachments. Thank you.

---

**From:** Elliott, Carl [<mailto:CElliott@babcockpower.com>]  
**Sent:** Friday, November 30, 2018 6:49 AM  
**To:** Lee, Paul (Denver) <[LeeP@bv.com](mailto:LeeP@bv.com)>  
**Cc:** Dittus, M. H. (Mark) <[DittusM@bv.com](mailto:DittusM@bv.com)>; Pauly, Josh S. <[PaulyJS@bv.com](mailto:PaulyJS@bv.com)>  
**Subject:** RE: 470005.60.1000 181129 Budgetary Quote for Boiler Wall Penetrations

Each opening panel will consist of 6 tubes 18 inches long with seal box attached. Budgetary cost is \$3,000 per opening panel.

No refractory is included in the estimate for the seal boxes nor is any modifications to the existing casing or insulation.

Please let me know if you need any other information.

Regards  
Carl

**Carl P. Elliott**  
Sr Account Executive

<image001.jpg>

**BABCOCK POWER SERVICES**  
A Babcock Power Inc. Company  
3805 SW Sandstone Dr | Lees Summit, MO 64082

**mobile** | 816-527-7590

**email** | [CElliott@babcockpower.com](mailto:CElliott@babcockpower.com)

**web** | <https://www.babcockpower.com>

---

**From:** Lee, Paul (Denver) <[LeeP@bv.com](mailto:LeeP@bv.com)>  
**Sent:** Thursday, November 29, 2018 2:14 PM  
**To:** Elliott, Carl <[CElliott@babcockpower.com](mailto:CElliott@babcockpower.com)>  
**Cc:** Dittus, M. H. (Mark) <[DittusM@bv.com](mailto:DittusM@bv.com)>; Pauly, Josh S. <[PaulyJS@bv.com](mailto:PaulyJS@bv.com)>  
**Subject:** RE: 470005.60.1000 181129 Budgetary Quote for Boiler Wall Penetrations

This message is from OUTSIDE THE COMPANY - be CAUTIOUS, particularly with links and attachments.

Carl,

Per our recent phone call, I have the following from our client:

“Our original tubing is 1.75” O.D. x .188” MWT SA210-A1 tubing on 2.25” centers. Typically .188” MWT tubing is not readily available and we buy .203” MWT tubing.”

If there's anything else that you need, please let me know.

Thank you,

**Paul Lee, P.E.\***

Boiler and Air Quality Group, Energy

\*Licensed in CO

Black & Veatch

4600 South Syracuse Street, Suite 800, Denver, CO 80237

o +1 720-834-4303

e [LeeP@BV.com](mailto:LeeP@BV.com)

**Building a World of Difference.\***

**Please consider the environment before printing my email**

Please note that the information and attachments in this email are intended for the exclusive use of the addressee and may contain confidential or privileged information. If you are not the intended recipient, please do not forward, copy or print the message or its attachments. Notify me at the above address, and delete this message and any attachments. Thank you.

---

**From:** Lee, Paul (Denver)

**Sent:** Thursday, November 29, 2018 11:09 AM

**To:** Elliott, Carl <[CElliott@babcockpower.com](mailto:CElliott@babcockpower.com)>

**Cc:** Dittus, M. H. (Mark) <[DittusM@bv.com](mailto:DittusM@bv.com)>; Pauly, Josh S. <[PaulyJS@bv.com](mailto:PaulyJS@bv.com)>

**Subject:** 470005.60.1000 181129 Budgetary Quote for Boiler Wall Penetrations

**PRIVILEGED AND CONFIDENTIAL – PREPARED AT THE DIRECTION OF COUNSEL**

Carl,

Thank you for willing to help on this project. The project is looking into NOx controls, including SNCR, and for the SNCR, we would need new penetrations for the injection lances. Please see the information below, and if there's anything else you need, please let me know.

Tube Material: SA210A1

Tube OD: 1 ¾"

Membrane Thickness: ½"

Number of openings: The SNCR will need three levels of lances, one with 24 penetrations, and two levels of 20 penetrations each.

Opening Size: Each injector is 3" OD

Please let me know if you need anything else. Thank you again,

**Paul Lee, P.E.\***

Boiler and Air Quality Group, Energy

\*Licensed in CO

Black & Veatch

4600 South Syracuse Street, Suite 800, Denver, CO 80237

o +1 720-834-4303

e [LeeP@BV.com](mailto:LeeP@BV.com)

**Building a World of Difference.\***

**Please consider the environment before printing my email**

---

**From:** Puski, Suzette <SPuski@babcockpower.com>  
**Sent:** Wednesday, May 29, 2019 8:58 AM  
**To:** Lee, Paul (Denver) <LeeP@bv.com>  
**Cc:** Elliott, Carl <CElliott@babcockpower.com>; Erickson, Clayton <cerickson@babcockpower.com>  
**Subject:** RE: 400075.60.1000 181010 RSCR Budgetary Quote Request

Paul,  
Thanks for the call.  
We have supplied both:

- High dust SCR's on units firing lignite coal (Luminant Oak Grove Units 1&2) that had a flue gas flow of 2,485,181 acfm per SCR reactor and
- Tail-end SCR's (WE Energy Oak Creek Units 5&6 and Units 7&8) that had a peak flue gas flow of 1,613,105 acfm per SCR reactor

The scope of supply on the tail-end SCR project included that gas-to-gas heat exchanger.  
We can review the current burner design to see if lower NOx emissions area feasible.  
We also can provide options for gas and dual-fuel conversion including utilizing alternative fuels such as ethanol.



Sincerely,

**Suzette M. Puski**  
Business Development Manager



**BABCOCK POWER ENVIRONMENTAL**

A Babcock Power Inc. Company

26 Forest St., Suite 300 | Marlborough, MA 01752

**office** | 508-854-3636  
**mobile** | 508-340-7836  
**email** | [SPuski@babcockpower.com](mailto:SPuski@babcockpower.com)  
**web** | <https://www.babcockpower.com/bpe/>

---

**From:** Lee, Paul (Denver) <[LeeP@bv.com](mailto:LeeP@bv.com)>

**Sent:** Tuesday, May 28, 2019 1:11 PM

**To:** Puski, Suzette <[SPuski@babcockpower.com](mailto:SPuski@babcockpower.com)>

**Cc:** Elliott, Carl <[CElliott@babcockpower.com](mailto:CElliott@babcockpower.com)>; Erickson, Clayton <[cerickson@babcockpower.com](mailto:cerickson@babcockpower.com)>

**Subject:** RE: 400075.60.1000 181010 RSCR Budgetary Quote Request I

This message is from OUTSIDE THE COMPANY - be CAUTIOUS, particularly with links and attachments.

Suzette,

Thanks for the assistance over the last several months on various questions, including the email chain below. We are actually still finalizing the report that your RSCR feedback supported. At the time, we focused our cost estimates on high-dust SCR's, but after some changes in direction, I'd like to approach BPEI on more "traditional tail-end SCR."

Based on the information below in my initial email, does Riley Engineering have any tail-end SCR experience in the size range requested?

I'm writing you and those copied since Riley is under BPEI, but if I should be going to someone else, please forward as necessary.

Thank you,

**Paul Lee, P.E.\***

Boiler and Air Quality Group, Energy

\*Licensed in CO

Black & Veatch

4600 South Syracuse Street, Suite 800, Denver, CO 80237

o +1 720-834-4303

e [LeeP@BV.com](mailto:LeeP@BV.com)

**Building a World of Difference.\***

**Please consider the environment before printing my email**

Please note that the information and attachments in this email are intended for the exclusive use of the addressee and may contain confidential or privileged information. If you are not the intended recipient, please do not forward, copy or print the message or its attachments. Notify me at the above address, and delete this message and any attachments. Thank you.

---

**From:** Puski, Suzette <[SPuski@babcockpower.com](mailto:SPuski@babcockpower.com)>  
**Sent:** Thursday, October 11, 2018 2:59 PM  
**To:** Lee, Paul (Denver) <[LeeP@bv.com](mailto:LeeP@bv.com)>  
**Cc:** Elliott, Carl <[CElliott@babcockpower.com](mailto:CElliott@babcockpower.com)>; Erickson, Clayton <[cerickson@babcockpower.com](mailto:cerickson@babcockpower.com)>  
**Subject:** RE: 400075.60.1000 181010 RSCR Budgetary Quote Request

---

Paul,  
For an RSCR application. This will not be very practical to do as the foot print gets quite large for the flue gas flow requested.  
See the following plot plan for a 54 MW RSCR. That is our largest RSCR system to date. The system is modular in design so the number of compartments can be increase but we cannot go larger in compartment size due to limits of maintaining fast acting dampers. We estimate largest practical size for an RSCR is 100 MW.

For this application we recommend a traditional tail-end SCR with an induct burner and gas/gas heat exchanger. It is not as energy efficient in terms of heat recovery (75% vs 95%) as an RSCR but it is more practical in terms of footprint. It can also meet future emissions requirements if necessary. Riley has tail-end SCR experience and a lot of experience in fitting SCRs in tight spots at the economizer outlet above the air heater inlet.

If you have any questions, please give me a call. If you can provide some GAs of the plant for us to provide a better response, we'd be happy to address this further.

Sincerely,

**Suzette M. Puski**  
Principal Business Dev Spec



**BABCOCK POWER ENVIRONMENTAL**  
A Babcock Power Inc. Company  
26 Forest St., Suite 300 | Marlborough, MA 01752

**office** | 508-854-3636  
**mobile** | 508-340-7836  
**email** | [SPuski@babcockpower.com](mailto:SPuski@babcockpower.com)  
**web** | <https://www.babcockpower.com/bpe/>

---

**From:** Elliott, Carl  
**Sent:** Wednesday, October 10, 2018 1:33 PM  
**To:** Puski, Suzette <[SPuski@babcockpower.com](mailto:SPuski@babcockpower.com)>; Erickson, Clayton <[cerickson@babcockpower.com](mailto:cerickson@babcockpower.com)>  
**Subject:** Fwd: 400075.60.1000 181010 RSCR Budgetary Quote Request |

Please see below.

**Carl P. Elliott**  
Babcock Power Inc.  
Sr. Account Executive  
[3805 SW Sandstone Dr.](#)  
[Lees Summit, MO 64082](#)

Mobile: [816.527.7590](tel:816.527.7590)

[CElliott@babcockpower.com](mailto:CElliott@babcockpower.com)  
<http://www.babcockpower.com>

Sent from my iPhone

Begin forwarded message:

**From:** "Lee, Paul (Denver)" <[LeeP@bv.com](mailto:LeeP@bv.com)>  
**Date:** October 10, 2018 at 11:00:31 AM CDT  
**To:** "Elliott, Carl" <[CElliott@babcockpower.com](mailto:CElliott@babcockpower.com)>  
**Cc:** "Dittus, M. H. (Mark)" <[DittusM@bv.com](mailto:DittusM@bv.com)>, "Pauly, Josh S." <[PaulyJS@bv.com](mailto:PaulyJS@bv.com)>, "[megan.berge@bakerbotts.com](mailto:megan.berge@bakerbotts.com)" <[megan.berge@bakerbotts.com](mailto:megan.berge@bakerbotts.com)>, "[laura.williams@BakerBotts.com](mailto:laura.williams@BakerBotts.com)" <[laura.williams@BakerBotts.com](mailto:laura.williams@BakerBotts.com)>  
**Subject:** 400075.60.1000 181010 RSCR Budgetary Quote Request

This message is from OUTSIDE THE COMPANY - be CAUTIOUS, particularly with links and attachments.

Carl,

Per our phone conversation last week, please see below some information for a budgetary quote of an RSCR. I understand that the units that these are be investigated for are larger than what BPEI has done in the past, so they may not be a good fit. However, per the study that I am doing, I must at least evaluate them at a superficial level.

Parameter	Units	Case 1	Case 2
Flow rate	lb/hr	7,927,427	
	acfm	2,203,068	
Site Elevation	ft	1940	
Stack Pressure	in. w.g.	-1.1	
Fuel Burn Rate	MMBtu/hr	5,868.7	
Stack Temperature	F	147.4	
Inlet NOx	ppmvd actual O2	126	
	lb/MMBtu	0.13	
O2	Vol%,wet	4.9	
O2 reference	Vol%,dry	3.0	
H2O	Vol%,wet	16.4	
CO2	Vol%,wet	14.4	
SO2	ppmvd actual O2	48	
SO3	ppmvd actual O2	9	
Particulate	lb/hr	28.50	
Outlet NOx (guarantee)	ppmvd actual O2	39	
Ammonia Slip (guarantee)	ppmvd ref. O2	2	
SO2 to SO3 Oxidation Rate (guarantee)	%	0.5/catalyst layer	
Operating Hours (guarantee)	hours	24,000	

If you need anything else, please let me know. Thank you,

**Paul Lee, P.E.\***

Boiler and Air Quality Group, Energy

\*Licensed in CO

Black & Veatch

4600 South Syracuse Street, Suite 800, Denver, CO 80237

o +1 720-834-4303

e [LeeP@BV.com](mailto:LeeP@BV.com)

**Building a World of Difference.\***

**Please consider the environment before printing my email**

Please note that the information and attachments in this email are intended for the exclusive use of the addressee and may contain confidential or privileged information. If you are not the intended recipient, please do not forward, copy or print the message or its attachments. Notify me at the above address, and delete this message and any attachments. Thank you.



Dale Pfaff  
Regional Sales Manager

December 20, 2018

Ms. Megan Berge  
Baker Botts LLP  
1299 Pennsylvania Ave, NW  
Washington, D.C. 20004  
P: (202) 639-1308

**SUBJECT: GREAT RIVER ENERGY – REQUEST FOR PROPOSAL  
COAL CREEK STATION UNIT 2 ADVANCED SCR SYSTEM  
TECHNOLOGY EVALUATION AND SYSTEM COSTS  
FUEL TECH BUDGETARY PROPOSAL NO. 18-B-064, ADDENDUM 1**

Dear Ms. Berge:

Fuel Tech, Inc. (FTEK) is pleased to submit our preliminary and budgetary Proposal 18-B-064, Addendum 1, to Great River Energy (GRE) for the Coal Creek Station (CCS) Unit 2. The following evaluation provides the technical, performance, and commercial details for the FTEK Advanced Selective Catalytic Reduction (ASCR™) system for CCS Unit 2 located in Underwood, ND.

FTEK's ASCR evaluation assumes the NOxOUT® Selective Non-Catalytic Reduction (SNCR) system has already been installed on CCS Unit 2 (pricing, performance, and scope provided previously under separate cover). The scope of supply for the FTEK's ASCR Process would include the ASCR system design, process review, ammonia injection grids (AIGs), and our ULTRA System Urea conversion technology to convert urea to ammonia for the AIGs. Our systems would be controlled via the Plant's Honeywell DCS System.

**CC Unit 2 Unit Description and ASCR Layout:**

Coal Creek Station Unit 2 is a 600 MWg Combustion Engineering tangential fired boiler with eight corners and a divided furnace. The boiler fires 100% ND lignite coal with a heat input of 5,971 MMBTU/hr at full load. The Unit has Foster Wheeler Low NOx Combustion System with close coupled over fire air (CCOFA) and separated over fire air (SOFA) systems. The NOx baseline at full load is 0.121 lb/MMBTU.

For the ASCR system layout, it is assumed the SNCR system is already deployed and is controlling NOx down to 0.103 lb/MMBTU. See FTEK's Proposal 18-B-064 for the SNCR performance. The SNCR performance utilized for the ASCR design incorporates our combined injection strategy of wall injectors + multiple nozzle lances (MNLs) with a 10 ppm ammonia slip at the economizer outlet.

The ASCR system would replace the existing ductwork from the economizer outlet to the air preheater (APH) inlet. This ASCR system would include two (2) SCR reactors that would be expanded to provide the appropriate catalyst quantity and flue gas flow distribution requirements.

**Fuel Tech Inc.** • 27601 Bella Vista Parkway • Warrenville, IL 60555  
Phone: (970) 368-6019 • Cell: (847) 504-6650  
[dpfaff@ftek.com](mailto:dpfaff@ftek.com) • [www.ftek.com](http://www.ftek.com)

The current SCR performance includes 2 layers of catalyst to provide 33% NO<sub>x</sub> reduction with an ammonia slip of 2 ppm at the catalyst outlet. Each SCR reactor train would include an ammonia injection frid (AIG), turning vanes, distribution devices and catalyst reactor as highlighted in the following Figure.

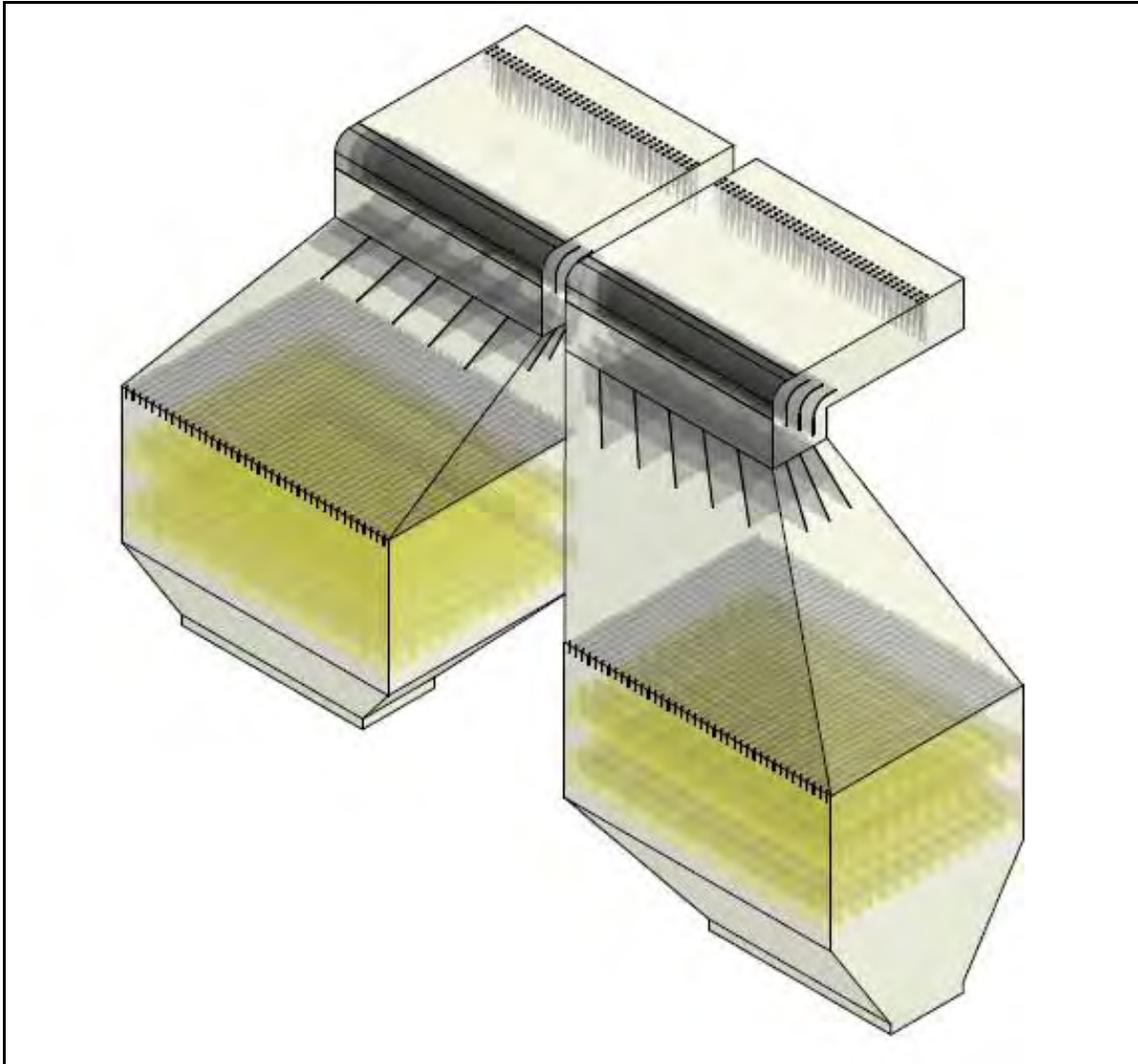


Figure 1 - GRE Coal Creek Unit 2 ASCR Preliminary Layout

See Appendices for more detailed drawings of the ASCR layout.

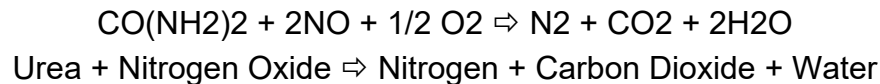
### **FTEK ASCR Process Description:**

#### **NO<sub>x</sub>OUT® Selective Non-Catalytic Reduction (SNCR) of NO<sub>x</sub> Process**

Fuel Tech's urea-based SNCR Process is a post-combustion NO<sub>x</sub> reduction method that reduces NO<sub>x</sub> through a controlled injection of an aqueous urea solution into the

combustion gas path of fossil-fired and waste-fired boilers, furnaces, incinerators, or heaters. The most commonly used reagent consists of a 50% urea solution plus a small amount of additives for scale and corrosion control. This reagent is readily available and requires no special safety precautions for handling.

The predominant overall reaction is described as:



Fuel Tech has enhanced the basic SNCR technology by developing chemical injection hardware, widening the applicable temperature range, and process control expertise required for commercial applications. Fuel Tech's urea based SNCR technology is the NOxOUT® process.

Two key parameters that affect the process performance are flue gas temperature and the reagent distribution. The NOx reducing reaction is temperature sensitive; by-product emissions become significant at lower than the optimum temperature range while chemical utilization and NOx reduction decrease at higher than the optimum. This optimum temperature range is specific to each application. The reagent needs to be distributed within this optimum temperature zone to obtain the best performance. Typically, the distribution is more difficult for large units and for units with high flue gas velocity.

Fuel Tech's SNCR Processes are designed with the aid of Computational Fluid Dynamics (CFD) and Chemical Kinetic Model (CKM) in addition to results from field tests. The CFD model simulates flue gas flows and temperature inside a unit while the CKM calculates the reaction between urea and NOx based on temperature and flow information from CFD. A combination of these two models determines the optimum temperature region and the optimum injection strategy to distribute the reagent. With an ability to estimate NOx reduction, a model study can be performed to determine if an application is a right fit for the process.

Chemical injectors developed by Fuel Tech facilitate the reagent distribution. The NOxOUT injection system utilizes air-atomized injectors which direct the urea solution into the combustion gas path. The droplet size distribution and spray coverage developed by the injectors promote efficient contact between the chemical and the NOx in the flue gas.

Fuel Tech's SNCR Processes provide effective boiler load following capabilities. Through the computer modeling, an injection strategy is developed that makes use of multilevel injection, control of reagent concentration, droplet size and spray patterns, as well as jet penetration.

Several years of field-testing indicate that NOxOUT systems are applicable on various types of units firing many different fuels. The process has been commercially proven on



units fired with coal, oil, gas, wood or municipal solid or hazardous waste. These units varied in size and type: package boilers, process heaters, incinerators, circulating or bubbling fluidized beds, waste heat boilers, utility boilers. By virtue of being a post-combustion process, unit size and type and fuel type have some, but not a major effect on the process.

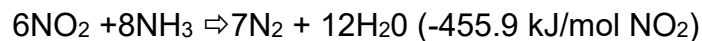
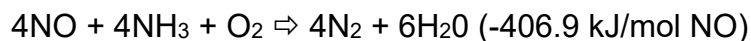
There are substantial benefits gained from the application of NO<sub>x</sub>OUT systems compared to first generation NO<sub>x</sub> control technologies, such as ammonia injection. These benefits are briefly summarized below:

- Use of non-toxic, non-hazardous chemicals.
- Potentially lower capital cost due to the lack of large system compressors and elimination of anhydrous ammonia storage, handling, and safety equipment.
- Lower operating costs resulting primarily from minimization of gas (steam or compressed air) requirements.
- Inherently more effective control of chemical distribution for better mixing with the use of liquid rather than gas-based reagents, thereby resulting in better chemical utilization.

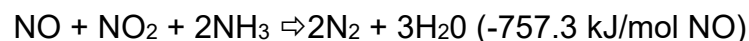
### **Advanced Selective Catalytic Reduction (ASCR®) of NO<sub>x</sub>**

Fuel Tech is a leader in development and deployment of a layered approach to NO<sub>x</sub> reduction combining technologies such as combustion modifications, SNCR, and a smaller implementation of SCR catalyst. Where SCR is involved, the combination of such proven technologies has come to be known as ASCR® Advanced SCR, or ASCR.

The SCR process is a post-combustion NO<sub>x</sub> reduction method that employs the use of catalyst to promote the conversion of nitrogen oxides (NO<sub>x</sub>) to nitrogen and water vapor in the flue gas. This conversion occurs between the combustion area and the exhaust gas stack in a specially designed ductwork section, called the SCR Reactor, which contains the catalyst. As the NO<sub>x</sub> and ammonia laden flue gas passes over the catalyst, the nitrogen monoxide (NO) and nitrogen dioxide (NO<sub>2</sub>) combine with ammonia (NH<sub>3</sub>) to form nitrogen (N<sub>2</sub>) and water (H<sub>2</sub>O), via the following exothermic reactions.



As long as a mixture of NO and NO<sub>2</sub> is present, the following faster reaction happens in parallel.

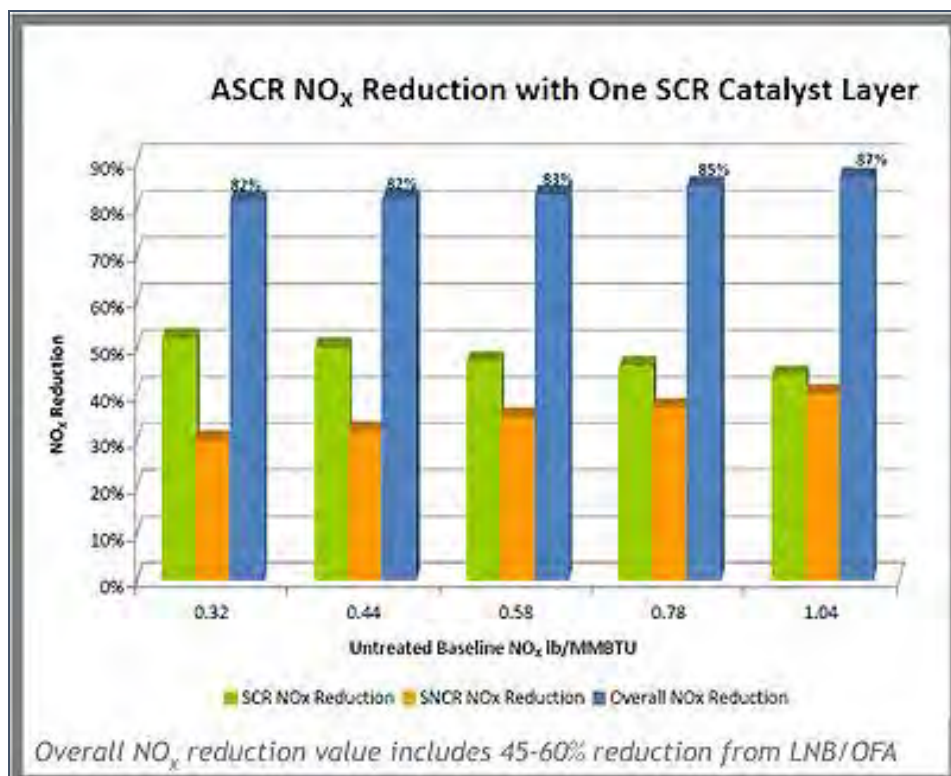


The distinguishing features that set Fuel Tech's ASCR technology apart are our commercial experience and state-of-the-art design capabilities that together allow us to



understand the working relationships of the combined NO<sub>x</sub> reduction technologies. These capabilities also allow FTEK to evaluate each application and tailor a solution that maximizes the contribution of each technology in our suite of offerings without pushing any one process to the point that it impacts boiler operation or negatively impacts another NO<sub>x</sub> reduction process downstream.

The ASCR process offers operational benefits due to its ability to quickly adapt to process condition changes and the fact that each deployed technology component can be optimized independently. This advantage manifests itself through a robust range of potential responses to process upsets or non-ideal operating conditions, and presents the opportunity for optimized urea consumption and lower operating costs.



**Figure 2 - NO<sub>x</sub> Reduction with Combined Technologies**

By utilizing an integrated technology approach, the catalyst quantity, weight, and space requirements can be minimized, potentially leading to the elimination of new foundations and the need to install new "steel to grade". Fuel Tech works with industry leading catalyst suppliers to determine the appropriate catalyst type and formulation for each application. With the concept of a smaller implementation of catalyst compared to standalone SCR, the ASCR system has the added benefit of minimizing the rate of SO<sub>2</sub> to SO<sub>3</sub> conversion which is a precursor to ammonium sulfate/bisulfate formation in the air heater. This low conversion rate allows for a broader unit operating range and fuel

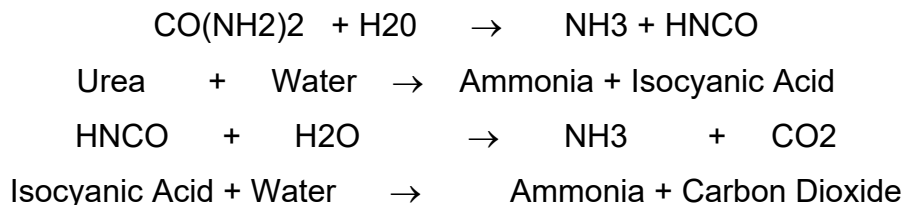
flexibility. In addition, the reduced volume of catalyst demands less time for replacement which results in shorter maintenance outages.

ASCR can be implemented in stages over time, providing financial advantages of both lower total installed capital costs and the ability to stage capital expenditures. Due to the various cost savings of a smaller SCR implementation, an ASCR system can achieve full scale SCR equivalent NOx reductions at 30-70% of the capital cost. Advanced SCR has now been applied on units up to 650 MWg.

### **ULTRA Process Description (Urea Conversion to Ammonia for SCR)**

Fuel Tech's ULTRA™ process is a patented approach that converts safe Urea reagent to Ammonia for use on new Selective Catalytic Reduction (SCR) systems and in retrofit applications for existing systems. The ULTRA technology offers a cost effective solution for simplifying on-site ammonia generation for SCR applications of all types.

The ULTRA System provides ammonia reagent to an SCR by controlling the injection of high quality aqueous urea into a compactly and specifically designed duct maintained within the appropriate temperature window. The reactions of the ULTRA Process are described as:



The use of urea in the ULTRA System eliminates all ammonia handling requirements so that the expenses, safety, and environmental concerns are eliminated. The urea solution is readily available for delivery in solution or in dry form for on-site solutionizing and requires no special safety precautions for handling which allows the aqueous solution to be stored in atmospheric tanks.

The aqueous urea solution, at a specific flow rate, is introduced into the hot air stream in at the top of the Decomposition Chamber. The chamber is specifically designed with the appropriate flow paths, residence time and post chamber HNCO catalyst to achieve a 100% conversion of urea to ammonia product.

The urea reagent is sprayed through proprietary chemical injectors developed by Fuel Tech to facilitate the reagent distribution, droplet size, and flow rate. Utilizing pressurized air from customer's existing plant compressed air system; these injectors atomize and direct the reagent into the dilution air stream of the ULTRA System.

The airflow through the Decomposition Chamber including the urea injection will be modeled using a computational fluid dynamics model with proprietary droplet trajectory

modeling. This will insure proper evaporation, mixing, and decomposition of injected urea reagent within the heated air stream.

The gas stream leaving the Decomposition Chamber containing the SCR reagent is then routed to the AIG. The pressure, flow, and temperature are monitored to conform to the requirements of the SCR system design and to maintain proper ULTRA operations.

The control of the urea injection will be based on a hardwired reagent demand signal from the Owner's DCS. A short residence time in the decomposition chamber will allow a rapid response time for SCR reagent production. The system will be able to shutdown almost instantaneously through halting of urea injection.

The ULTRA Process thermally decomposes urea and does not involve hydrolysis. The ULTRA design and process is simple to operate and has no disposal requirements for by-products during operation, start-up, and shutdown. The added benefits include the system's ability to be brought off line quickly, with very responsive boiler load following capabilities.

The features of the ULTRA system include:

- Safe Reagent Supply
- Skid mounted system for easy installation
- No requirement for formaldehyde free urea supply
- No hazardous material disposal that is common with the hydrolysis urea conversion process.
- Simplified process and controls compared to other systems (patent pending)
- Designed for maximum system availability and minimum maintenance
- Load following controls for safe operation and easy system shutdown
- Low pressure operation
- Fuel Tech's proven experience with urea-based systems
- Experience with proven system components

System supported by Fuel Tech's field personnel with startup, optimization and service experience.

### **FTEK Process Performance for GRE CCS Unit 2**

Unit Identification	Unit 2
Type of Unit	600 MW CE T-Fired, Eight (8) Corner, Divided Furnace
Type of Fuel	North Dakota Lignite
Load Range	100% MCR

**ASCR Expected Process Design Table**

Parameter	U/M	Units
Plant Elevation at Grade	ft above MSL	1940
Atmospheric Pressure at Grade	atm	0.93
Fuel		ND Lignite Coal
Flue Gas Analysis (at catalyst inlet)		
Flue Gas Flow, wet	SCFM	1,372,588
Flue Gas Flow, wet	lb/hr	6,143,001
Boiler Heat Input	mmBTU/hr	5,971
O <sub>2</sub>	% (by Volume)	2.60%
CO <sub>2</sub>	% (by Volume)	13.82%
N <sub>2</sub>	% (by Volume)	67.88%
H <sub>2</sub> O	% (by Volume)	15.61%
NO <sub>x</sub> , After SNCR w/MNLs, 10 ppm Slip	lb/mmBTU	0.103
SO <sub>2</sub>	ppm, dry @ Ref O <sub>2</sub>	830
SO <sub>3</sub>	ppm, dry @ Ref O <sub>2</sub>	9
NH <sub>3</sub> from SNCR	ppmw @ Op O <sub>2</sub>	10.00
Temperature	°F	820
Duct Pressure (Gauge)	inH <sub>2</sub> O	-5.5
Fly Ash Flow	lb/hr	82,924
Emissions and SCR Performance Requirements:		
Post SNCR NO <sub>x</sub> Emission Rate to Catalyst	lb/mmBTU	0.103
SCR Outlet NO <sub>x</sub> Emission Rate	lb/mmBTU	0.069
Catalyst SO <sub>2</sub> to SO <sub>3</sub> Oxidation Rate	%	4.0%
Ammonia Slip @ Catalyst Outlet	ppm, dry @ Ref O <sub>2</sub>	2
Catalyst lifetime	hours	16000
Catalyst draft loss (dirty)	in H <sub>2</sub> O	1.94
NO:NO <sub>x</sub> ratio (by volume)		0.90
Catalyst and NH <sub>3</sub> Design		
Catalyst Type (Honeycomb or Plate)		Honeycomb

Parameter	U/M	Units
Pitch	mm	7.4
# of reactors	#	2
# of modules per reactor per layer	#	117
# of layers per reactor	#	2
Single Layer Depth	mm	1,300
Total catalyst volume per reactor	m3	493.1
Total catalyst weight per reactor	lb	679,770
Ammonia Consumption per reactor	lb/hr	44.8
SCR Minimum Operating Temperature	°F	592

### **ULTRA System Expected Process Design Table**

<b>Two (2) Chambers Required - Information below is Per Chamber</b>		
ULTRA Heating Type	U/M	Electric
Case		Full Load
Flue gas flow	lb/hr	6143001
Baseline NOx	lb/MMBTU	0.103
Target NOx	lb/MMBTU	0.069
NOx Reduction	%	33
NH3 slip	ppm	2
Temperature requirements		
Dilution Air Temperature	(°F)	-31
Temperature at Decomposition Chamber outlet	(°F)	550
Pre-injection temperature at Decomposition Chamber	(°F)	856
At Decomposition Chamber outlet		
Ammonia Flow	(lb/hr)	47.9
Ammonia to air ratio	(vol%)	2.72
Total flow at Decomposition Chamber outlet	(scfm)	664
Total flow at Decomposition Chamber outlet	(lb/hr)	2923
Injection and duct burner requirements		
50% Aqueous Urea Flow Rate	(gph)	18.1

<b>Two (2) Chambers Required - Information below is Per Chamber</b>		
<b>ULTRA Heating Type</b>	<b>U/M</b>	<b>Electric</b>
Air flow through Decomposition Chamber	(scfm)	600
Air flow through Decomposition Chamber	(lb/hr)	2683
Injection air	(scfm)	15
Requirement to raise the temperature to pre-injection		
Heat Input (Electrical Heater)	(kW)	192

For FTEK to provide system and performance guarantees, we would be responsible for the design and supply of all ASCR “smart parts” which would include the flow modeling, SCR and reagent system process design, catalyst specification and procurement, internal flow and catalyst cleaning devices, and reagent and AIG system design and procurement. For the purpose of this evaluation, our current scope only includes the ASCR process design and modeling, reagent and AIG systems design and supply, and field services. See “Scope of Supply by Others” below.

### **FTEK Scope of Supply**

<b>Description</b>	<b>Quantity</b>
Ammonia Injection Grid, Design and Supply, Lances and Distribution Manifolds. Shipped loose for installation by Others	Two (2)
ULTRA Urea Conversion – Redundant Ambient Air Fans, Electric Heaters, Decomposition Chamber, Metering and Distribution Modules, w/Junction Boxes	Two (2)
ASCR Process Engineering Services including Flow Modeling, System Layout, Process Performance Review, and Preliminary General Arrangement Drawings for Ducts, SCR Reactor, and Internal Flow Distribution Devices	One (1) Lot

### **Scope of Supply by Others, BOP, and Utility Requirements**

1. Offloading of All Fuel Tech Supplied Equipment
2. Installation Labor and Materials for Fuel Tech, Inc. Supplied Equipment.
3. BOP and Installation Engineering, Installation Project Management
4. Interconnecting Piping and Wiring of Fuel Tech, Inc. Supplied Equipment.
5. Demolition of Existing Ductwork
6. Building and Boiler House Structural Steel Review and Redesign to Support New ASCR Ductwork, and SCR Reactor. Review of Building Interferences.
7. Cost for Demolition, New Structural Steel, Foundations, and Boiler House Modifications as Needed.



8. Costs for New Ductwork, Internal Flue Gas Flow Distribution Devices, Catalyst, Catalyst Reactor (Ductwork, Supports, and Seals), and External Insulation.
9. Sonic Horns and SCR Cleaning Devices (quantity TBD by others)
  - a. Operated on sequencing (typically, 10 seconds every 10 minutes)
10. Evaluate ID Fan Capacity and Boiler (Implosion Study) for Additional SCR Pressure Drop. Provide Modifications/Upgrades as Needed.
11. Replacement of Stack Reheat System and All Modified Equipment.
12. No Costs were included for Performance or Bid Bonding
13. Professional Engineering Stamps if required
14. Implement Control Logic Schemes into Plant DCS (as required).
  - a. Procurement of DCS Hardware (as required)
  - b. Graphic Screens Development and Programming
  - c. SNCR-related Distributed Control System Programming
15. Project Controls – Scheduling and Master Milestone Schedule
16. Air Compressors.
17. Chemical Supply: Licensed Quality or Industrial Grade urea (50% Solution).
18. Plant service water (NOxOUT® reagent) or demineralized water (unstabilized urea).
19. NOx, Ammonia, and CO Monitoring Equipment, if Required.
20. Structural Support for System Modules.
21. Appropriate Indoor Location/Building and Freeze Protection for FTEK Equipment as Required.
22. Permits as Required
23. Taxes as Required
24. Asbestos and Lead Paint Abatement, if Required
25. System Performance Testing
26. Spare Parts
27. Estimated System Utilities, Total:

<b>Description - Total</b>	<b>Instrument Air, SCFM (80 PSIG 70 °F)</b>	<b>Atomizing Air, SCFM (100 PSIG, Clean)</b>	<b>Flush Water, GPM (60 PSIG/60 °F)</b>	<b>Power, kW (480 VAC) <sup>(1)</sup></b>
ULTRA System, Total	10	30	2 (Intermittent)	450
	<b>Catalyst Pressure Drop, "W.C.</b>	<b>SCR System Pressure Drop, "W.C.</b>	<b>Additional 50% Aqueous Urea Usage, GPH</b>	<b>Sonic Horn Air, SCFM (80 PSIG 70 °F) <sup>(2)</sup></b>
ASCR, Total	2.0	4.0	36	320 (cycled, intermittent)

Note 1: Electric heaters and blowers

Note 2: Based on four (4) sonic horns being required with 40 – 80 SCFM per horn air consumption.



### **Schedule and Pricing:**

The following is a preliminary schedule for the FTEK provided equipment and engineering:

- ASCR Modeling, Design, and Layout – Twenty (20) Weeks from Receipt of PO.
- ULTRA System and AIG Design and Supply – Thirty (30) Weeks from Receipt of PO or Twenty-Six (26) Weeks from Confirmation of ASCR Confirmed Ammonia Demand Flow.

For the components, engineering, and field technical assistance detailed in this evaluation, FTEK quotes the preliminary and budgetary pricing of ~~XXXXXXXXXXXX~~.

### **FTEK Recommendations and Design Concerns**

FTEK has performed a "high level" evaluation of the ASCR process for GRE CCS Unit 2. As stated previously, the ASCR process is a component of a layered approach to NOx reduction combining technologies of combustion modifications/optimization, SNCR, and a smaller implementation of SCR catalyst. Upon preview of the system sizing and layout requirements, there are significant retrofit impacts for the catalyst reactors that must be considered.

The backend of Unit 2 has a split flue gas ductwork configuration leaving the economizer and entering the air heaters. Due to the ash loading of the ND Lignite at 10 – 12% ash and an "Si + Al" total > 80%, the ash particles are harder and may be erosive at higher velocities. Therefore, the catalyst face velocity has to be lowered to ~ 15 fps to minimize catalyst erosion. The ductwork expansion required to achieve adequate face velocities while providing adequate NOx reduction will require significant retrofit design consideration and will prove very costly. The ASCR duct expansion would require changes to and redesign of both the existing boiler structural steel and the stack reheat system.

In addition to the spatial limitations, FTEK has several process concerns regarding the sodium (Na) levels in the fuel/ash and sulfur trioxide (SO3) levels in flue gas. SO3 in the presence of ammonia (NH3) in the form of ammonia slip from the SCR process could lead to ammonium bisulfate plugging in the air heater. Additionally, the SO3 concentration in the flue gas may convert the Na in the solid phase to a gaseous phase which may cause significant catalyst deactivation.

To provide acceptable NOx reduction "activity" and catalyst life expectancy, the existing catalyst formulation has a ~2% oxidation rate per layer. This will cause SO2 in the flue gas to be converted to SO3 which in turn could lead to ammonium bisulfate pluggage of the catalyst and air heater along with accelerated catalyst deactivation rates due to Na poisoning.





Great River Energy  
Coal Creek Station Unit 2  
ASCR Budgetary Evaluation

December 20, 2018  
Proposal 18-B-064, Addm 1  
Page 13

For these reasons, FTEK would not recommend the deployment of the ASCR technology on CCS Unit 2. We would not be willing to provide any performance guarantees on the SCR portion at this time until more is known about the effects of ND lignite ash on catalyst performance and deactivation. FTEK would recommend that pilot scale testing should be performed to obtain actual operational data and learn more about the ND Lignite and prove catalyst operation and performance.

We trust this information meets your needs. Upon completion of your review, please do not hesitate to contact me if there are any questions or comments. Thank you.

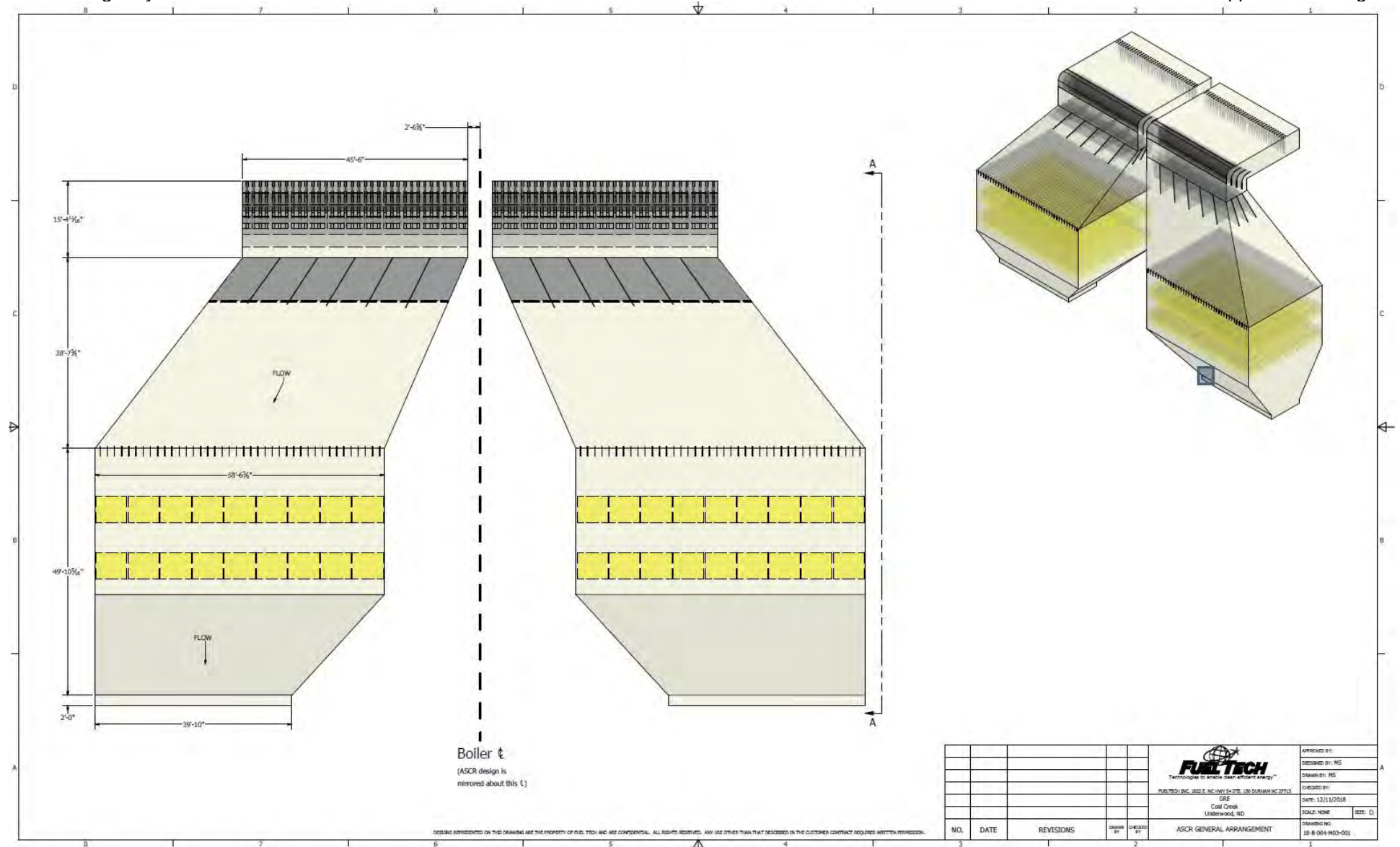
Sincerely,

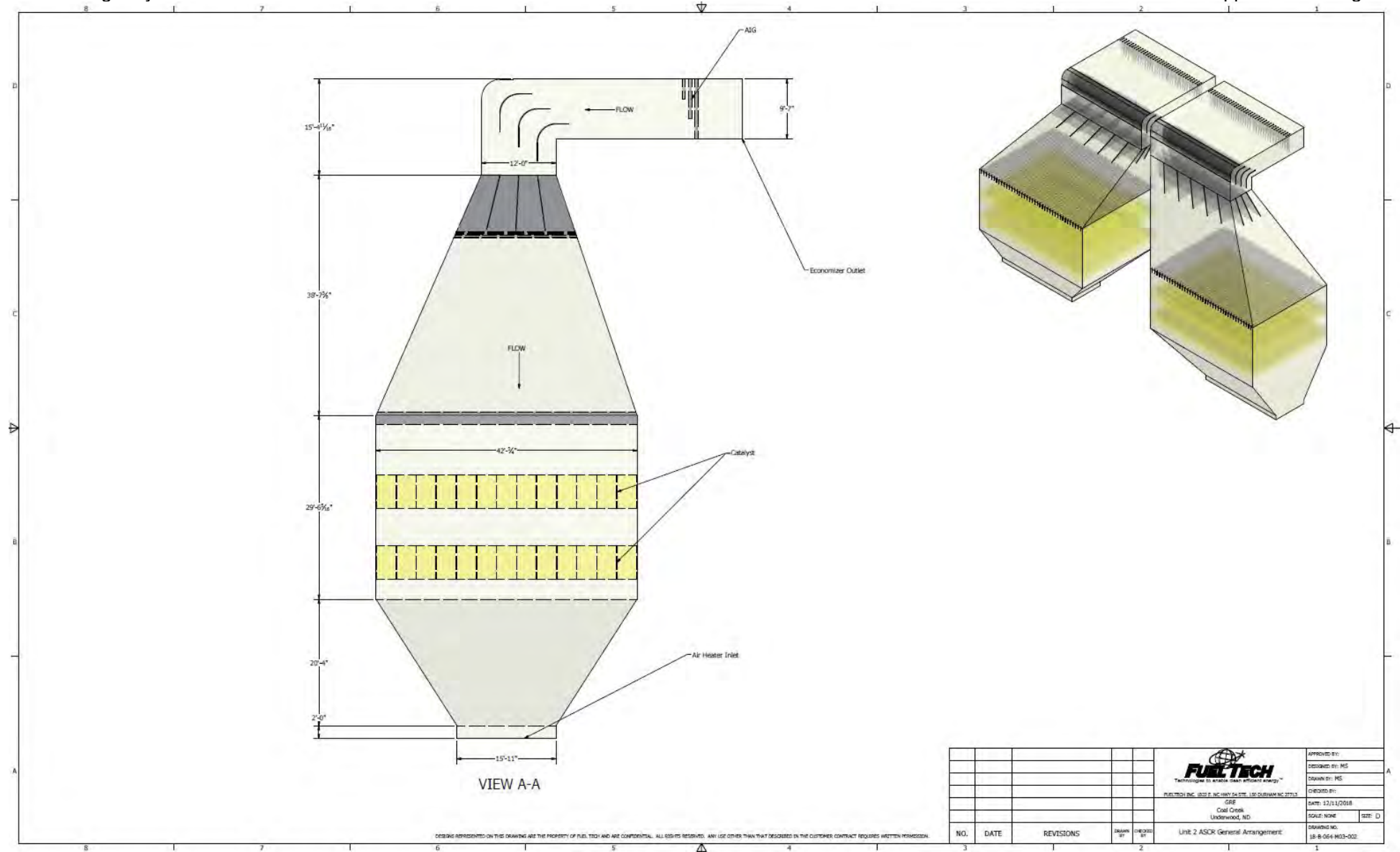
Dale Pfaff  
Regional Sales Manager

cc:

Mary Jo Roth, GRE  
Greg Heinz, GRE  
Paul Lee, B&V  
Mark Dittus, B&V  
William Cummings, FTEK

Kevin Dougherty, FTEK  
Terry Brown, FTEK  
Mark Siebeking, FTEK  
Joe DiFiglio, FTEK  
Volker Rummenhohl, FTEK





## Appendix F. Texas and WRAP Data



State	Facility Name	ORFID/ID	Unit ID	Year	Operating Time	Notes	Generate Capacity (MW)	Nameplate Capacity Factor	Heat Rate (Btu/mwhr)	Case 1 MW/h or Higher)	BSF	Nox ER	SO2 ER	N0x (tons)	SO2 Tons	Gross Load (MWh/h)	Avg. NOx Rate (lb/MWhr)	SO2 ER	N0x (tons)	SO2 (tons)	CO2 (short tons)	Heat Input (MMBtu)	Operator	SO2 Control(s)	NOx Control(s)
AZ	Apache Station	160	2	2014	8,618		10,690		1,476,833		0.349					2,773	2,037	1,613,243	1,538-07	Arizona Electric Power Cooperative	Wet Lime FGD		Overfire Air		
AZ	Apache Station	160	3	2015	7,793		10,543		965,351,389		1,697					1,861	1,139	1,033,108	1,538-07	Arizona Electric Power Cooperative	Wet Lime FGD		Overfire Air		
AZ	Apache Station	160	4	2016	8,356		10,308		1,018,624		0.351					1,950	400	1,063,400	1,538-07	Arizona Electric Power Cooperative	Wet Lime FGD		Overfire Air		
AZ	Apache Station	160	2	2017	5,660	on gas as of Dec 2017	10,245		2018 YTD YTD	2018 YTD						1,319	123	773,625	7,638-06	Arizona Electric Power Cooperative	Wet Lime FGD		Overfire Air		
						2018 YTD on gas			2018 YTD HR =			0.066	0.000	338	0	723,880	0.066		250	2	440,055	7,41-06			
AZ	Apache Station	160	3	2014	7,851		204	82%	10,544							3,228	2,774	1,573,258	1,544-07	Arizona Electric Power Cooperative	Wet Lime FGD		Overfire Air		
AZ	Apache Station	160	3	2015	8,221			88%	10,566							2,642	1,423	1,268,718	1,540-07	Arizona Electric Power Cooperative	Wet Lime FGD		Overfire Air		
AZ	Apache Station	160	3	2016	7,046			87%	10,335							2,796	556	1,261,877	1,540-07	Arizona Electric Power Cooperative	Wet Lime FGD		Overfire Air		
AZ	Apache Station	160	3	2017	6,912	SNCR 2017 (0.23 by permit)		58%	10,365	85%	2018 YTD					1,663	189	1,097,580	1,081-07	Arizona Electric Power Cooperative	Wet Lime FGD		Overfire Air		
									Average HR =	10,377	1,518,984	0.184	0.015	1,450	275										
AZ	Cholla	113	1	2014	8,183				856,272	0		980	604	989,512	9,646-07	Arizona Public Service Company							Wet Lime FGD	Low NOx Burner Technology w/ Separated OFA	
AZ	Cholla	113	1	2015	7,182				848,665	0		807	467	801,503	7,811-06	Arizona Public Service Company								Wet Lime FGD	Low NOx Burner Technology w/ Separated OFA
AZ	Cholla	113	1	2016	8,394				142,285	0		91	189	189,502	9,181-06	Arizona Public Service Company								Wet Lime FGD	Low NOx Burner Technology w/ Separated OFA
AZ	Cholla	113	1	2017	8,850	2025 retirement			442,279	0		452	244	567,943	5,546-07	Arizona Public Service Company								Wet Lime FGD	Low NOx Burner Technology w/ Separated OFA
AZ	Cholla	113	2	2014	7,722				1,835,723	0		2,783	1,136	1,929,369	1,888-07	Arizona Public Service Company								Wet Lime FGD	Low NOx Burner Technology w/ Closed-coupled
AZ	Cholla	113	2	2015	8,836	retired			1,210,852	0		1,859	1,131	1,291,665	1,286-07	Arizona Public Service Company								Wet Lime FGD	Low NOx Burner Technology w/ Closed-coupled
AZ	Cholla	113	3	2014	7,244				1,733,323	0		2,054	657	1,963,436	1,916-07	Arizona Public Service Company								Wet Lime FGD	Low NOx Burner Technology w/ Closed-coupled
AZ	Cholla	113	3	2015	6,737				1,436,796	0		1,677	646	1,668,827	1,633-07	Arizona Public Service Company								Wet Lime FGD	Low NOx Burner Technology w/ Closed-coupled
AZ	Cholla	113	3	2016	3,873				659,839	0		674	342	740,142	7,411-06	Arizona Public Service Company								Wet Lime FGD	Low NOx Burner Technology w/ Closed-coupled
AZ	Cholla	113	3	2017	7,520	2025 retirement			1,413,113	0		1,510	649	1,679,756	1,644-07	Arizona Public Service Company								Wet Lime FGD	Low NOx Burner Technology w/ Closed-coupled
AZ	Cholla	113	4	2014	6,098				2,893,267	0		3,089													



COLORADO UNITS

State	Facility Name	Facility ID (COPRPL)	Unit ID	Year	Operating Time	Notes	Netnameplate Capacity (MW)	Netnameplate Capacity Factor	Heat Rate (mmBtu/kwhr)	Case 1 MW-hr or Higher	BSN	NOx ER	SO2 ER	NOx (tons)	SO2 (tons)	Gross Load (MW)	Avg. NOx Rate (lb/MMBtu)	SO2 ER (calculated)	NOx (tons)	SO2 (tons)	CO2 (short tons)	Heat Input (MMBtu)	Operator	SO2 Controls	NOx Controls
CO	Cherokee	460	3	2014	8,535	retired in 2015										1,146,353	0.536		1,997	1,688	1,216,963	1,264	Public Service Company of Colorado	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air
CO	Cherokee	460	3	2014	8,535	retired in 2015										956,325	0.509		792	749	555,617	515	Public Service Company of Colorado	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air
CO	Cherokee	460	4	2014	7,343		381	67%	10,366	3,343	1,771	2,572,875	2,367	1,771	2,572,875	2,367	1,771	2,572,875	2,367	1,771	2,572,875	2,367	Public Service Company of Colorado	Dry Lime FGD	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
CO	Cherokee	460	4	2013	7,511			63%	11,392	2,006,364	0.271	0.158	3,407	1,802	2,453,615	2,467	1,802	2,453,615	2,467	1,802	2,453,615	2,467	Public Service Company of Colorado	Dry Lime FGD	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
CO	Cherokee	460	4	2014	8,507	switched to gas 10/1/17			10,825	2,170,966	0.281	0.162	3,382	1,901	2,397,497	2,467	1,901	2,397,497	2,467	1,901	2,397,497	2,467	Public Service Company of Colorado	Dry Lime FGD	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
CO	Cherokee	460	4	2017	5,507				11,217	1,950,726	0.277	0.168	3,391	1,911	2,411,428	2,467	1,911	2,411,428	2,467	1,911	2,411,428	2,467	Public Service Company of Colorado	Dry Lime FGD (Retired Sep 30, 2017)	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
									2018 YTD HR +	11,159	999,043	0.071	0.000	397	4	749,283	0.071		305	8	495,658	8,416			
CO	Comanche (470)	470	1	2014	6,909				12,020	2,120,620	0.130	0.077	1,234	726	1,969,839	1,917	726	1,969,839	1,917	726	1,969,839	1,917	Public Service Company of Colorado	Dry Lime FGD	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
CO	Comanche (470)	470	1	2013	8,145				12,227,104	0.118	0.074	1,210	733	2,105,839	2,087	733	2,105,839	2,087	733	2,105,839	2,087	Public Service Company of Colorado	Dry Lime FGD	Low NOx Burner Technology w/ Closed-coupled/Separated OFA	
CO	Comanche (470)	470	1	2014	8,127				12,374,436	0.112	0.081	1,302	815	2,312,728	2,245	815	2,312,728	2,245	815	2,312,728	2,245	Public Service Company of Colorado	Dry Lime FGD	Low NOx Burner Technology w/ Closed-coupled/Separated OFA	
CO	Comanche (470)	470	1	2017	7,785	2022 retirement			12,241,968	0.118	0.088	1,255	822	2,187,267	2,114	822	2,187,267	2,114	822	2,187,267	2,114	Public Service Company of Colorado	Dry Lime FGD	Low NOx Burner Technology w/ Closed-coupled/Separated OFA	
CO	Comanche (470)	470	2	2014	8,494				12,546,999	0.181	0.076	2,089	973	2,460,133	2,617	973	2,460,133	2,617	973	2,460,133	2,617	Public Service Company of Colorado	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air	
CO	Comanche (470)	470	2	2013	8,122				12,529,241	0.148	0.076	1,930	973	2,679,647	2,667	973	2,679,647	2,667	973	2,679,647	2,667	Public Service Company of Colorado	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air	
CO	Comanche (470)	470	2	2014	8,939				12,605,389	0.154	0.061	1,923	863	2,165,996	2,617	863	2,165,996	2,617	863	2,165,996	2,617	Public Service Company of Colorado	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air	
CO	Comanche (470)	470	2	2017	8,390	2025 retirement			12,653,858	0.162	0.085	2,211	1,146	2,831,988	2,767	1,146	2,831,988	2,767	1,146	2,831,988	2,767	Public Service Company of Colorado	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air	
CO	Comanche (470)	470	3	2014	8,467		857	58%	8,958	4,372,431	0.058	0.075	1,333	1,459	4,002,522	3,987	1,459	4,002,522	3,987	1,459	4,002,522	3,987	Public Service Company of Colorado	Dry Lime FGD	Selective Catalytic Reduction
CO	Comanche (470)	470	3	2013	8,788				9,132	4,655,984	0.066	0.074	1,405	1,569	4,451,718	4,367	1,569	4,451,718	4,367	1,569	4,451,718	4,367	Public Service Company of Colorado	Dry Lime FGD	Selective Catalytic Reduction
CO	Comanche (470)	470	3	2014	8,019	representative year			724	5,453,056	0.060	0.085	1,605	2,067	5,189,494	5,067	2,067	5,189,494	5,067	2,067	5,189,494	5,067	Public Service Company of Colorado	Dry Lime FGD	Selective Catalytic Reduction
CO	Comanche (470)	470	3	2017	7,238	major overhaul year			88%	9,941	85%	2017	2017												Selective Catalytic Reduction
									Average HR +	9,072	6,379,733	0.066	0.083	1,919	2,418										
CO	Craig	6021-C1		2014	7,017					2,865,104	0.260	0.056	3,768	799	3,013,854	2,967	799	3,013,854	2,967	799	3,013,854	2,967	Tri-State Generation & Transmission	Wet Limestone	Low NOx Burner Technology w/ Overfire Air
CO	Craig	6021-C1		2013	8,528					3,211,106	0.246	0.048	4,035	770	3,350,738	3,267	770	3,350,738	3,267	770	3,350,738	3,267	Tri-State Generation & Transmission	Wet Limestone	Low NOx Burner Technology w/ Overfire Air
CO	Craig	6021-C1		2014	7,097					2,465,878	0.239	0.048	3,746	367	2,778,527	2,667	367	2,778,527	2,667	367	2,778,527	2,667	Tri-State Generation & Transmission	Wet Limestone	Low NOx Burner Technology w/ Overfire Air
CO	Craig	6021-C1		2013	8,343	12/31/2025 retirement				3,062,868	0.246	0.045	3,784	874	3,165,996	3,067	874	3,165,996	3,067	874	3,165,996	3,067	Tri-State Generation & Transmission	Wet Limestone	Low NOx Burner Technology w/ Overfire Air
CO	Craig	6021-C2		2014	8,549		446	88%	9,854	3,478,091	0.260	0.055	4,683	763	3,594,704	3,487	763	3,594,704	3,487	763	3,594,704	3,487	Tri-State Generation & Transmission	Wet Limestone	Low NOx Burner Technology w/ Overfire Air
CO	Craig	6021-C2		2013	7,637					2,864,197	0.240	0.050	3,601	773	3,009,108	2,967	773	3,009,108	2,967	773	3,009,108	2,967	Tri-State Generation & Transmission	Wet Limestone	Low NOx Burner Technology w/ Overfire Air
CO	Craig	6021-C2		2014	8,115					3,112,476	0.247	0.046	3,889	729	3,271,088	3,147	729	3,271,088	3,147	729	3,271,088	3,147	Tri-State Generation & Transmission	Wet Limestone	Low NOx Burner Technology w/ Overfire Air
CO	Craig	6021-C2		2017	6,913	SCR 2017 (08 by permit)			83%	10,109	85%	2018HR	2017			2,452,238	0.219	0.045	2,787	362	2,199,907	2,547	Tri-State Generation & Transmission	Wet Limestone	Low NOx Burner Technology w/ Overfire Air
									Average HR +	9,382	1,123,894	0.059	0.045	979	732										
CO	Craig	6021-C3		2014	8,334		535	79%	9,146	3,678,128	0.314	0.119	5,368	2,001	3,551,930	3,487	2,001	3,551,930	3,487	2,001	3,551,930	3,487	Tri-State Generation & Transmission	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air
CO	Craig	6021-C3		2013	8,177					2,647,449	0.276	0.126	4,426	1,426	2,811,669	2,547	1,426	2,811,669	2,547	1,426	2,811,669	2,547	Tri-State Generation & Transmission	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air
CO	Craig	6021-C3		2014	8,139					1,518,931	0.189	0.140	4,334	2,038	3,051,448	2,967	2,038	3,051,448	2,967	2,038	3,051,448	2,967	Tri-State Generation & Transmission	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air
CO	Craig	6021-C3		2017	8,157	SNCR 2017 (28 by permit)			58%	9,265	85%	2018HR	2017			1,168,884	0.278	0.136	4,158	1,448	3,078,660	2,967	Tri-State Generation & Transmission	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air
									Average HR +	9,384	2,982,121	0.212	0.126	3,319	2,328										
CO	Hayden	525-H1		2014	8,458		190	98%	11,384	1,462,989	0.299	0.100	2,486	1,003	1,714,616	1,767	1,003	1,714,616	1,767	1,003	1,714,616	1,767	Public Service Company of Colorado	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air
CO	Hayden	525-H1		2013	8,895	outage for scr install				1,153,825	0.325	0.120	2,158	779	1,335,720	1,367	779	1,335,720	1,367	779	1,335,720	1,367	Public Service Company of Colorado	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air-Selective Catalytic Reduction (Began Aug 25, 2015)
CO	Hayden	525-H1		2018	8,335					1,308,976	0.043	0.122	294	842	1,430,656	1,467	294	1,430,656	1,467	294	1,430,656	1,467	Public Service Company of Colorado	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air-Selective Catalytic Reduction
CO	Hayden	525-H2		2013	8,671	representative				1,456,468	85%	2017	2017			5,245,720	0.042	0.122	3,205	821	5,546,568	1,567	Public Service Company of Colorado	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air-Selective Catalytic Reduction
									Average HR +	11,427	1,414,740	0.043	0.122	343	987										
CO	Hayden	525-H2		2014	8,648		275	81%	10,030	1,954,302	0.268	0.122	2,654	1,226	2,011,222	2,087	1,226	2,011,222	2,087	1,226	2,011,222	2,087	Public Service Company of Colorado	Dry Lime FGD	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
CO	Hayden	525-H2		2013	8,449					2,013,548	0.272	0.120	2,734	1,214	2,066,903	2,087	1,214	2,066,903	2,087	1,214	2,066,903	2,087	Public Service Company of Colorado	Dry Lime FGD	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
CO	Hayden	525-H2		2018	7,127	outage for scr install				1,495,242	0.173	0.119	1,269	855	1,476,117	1,467	855	1,476,117	1,467	855	1,476,117	1,467	Public Service Company of Colorado	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air-Selective Catalytic Reduction (Began Jun 28, 2018)
CO	Hayden	525-H2		2017	8,156	representative			61%	9,463	85%	2017	2017			1,571,746	0.045	0.113	317	971	1,547,186	1,567	Public Service Company of Colorado	Dry Lime FGD	Low NOx Burner Technology w/ Closed-coupled/Separated OFA-Selective Catalytic Reduction
									Average HR +	9,860	2,050,628	0.045	0.123	457	1,239										
CO	Martin Drake	482	5	2014	2,657					112,643	0.042		217	278	128,603	1,264	278	128,603	1,264	278	128,603	1,264	Colorado Springs Utilities		Low NOx Burner Technology (Dry Bottom only)
CO	Martin Drake	482	5	2013	5,565					225,496	0.190		493	585	288,172	2,864	585	288,172	2,864	585	288,172	2,864	Colorado Springs Utilities		Low NOx Burner Technology (Dry Bottom only)
CO	Martin Drake	482	5	2014	161	retired				3,777	0.312		9	9	4,682	5,184	9	4,682	5,184	9	4,682	5,184	Colorado Springs Utilities		Low NOx Burner Technology (Dry Bottom only)
CO	Martin Drake	482	6	2014	6,468		75	67%	12,019	438,001	0.226	0.482	680	1,272	550,000	5,106	1,272	550,000	5,106	1,272	550,000	5,106	Colorado Springs Utilities		Low NOx Burner Technology (Dry Bottom only) (Retired Sep 30, 2014)-dry Low NOx Burner Technology w/ Overfire Air (Began Oct 01, 2014)
CO	Martin Drake	482	6	2013	8,143					520,784	0.215	0.468	670	1,440	648,813	6,226	1,440	648,813	6,226	1,440	648,813	6,226	Colorado Springs Utilities		Low NOx Burner Technology w/ Overfire Air
CO	Martin Drake	482	6	2014	7,273	scr controls installed				11,715	85%	2017	2018 YTD			396,380	0.208	0.312	490	724	485,441	4,664	Colorado Springs Utilities	Dual Alkal (Began Sep 26, 2018)	Low NOx Burner Technology w/ Overfire Air
CO	Martin Drake	482	6	2017	7,916					11,362	85%	2017	2018 YTD			447,960	0.215	0.032	556	82	523,628	5,106	Colorado Springs Utilities	Dual Alkal	Low NOx Burner Technology w/ Overfire Air
									Average HR +	11,255	558,450	0.215													

## MONTANA UNITS

State	Facility Name	Facility ID (RRSP#)	Unit ID	Year	Operating Time	Notes	Nameplate Capacity (MW)	Nameplate Capacity Factor (%)	Heat Rate (mmBtu/kWhr)	Case 1 MW-h (85% or Higher)	Nox ER	SO <sub>2</sub> ER	Nox (tons)	SO <sub>2</sub> Tons	Gross Load (MW-h)	Avg. NOx Rate (lb/MW-hr)	SO <sub>2</sub> ER	Nox (tons)	SO <sub>2</sub> (tons)	CO2 (short tons)	Heat Input (MMBtu)	Operator	NO <sub>x</sub> Controls	Nox Controls
MT	Colstrip	6076	1	2015	2,920										2,254,365	0.292		3,881	2,603	2,504,418	2.4E+07	P & B L Montana, LLC	Wet Lime FGD	Low Nox Burner Technology w/ Closed-coupled OFA
MT	Colstrip	6076	1	2015	8,055										2,244,281	0.327		3,797	2,038	2,370,011	2.3E+07	P & B L Montana, LLC, Talen Montana, LLC	Wet Lime FGD	Low Nox Burner Technology w/ Closed-coupled OFA
MT	Colstrip	6076	1	2016	6,779										1,824,035	0.340		3,475	1,740	2,089,555	2.0E+07	Talen Montana, LLC	Wet Lime FGD	Low Nox Burner Technology w/ Closed-coupled OFA
MT	Colstrip	6076	1	2017	6,788	2022 retirement									1,792,272	0.344		3,236	1,936	1,945,022	1.9E+07	Talen Montana, LLC	Wet Lime FGD	Low Nox Burner Technology w/ Closed-coupled OFA
MT	Colstrip	6076	2	2014	8,458										2,275,561	0.308		3,567	3,518	2,586,849	2.5E+07	P & B L Montana, LLC	Wet Lime FGD	Low Nox Burner Technology w/ Closed-coupled OFA
MT	Colstrip	6076	2	2015	6,956										1,857,608	0.218		2,229	1,848	2,188,185	2.1E+07	P & B L Montana, LLC, Talen Montana, LLC	Wet Lime FGD	Low Nox Burner Technology w/ Closed-coupled OFA
MT	Colstrip	6076	2	2016	8,045										2,152,697	0.144		1,737	2,056	2,486,107	2.4E+07	Talen Montana, LLC	Wet Lime FGD	Low Nox Burner Technology w/ Closed-coupled OFA
MT	Colstrip	6076	2	2017	6,043	2022 retirement									2,180,091	0.159		1,890	2,526	2,445,267	2.3E+07	Talen Montana, LLC	Wet Lime FGD	Low Nox Burner Technology w/ Closed-coupled OFA
MT	Colstrip	6076	3	2014	6,994		778	73%	10,157						5,006,381	0.159	0.087	4,093	2,207	4,093,207	5.1E+07	P & B L Montana, LLC	Wet Lime FGD	Low Nox Burner Technology w/ Closed-coupled/separated OFA
MT	Colstrip	6076	3	2015	8,448			90%	9,964						6,116,257	0.164	0.095	5,053	2,903	6,391,958	6.1E+07	P & B L Montana, LLC, Talen Montana, LLC	Wet Lime FGD	Low Nox Burner Technology w/ Closed-coupled/separated OFA
MT	Colstrip	6076	3	2016	8,146			83%	9,977						5,633,089	0.158	0.093	4,505	2,603	5,894,418	5.6E+07	Talen Montana, LLC	Wet Lime FGD	Low Nox Burner Technology w/ Closed-coupled/separated OFA
MT	Colstrip	6076	3	2017	7,251			74%	9,816	85%	2017	2017			5,029,733	0.149	0.092	3,753	2,280	5,178,018	4.9E+07	Talen Montana, LLC	Wet Lime FGD	Low Nox Burner Technology w/ Closed-coupled/separated OFA
								Average HR =	9,979	5,792,988	0.149	0.092	4,301	2,668										
MT	Colstrip	6076	4	2014	7,915		778	81%	10,109						5,551,215	0.164	0.088	4,592	2,474	5,885,405	5.6E+07	P & B L Montana, LLC, Talen Montana, LLC	Wet Lime FGD	Low Nox Burner Technology w/ Closed-coupled/separated OFA
MT	Colstrip	6076	4	2015	8,481			91%	10,084						6,170,099	0.165	0.092	5,660	2,864	6,525,755	6.2E+07	P & B L Montana, LLC, Talen Montana, LLC	Wet Lime FGD	Low Nox Burner Technology w/ Closed-coupled/separated OFA
MT	Colstrip	6076	4	2016	7,385			75%	9,821						5,118,577	0.151	0.093	3,817	2,328	5,272,267	5.0E+07	Talen Montana, LLC	Wet Lime FGD	Low Nox Burner Technology w/ Closed-coupled/separated OFA
MT	Colstrip	6076	4	2017	8,449			84%	9,480	85%	2017	2017			5,705,121	0.154	0.088	4,195	2,382	5,672,252	5.4E+07	Talen Montana, LLC	Wet Lime FGD	Low Nox Burner Technology w/ Closed-coupled/separated OFA
								Average HR =	9,879	5,792,988	0.154	0.088	4,410	2,519										
MT	Hardin Generating Station	55749	U1	2014	7,175										766,446	0.079		359	391	931,025	8.9E+06	Colorado Energy Management, LLC	Dry Lime FGD	Low Nox Burner Technology (Dry Bottom only)w/Selective Catalytic Reduction
MT	Hardin Generating Station	55749	U1	2015	5,424										553,747	0.079		259	297	672,248	6.4E+06	Colorado Energy Management, LLC	Dry Lime FGD	Low Nox Burner Technology (Dry Bottom only)w/Selective Catalytic Reduction
MT	Hardin Generating Station	55749	U1	2016	5,320										392,352	0.079		185	209	483,941	4.6E+06	Colorado Energy Management, LLC	Dry Lime FGD	Low Nox Burner Technology (Dry Bottom only)w/Selective Catalytic Reduction
MT	Hardin Generating Station	55749	U1	2017	3,379	retired in 2017									133,348	0.080		66	72	169,936	1.6E+06	Colorado Energy Management, LLC	Dry Lime FGD	Low Nox Burner Technology (Dry Bottom only)w/Selective Catalytic Reduction
MT	F E Corlette	2187	2	2014	5,283										622,024	0.260		864	1,620	687,763	6.6E+06	P & B L Montana, LLC	Wet Lime FGD	Low Nox Burner Technology w/ Closed-coupled OFA
MT	F E Corlette	2187	2	2015	1,470										164,196	0.270		234	435	184,427	1.8E+06	P & B L Montana, LLC, Talen Montana, LLC	Wet Lime FGD	Low Nox Burner Technology w/ Closed-coupled OFA
MT	Lewis & Clark	6089	B1	2014	7,679		50	72%	12,772						317,318	0.368	0.516	753	1,045	440,778	4.1E+06	Montana Dakota Utilities Company	Wet Lime FGD	Low Nox Burner Technology w/ Closed-coupled OFA
MT	Lewis & Clark	6089	B1	2015	6,123			56%	12,412						244,033	0.372	0.452	573	685	329,141	3.0E+06	Montana Dakota Utilities Company	Wet Lime FGD	Low Nox Burner Technology w/ Closed-coupled OFA
MT	Lewis & Clark	6089	B1	2016	7,574			66%	11,931						287,157	0.361	0.020	624	35	372,294	3.4E+06	Montana Dakota Utilities Company	Wet Lime FGD	Low Nox Burner Technology w/ Closed-coupled OFA
MT	Lewis & Clark	6089	B1	2017	6,351			57%	12,485	85%	2017	2017			249,664	0.368	0.016	579	25	338,821	3.1E+06	Montana Dakota Utilities Company	Wet Lime FGD	Low Nox Burner Technology w/ Closed-coupled OFA
								Average HR =	12,400	372,300	0.368	0.016	848	37										



## NEVADA UNITS

State	Facility Name	Facility ID (ORISPL)	Unit ID	Year	Operating Time	Notes	Nameplate Capacity (MW)	Nameplate Capacity Factor	Heat Rate (mmbtu/kwhr)	Case 1 MW-h (85% or Higher)	NOx ER	SO2 ER	NOx (tons)	SO2 Tons	Gross Load (MW-h)	Avg. NOx Rate (lb/MMBtu)	SO2 ER	NOx (tons)	SO2 (tons)	CO2 (short tons)	Heat Input (MMBtu)	Operator	SO2 Control(s)	NOx Control(s)
NV	North Valmy	8224	1	2014	7,740										1,662,293	0.288		2,243	6,363	1,600,173	1.5E+07	Sierra Pacific Power Company		Low NOx Burner Technology (Dry Bottom only)
NV	North Valmy	8224	1	2015	7,662										1,296,560	0.293		1,688	4,470	1,211,930	1.3E+07	Sierra Pacific Power Company		Low NOx Burner Technology (Dry Bottom only)
NV	North Valmy	8224	1	2016	3,433										557,937	0.321		797	1,848	513,084	4.9E+06	Sierra Pacific Power Company		Low NOx Burner Technology (Dry Bottom only)
NV	North Valmy	8224	1	2017	2,327										353,877	0.365		587	1,232	341,292	3.3E+06	Sierra Pacific Power Company		Low NOx Burner Technology (Dry Bottom only)
NV	North Valmy	8224	2	2014	6,372										1,340,468	0.326		2,229	1,454	1,376,276	1.3E+07	Sierra Pacific Power Company	Dry Lime FGD	Low NOx Burner Technology (Dry Bottom only)
NV	North Valmy	8224	2	2015	2,116										328,737	0.294		580	413	376,075	3.6E+06	Sierra Pacific Power Company	Dry Lime FGD	Low NOx Burner Technology (Dry Bottom only)
NV	North Valmy	8224	2	2016	3,134										535,465	0.291		839	431	575,186	5.5E+06	Sierra Pacific Power Company	Dry Lime FGD	Low NOx Burner Technology (Dry Bottom only)
NV	North Valmy	8224	2	2017	2,441										403,652	0.297		674	356	439,962	4.2E+06	Sierra Pacific Power Company	Dry Lime FGD	Low NOx Burner Technology (Dry Bottom only)
NV	Reid Gardner	2324	1	2014	6,938										639,070	0.371		1,320	1,502	727,266	6.9E+06	NV Energy	Sodium Based	Low NOx Burner Technology (Dry Bottom only)
NV	Reid Gardner	2324	2	2014	6,447										582,068	0.277		841	266	648,112	6.2E+06	NV Energy	Sodium Based	Low NOx Burner Technology (Dry Bottom only)
NV	Reid Gardner	2324	3	2014	4,625										421,853	0.269		579	252	459,477	4.4E+06	NV Energy	Sodium Based	Low NOx Burner Technology (Dry Bottom only)
NV	Reid Gardner	2324	4	2014	5,190										1,041,722	0.177		933	488	1,108,732	1.1E+07	NV Energy	Sodium Based	Low NOx Burner Technology w/ Overfire Air
NV	Reid Gardner	2324	4	2015	2,727										479,359	0.198		534	287	553,241	5.3E+06	NV Energy	Sodium Based	Low NOx Burner Technology w/ Overfire Air
NV	Reid Gardner	2324	4	2016	2,277										382,880	0.195		423	232	453,183	4.3E+06	NV Energy	Sodium Based	Low NOx Burner Technology w/ Overfire Air
NV	Reid Gardner	2324	4	2017	1,632										292,772	0.220		389	168	382,487	3.6E+06	NV Energy	Sodium Based	Low NOx Burner Technology w/ Overfire Air
NV	TS Power Plant	56224	1	2014	7,513		242		74%						1,564,200	0.047		339	239	1,487,421	1.4E+07	Newmont Nevada Energy Investment	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air Selective Catalytic Reduction
NV	TS Power Plant	56224	1	2015	8,026				45%						960,405	0.048		232	114	1,009,783	9.6E+06	Newmont Nevada Energy Investment	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air Selective Catalytic Reduction
NV	TS Power Plant	56224	1	2016	8,164				47%						994,073	0.049		233	116	993,318	9.5E+06	Newmont Nevada Energy Investment	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air Selective Catalytic Reduction
NV	TS Power Plant	56224	1	2017	8,233				51%						1,081,870	0.049		257	148	1,097,749	1.0E+07	Newmont Nevada Energy Investment	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air Selective Catalytic Reduction

NEW MEXICO UNITS																								
State	Facility Name	Facility ID (ORISPL)	Unit ID	Year	Operating Time	Notes	Nameplate Capacity (MW)	Nameplate Capacity Factor	Heat Rate (mmbtu/kwhr)	Case 1 MW/h (85% or Higher)	Nox ER	SO2 ER	NOx (tons)	SO2 Tons	Gross Load (MW-h)	Avg. NOx Rate (lb/MMBtu)	SO2 ER	NOx (tons)	SO2 (tons)	CO2 (short tons)	Heat Input (MMBtu)	Operator	SO2 Control(s)	NOx Control(s)
NM	Escalante	87	1	2014	7,586		257	66%	10,014						1,492,632	0.340	0.098	2,579	732	1,567,634	1.5E+07	Tri-State Generation & Transmission	Wet Limestone	Other
NM	Escalante	87	1	2015	8,061			65%	9,501						1,462,298	0.351	0.122	2,450	847	1,457,200	1.4E+07	Tri-State Generation & Transmission	Wet Limestone	Other
NM	Escalante	87	1	2016	8,794			62%	9,885						1,402,242	0.351	0.120	2,437	899	1,453,830	1.4E+07	Tri-State Generation & Transmission	Wet Limestone	Other
NM	Escalante	87	1	2017	6,989			53%	9,972	85%	2017	2017			1,186,948	0.355	0.123	2,125	728	1,241,436	1.2E+07	Tri-State Generation & Transmission	Wet Limestone	Other
								Average HR =	9,843	1,913,622	0.355	0.123	3,343	1,159										
NM	Four Corners Steam Elec Station	2442	4	2014	7,166		818	73%	10,488						5,240,673	0.523	0.146	14,570	4,024	5,638,855	5.5E+07	Arizona Public Service Company	Wet Lime FGD	Low NOx Cell Burner
NM	Four Corners Steam Elec Station	2442	4	2015	7,689			78%	10,397						5,610,305	0.524	0.125	15,427	3,648	5,978,648	5.8E+07	Arizona Public Service Company	Wet Lime FGD	Low NOx Cell Burner
NM	Four Corners Steam Elec Station	2442	4	2016	5,927	SCR & SO2 controls		55%	9,073						3,968,546	0.484	0.133	9,216	2,399	3,693,588	3.6E+07	Arizona Public Service Company	Wet Lime FGD	Low NOx Cell Burner
NM	Four Corners Steam Elec Station	2442	4	2017	6,628			59%	9,144	85%	Per APS	Per APS			4,221,464	0.484	0.114	9,654	2,204	3,960,402	3.9E+07	Arizona Public Service Company	Wet Lime FGD	Low NOx Cell Burner
								2016-17 Average HR =	9,109	6,091,573	0.080	0.050	2,219	1,387										
NM	Four Corners Steam Elec Station	2442	5	2014	5,996		818	57%	11,140						4,093,242	0.512	0.176	11,903	4,012	4,679,593	4.6E+07	Arizona Public Service Company	Wet Lime FGD	Low NOx Cell Burner
NM	Four Corners Steam Elec Station	2442	5	2015	7,547			72%	11,122						5,208,945	0.506	0.183	14,807	5,310	5,944,382	5.8E+07	Arizona Public Service Company	Wet Lime FGD	Low NOx Cell Burner
NM	Four Corners Steam Elec Station	2442	5	2016	5,380	SCR & SO2 controls		47%	9,098						3,381,920	0.506	0.131	8,137	2,013	3,156,597	3.1E+07	Arizona Public Service Company	Wet Lime FGD	Low NOx Cell Burner
NM	Four Corners Steam Elec Station	2442	5	2017	4,723			40%	9,193	85%	Per APS	Per APS			2,836,197	0.494	0.120	6,637	1,566	2,674,206	2.6E+07	Arizona Public Service Company	Wet Lime FGD	Low NOx Cell Burner
								2016-17 Average HR =	9,146	6,091,573	0.080	0.050	2,228	1,393										
NM	San Juan	2451	1	2014	6,636										1,921,740	0.278		2,837	656	2,072,892	2.0E+07	Public Service Company of New Mexico	Wet Limestone	Low NOx Burner Technology w/ Overfire Air
NM	San Juan	2451	1	2015	6,263										1,852,664	0.274		2,719	604	1,991,705	1.9E+07	Public Service Company of New Mexico	Wet Limestone	Low NOx Burner Technology w/ Overfire Air
NM	San Juan	2451	1	2016	7,783										2,489,619	0.225		2,941	598	2,701,314	2.6E+07	Public Service Company of New Mexico	Wet Limestone	Selective Non-catalytic Reduction Low NOx Burner Technology w/ Overfire Air
NM	San Juan	2451	1	2017	7,893										2,481,790	0.221		2,869	519	2,694,585	2.6E+07	Public Service Company of New Mexico	Wet Limestone	Selective Non-catalytic Reduction Low NOx Burner Technology w/ Overfire Air
NM	San Juan	2451	2	2014	7,753										2,472,849	0.281		3,457	641	2,544,448	2.4E+07	Public Service Company of New Mexico	Wet Limestone	Overfire Air
NM	San Juan	2451	2	2015	7,460										2,287,448	0.274		3,235	622	2,405,109	2.3E+07	Public Service Company of New Mexico	Wet Limestone	Overfire Air
NM	San Juan	2451	2	2016	7,171										2,222,434	0.279		3,252	361	2,388,994	2.3E+07	Public Service Company of New Mexico	Wet Limestone	Overfire Air
NM	San Juan	2451	2	2017	7,082										2,172,695	0.276		3,208	462	2,374,022	2.3E+07	Public Service Company of New Mexico	Wet Limestone	Overfire Air
NM	San Juan	2451	3	2014	7,966										3,535,553	0.385		5,693	2,056	3,903,664	3.7E+07	Public Service Company of New Mexico	Wet Limestone	Low NOx Burner Technology w/ Overfire Air
NM	San Juan	2451	3	2015	7,751										3,069,126	0.263		4,331	1,211	3,323,149	3.2E+07	Public Service Company of New Mexico	Wet Limestone	Low NOx Burner Technology w/ Overfire Air
NM	San Juan	2451	3	2016	7,471										3,111,924	0.266		4,479	830	3,372,729	3.2E+07	Public Service Company of New Mexico	Wet Limestone	Low NOx Burner Technology w/ Overfire Air
NM	San Juan	2451	3	2017	7,790										3,489,703	0.276		5,378	2,264	3,980,653	3.8E+07	Public Service Company of New Mexico	Wet Limestone	Low NOx Burner Technology w/ Overfire Air
NM	San Juan	2451	4	2014	7,973										3,574,585	0.278		5,215	1,616	3,823,863	3.6E+07	Public Service Company of New Mexico	Wet Limestone	Low NOx Burner Technology w/ Overfire Air
NM	San Juan	2451	4	2015	7,938										2,880,673	0.273		4,246	1,078	3,131,026	3.0E+07	Public Service Company of New Mexico	Wet Limestone	Low NOx Burner Technology w/ Overfire Air
NM	San Juan	2451	4	2016	7,928										3,566,642	0.221		4,229	1,141	3,962,433	3.8E+07	Public Service Company of New Mexico	Wet Limestone	Low NOx Burner Technology w/ Overfire Air
NM	San Juan	2451	4	2017	8,100										3,833,600	0.222		4,725	1,281	4,411,439	4.2E+07	Public Service Company of New Mexico	Wet Limestone	Low NOx Burner Technology w/ Overfire Air

## NORTH DAKOTA &amp; SOUTH DAKOTA UNITS

State	Facility Name	Facility ID (SD/ND)	Unit ID	Year	Operating Time	Notes	Nameplate Capacity (MW)	Nameplate Capacity Factor	Heat Rate (mmBtu/kWh)	Case 1 MW-h (85% or Higher)	Nox ER	SO <sub>2</sub> ER	NO <sub>x</sub> (tons)	SO <sub>2</sub> (tons)	Gross Load (MW-h)	Avg. NO <sub>x</sub> Rate (lb/MMBtu)	SO <sub>2</sub> ER (tons)	NO <sub>x</sub> (tons)	SO <sub>2</sub> (tons)	CO <sub>2</sub> (short tons)	Heat Input (MMBtu)	Operator	SO <sub>2</sub> Control(s)	NO <sub>x</sub> Control(s)
ND	Antelope Valley	6469 B1	2024	7,030	UNB + SOFA installed		435	77%	10,527						2,960,640	0.201	0.373	3,136	5,809	3,387,856	3.11+07	Basin Electric Power Cooperative	Dry Lime FGD	Overfire Air (Retired May 27, 2014)-dry-LOW NOx Burner Technology w/ Closed-coupled/Separated OFA (Began May 28, 2014)
ND	Antelope Valley	6469 B1	2013	8,791				92%	10,574						3,009,988	0.112	0.340	2,169	6,312	4,040,771	3.71+07	Basin Electric Power Cooperative	Dry Lime FGD	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
ND	Antelope Valley	6469 B1	2016	8,374				94%	10,344						3,051,136	0.126	0.391	2,338	7,254	4,044,308	3.71+07	Basin Electric Power Cooperative	Dry Lime FGD	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
ND	Antelope Valley	6469 B1	2017	7,235				81%	9,860	94%	2017	2017			3,080,412	0.109	0.347	1,662	5,238	3,299,853	3.71+07	Basin Electric Power Cooperative	Dry Lime FGD	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
								Average HR =	10,335	3,581,141	0.109	0.347	2,015	6,422										
ND	Antelope Valley	6469 B2	2014	8,134			435	86%	11,060						3,291,878	0.322	0.383	6,052	6,975	3,966,340	3.61+07	Basin Electric Power Cooperative	Dry Lime FGD	Overfire Air
ND	Antelope Valley	6469 B2	2015	8,582				94%	10,991						3,999,800	0.160	0.340	7,283	6,716	4,307,548	4.01+07	Basin Electric Power Cooperative	Dry Lime FGD	Overfire Air
ND	Antelope Valley	6469 B2	2016	6,619	UNB + SOFA installed			72%	10,688						2,752,701	0.183	0.346	2,683	5,089	3,203,057	2.91+07	Basin Electric Power Cooperative	Dry Lime FGD	Overfire Air (Retired Jun 10, 2016)-dry-LOW NOx Burner Technology w/ Closed-coupled/Separated OFA (Began Jun 11, 2016)
ND	Antelope Valley	6469 B2	2017	8,507				94%	10,413	94%	2017	2017			3,595,344	0.108	0.405	2,040	7,603	4,088,152	3.81+07	Basin Electric Power Cooperative	Dry Lime FGD	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
								Average HR =	10,793	3,581,141	0.108	0.405	2,089	7,834										
SD	Big Stone	6098	1	2014	8,325	outage for installation of new controls	460	72%	10,634						2,825,233	0.687	0.922	10,507	13,845	3,150,887	3.01+07	Other Tail Power Company		Overfire Air
SD	Big Stone	6098	1	2015	4,628			40%	10,636						1,563,251	0.338	0.578	3,148	4,805	1,743,876	1.71+07	Other Tail Power Company	Dry Lime FGD (Began Aug 31, 2015)	Overfire Air-Selective Catalytic Reduction (Began Aug 26, 2015)
SD	Big Stone	6098	1	2016	7,843	first full year of new controls		56%	10,740						2,388,733	0.083	0.073	862	827	2,487,232	2.41+07	Other Tail Power Company	Dry Lime FGD	Overfire Air-Selective Catalytic Reduction
SD	Big Stone	6098	1	2017	7,815			55%	10,867	85%	2017	2017			2,182,037	0.085	0.071	984	946	2,487,044	2.41+07	Other Tail Power Company	Dry Lime FGD	Overfire Air-Selective Catalytic Reduction
								Average HR =	10,722	3,350,700	0.085	0.071	1,520	1,381										
ND	Coal Creek	6030	1	2014	7,985		605	89%	9,796						4,724,861	0.203	0.341	4,697	7,885	5,039,198	4.61+07	Great River Energy	Wet Lime FGD	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
ND	Coal Creek	6030	1	2015	8,404			90%	9,852						4,776,889	0.219	0.326	5,087	7,667	5,123,402	4.71+07	Great River Energy	Wet Lime FGD	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
ND	Coal Creek	6030	1	2016	8,772			89%	9,628						4,129,458	0.193	0.336	4,227	7,643	4,946,752	4.51+07	Great River Energy	Wet Lime FGD	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
ND	Coal Creek	6030	1	2017	6,723	SO2 controls added - use 2018		73%	9,712	90%	#2 2017	2018			3,843,520	0.182	0.168	3,363	3,098	4,063,791	3.71+07	Great River Energy	Wet Lime FGD	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
								Average HR =	9,747	4,768,243	0.130	0.143	3,021	3,323										
ND	Coal Creek	6030	2	2014	8,317		605	92%	9,535						4,879,864	0.143	0.341	3,287	7,940	5,065,733	4.71+07	Great River Energy	Wet Lime FGD	Low NOx Burner Technology w/ Closed-coupled/Separated OFA-dry-Overfire Air
ND	Coal Creek	6030	2	2015	8,429			90%	9,644						4,775,408	0.157	0.338	3,699	7,776	5,013,823	4.61+07	Great River Energy	Wet Lime FGD	Low NOx Burner Technology w/ Closed-coupled/Separated OFA-dry-Overfire Air
ND	Coal Creek	6030	2	2016	7,134			77%	9,491						4,056,301	0.136	0.291	2,564	5,613	4,191,283	3.81+07	Great River Energy	Wet Lime FGD	Low NOx Burner Technology w/ Closed-coupled/Separated OFA-dry-Overfire Air
ND	Coal Creek	6030	2	2017	8,293	SO2 controls added - use 2018		87%	9,469	90%	2017	2018			4,212,080	0.130	0.147	2,889	3,796	4,802,176	4.41+07	Great River Energy	Wet Lime FGD	Low NOx Burner Technology w/ Closed-coupled/Separated OFA-dry-Overfire Air
								Average HR =	9,541	4,768,243	0.130	0.142	2,957	3,236										
ND	Coyote	8222 B1	2014	7,641			450	74%	11,044						2,914,829	0.700	0.794	11,374	12,777	3,505,393	3.21+07	Other Tail Power Company	Dry Lime FGD	
ND	Coyote	8222 B1	2015	8,308	derate for mechanical			52%	11,051						2,058,997	0.774	0.772	8,820	8,786	2,477,576	2.31+07	Other Tail Power Company	Dry Lime FGD	
ND	Coyote	8222 B1	2016	6,746	separated overfire air added			66%	10,477						2,586,763	0.580	0.676	7,772	11,871	2,950,668	2.71+07	Other Tail Power Company	Dry Lime FGD	Overfire Air (Began Jun 15, 2016)
ND	Coyote	8222 B1	2017	7,550				70%	10,744	85%	2017	2017			2,778,245	0.424	0.601	6,378	13,440	3,248,072	3.61+07	Other Tail Power Company	Dry Lime FGD	Overfire Air
								Average HR =	10,830	3,350,700	0.424	0.901	7,688	16,344										
ND	Leland Olds	2817	1	2014	6,543		216	58%	10,656						1,118,902	0.234	0.069	1,272	412	1,299,328	1.31+07	Basin Electric Power Cooperative	Wet Lime FGD	Low NOx Burner Technology (Dry Bottom only)-Overfire Air
ND	Leland Olds	2817	1	2015	6,528			80%	10,280						1,519,408	0.237	0.086	1,214	681	1,718,734	1.61+07	Basin Electric Power Cooperative	Wet Lime FGD	Low NOx Burner Technology (Dry Bottom only)-Overfire Air
ND	Leland Olds	2817	1	2016	8,366			79%	10,397						1,497,217	0.247	0.091	1,856	711	1,684,776	1.61+07	Basin Electric Power Cooperative	Wet Lime FGD	Low NOx Burner Technology (Dry Bottom only)-Overfire Air
ND	Leland Olds	2817	1	2017	6,747	SNCR Optimized - use 2018		64%	10,383	85%	2018	2017			1,205,382	0.177	0.089	1,121	354	1,362,385	1.31+07	Basin Electric Power Cooperative	Wet Lime FGD	Low NOx Burner Technology (Dry Bottom only)-Overfire Air
								Average HR =	10,456	1,608,336	0.147	0.089	1,336	745										
ND	Leland Olds	2817	2	2014	7,972		440	72%	10,258						2,761,953	0.365	0.072	5,202	1,075	3,086,004	3.01+07	Basin Electric Power Cooperative	Wet Lime FGD	Overfire Air
ND	Leland Olds	2817	2	2015	6,935			65%	9,940						2,487,888	0.367	0.086	4,537	1,066	2,692,426	2.51+07	Basin Electric Power Cooperative	Wet Lime FGD	Overfire Air
ND	Leland Olds	2817	2	2016	8,172	SNCR Optimized		77%	10,232						2,965,565	0.366	0.080	5,434	1,217	3,303,589	3.01+07	Basin Electric Power Cooperative	Wet Lime FGD	Overfire Air
ND	Leland Olds	2817	2	2017	8,110			77%	10,128	85%	2017	2017			2,953,693	0.291	0.091	4,438	1,864	3,256,736	3.01+07	Basin Electric Power Cooperative	Wet Lime FGD	Overfire Air
								Average HR =	10,340	3,276,240	0.293	0.091	4,873	1,535										
ND	Milton R Young	2823 B1	2014	7,888			257	89%	9,552						2,082,732	0.334	0.038	1,230	361	2,082,651	1.91+07	Minnesota Power Cooperative, Inc.	Wet Lime FGD-dry-Wet Limestone	Overfire Air-dry-Selective Non-catalytic Reduction
ND	Milton R Young	2823 B1	2015	7,063				78%	10,099						1,747,255	0.333	0.069	2,950	604	1,921,157	1.81+07	Minnesota Power Cooperative, Inc.	Wet Lime FGD-dry-Wet Limestone	Overfire Air-dry-Selective Non-catalytic Reduction
ND	Milton R Young	2823 B1	2016	8,433				94%	10,969						2,105,676	0.331	0.079	3,841	909	2,514,618	2.31+07	Minnesota Power Cooperative, Inc.	Wet Lime FGD-dry-Wet Limestone	Overfire Air-dry-Selective Non-catalytic Reduction
ND	Milton R Young	2823 B1	2017	8,298				91%	10,508	91%	2017	2017			2,058,278	0.330	0.084	3,579	905	2,354,655	2.21+07	Minnesota Power Cooperative, Inc.	Wet Lime FGD-dry-Wet Limestone	Overfire Air-dry-Selective Non-catalytic Reduction
								Average HR =	10,282	2,066,701	0.330	0.084	3,477	881										
ND	Milton R Young	2823 B2	2014	6,730			477	72%	9,887						3,018,256	0.335	0.115	5,004	1,710	3,248,684	3.01+07	Minnesota Power Cooperative, Inc.	Dual Alkali-dry-Wet Lime FGD	Overfire Air-dry-Selective Non-catalytic Reduction
ND	Milton R Young	2823 B2	2015	8,187				88%	9,838						3,461,385	0.336	0.117	6,128	2,126	3,961,753	3.61+07	Minnesota Power Cooperative, Inc.	Dual Alkali-dry-Wet Lime FGD	Overfire Air-dry-Selective Non-catalytic Reduction
ND	Milton R Young	2823 B2	2016	6,113				65%	9,824						2,709,570	0.335	0.130	4,488	1,729	2,897,994	2.71+07	Minnesota Power Cooperative, Inc.	Dual Alkali-dry-Wet Lime FGD	Overfire Air-dry-Selective Non-catalytic Reduction
ND	Milton R Young	2823 B2	2017	8,487				91%	10,088	81%	2017	2017			3,811,876	0.333	0.130	6,396	2,507	4,186,682	3.81+07	Minnesota Power Cooperative, Inc.	Dual Alkali-dry-Wet Lime FGD	Overfire Air-dry-Selective Non-catalytic Reduction
								Average HR =	9,934	3,802,453	0.333	0.130	6,293	2,463										
ND	R M Heskett	2790 B2	2014	8,012			75	75%	11,173						493,010	0.360	0.849	995	2,339	599,718	5.51+06	Montana Dakota Utilities Company		
ND	R M Heskett	2790 B2	2015	7,947				71%	11,446						463,437	0.367	0.771	869	2,046	577,507	5.31+06	Montana Dakota Utilities Company		
ND	R M Heskett	2790 B2	2016	7,754				69%	11,543						453,257	0.387	0.721	1,010	1,887	569,610	5.21+06	Montana Dakota Utilities Company		
ND	R M Heskett	2790 B2	2017	7,888	New SO2 controls in 2017			69%	11,494	85%	2017	2018			455,535	0.371	0.567	985	1,485	570,011	5.21+06	Montana Dakota Utilities Company	Fluidized Bed Limestone Injection (Began Apr 16, 2017)	
								Average HR =	11,414	518,400	0.371	0.464	1,181	1,476										
ND	Spiritwood Station	56786	1	2014	2,769		106	10%	24,617						91,481	0.682	1,294	1,435	245,389	2.31+06	Great River Energy	Dry Lime FGD-dry-Fluidized Bed Limestone	Overfire Air-dry-Selective Non-catalytic Reduction	
ND	Spiritwood Station	56786	1	2015	7,214				133,881							0.098	231	67	545,513	1.01+06	Great River Energy	Dry Lime FGD-dry-Fluidized Bed Limestone	Overfire Air-dry-Selective Non-catalytic Reduction	
ND	Spiritwood Station	56786	1	2016	5,535				RDV/01							0.095	289	17	576,798	6.21+06	Great River Energy	Dry Lime FGD-dry-Fluidized Bed Limestone	Overfire Air-dry-Selective Non-catalytic Reduction	
ND	Spiritwood Station	56786	1	2017	8,138				RDV/01							0.103</								

UTAH-WYOMING UNITS

[illegible]

## UTAH-WYOMING UNITS

[illegible]

## TEXAS UNITS

State	Facility Name	Facility ID (ORISPL)	Unit ID	Associate d Stacks	Year	Program (s)	Operating Time	Gross Load (MW-h)	SO2 (tons)	Avg. NOx Rate (lb/MMBtu)	NOx (tons)	CO2 (short tons)	Heat Input (MMBtu)	SO2 Control(s)	NOx Control(s)
TX	Big Brown	3497	1		2016	ARP	7157.1	3425424	21532.3	0.1261	2276.778	3777236	3.47E+07		Low NOx Burner Technology w/ Separated OFA Selective Non-catalytic Reduction
TX	Big Brown	3497	1		2017	ARP	8411.19	4255859	24138.15	0.1342	2845.022	4604829	4.23E+07		Low NOx Burner Technology w/ Separated OFA Selective Non-catalytic Reduction
TX	Big Brown	3497	1		2018	ARP	946.89	452952.7	3401.109	0.1725	378.81	489103.3	4492536		Low NOx Burner Technology w/ Separated OFA Selective Non-catalytic Reduction
TX	Big Brown	3497	2		2016	ARP	7246.57	3325597	20937.62	0.1288	2243.173	3720802	3.42E+07		Low NOx Burner Technology w/ Separated OFA Selective Non-catalytic Reduction
TX	Big Brown	3497	2		2017	ARP	8313.61	4115184	23494.3	0.1477	2953.39	4496091	4.13E+07		Low NOx Burner Technology w/ Separated OFA Selective Non-catalytic Reduction
TX	Big Brown	3497	2		2018	ARP	1003.95	427081.6	3257.931	0.1948	394.28	470783.5	4324247		Low NOx Burner Technology w/ Separated OFA Selective Non-catalytic Reduction
TX	Coletto Creek	6178	1		2018	ARP	5639.27	2887759	9198.481	0.1291	1917.508	3081848	2.94E+07		Low NOx Burner Technology w/ Closed-coupled/Separated OFA
TX	Coletto Creek	6178	1		2017	ARP	7577.44	4092253	12201.28	0.1275	2636.788	4325803	4.12E+07		Low NOx Burner Technology w/ Closed-coupled/Separated OFA
TX	Coletto Creek	6178	1		2016	ARP	5674.3	3295551	8231.219	0.1246	2049.047	3418103	3.26E+07		Low NOx Burner Technology w/ Closed-coupled/Separated OFA
TX	Gibbons Creek Steam Ele	6136	1		2016	ARP	6986.02	1779195	198.221	0.1143	1141.899	2024555	1.98E+07	Wet Lime I	Low NOx Burner Technology w/ Closed-coupled OFA
TX	Gibbons Creek Steam Ele	6136	1		2017	ARP	6127.35	1698489	334.962	0.1073	1017.21	1905128	1.86E+07	Wet Lime I	Low NOx Burner Technology w/ Closed-coupled OFA
TX	Gibbons Creek Steam Ele	6136	1		2018	ARP	2705.3	836985.4	270.858	0.1059	523.034	974388.6	9527039	Wet Lime I	Low NOx Burner Technology w/ Closed-coupled OFA
TX	Harrington Station	6193 061B			2016	ARP	6780.26	1609193	3795.67	0.1448	1144.133	1621089	1.55E+07		Low NOx Burner Technology w/ Separated OFA Overfire Air
TX	Harrington Station	6193 061B			2017	ARP	5932.51	1417533	3513.534	0.1315	942.025	1434718	1.37E+07		Low NOx Burner Technology w/ Separated OFA Overfire Air
TX	Harrington Station	6193 061B			2018	ARP	6139.85	1510142	3616.701	0.176	1279.917	1499055	1.43E+07		Low NOx Burner Technology w/ Separated OFA Overfire Air
TX	Harrington Station	6193 062B			2018	ARP	8383.27	2120564	5226.341	0.1393	1518.954	2228592	2.13E+07		Low NOx Burner Technology w/ Closed-coupled/Separated OFA Overfire Air
TX	Harrington Station	6193 062B			2016	ARP	7683.75	1898746	5072.905	0.1442	1422.813	2049314	1.96E+07		Low NOx Burner Technology w/ Closed-coupled/Separated OFA Overfire Air
TX	Harrington Station	6193 062B			2017	ARP	7330.73	1792088	4763.524	0.1465	1335.093	1886623	1.80E+07		Low NOx Burner Technology w/ Closed-coupled/Separated OFA Overfire Air
TX	Harrington Station	6193 063B			2017	ARP	7089.41	1784596	4604.464	0.1411	1275.586	1830958	1.75E+07		Low NOx Burner Technology w/ Closed-coupled/Separated OFA Overfire Air
TX	Harrington Station	6193 063B			2018	ARP	5925.46	1523601	3569.268	0.1413	1180.925	1628743	1.56E+07		Low NOx Burner Technology w/ Closed-coupled/Separated OFA Overfire Air
TX	Harrington Station	6193 063B			2016	ARP	7770.44	1942860	5385.632	0.1365	1460.102	2176182	2.08E+07		Low NOx Burner Technology w/ Closed-coupled/Separated OFA Overfire Air
TX	J K Spruce	7097 **1			2016	ARP	6977.5	2500758	466.784	0.1652	2023.975	2776093	2.71E+07	Wet Limes	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
TX	J K Spruce	7097 **1			2017	ARP	6909.23	2553061	592.237	0.1443	1920.653	2820587	2.75E+07	Wet Limes	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
TX	J K Spruce	7097 **1			2018	ARP	7934.88	3216193	823.731	0.1513	2446.174	3501951	3.41E+07	Wet Limes	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
TX	J K Spruce	7097 **2			2017	ARP	6677.28	3760387	147.514	0.049	892.204	3726494	3.63E+07	Wet Limes	Selective Catalytic Reduction
TX	J K Spruce	7097 **2			2018	ARP	6915.11	4400356	180.809	0.047	995.222	4370672	4.26E+07	Wet Limes	Selective Catalytic Reduction
TX	J K Spruce	7097 **2			2016	ARP	5550.25	3248413	150.835	0.0496	795.412	3293951	3.21E+07	Wet Limes	Selective Catalytic Reduction
TX	J T Deely	6181	1	CS012	2018	ARP	8078.21	2587997	8151.335	0.1079	1633.815	3155511	3.08E+07		Low NOx Burner Technology w/ Closed-coupled/Separated OFA
TX	J T Deely	6181	1	CS012	2017	ARP	8134.71	2051161	6103.036	0.0969	1151.921	2490794	2.43E+07		Low NOx Burner Technology w/ Closed-coupled/Separated OFA
TX	J T Deely	6181	1	CS012	2016	ARP	4956.75	1224239	3569.4	0.0956	643.051	1420950	1.38E+07		Low NOx Burner Technology w/ Closed-coupled/Separated OFA
TX	J T Deely	6181	2	CS012	2016	ARP	5875	1381507	4055.642	0.0824	637.91	1616897	1.58E+07		Low NOx Burner Technology w/ Closed-coupled/Separated OFA
TX	J T Deely	6181	2	CS012	2017	ARP	7360.53	1758818	5253.288	0.0849	869.499	2161662	2.11E+07		Low NOx Burner Technology w/ Closed-coupled/Separated OFA
TX	J T Deely	6181	2	CS012	2018	ARP	8134.87	2297785	7211.916	0.1011	1369.947	2801356	2.73E+07		Low NOx Burner Technology w/ Closed-coupled/Separated OFA
TX	Limestone	298 LIM1			2016	ARP	7947.3	5026723	9772.637	0.198	4350.823	4886364	4.49E+07	Wet Limes	Overfire Air
TX	Limestone	298 LIM1			2017	ARP	7306.25	4482068	4336.75	0.1662	3579.626	4707121	4.33E+07	Wet Limes	Overfire Air
TX	Limestone	298 LIM1			2018	ARP	8209.4	5117320	4156.105	0.155	3963.119	5445148	5.19E+07	Wet Limes	Overfire Air
TX	Limestone	298 LIM2			2016	ARP	7082.01	4819352	11028.43	0.1942	4446.411	4860396	4.47E+07	Wet Limes	Overfire Air
TX	Limestone	298 LIM2			2017	ARP	7667.08	5389276	5903.464	0.186	4904.547	5883471	5.40E+07	Wet Limes	Overfire Air
TX	Limestone	298 LIM2			2018	ARP	7311.39	5124353	4163.783	0.17	4167.339	5163189	4.92E+07	Wet Limes	Overfire Air
TX	Martin Lake	6146	1		2016	ARP	8447.14	5159856	11515.4	0.1571	4074.554	5608518	5.15E+07	Wet Limes	Low NOx Burner Technology w/ Separated OFA
TX	Martin Lake	6146	1		2017	ARP	8321.8	4634237	12559.84	0.1543	3594.205	5249546	4.82E+07	Wet Limes	Low NOx Burner Technology w/ Separated OFA
TX	Martin Lake	6146	1		2018	ARP	8323.94	5193391	19282.03	0.1465	3751.522	5731222	5.26E+07	Wet Limes	Low NOx Burner Technology w/ Separated OFA
TX	Martin Lake	6146	2		2017	ARP	8262.09	4423403	9570.985	0.1628	3492.514	4895122	4.50E+07	Wet Limes	Low NOx Burner Technology w/ Separated OFA
TX	Martin Lake	6146	2		2016	ARP	5326.94	3259332	5265.967	0.1526	2512.265	3606971	3.31E+07	Wet Limes	Low NOx Burner Technology w/ Separated OFA
TX	Martin Lake	6146	2		2018	ARP	7352.77	4543501	17166.8	0.1637	3457.159	4801149	4.41E+07	Wet Limes	Low NOx Burner Technology w/ Separated OFA
TX	Martin Lake	6146	3		2016	ARP	6568.09	3852017	8689.858	0.1562	2918.882	4136191	3.80E+07	Wet Limes	Low NOx Burner Technology w/ Separated OFA
TX	Martin Lake	6146	3		2018	ARP	8412.83	5474969	19749.35	0.1494	3787.965	5735272	5.27E+07	Wet Limes	Low NOx Burner Technology w/ Separated OFA
TX	Martin Lake	6146	3		2017	ARP	8104.58	4683143	14310.59	0.1548	3504.56	5102241	4.69E+07	Wet Limes	Low NOx Burner Technology w/ Separated OFA
TX	Monticello	6147	1		2017	ARP	6885.02	2696357	11432.98	0.1464	2136.678	3112154	2.97E+07		Low NOx Burner Technology w/ Separated OFA Selective Non-catalytic Reduction
TX	Monticello	6147	1		2016	ARP	5260.16	2056582	8834.572	0.1398	1537.138	2426490	2.31E+07		Low NOx Burner Technology w/ Separated OFA Selective Non-catalytic Reduction
TX	Monticello	6147	2		2017	ARP	7830.71	3034838	12808.01	0.1557	2523.346	3486034	3.32E+07		Low NOx Burner Technology w/ Separated OFA Selective Non-catalytic Reduction
TX	Monticello	6147	2		2016	ARP	5248.09	2053748	8716.265	0.1385	1526.05	2345309	2.24E+07		Low NOx Burner Technology w/ Separated OFA Selective Non-catalytic Reduction
TX	Oak Grove	6180	1		2018	ARP	8314.99	7192075	4453.418	0.0735	2452.762	7477355	6.87E+07	Wet Limes	Low NOx Burner Technology w/ Separated OFA Ammonia Injection Selective Catalytic Reduction
TX	Oak Grove	6180	1		2017	ARP	8450.26	7343191	4442.479	0.0717	2511.704	7612561	6.99E+07	Wet Limes	Low NOx Burner Technology w/ Separated OFA Ammonia Injection Selective Catalytic Reduction
TX	Oak Grove	6180	1		2016	ARP	7387.85	6212457	3333.947	0.0745	2166.382	6658215	6.12E+07	Wet Limes	Low NOx Burner Technology w/ Separated OFA Ammonia Injection Selective Catalytic Reduction
TX	Sam Seymour	6179	1		2017	ARP	8647.74	4536347	386.54	0.1124	2464.727	4877370	4.65E+07	Wet Limes	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
TX	Sam Seymour	6179	1		2018	ARP	8498.54	4479534	532.194	0.1301	2723.788	4572604	4.36E+07	Wet Limes	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
TX	Sam Seymour	6179	1		2016	ARP	7154.93	3396258	498.297	0.1092	1742.636	3607878	3.44E+07	Wet Limes	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
TX	Sam Seymour	6179	2		2017	ARP	8139.77	4403340	487.053	0.1207	2599.233	4621246	4.41E+07	Wet Limes	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
TX	Sam Seymour	6179	2		2018	ARP	7066.86	3775179	538.316	0.1254	2552.725	4288692	4.09E+07	Wet Limes	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
TX	Sam Seymour	6179	2		2016	ARP	8469.25	4255504	378.503	0.1157	2512.531	4731047	4.51E+07	Wet Limes	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
TX	Sam Seymour	6179	3		2017	ARP	8349.45	3263070	266.016	0.123	2054.243	3507916	3.34E+07	Wet Limes	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
TX	Sam Seymour	6179	3		2018	ARP	6942.01	2759367	273.44	0.1304	1857.546	3062037	2.92E+07	Wet Limes	Low NOx Burner Technology w/ Closed-coupled/Separated OFA

## TEXAS UNITS

State	Facility Name	Facility ID (ORISPL)	Unit ID	Associate d Stacks	Year	Program(s)	Operating Time	Gross Load (MW-h)	SO2 (tons)	Avg. NOx Rate (lb/MMBtu)	NOx (tons)	CO2 (short tons)	Heat Input (MMBtu)	SO2 Control(s)	NOx Control(s)
TX	Sam Seymour	6179	3		2016	ARP	8268.82	3218149	230.992	0.1085	1876.775	3686370	3.51E+07	Wet Limes	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
TX	Sandow	6648	4		2018	ARP	239.63	122035.8	487.424	0.0623	36.249	141589.8	1.300541	Wet Limes	Low NOx Burner Technology w/ Separated OFA Selective Catalytic Reduction
TX	Sandow	6648	4		2016	ARP	7887.82	4383004	12105.28	0.0671	1465.451	4686781	4.30E+07	Wet Limes	Low NOx Burner Technology w/ Separated OFA Selective Catalytic Reduction
TX	Sandow	6648	4		2017	ARP	8063.83	4464335	17446.08	0.067	1465.917	4835292	4.44E+07	Wet Limes	Low NOx Burner Technology w/ Separated OFA Selective Catalytic Reduction
TX	Tolk Station	6194 171B			2017	ARP	7587.46	2796027	6719.003	0.1237	1621.245	2652459	2.53E+07		Low NOx Burner Technology w/ Separated OFA Overfire Air
TX	Tolk Station	6194 171B			2018	ARP	7098.49	2208999	5513.121	0.1307	1386.387	2092475	2.00E+07		Low NOx Burner Technology w/ Separated OFA Overfire Air
TX	Tolk Station	6194 171B			2016	ARP	7811.06	2928015	7080.891	0.1333	1863.827	2819218	2.69E+07		Low NOx Burner Technology w/ Separated OFA Overfire Air
TX	Tolk Station	6194 172B			2017	ARP	7048.55	2657682	6907.293	0.1284	1726.475	2742397	2.62E+07		Low NOx Burner Technology w/ Separated OFA Overfire Air
TX	Tolk Station	6194 172B			2016	ARP	8148	3093955	7896.061	0.1378	2137.017	3166776	3.02E+07		Low NOx Burner Technology w/ Separated OFA Overfire Air
TX	Tolk Station	6194 172B			2018	ARP	5740.21	1818179	4446.412	0.1307	1210.072	1893840	1.81E+07		Low NOx Burner Technology w/ Separated OFA Overfire Air
TX	W A Parish	3470 WAP7			2016	ARP	6525.49	2986930	9184.24	0.0449	603.91	2948540	2.82E+07		Selective Catalytic Reduction
TX	W A Parish	3470 WAP7			2017	ARP	7997.36	3848578	10357.6	0.0473	733.313	3523198	3.39E+07		Selective Catalytic Reduction
TX	W A Parish	3470 WAP7			2018	ARP	8246.2	4032458	10958.69	0.0487	756.118	3563273	3.41E+07		Selective Catalytic Reduction
TX	W A Parish	3470 WAP8	MS1, MS2		2016	ARP	7731.38	3792115	3111.952	0.045	855.694	4011512	3.81E+07	Sodium Ba	Low NOx Burner Technology w/ Closed-coupled/Separated OFA Selective Catalytic Reduction Ammonia Injection
TX	W A Parish	3470 WAP8	MS1, MS2		2017	ARP	8224.36	4297991	1929.215	0.056	1122.789	3459991	4.42E+07	Sodium Ba	Low NOx Burner Technology w/ Closed-coupled/Separated OFA Selective Catalytic Reduction Ammonia Injection
TX	W A Parish	3470 WAP8	MS1, MS2		2018	ARP	5039.92	2666222	1084.505	0.0489	661.656	2126266	2.81E+07	Sodium Ba	Low NOx Burner Technology w/ Closed-coupled/Separated OFA Selective Catalytic Reduction Ammonia Injection
TX	Big Brown	3497	1		2014	ARP	6822.27	3464103	25814.82	0.1297	2261.964	3750264	3.44E+07		Low NOx Burner Technology w/ Separated OFA Selective Non-catalytic Reduction
TX	Big Brown	3497	1		2015	ARP	8282.47	4161876	25378.96	0.1227	2625.154	4532298	4.16E+07		Low NOx Burner Technology w/ Separated OFA Selective Non-catalytic Reduction
TX	Big Brown	3497	2		2014	ARP	8225.84	4303676	31645.55	0.1316	2810.237	4598807	4.22E+07		Low NOx Burner Technology w/ Separated OFA Selective Non-catalytic Reduction
TX	Big Brown	3497	2		2015	ARP	8012.11	4002944	24458.47	0.1317	2695.691	4399654	4.04E+07		Low NOx Burner Technology w/ Separated OFA Selective Non-catalytic Reduction
TX	Coletto Creek	6178	1		2015	ARP	6370.13	3395649	8261.084	0.1229	2006.601	3430431	3.27E+07		Low NOx Burner Technology w/ Closed-coupled/Separated OFA
TX	Coletto Creek	6178	1		2014	ARP	8425.95	5423755	16942.22	0.1303	3271.538	5253412	5.01E+07		Low NOx Burner Technology w/ Closed-coupled/Separated OFA
TX	Gibbons Creek Steam Ele	6136	1		2015	ARP	8539.15	2331127	154.101	0.1129	1656.914	2929325	2.87E+07	Wet Lime	Low NOx Burner Technology w/ Closed-coupled OFA
TX	Gibbons Creek Steam Ele	6136	1		2014	ARP	7322.85	2941482	709.097	0.14	2044.178	2981204	2.91E+07	Wet Lime	Low NOx Burner Technology w/ Closed-coupled OFA
TX	Harrington Station	6193 061B			2014	ARP	8376.78	2342344	5752.961	0.1367	1610.707	2444079	2.33E+07		Low NOx Burner Technology w/ Separated OFA Overfire Air
TX	Harrington Station	6193 061B			2015	ARP	8202.21	2186567	5062.15	0.1434	1524.926	2199407	2.10E+07		Low NOx Burner Technology w/ Separated OFA Overfire Air
TX	Harrington Station	6193 062B			2015	ARP	8300.25	2169163	5161.291	0.1468	1610.419	2266125	2.16E+07		Low NOx Burner Technology w/ Closed-coupled/Separated OFA Overfire Air
TX	Harrington Station	6193 062B			2014	ARP	5985.4	1584793	4006.845	0.1451	1254.199	1727225	1.65E+07		Low NOx Burner Technology w/ Closed-coupled/Separated OFA Overfire Air
TX	Harrington Station	6193 063B			2015	ARP	6781.95	1854813	4915.292	0.1458	1461.722	2053247	1.96E+07		Low NOx Burner Technology w/ Closed-coupled/Separated OFA Overfire Air
TX	Harrington Station	6193 063B			2014	ARP	8239.33	2229901	5708.216	0.1418	1715.56	2493491	2.38E+07		Low NOx Burner Technology w/ Closed-coupled/Separated OFA Overfire Air
TX	J K Spruce	7097 **1			2014	ARP	8253	4332127	1012.108	0.1319	3021.622	4637622	4.52E+07	Wet Limes	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
TX	J K Spruce	7097 **1			2015	ARP	6490	2065322	397.185	0.167	1723.396	2325474	2.27E+07	Wet Limes	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
TX	J K Spruce	7097 **2			2014	ARP	6974.5	5406238	226.022	0.0477	1228.469	5300513	5.17E+07	Wet Limes	Selective Catalytic Reduction
TX	J K Spruce	7097 **2			2015	ARP	5842.75	2706186	84.396	0.0455	633.337	2843837	2.77E+07	Wet Limes	Selective Catalytic Reduction
TX	J T Deely	6181	1	CS012	2015	ARP	7311.25	1750091	5004.704	0.0933	905.009	2000304	1.95E+07		Low NOx Burner Technology w/ Closed-coupled/Separated OFA
TX	J T Deely	6181	1	CS012	2014	ARP	7544.25	2753895	7452.355	0.0747	1117.212	3036057	2.96E+07		Low NOx Burner Technology w/ Closed-coupled/Separated OFA
TX	J T Deely	6181	2	CS012	2014	ARP	8517.25	3139299	8441.147	0.0667	1112.756	3468363	3.38E+07		Low NOx Burner Technology w/ Closed-coupled/Separated OFA
TX	J T Deely	6181	2	CS012	2015	ARP	6775	1595442	4688.803	0.0786	716.957	1880691	1.83E+07		Low NOx Burner Technology w/ Closed-coupled/Separated OFA
TX	Limestone	298 LIM1			2014	ARP	8185.2	6613040	14266	0.2075	6309.699	6573231	6.04E+07	Wet Limes	Overfire Air
TX	Limestone	298 LIM1			2015	ARP	6769.27	4375943	6832.679	0.1919	3898.046	4409396	4.05E+07	Wet Limes	Overfire Air
TX	Limestone	298 LIM2			2014	ARP	7387.53	6157131	13596.4	0.2076	5881.387	6125639	5.63E+07	Wet Limes	Overfire Air
TX	Limestone	298 LIM2			2015	ARP	7573.88	5454754	10385.59	0.1926	4908.483	5459967	5.02E+07	Wet Limes	Overfire Air
TX	Martin Lake	6146	1		2014	ARP	7798.26	5340338	20382.95	0.1619	4403.397	6002495	5.51E+07	Wet Limes	Low NOx Burner Technology w/ Separated OFA
TX	Martin Lake	6146	1		2015	ARP	7306.37	4276999	9494.243	0.1755	3786.724	4916687	4.52E+07	Wet Limes	Low NOx Burner Technology w/ Separated OFA
TX	Martin Lake	6146	2		2014	ARP	8263.75	5761233	19820.06	0.1619	4549.724	6199998	5.69E+07	Wet Limes	Low NOx Burner Technology w/ Separated OFA
TX	Martin Lake	6146	2		2015	ARP	6261.01	3707000	6959.776	0.1675	3160.556	4230206	3.89E+07	Wet Limes	Low NOx Burner Technology w/ Separated OFA
TX	Martin Lake	6146	3		2015	ARP	5199.21	2967721	6474.298	0.184	2702.443	3311871	3.04E+07	Wet Limes	Low NOx Burner Technology w/ Separated OFA
TX	Martin Lake	6146	3		2014	ARP	5382.26	3673880	13452.57	0.1554	2799.617	4035035	3.71E+07	Wet Limes	Low NOx Burner Technology w/ Separated OFA
TX	Monticello	6147	1		2014	ARP	3452.91	1583426	6833.144	0.1268	1047.774	1804030	1.66E+07		Low NOx Burner Technology w/ Separated OFA Selective Non-catalytic Reduction
TX	Monticello	6147	1		2015	ARP	3896.69	1544949	7963.367	0.1353	1116.535	1831410	1.68E+07		Low NOx Burner Technology w/ Separated OFA Selective Non-catalytic Reduction
TX	Monticello	6147	2		2015	ARP	3098.67	1263864	6719.284	0.1347	891.547	1459200	1.34E+07		Low NOx Burner Technology w/ Separated OFA Selective Non-catalytic Reduction
TX	Monticello	6147	2		2014	ARP	3182.87	1483449	6379.853	0.1199	925.675	1703946	1.57E+07		Low NOx Burner Technology w/ Separated OFA Selective Non-catalytic Reduction
TX	Oak Grove	6180	1		2014	ARP	8248.82	7130788	3861.24	0.0714	2449.216	7329006	6.73E+07	Wet Limes	Low NOx Burner Technology w/ Separated OFA Ammonia Injection Selective Catalytic Reduction
TX	Oak Grove	6180	1		2015	ARP	8011.06	6768075	2552.679	0.071	2345.943	7120485	6.54E+07	Wet Limes	Low NOx Burner Technology w/ Separated OFA Ammonia Injection Selective Catalytic Reduction
TX	Sam Seymour	6179	1		2014	ARP	7130.36	3314176	237.441	0.1102	1729.419	3410696	3.25E+07	Wet Limes	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
TX	Sam Seymour	6179	1		2015	ARP	8449.88	3789126	384.431	0.1082	2008.698	4081177	3.89E+07	Wet Limes	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
TX	Sam Seymour	6179	2		2014	ARP	8199.95	3893772	392.799	0.1042	2185.561	4427802	4.22E+07	Wet Limes	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
TX	Sam Seymour	6179	2		2015	ARP	6626.84	3138641	361.804	0.1061	1775.79	3576990	3.41E+07	Wet Limes	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
TX	Sam Seymour	6179	3		2014	ARP	8284.67	2773250	173.207	0.0943	1351.49	3018623	2.88E+07	Wet Limes	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
TX	Sam Seymour	6179	3		2015	ARP	6703.11	2265197	196.082	0.1026	1225.695	2554313	2.44E+07	Wet Limes	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
TX	Sandow	6648	4		2014	ARP	7957.99	4792750	21937.65	0.0642	1466.006	5136676	4.72E+07	Wet Limes	Low NOx Burner Technology w/ Separated OFA Selective Catalytic Reduction
TX	Sandow	6648	4		2015	ARP	8184.46	4516400	20924.96	0.0639	1426.61	4886940	4.49E+07	Wet Limes	Low NOx Burner Technology w/ Separated OFA Selective Catalytic Reduction
TX	Tolk Station	6194 171B			2015	ARP	6896.5	2997365	6497.793	0.1461	1989.777	2854734	2.72E+07		Low NOx Burner Technology w/ Separated OFA Overfire Air

## TEXAS UNITS

State	Facility Name	Facility ID (ORISPL)	Unit ID	Associated Stacks	Year	Program(s)	Operating Time	Gross Load (MW-h)	SO2 (tons)	Avg. NOx Rate (lb/MMBtu)	NOx (tons)	CO2 (short tons)	Heat Input (MMBtu)	SO2 Control(s)	NOx Control(s)
TX	Tolk Station	6194 171B			2014	ARP	8425.14	4079809	9282.835	0.1355	2497.566	3847506	3.67E+07		Low NOx Burner Technology w/ Separated OFA Overfire Air
TX	Tolk Station	6194 172B			2014	ARP	6390.45	2993206	7475.673	0.1441	2130.368	3029339	2.89E+07		Low NOx Burner Technology w/ Separated OFA (Began Apr 05, 2014) Overfire Air
TX	Tolk Station	6194 172B			2015	ARP	8468.35	3859455	9584.632	0.1464	2823.599	4041125	3.85E+07		Low NOx Burner Technology w/ Separated OFA Overfire Air
TX	W A Parish	3470 WAP7			2015	ARP	6823.83	3479366	11277.09	0.0417	667.875	3353369	3.20E+07		Selective Catalytic Reduction
TX	W A Parish	3470 WAP7			2014	ARP	8182.73	4143520	13606.02	0.0487	940.868	4066295	3.88E+07		Selective Catalytic Reduction
TX	W A Parish	3470 WAP8			2015	ARP	7602.69	4046576	2381.104	0.0472	887.787	3971103	3.79E+07	Wet Lime I	Low NOx Burner Technology w/ Closed-coupled/Separated OFA Selective Catalytic Reduction Ammonia Injection
TX	W A Parish	3470 WAP8			2014	ARP	8313.04	4481612	2886.438	0.0473	1031.518	4625523	4.41E+07	Wet Lime I	Low NOx Burner Technology w/ Closed-coupled/Separated OFA Selective Catalytic Reduction Ammonia Injection



## Appendix G. EPA Cost Manual Cost Estimate Sheets

## Data Inputs

## Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler?

Utility ▼

What type of fuel does the unit burn?

Coal ▼

Is the SCR for a new boiler or retrofit of an existing boiler?

Retrofit ▼

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty.

1

## Complete all of the highlighted data fields:

What is the MW rating at full load capacity (Bmw)?

563.42 MW

What is the higher heating value (HHV) of the fuel?

6,612 Btu/lb

What is the estimated actual annual MWhs output?

4,293,936 MWhs

Enter the net plant heat input rate (NPHR)

10.416 MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation

1980 Feet above sea level

## Provide the following information for coal-fired boilers:

Type of coal burned:

Lignite ▼

Enter the sulfur content (%S) =

0.61 percent by weight

## For units burning coal blends:

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the **Cost Estimate** tab. Please select your preferred method:

- ☐ Method 1  
☒ Method 2  
☐ Not applicable

# SCR

## Enter the following design parameters for the proposed SCR:

Number of days the SCR operates ( $t_{SCR}$ )

318 days

Number of days the boiler operates ( $t_{plant}$ )

318 days

Inlet  $NO_x$  Emissions ( $NO_{x,in}$ ) to SCR

0.13 lb/MMBtu

Outlet  $NO_x$  Emissions ( $NO_{x,out}$ ) from SCR

0.04 lb/MMBtu

Stoichiometric Ratio Factor (SRF)

1.050

\*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Estimated operating life of the catalyst ( $H_{catalyst}$ )

24,000 hours

Estimated SCR equipment life

30 Years\*

\* For utility boilers, the typical equipment life of an SCR is at least 30 years.

Concentration of reagent as stored ( $C_{stored}$ )

100 percent

Density of reagent as stored ( $\rho_{stored}$ )

38.55 lb/cubic feet

Number of days reagent is stored ( $t_{storage}$ )

30 days

Select the reagent used

Ammonia

Number of SCR reactor chambers ( $n_{scr}$ )

1

Number of catalyst layers ( $R_{layer}$ )

3

Number of empty catalyst layers ( $R_{empty}$ )

1

Ammonia Slip (Slip) provided by vendor

2 ppm

Volume of the catalyst layers ( $Vol_{catalyst}$ )  
(Enter "UNK" if value is not known)

UNK Cubic feet

Flue gas flow rate ( $Q_{fluegas}$ )

(Enter "UNK" if value is not known)

3,202,636 acfm

Gas temperature at the SCR inlet (T)

830 °F

Base case fuel gas volumetric flow rate factor ( $Q_{fuel}$ )

547 ft<sup>3</sup>/min-MMBtu/hour

### Densities of typical SCR reagents:

50% urea solution

71 lbs/ft<sup>3</sup>

29.4% aqueous NH<sub>3</sub>

56 lbs/ft<sup>3</sup>

## Enter the cost data for the proposed SCR:

Desired dollar-year

2018

CEPCI for 2018

615.3 Enter the CEPCI value for 2018

541.7

2016 CEPCI

CEPCI = Chemical Engineering Plant Cost Index

Annual Interest Rate (i)

5.25 Percent

Reagent ( $Cost_{reag}$ )

1.560 \$/gallon for 100% ammonia

Electricity ( $Cost_{elect}$ )

0.0329 \$/kWh

Catalyst cost ( $CC_{replace}$ )

\$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst)

Operator Labor Rate

71.81 \$/hour (including benefits)

Operator Hours/Day

4.00 hours/day\*

\* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

## SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units
Maximum Annual Heat Input Rate ( $Q_B$ ) =	$B_{mw} \times NPHR =$	5,869	MMBtu/hour
Maximum Annual MW Output ( $B_{mw}$ ) =	$B_{mw} \times 8760 =$	4,935,559	MWhts
Estimated Actual Annual MWhts Output (Boutput) =		4,293,936	MWhts
Heat Rate Factor (HRF) =	$NPHR/10 =$	1.04	
Total System Capacity Factor ( $CF_{total}$ ) =	$(Boutput/B_{mw}) \times (t_{scr}/t_{plant}) =$	0.870	fraction
Total operating time for the SCR ( $t_{op}$ ) =	$CF_{total} \times 8760 =$	7621	hours
NO <sub>x</sub> Removal Efficiency (EF) =	$(NO_{x_{in}} - NO_{x_{out}})/NO_{x_{in}} =$	69.2	percent
NO <sub>x</sub> removed per hour =	$NO_{x_{in}} \times EF \times Q_B =$	528.17	lb/hour
Total NO <sub>x</sub> removed per year =	$(NO_{x_{in}} \times EF \times Q_B \times t_{op})/2000 =$	2,012.65	tons/year
NO <sub>x</sub> removal factor (NRF) =	$EF/80 =$	0.87	
Volumetric flue gas flow rate ( $q_{flue\ gas}$ ) =	$Q_{fuel} \times Q_B \times (460 + T)/(460 + 700)n_{scr} =$	3,202,636	acfm
Space velocity ( $V_{space}$ ) =	$q_{flue\ gas}/Vol_{catalyst} =$	135.19	/hour
Residence Time	$1/V_{space}$	0.01	hour
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.07	
SO <sub>2</sub> Emission rate =	$(\%S/100) \times (64/32) \times 1 \times 10^6 / HHV =$	< 3	lbs/MMBtu
Elevation Factor (ELEVf) =	$14.7\ psia/P =$	1.07	
Atmospheric pressure at sea level (P) =	$2116 \times [(59 - (0.00356 \times h) + 459.7)/518.6]^{5.256} \times (1/144)^* =$	13.7	psia
Retrofit Factor (RF)	Retrofit to existing boiler	1.00	

\* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at <https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html>.

### Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	$(interest\ rate)(1/((1 + interest\ rate)^Y - 1))$ , where $Y = H_{catalysts}/(t_{SCR} \times 24\ hours)$ rounded to the nearest integer	0.3164	Fraction
Catalyst volume ( $Vol_{catalyst}$ ) =	$2.81 \times Q_B \times EF_{adj} \times Slip_{adj} \times NO_{x_{adj}} \times S_{adj} \times (T_{adj}/N_{scr})$	23,689.22	Cubic feet
Cross sectional area of the catalyst ( $A_{catalyst}$ ) =	$q_{flue\ gas} / (16\ ft/sec \times 60\ sec/min)$	3,336	ft <sup>2</sup>

Height of each catalyst layer ( $H_{\text{layer}}$ ) =	$(\text{Vol}_{\text{catalyst}} / (R_{\text{layer}} \times A_{\text{catalyst}})) + 1$ (rounded to next highest integer)	3	feet
--	--	---	------

**SCR Reactor Data:**

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor ( $A_{\text{SCR}}$ ) =	$1.15 \times A_{\text{catalyst}}$	3,836	ft <sup>2</sup>
Reactor length and width dimensions for a square reactor =	$(A_{\text{SCR}})^{0.5}$	61.9	feet
Reactor height =	$(R_{\text{layer}} + R_{\text{empty}}) \times (7\text{ft} + h_{\text{layer}}) + 9\text{ft}$	50	feet

Reagent Data:

Type of reagent used	Ammonia	Molecular Weight of Reagent (MW) =	17.03 g/mole
		Density =	38.55 lb/ft <sup>3</sup>

Parameter	Equation	Calculated Value	Units
Reagent consumption rate (m <sub>reagent</sub> ) =	(NO <sub>x</sub> <sub>in</sub> x Q <sub>B</sub> x EF x SRF x MW <sub>R</sub> )/MW <sub>NOx</sub> =	205	lb/hour
Reagent Usage Rate (m <sub>sol</sub> ) =	m <sub>reagent</sub> /C <sub>sol</sub> =	205	lb/hour
	(m <sub>sol</sub> x 7.4805)/Reagent Density	40	gal/hour
Estimated tank volume for reagent storage =	(m <sub>sol</sub> x 7.4805 x t <sub>storage</sub> x 24)/Reagent Density =	28,700	gallons (storage needed to store a 30 day reagent supply rounded to

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i (1+i)^n / ((1+i)^n - 1) =$ Where n = Equipment Life and i= Interest Rate	0.0669

Other parameters	Equation	Calculated Value	Units
<b>Electricity Usage:</b>			
Electricity Consumption (P) =	$A \times 1,000 \times 0.0056 \times (\text{CoalF} \times \text{HRF})^{0.43} =$ where A = Bmw for utility boilers	3305.73	kW

## Cost Estimate

### Total Capital Investment (TCI)

#### TCI for Coal-Fired Boilers

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SCR_{cost} + RPC + APHC + BPC)$$

Capital costs for the SCR ( $SCR_{cost}$ ) =	\$137,775,430	in 2018 dollars
Reagent Preparation Cost (RPC) =	\$3,071,151	in 2018 dollars
Air Pre-Heater Costs (APHC)* =	\$0	in 2018 dollars
Balance of Plant Costs (BPC) =	\$9,657,516	in 2018 dollars
Total Capital Investment (TCI) =	\$195,655,325	in 2018 dollars

\* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 3lb/MMBtu of sulfur dioxide.

#### SCR Capital Costs ( $SCR_{cost}$ )

For Coal-Fired Utility Boilers >25 MW:

$$SCR_{cost} = 310,000 \times (NRF)^{0.2} \times (B_{MW} \times HRF \times CoalF)^{0.92} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$SCR_{cost} = 310,000 \times (NRF)^{0.2} \times (0.1 \times Q_B \times CoalF)^{0.92} \times ELEVF \times RF$$

SCR Capital Costs ( $SCR_{cost}$ ) =

\$137,775,430 in 2018 dollars

#### Reagent Preparation Costs (RPC)

For Coal-Fired Utility Boilers >25 MW:

$$RPC = 564,000 \times (NO_{x,in} \times B_{MW} \times NPHR \times EF)^{0.25} \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$RPC = 564,000 \times (NO_{x,in} \times Q_B \times EF)^{0.25} \times RF$$

Reagent Preparation Costs (RPC) =

\$3,071,151 in 2018 dollars

#### Air Pre-Heater Costs (APHC)\*

For Coal-Fired Utility Boilers >25MW:

$$APHC = 69,000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$APHC = 69,000 \times (0.1 \times Q_B \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs ( $APH_{cost}$ ) =

\$0 in 2018 dollars

\* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 3lb/MMBtu of sulfur dioxide.

#### Balance of Plant Costs (BPC)

For Coal-Fired Utility Boilers >25MW:

$$BPC = 529,000 \times (B_{MW} \times HRF \times CoalF)^{0.42} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$BPC = 529,000 \times (0.1 \times Q_B \times CoalF)^{0.42} \times ELEVF \times RF$$

Balance of Plant Costs ( $BOP_{cost}$ ) =

\$9,657,516 in 2018 dollars



## Annual Costs

## Total Annual Cost (TAC)

$$\text{TAC} = \text{Direct Annual Costs} + \text{Indirect Annual Costs}$$

Direct Annual Costs (DAC) =	\$3,313,274 in 2018 dollars
Indirect Annual Costs (IDAC) =	\$13,103,821 in 2018 dollars
Total annual costs (TAC) = DAC + IDAC	\$16,417,095 in 2018 dollars

## Direct Annual Costs (DAC)

$$\text{DAC} = (\text{Annual Maintenance Cost}) + (\text{Annual Reagent Cost}) + (\text{Annual Electricity Cost}) + (\text{Annual Catalyst Cost})$$

Annual Maintenance Cost =	$0.005 \times \text{TCI} =$	\$978,277 in 2018 dollars
Annual Reagent Cost =	$m_{\text{sol}} \times \text{Cost}_{\text{reag}} \times t_{\text{op}} =$	\$473,567 in 2018 dollars
Annual Electricity Cost =	$P \times \text{Cost}_{\text{elect}} \times t_{\text{op}} =$	\$828,869 in 2018 dollars
Annual Catalyst Replacement Cost =		\$1,032,561 in 2018 dollars

For coal-fired boilers, the following methods may be used to calculate the catalyst replacement cost.

Method 1 (for all fuel types):  $n_{\text{scr}} \times \text{Vol}_{\text{cat}} \times (\text{CC}_{\text{replace}} / R_{\text{layer}}) \times \text{FWF}$  \* Calculation Method 2 selected.

Method 2 (for coal-fired utility boilers):  $B_{\text{MW}} \times 0.4 \times (\text{CoalF})^{2.9} \times (\text{NRF})^{0.71} \times (\text{CC}_{\text{replace}}) \times 35.3$

Direct Annual Cost =	\$3,313,274 in 2018 dollars
----------------------	-----------------------------

## Indirect Annual Cost (IDAC)

$$\text{IDAC} = \text{Administrative Charges} + \text{Capital Recovery Costs}$$

Administrative Charges (AC) =	$0.03 \times (\text{Operator Cost} + 0.4 \times \text{Annual Maintenance Cost}) =$	\$14,480 in 2018 dollars
Capital Recovery Costs (CR)=	$\text{CRF} \times \text{TCI} =$	\$13,089,341 in 2018 dollars
Indirect Annual Cost (IDAC) =	$\text{AC} + \text{CR} =$	\$13,103,821 in 2018 dollars

## Cost Effectiveness

$$\text{Cost Effectiveness} = \text{Total Annual Cost} / \text{NOx Removed/year}$$

Total Annual Cost (TAC) =	\$16,417,095 per year in 2018 dollars
NOx Removed =	2,013 tons/year
Cost Effectiveness =	\$8,157 per ton of NOx removed in 2018 dollars

## Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler?

Utility ▼

What type of fuel does the unit burn?

Coal ▼

Is the SNCR for a new boiler or retrofit of an existing boiler?

Retrofit ▼

Please enter a retrofit factor equal to or greater than 0.84 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty.

1

Complete all of the highlighted data fields:

What is the MW rating at full load capacity (Bmw)?

563.42 MW

What is the higher heating value (HHV) of the fuel?

6,612 Btu/lb

What is the estimated actual annual MWh output?

4,293,936 MWh

Is the boiler a fluid-bed boiler?

No ▼

Enter the net plant heat input rate (NPHR)

10.416 MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Provide the following information for coal-fired boilers:

Type of coal burned:

Lignite ▼

Enter the sulfur content (%S) =

0.61 percent by weight

or

Select the appropriate SO<sub>2</sub> emission rate:

Not Applicable ▼

Ash content (%Ash):

12.89 percent by weight

For units burning coal blends:

Note: The table below is pre-populated with default values for HHV, %S, %Ash and cost. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

	Fraction in Coal Blend	%S	%Ash	HHV (Btu/lb)	Fuel Cost (\$/MMBtu)
Bituminous	0	1.84	9.23	11,841	2.4
Sub-Bituminous	0	0.41	5.84	8,826	1.89
Lignite	0	0.82	13.6	6,626	1.74

Please click the calculate button to calculate weighted values based on the data in the table above.

## Enter the following design parameters for the proposed SNCR:

Number of days the SNCR operates ( $t_{\text{SNCR}}$ )

365 days

Inlet  $\text{NO}_x$  Emissions ( $\text{NO}_{x\text{in}}$ ) to SNCR

0.13 lb/MMBtu

Outlet  $\text{NO}_x$  Emissions ( $\text{NO}_{x\text{out}}$ ) from SNCR

0.1105 lb/MMBtu

Estimated Normalized Stoichiometric Ratio (NSR)

3.33

\*The NSR for a urea system may be calculated using equation 1.17 in Section 4, Chapter 1 of the Air Pollution Control Cost Manual (as updated March 2019).

Concentration of reagent as stored ( $C_{\text{stored}}$ )

50 Percent

Density of reagent as stored ( $\rho_{\text{stored}}$ )

71 lb/ft<sup>3</sup>

Concentration of reagent injected ( $C_{\text{inj}}$ )

50 percent

Number of days reagent is stored ( $t_{\text{storage}}$ )

30 days

Estimated equipment life

20 Years

Plant Elevation

1980 Feet above sea level

Select the reagent used

Urea

### Densities of typical SNCR reagents:

50% urea solution	71 lbs/ft <sup>3</sup>
29.4% aqueous $\text{NH}_3$	56 lbs/ft <sup>3</sup>

## Enter the cost data for the proposed SNCR:

Desired dollar-year

2018

CEPCI for 2018

615.3 Enter the CEPCI value for 2018

541.7

2016 CEPCI

CEPCI = Chemical Engineering Plant Cost Index

Annual Interest Rate ( $i$ )

5.25 Percent

Fuel ( $\text{Cost}_{\text{fuel}}$ )

1.85 \$/MMBtu\*

Reagent ( $\text{Cost}_{\text{reag}}$ )

1.35 \$/gallon for a 50 percent solution of urea

Water ( $\text{Cost}_{\text{water}}$ )

0.0037 \$/gallon

Electricity ( $\text{Cost}_{\text{elect}}$ )

0.0329 \$/kWh

Ash Disposal (for coal-fired boilers only) ( $\text{Cost}_{\text{ash}}$ )

10.50 \$/ton

\* The values marked are default values. See the table below for the default values used and their references. Enter actual values, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

## Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =

0.015

Administrative Charges Factor (ACF) =

0.03

## SNCR Design Parameters

The following design parameters for the SNCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units
Maximum Annual Heat Input Rate ( $Q_B$ ) =	$Bmw \times NPHR =$	5,869	MMBtu/hour
Maximum Annual MWh Output =	$Bmw \times 8760 =$	4,935,559	MWh
Estimated Actual Annual MWh Output (Boutput) =		4,293,936	MWh
Heat Rate Factor (HRF) =	$NPHR/10 =$	1.04	
Total System Capacity Factor ( $CF_{total}$ ) =	$(Boutput/Bmw) \times (tsnrcr/365) =$	0.87	fraction
Total operating time for the SNCR ( $t_{op}$ ) =	$CF_{total} \times 8760 =$	7621	hours
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in} =$	15	percent
NOx removed per hour =	$NOx_{in} \times EF \times Q_B =$	114.44	lb/hour
Total NO <sub>x</sub> removed per year =	$(NOx_{in} \times EF \times Q_B \times t_{op})/2000 =$	436.08	tons/year
Coal Factor ( $Coal_F$ ) =	1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.07	
SO <sub>2</sub> Emission rate =	$(\%S/100) \times (64/32) \times (1 \times 10^6)/HHV =$	< 3	lbs/MMBtu
Elevation Factor (ELEV <sub>F</sub> ) =	$14.7 \text{ psia}/P =$	1.07	
Atmospheric pressure at 1980 feet above sea level (P) =	$2116 \times [(59 - (0.00356 \times h) + 459.7)/518.6]^{5.256} \times (1/144)^* =$	13.7	psia
Retrofit Factor (RF) =	Retrofit to existing boiler	1.00	

\* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at <https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html>.

**Reagent Data:**

Type of reagent used

Urea

Molecular Weight of Reagent (MW) = 60.06 g/mole  
Density = 71 lb/gallon

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ( $m_{\text{reagent}}$ ) =	$(\text{NOx}_{\text{in}} \times Q_{\text{B}} \times \text{NSR} \times \text{MW}_{\text{R}}) / (\text{MW}_{\text{NOx}} \times \text{SR}) =$ (whre SR = 1 for $\text{NH}_3$ ; 2 for Urea)	1658	lb/hour
Reagent Usage Rate ( $m_{\text{sol}}$ ) =	$m_{\text{reagent}} / C_{\text{sol}} =$	3,316	lb/hour
	$(m_{\text{sol}} \times 7.4805) / \text{Reagent Density} =$	349.4	gal/hour
Estimated tank volume for reagent storage =	$(m_{\text{sol}} \times 7.4805 \times t_{\text{storage}} \times 24 \text{ hours/day}) / \text{Reagent Density} =$	251,600	gallons (storage needed to store a 30 day reagent supply rounded up to the nearest 100 gallons)

**Capital Recovery Factor:**

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i (1+i)^n / (1+i)^n - 1 =$ Where n = Equipment Life and i= Interest Rate	0.0820

Parameter	Equation	Calculated Value	Units
<b>Electricity Usage:</b> Electricity Consumption (P) =	$(0.47 \times \text{NOx}_{\text{in}} \times \text{NSR} \times Q_{\text{B}}) / \text{NPHR} =$	114.6	kW/hour
<b>Water Usage:</b> Water consumption ( $q_{\text{w}}$ ) =	$(m_{\text{sol}} / \text{Density of water}) \times ((C_{\text{stored}} / C_{\text{inj}}) - 1) =$	0	gallons/hour
<b>Fuel Data:</b> Additional Fuel required to evaporate water in injected reagent ( $\Delta \text{Fuel}$ ) =	$H_v \times m_{\text{reagent}} \times ((1/C_{\text{inj}}) - 1) =$	1.49	MMBtu/hour
<b>Ash Disposal:</b> Additional ash produced due to increased fuel consumption ( $\Delta \text{ash}$ ) =	$(\Delta \text{fuel} \times \% \text{Ash} \times 1 \times 10^6) / \text{HHV} =$	29.1	lb/hour

## Cost Estimate

### Total Capital Investment (TCI)

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + APH_{cost} + BOP_{cost})$$

For Fuel Oil and Natural Gas-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + BOP_{cost})$$

Capital costs for the SNCR ( $SNCR_{cost}$ ) =	\$4,177,101 in 2018 dollars
Air Pre-Heater Costs ( $APH_{cost}$ )* =	\$0 in 2018 dollars
Balance of Plant Costs ( $BOP_{cost}$ ) =	\$5,191,356 in 2018 dollars
Total Capital Investment (TCI) =	\$12,178,995 in 2018 dollars

\* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 0.3lb/MMBtu of sulfur dioxide.

### SNCR Capital Costs ( $SNCR_{cost}$ )

For Coal-Fired Utility Boilers:

$$SNCR_{cost} = 220,000 \times (B_{MW} \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$SNCR_{cost} = 147,000 \times (B_{MW} \times HRF)^{0.42} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers:

$$SNCR_{cost} = 220,000 \times (0.1 \times Q_B \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$SNCR_{cost} = 147,000 \times ((Q_B/NPHR) \times HRF)^{0.42} \times ELEVF \times RF$$

SNCR Capital Costs ( $SNCR_{cost}$ ) =	\$4,177,101 in 2018 dollars
--	-----------------------------

### Air Pre-Heater Costs ( $APH_{cost}$ )\*

For Coal-Fired Utility Boilers:

$$APH_{cost} = 69,000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers:

$$APH_{cost} = 69,000 \times (0.1 \times Q_B \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs ( $APH_{cost}$ ) =	\$0 in 2018 dollars
---	---------------------

\* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 3lb/MMBtu of sulfur dioxide.

### Balance of Plant Costs ( $BOP_{cost}$ )

For Coal-Fired Utility Boilers:

$$BOP_{cost} = 320,000 \times (B_{MW})^{0.33} \times (NO_x \text{ Removed/hr})^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$BOP_{cost} = 213,000 \times (B_{MW})^{0.33} \times (NO_x \text{ Removed/hr})^{0.12} \times RF$$

For Coal-Fired Industrial Boilers:

$$BOP_{cost} = 320,000 \times (0.1 \times Q_B)^{0.33} \times (NO_x \text{ Removed/hr})^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$BOP_{cost} = 213,000 \times (Q_B/NPHR)^{0.33} \times (NO_x \text{ Removed/hr})^{0.12} \times RF$$

Balance of Plant Costs ( $BOP_{cost}$ ) =	\$5,191,356 in 2018 dollars
---	-----------------------------

## Annual Costs

### Total Annual Cost (TAC)

$$\text{TAC} = \text{Direct Annual Costs} + \text{Indirect Annual Costs}$$

Direct Annual Costs (DAC) =	\$3,828,504 in 2018 dollars
Indirect Annual Costs (IDAC) =	\$1,004,158 in 2018 dollars
Total annual costs (TAC) = DAC + IDAC	\$4,832,662 in 2018 dollars

### Direct Annual Costs (DAC)

$$\text{DAC} = (\text{Annual Maintenance Cost}) + (\text{Annual Reagent Cost}) + (\text{Annual Electricity Cost}) + (\text{Annual Water Cost}) + (\text{Annual Fuel Cost}) + (\text{Annual Ash Cost})$$

Annual Maintenance Cost =	$0.015 \times \text{TCI} =$	\$182,685 in 2018 dollars
Annual Reagent Cost =	$q_{\text{sol}} \times \text{Cost}_{\text{reag}} \times t_{\text{op}} =$	\$3,594,871 in 2018 dollars
Annual Electricity Cost =	$P \times \text{Cost}_{\text{elect}} \times t_{\text{op}} =$	\$28,743 in 2018 dollars
Annual Water Cost =	$q_{\text{water}} \times \text{Cost}_{\text{water}} \times t_{\text{op}} =$	\$0 in 2018 dollars
Additional Fuel Cost =	$\Delta \text{Fuel} \times \text{Cost}_{\text{fuel}} \times t_{\text{op}} =$	\$21,041 in 2018 dollars
Additional Ash Cost =	$\Delta \text{Ash} \times \text{Cost}_{\text{ash}} \times t_{\text{op}} \times (1/2000) =$	\$1,164 in 2018 dollars
Direct Annual Cost =		\$3,828,504 in 2018 dollars

### Indirect Annual Cost (IDAC)

$$\text{IDAC} = \text{Administrative Charges} + \text{Capital Recovery Costs}$$

Administrative Charges (AC) =	$0.03 \times \text{Annual Maintenance Cost} =$	\$5,481 in 2018 dollars
Capital Recovery Costs (CR)=	$\text{CRF} \times \text{TCI} =$	\$998,678 in 2018 dollars
Indirect Annual Cost (IDAC) =	$\text{AC} + \text{CR} =$	\$1,004,158 in 2018 dollars

## Cost Effectiveness

$$\text{Cost Effectiveness} = \text{Total Annual Cost} / \text{NOx Removed/year}$$

Total Annual Cost (TAC) =	\$4,832,662 per year in 2018 dollars
NOx Removed =	436 tons/year
Cost Effectiveness =	\$11,082 per ton of NOx removed in 2018 dollars

## Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler?

Utility ▼

What type of fuel does the unit burn?

Coal ▼

Is the SNCR for a new boiler or retrofit of an existing boiler?

Retrofit ▼

Please enter a retrofit factor equal to or greater than 0.84 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty.

1

Complete all of the highlighted data fields:

What is the MW rating at full load capacity (Bmw)?

563.42 MW

What is the higher heating value (HHV) of the fuel?

6,612 Btu/lb

What is the estimated actual annual MWh output?

4,293,936 MWh

Is the boiler a fluid-bed boiler?

No ▼

Enter the net plant heat input rate (NPHR)

10.416 MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Provide the following information for coal-fired boilers:

Type of coal burned:

Lignite ▼

Enter the sulfur content (%S) =

0.61 percent by weight

or

Select the appropriate SO<sub>2</sub> emission rate:

Not Applicable ▼

Ash content (%Ash):

12.89 percent by weight

For units burning coal blends:

Note: The table below is pre-populated with default values for HHV, %S, %Ash and cost. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

	Fraction in Coal Blend	%S	%Ash	HHV (Btu/lb)	Fuel Cost (\$/MMBtu)
Bituminous	0	1.84	9.23	11,841	2.4
Sub-Bituminous	0	0.41	5.84	8,826	1.89
Lignite	0	0.82	13.6	6,626	1.74

Please click the calculate button to calculate weighted values based on the data in the table above.



Enter the following design parameters for the proposed SNCR:

Number of days the SNCR operates ( $t_{\text{SNCR}}$ )	365 days	Plant Elevation	1980 Feet above sea level
Inlet $\text{NO}_x$ Emissions ( $\text{NO}_{x\text{in}}$ ) to SNCR	0.13 lb/MMBtu		
Outlet $\text{NO}_x$ Emissions ( $\text{NO}_{x\text{out}}$ ) from SNCR	0.1001 lb/MMBtu		
Estimated Normalized Stoichiometric Ratio (NSR)	3.33		
Concentration of reagent as stored ( $C_{\text{stored}}$ )	50 Percent		
Density of reagent as stored ( $\rho_{\text{stored}}$ )	71 lb/ft <sup>3</sup>		
Concentration of reagent injected ( $C_{\text{inj}}$ )	50 percent		
Number of days reagent is stored ( $t_{\text{storage}}$ )	30 days		
Estimated equipment life	20 Years		
Select the reagent used	Urea		

\*The NSR for a urea system may be calculated using equation 1.17 in Section 4, Chapter 1 of the Air Pollution Control Cost Manual (as updated March 2019).

Densities of typical SNCR reagents:	
50% urea solution	71 lbs/ft <sup>3</sup>
29.4% aqueous $\text{NH}_3$	56 lbs/ft <sup>3</sup>

Enter the cost data for the proposed SNCR:

Desired dollar-year	2018		
CEPCI for 2018	615.3 Enter the CEPCI value for 2018	541.7	2016 CEPCI
Annual Interest Rate (i)	5.25 Percent		
Fuel ( $\text{Cost}_{\text{fuel}}$ )	1.85 \$/MMBtu*		
Reagent ( $\text{Cost}_{\text{reag}}$ )	1.35 \$/gallon for a 50 percent solution of urea		
Water ( $\text{Cost}_{\text{water}}$ )	0.0037 \$/gallon		
Electricity ( $\text{Cost}_{\text{elect}}$ )	0.0329 \$/kWh		
Ash Disposal (for coal-fired boilers only) ( $\text{Cost}_{\text{ash}}$ )	10.50 \$/ton		

CEPCI = Chemical Engineering Plant Cost Index

\* The values marked are default values. See the table below for the default values used and their references. Enter actual values, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.015
Administrative Charges Factor (ACF) =	0.03

## SNCR Design Parameters

The following design parameters for the SNCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units
Maximum Annual Heat Input Rate ( $Q_B$ ) =	$B_{mw} \times NPHR =$	5,869	MMBtu/hour
Maximum Annual MWh Output =	$B_{mw} \times 8760 =$	4,935,559	MWh
Estimated Actual Annual MWh Output (Boutput) =		4,293,936	MWh
Heat Rate Factor (HRF) =	$NPHR/10 =$	1.04	
Total System Capacity Factor ( $CF_{total}$ ) =	$(B_{output}/B_{mw}) \times (tsnrcr/365) =$	0.87	fraction
Total operating time for the SNCR ( $t_{op}$ ) =	$CF_{total} \times 8760 =$	7621	hours
NOx Removal Efficiency (EF) =	$(NO_{x_{in}} - NO_{x_{out}})/NO_{x_{in}} =$	23	percent
NOx removed per hour =	$NO_{x_{in}} \times EF \times Q_B =$	175.47	lb/hour
Total NO <sub>x</sub> removed per year =	$(NO_{x_{in}} \times EF \times Q_B \times t_{op})/2000 =$	668.65	tons/year
Coal Factor ( $Coal_F$ ) =	1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.07	
SO <sub>2</sub> Emission rate =	$(\%S/100) \times (64/32) \times (1 \times 10^6)/HHV =$	< 3	lbs/MMBtu
Elevation Factor (ELEV <sub>F</sub> ) =	$14.7 \text{ psia}/P =$	1.07	
Atmospheric pressure at 1980 feet above sea level (P) =	$2116 \times [(59 - (0.00356 \times h) + 459.7)/518.6]^{5.256} \times (1/144)^* =$	13.7	psia
Retrofit Factor (RF) =	Retrofit to existing boiler	1.00	

\* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at <https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html>.

**Reagent Data:**

Type of reagent used

Urea

Molecular Weight of Reagent (MW) = 60.06 g/mole

Density = 71 lb/gallon

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ( $m_{\text{reagent}}$ ) =	$(\text{NOx}_{\text{in}} \times Q_{\text{B}} \times \text{NSR} \times \text{MW}_{\text{R}}) / (\text{MW}_{\text{NOx}} \times \text{SR}) =$ (where SR = 1 for $\text{NH}_3$ ; 2 for Urea)	1658	lb/hour
Reagent Usage Rate ( $m_{\text{sol}}$ ) =	$m_{\text{reagent}} / C_{\text{sol}} =$	3,316	lb/hour
	$(m_{\text{sol}} \times 7.4805) / \text{Reagent Density} =$	349.4	gal/hour
Estimated tank volume for reagent storage =	$(m_{\text{sol}} \times 7.4805 \times t_{\text{storage}} \times 24 \text{ hours/day}) / \text{Reagent Density} =$	251,600	gallons (storage needed to store a 30 day reagent supply rounded up to the nearest 100 gallons)

**Capital Recovery Factor:**

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i (1+i)^n / (1+i)^n - 1 =$ Where n = Equipment Life and i= Interest Rate	0.0820

Parameter	Equation	Calculated Value	Units
<b>Electricity Usage:</b> Electricity Consumption (P) =	$(0.47 \times \text{NOx}_{\text{in}} \times \text{NSR} \times Q_{\text{B}}) / \text{NPHR} =$	114.6	kW/hour
<b>Water Usage:</b> Water consumption ( $q_{\text{w}}$ ) =	$(m_{\text{sol}} / \text{Density of water}) \times ((C_{\text{stored}} / C_{\text{inj}}) - 1) =$	0	gallons/hour
<b>Fuel Data:</b> Additional Fuel required to evaporate water in injected reagent ( $\Delta \text{Fuel}$ ) =	$H_v \times m_{\text{reagent}} \times ((1/C_{\text{inj}}) - 1) =$	1.49	MMBtu/hour
<b>Ash Disposal:</b> Additional ash produced due to increased fuel consumption ( $\Delta \text{ash}$ ) =	$(\Delta \text{fuel} \times \% \text{Ash} \times 1 \times 10^6) / \text{HHV} =$	29.1	lb/hour

## Cost Estimate

### Total Capital Investment (TCI)

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + APH_{cost} + BOP_{cost})$$

For Fuel Oil and Natural Gas-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + BOP_{cost})$$

Capital costs for the SNCR ( $SNCR_{cost}$ ) =	\$4,177,101 in 2018 dollars
Air Pre-Heater Costs ( $APH_{cost}$ )* =	\$0 in 2018 dollars
Balance of Plant Costs ( $BOP_{cost}$ ) =	\$5,464,586 in 2018 dollars
Total Capital Investment (TCI) =	\$12,534,193 in 2018 dollars

\* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 0.3lb/MMBtu of sulfur dioxide.

### SNCR Capital Costs ( $SNCR_{cost}$ )

For Coal-Fired Utility Boilers:

$$SNCR_{cost} = 220,000 \times (B_{MW} \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$SNCR_{cost} = 147,000 \times (B_{MW} \times HRF)^{0.42} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers:

$$SNCR_{cost} = 220,000 \times (0.1 \times Q_B \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$SNCR_{cost} = 147,000 \times ((Q_B/NPHR) \times HRF)^{0.42} \times ELEVF \times RF$$

SNCR Capital Costs ( $SNCR_{cost}$ ) =	\$4,177,101 in 2018 dollars
--	-----------------------------

### Air Pre-Heater Costs ( $APH_{cost}$ )\*

For Coal-Fired Utility Boilers:

$$APH_{cost} = 69,000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers:

$$APH_{cost} = 69,000 \times (0.1 \times Q_B \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs ( $APH_{cost}$ ) =	\$0 in 2018 dollars
---	---------------------

\* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 3lb/MMBtu of sulfur dioxide.

### Balance of Plant Costs ( $BOP_{cost}$ )

For Coal-Fired Utility Boilers:

$$BOP_{cost} = 320,000 \times (B_{MW})^{0.33} \times (NO_x \text{ Removed/hr})^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$BOP_{cost} = 213,000 \times (B_{MW})^{0.33} \times (NO_x \text{ Removed/hr})^{0.12} \times RF$$

For Coal-Fired Industrial Boilers:

$$BOP_{cost} = 320,000 \times (0.1 \times Q_B)^{0.33} \times (NO_x \text{ Removed/hr})^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$BOP_{cost} = 213,000 \times (Q_B/NPHR)^{0.33} \times (NO_x \text{ Removed/hr})^{0.12} \times RF$$

Balance of Plant Costs ( $BOP_{cost}$ ) =	\$5,464,586 in 2018 dollars
---	-----------------------------

## Annual Costs

### Total Annual Cost (TAC)

$$\text{TAC} = \text{Direct Annual Costs} + \text{Indirect Annual Costs}$$

Direct Annual Costs (DAC) =	\$3,833,832 in 2018 dollars
Indirect Annual Costs (IDAC) =	\$1,033,444 in 2018 dollars
Total annual costs (TAC) = DAC + IDAC	\$4,867,276 in 2018 dollars

### Direct Annual Costs (DAC)

$$\text{DAC} = (\text{Annual Maintenance Cost}) + (\text{Annual Reagent Cost}) + (\text{Annual Electricity Cost}) + (\text{Annual Water Cost}) + (\text{Annual Fuel Cost}) + (\text{Annual Ash Cost})$$

Annual Maintenance Cost =	$0.015 \times \text{TCI} =$	\$188,013 in 2018 dollars
Annual Reagent Cost =	$q_{\text{sol}} \times \text{Cost}_{\text{reag}} \times t_{\text{op}} =$	\$3,594,871 in 2018 dollars
Annual Electricity Cost =	$P \times \text{Cost}_{\text{elect}} \times t_{\text{op}} =$	\$28,743 in 2018 dollars
Annual Water Cost =	$q_{\text{water}} \times \text{Cost}_{\text{water}} \times t_{\text{op}} =$	\$0 in 2018 dollars
Additional Fuel Cost =	$\Delta \text{Fuel} \times \text{Cost}_{\text{fuel}} \times t_{\text{op}} =$	\$21,041 in 2018 dollars
Additional Ash Cost =	$\Delta \text{Ash} \times \text{Cost}_{\text{ash}} \times t_{\text{op}} \times (1/2000) =$	\$1,164 in 2018 dollars
Direct Annual Cost =		\$3,833,832 in 2018 dollars

### Indirect Annual Cost (IDAC)

$$\text{IDAC} = \text{Administrative Charges} + \text{Capital Recovery Costs}$$

Administrative Charges (AC) =	$0.03 \times \text{Annual Maintenance Cost} =$	\$5,640 in 2018 dollars
Capital Recovery Costs (CR)=	$\text{CRF} \times \text{TCI} =$	\$1,027,804 in 2018 dollars
Indirect Annual Cost (IDAC) =	$\text{AC} + \text{CR} =$	\$1,033,444 in 2018 dollars

## Cost Effectiveness

$$\text{Cost Effectiveness} = \text{Total Annual Cost} / \text{NOx Removed/year}$$

Total Annual Cost (TAC) =	\$4,867,276 per year in 2018 dollars
NOx Removed =	669 tons/year
Cost Effectiveness =	\$7,279 per ton of NOx removed in 2018 dollars

## Appendix H. Alstom Power MATS Tuning Report



# **Great River Energy**

Coal Creek Station

Unit's #1 and #2

## **MATS Tuning**

### **EXECUTIVE SUMMARY REPORT**

June 2015



## EXECUTIVE SUMMARY

Alstom Power Technical Services was on site beginning the week of 6/8/2015 to conduct a series of emissions tests under the MATS ruling. The testing/tuning consisted of monitoring flue gas emission for O<sub>2</sub>, NO<sub>x</sub> and CO while the units were operated at full load conditions. Data was collected before, during and after all matrix parameter adjustments.

Coal Creek Units #1 and #2 are Alstom Power designed CCRRD steam generators (Controlled Circulation Radiant Reheat Divided Furnace). The MCR (Maximum Continuous Rating) of each unit is 3,730 Klbs/hr. steam flow. The unit's burn North Dakota lignite through eight (8) elevations of pulverized coal, supplied by Alstom designed 1043 RP mills. Design operating pressure is 2,620 psi.

Alstom Power Testing Services had installed a twelve (12) point sampling test grid across the furnace backpass, just after the economizer outlet for each unit tested. Vacuum pumps pulled a continuous flue gas sample through our analyzer system and this gas sample was monitored for O<sub>2</sub>, (% dry) CO (ppm) and NO<sub>x</sub> (#/MMBtu).

Alstom followed a test matrix to affect either a positive or negative response to manipulated parameters. This test matrix included the following parameters that were adjusted with controller biases:

- WB/F  $\Delta P$
- O<sub>2</sub>
- Burner tilts
- SOFA tilts
- SOFA dampers





## UNIT #2

The following data was monitored and recorded at the beginning of each parameter adjustment. The first set of data is recorded as “base load” at the start of tuning on 6/10/2015. Unit #2 was tested first.

### Plant Data

- Load 606 MW
- Throttle Press. 2520 psi
- SHO (L/R) 994/989° F
- RHO (L/R) 987/997° F
- Mills in Service 6
- Tilts (L/R) 9/19 degrees up
- O<sub>2</sub> Plant 2.75 %
- WB/F  $\Delta$ P 5.3”
- NO<sub>x</sub> .152 #/MMBtu (plant CEMS)

### Alstom Test Grid

- O<sub>2</sub> 3.2 %
- CO 8.5 ppm
- NO<sub>x</sub> .148 #/MMBtu

Alstom began making adjustments to the WB/F  $\Delta$ P controller bias. The as found output of 5.3” was incrementally increased up to 6.2” by removing the negative bias of .9” that had been installed earlier by GRE. These small step adjustments brought the NO<sub>x</sub> down to:

- CEMS .139 #/MMBtu
- Alstom .141 #/MMBtu

The following spreadsheet shows flue gas analysis of all 12 Alstom grid intersects on our point-to-point sampling. The sheet indicates the grid depth and length across the economizer outlet ducts, both Left and Right.

Great River Energy  
Coal Creek #1  
Economizer Outlet

ALSTOM POWER, INC.  
PERFORMANCE SERVICES  
WINDSOR, CONNECTICUT

TEST DATA AND RESULTS  
FLUE GAS ANALYSIS - POINT BY POINT GRID DATA

Economizer Outlet Left Duct

TEST NUMBER: 1

DATE: 6/15/15

START TIME: 0857

F FACTOR: 9860

STOP TIME: 0935

LOAD:

S = 19"

M = 57"

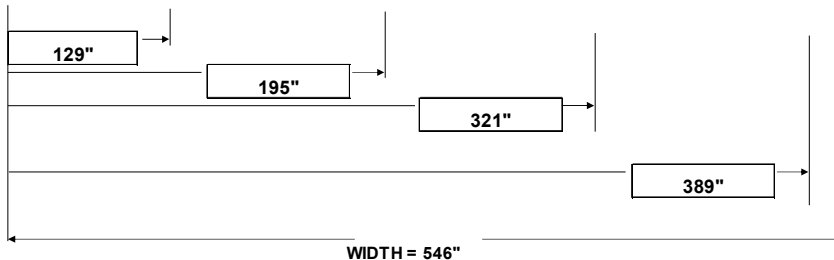
Left

L = 95"

TEST PORT	TEST PORT	TEST PORT	TEST PORT
1	2	3	4
O2, % 3.7 CO, PPM 0 NOX, PPM 138 CO,corr 3% O2, PPM 0 NOX, corr 3% O2, PPM 144 NOX, Lb/Mbtu 0.197	O2, % 3.1 CO, PPM 0 NOX, PPM 154 CO,corr 3% O2, PPM 0 NOX, corr 3% O2, PPM 155 NOX, Lb/Mbtu 0.213	O2, % 3.2 CO, PPM 7 NOX, PPM 152 CO,corr 3% O2, PPM 7 NOX, corr 3% O2, PPM 154 NOX, Lb/Mbtu 0.211	O2, % 3.1 CO, PPM 0 NOX, PPM 152 CO,corr 3% O2, PPM 0 NOX, corr 3% O2, PPM 153 NOX, Lb/Mbtu 0.210
O2, % 2.0 CO, PPM 20 NOX, PPM 147 CO,corr 3% O2, PPM 19 NOX, corr 3% O2, PPM 139 NOX, Lb/Mbtu 0.191	O2, % 2.2 CO, PPM 10 NOX, PPM 157 CO,corr 3% O2, PPM 10 NOX, corr 3% O2, PPM 150 NOX, Lb/Mbtu 0.207	O2, % 2.6 CO, PPM 7 NOX, PPM 154 CO,corr 3% O2, PPM 7 NOX, corr 3% O2, PPM 151 NOX, Lb/Mbtu 0.207	O2, % 2.5 CO, PPM 6 NOX, PPM 153 CO,corr 3% O2, PPM 6 NOX, corr 3% O2, PPM 149 NOX, Lb/Mbtu 0.205
O2, % 2.6 CO, PPM 5 NOX, PPM 136 CO,corr 3% O2, PPM 5 NOX, corr 3% O2, PPM 133 NOX, Lb/Mbtu 0.183	O2, % 2.4 CO, PPM 0 NOX, PPM 148 CO,corr 3% O2, PPM 0 NOX, corr 3% O2, PPM 143 NOX, Lb/Mbtu 0.197	O2, % 2.7 CO, PPM 0 NOX, PPM 146 CO,corr 3% O2, PPM 0 NOX, corr 3% O2, PPM 144 NOX, Lb/Mbtu 0.197	O2, % 2.4 CO, PPM 0 NOX, PPM 145 CO,corr 3% O2, PPM 0 NOX, corr 3% O2, PPM 140 NOX, Lb/Mbtu 0.193

DEPTH = 115"

Right



Grid Avg. O2, % = 2.7

Grid Avg. CO, PPM = 9

Grid Avg. NOX, PPM = 149

Grid Avg. CO corr 3% O2, PPM = 9

Grid Avg. NOX corr 3% O2, PPM = 146

Grid Avg. NOX, LB/MBtu = 0.201

Great River Energy  
Coal Creek #2  
Economizer Outlet

ALSTOM POWER, INC.  
PERFORMANCE SERVICES  
WINDSOR, CONNECTICUT

TEST DATA AND RESULTS  
FLUE GAS ANALYSIS - POINT BY POINT GRID DATA

Economizer Outlet Left Duct

TEST NUMBER: 1

DATE: 6/10/15

START TIME: 0740

F FACTOR: 9860

STOP TIME: 0835

LOAD:

S = 19"

M : 57"

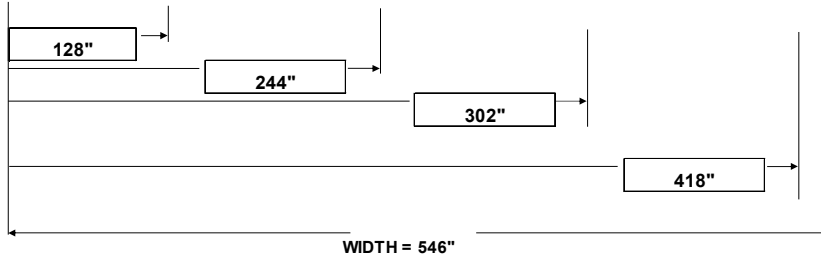
Left

L = 95"

DEPTH = 115"

Right

TEST PORT	TEST PORT	TEST PORT	TEST PORT
1	2	3	4
O2, % 2.8	O2, % 2.7	O2, % 2.6	O2, % 2.9
CO, PPM 0	CO, PPM 5	CO, PPM 5	CO, PPM 0
NOX, PPM 98	NOX, PPM 104	NOX, PPM 113	NOX, PPM 125
CO,corr 3% O2, PPM 0	CO,corr 3% O2, PPM 5	CO,corr 3% O2, PPM 5	CO,corr 3% O2, PPM 0
NOX, corr 3% O2, PPM 97	NOX, corr 3% O2, PPM 102	NOX, corr 3% O2, PPM 111	NOX, corr 3% O2, PPM 124
NOX, Lb/Mbtu 0.133	NOX, Lb/Mbtu 0.141	NOX, Lb/Mbtu 0.152	NOX, Lb/Mbtu 0.171
O2, % 2.1	O2, % 2.1	O2, % 2.3	O2, % 2.3
CO, PPM 32	CO, PPM 0	CO, PPM 0	CO, PPM 0
NOX, PPM 97	NOX, PPM 109	NOX, PPM 123	NOX, PPM 132
CO,corr 3% O2, PPM 30	CO,corr 3% O2, PPM 0	CO,corr 3% O2, PPM 0	CO,corr 3% O2, PPM 0
NOX, corr 3% O2, PPM 92	NOX, corr 3% O2, PPM 104	NOX, corr 3% O2, PPM 118	NOX, corr 3% O2, PPM 127
NOX, Lb/Mbtu 0.127	NOX, Lb/Mbtu 0.143	NOX, Lb/Mbtu 0.163	NOX, Lb/Mbtu 0.175
O2, % 2.8	O2, % 3.1	O2, % 2.2	O2, % 3.1
CO, PPM 0	CO, PPM 0	CO, PPM 0	CO, PPM 0
NOX, PPM 98	NOX, PPM 104	NOX, PPM 124	NOX, PPM 137
CO,corr 3% O2, PPM 0	CO,corr 3% O2, PPM 0	CO,corr 3% O2, PPM 0	CO,corr 3% O2, PPM 0
NOX, corr 3% O2, PPM 97	NOX, corr 3% O2, PPM 105	NOX, corr 3% O2, PPM 119	NOX, corr 3% O2, PPM 138
NOX, Lb/Mbtu 0.133	NOX, Lb/Mbtu 0.144	NOX, Lb/Mbtu 0.163	NOX, Lb/Mbtu 0.189



Grid Avg. O2, % = 2.6

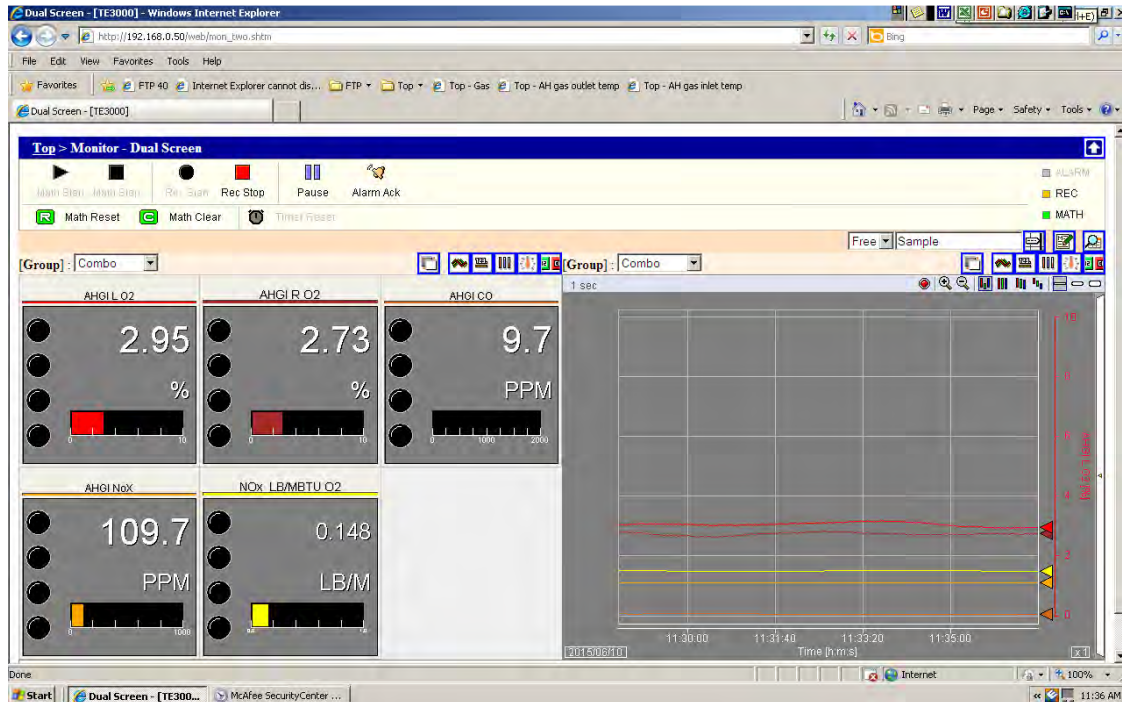
Grid Avg. CO, PPM = 14

Grid Avg. NOX, PPM = 114

Grid Avg. CO corr 3% O2, PPM = 13

Grid Avg. NOX corr 3% O2, PPM = 111

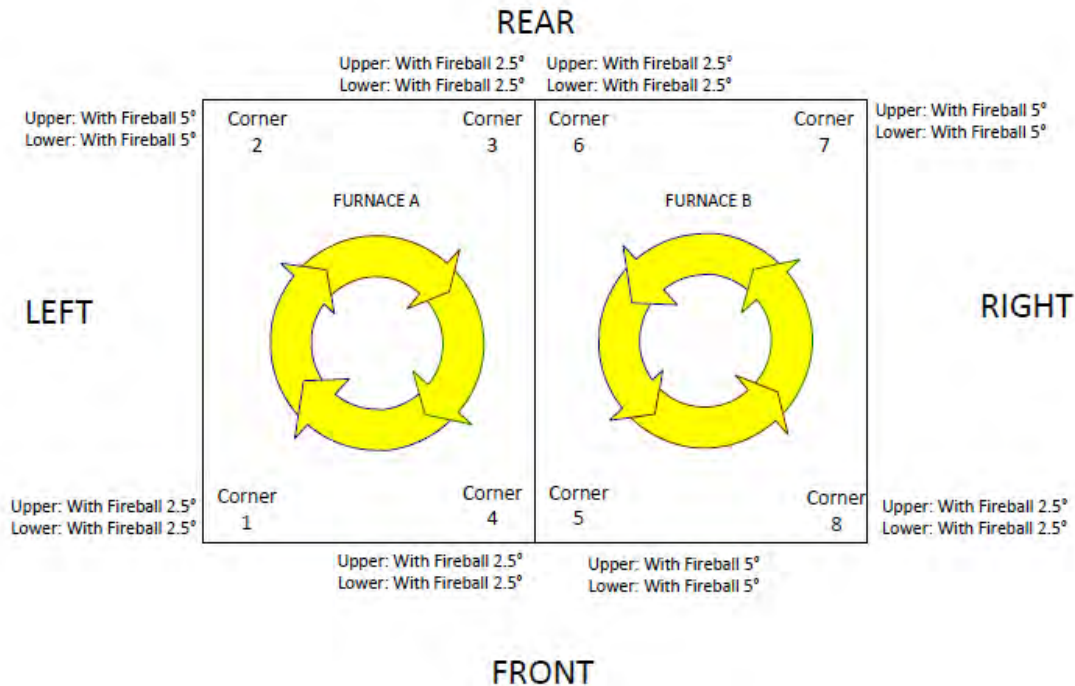
Grid Avg. NOX, LB/MBtu = 0.153



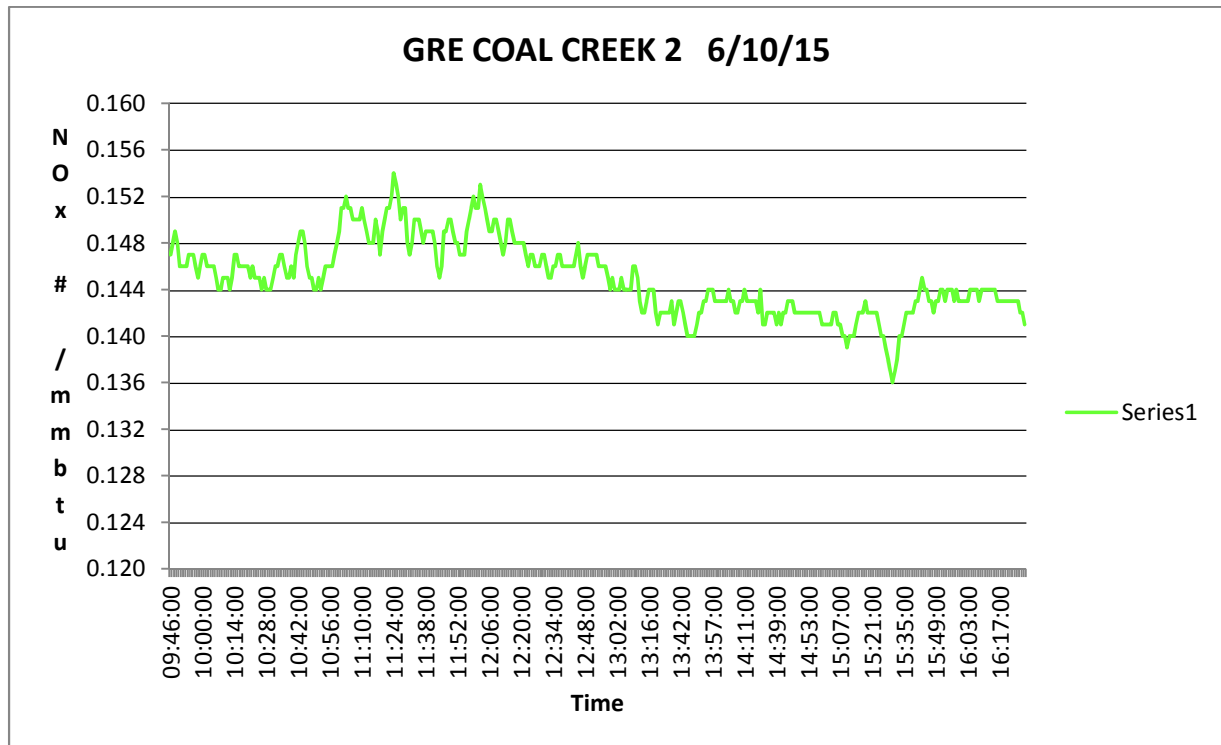
The above data shows sampling points across the economizer outlet duct on June 10<sup>th</sup>, after the unit reached a steady state of full load and prior to making a parameter adjustment. Note the low CO values and NO<sub>x</sub> ppm and #/MMBtu output.

From 6/10 through 6/12, Alstom manipulated O<sub>2</sub>, WB/F  $\Delta P$ , Burner tilts, SOFA tilts and SOFA dampers. The O<sub>2</sub> adjustments were small (2.75% to 2.5% range) and did not affect the NO<sub>x</sub> output positively. WB/F  $\Delta P$  adjustments accounted for the best positive effect in further reducing the already good NO<sub>x</sub> output. No amount of adjustments to the units SOFA yaw or dampers mechanisms made any positive NO<sub>x</sub> reduction. In fact, the SOFA system is so well tuned, that any all adjustments from in-place control, only made the NO<sub>x</sub> value increase.

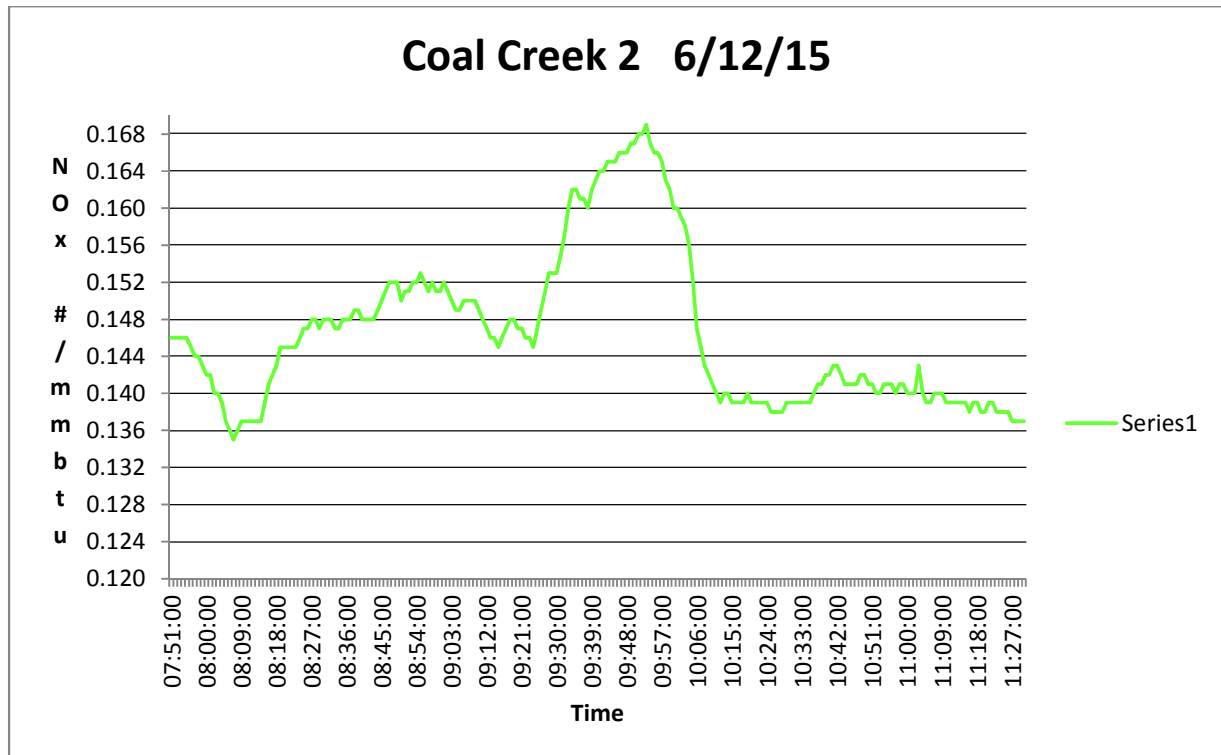
**GREAT RIVER ENERGY**  
**COAL CREEK #2**  
**SOFA YAW POSTIONS**



This diagram shows the optimum positioning of SOFA yaw on Unit #2, in a range of +15 to -15 degrees. These positions should not be modified. In addition, the SOFA damper control curves for the Upper and Lower SOFA compartments are working quite well and should not be modified.



The above graph shows NOx output reduction on Unit #2 after making adjustments to increase WB/F  $\Delta P$ .



NOx output after final parameter adjustments made to Unit #2. Ending average was .138 to .140 #/MMBtu.

#### Plant Data

- Load 612MW
- O<sub>2</sub> 2.6%
- WB/FΔP 6.2"
- SHO 992/985 degrees
- RHO 1005/1004 degrees
- CEMS .140 #/MMBtu

Alstom Grid .139 #/MMBtu NOx 5.1 ppm CO



## UNIT #1

Unit #1 was tested the week of 6/15, using the same equipment installed in the unit's economizer backpass and following the same matrix. Although this was only one week after testing was conducted on Unit #2, there were significant changes noted in operation of both units. While Unit #2 had recorded a relatively low NO<sub>x</sub> output (.139 #/MMBtu), Unit #1 was operating with a low NO<sub>x</sub> output as well. While in the Control Room, Alstom noted that Unit #1 NO<sub>x</sub> was at .181 to .183 #/MMBtu. This value is well below the permitted value of .226 #/MMBtu. However, during our week of testing on Unit #2, the NO<sub>x</sub> level had increased up to .218, with occasional spikes up to .226 #/MMBtu. We also noted that the NO<sub>x</sub> output on Unit #2 had increased as well, up to an average of .165, from our low tested point of .139 #/MMBtu average.

After discussions with GRE, we were informed that the fuel quality had changed, to the detriment of NO<sub>x</sub> increases on both units. The fuel quality change was enough that neither unit was able to achieve and maintain design SH and RH outlet temperatures. As a result, operators had raised the burner tilts to compensate for the loss of steam temperatures. Operating with burner tilts greater than 0° (horizontal) will over-stage the Low NO<sub>x</sub> system (staging is the term associated with the total distance between the Top of the burner OFA compartments and the Bottom of the SOFA compartments).

Further discussions with GRE personnel revealed the fuel quality change was not related to a reduction of HHV (Btu content) so much, but rather a change in Sodium content. GRE stated that when burning North Dakota lignite with a Sodium content of 2.0% or less, slagging conditions within the furnace cavity is virtually non-existent. With no slag/ash build up on the units Water Walls, the heat absorption rate in the lower furnace (from Nose Arch to Lower Couton Slope) is at its maximum. This rate of heat absorption in the Water Wall circuits takes away heat that would typically be absorbed in the upper SH/RH and Back Pass areas.





As a result of this fuel change, both unit burner tilts were raised in an attempt to increase SH and RH steam outlet temperatures. Tilt positions on both units averaged from +14 / +22 degrees (Left and Right furnaces). As stated prior, raising burner tilts above the horizontal plane has a negative effect on NOx emissions.



Screen shot taken from Alstom grid On Unit #1 emissions on 6/15/2015. Note the NOx at .213 #/MMBtu. While still below its permitted level, this value is higher than the previous week with operating conditions being identical. The increased NOx output is directly related to burner tilts being elevated to obtain design SH and RH outlet steam temperatures.

The following spreadsheet shows flue gas analysis of all 12 Alstom grid intersects on our point-to-point sampling. The sheet indicates the grid depth and length across the economizer outlet ducts, both Left and Right.

Great River Energy  
Coal Creek #1  
Economizer Outlet

ALSTOM POWER, INC.  
PERFORMANCE SERVICES  
WINDSOR, CONNECTICUT

TEST DATA AND RESULTS  
FLUE GAS ANALYSIS - POINT BY POINT GRID DATA

Economizer Outlet Left Duct

TEST NUMBER: 1

DATE: 6/15/15

START TIME: 0857

F FACTOR: 9860

STOP TIME: 0935

	TEST PORT		TEST PORT		TEST PORT		TEST PORT	
	1		2		3		4	
S = 19"	O2, %	3.7	O2, %	3.1	O2, %	3.2	O2, %	3.1
	CO, PPM	0	CO, PPM	0	CO, PPM	7	CO, PPM	0
	NOX, PPM	138	NOX, PPM	154	NOX, PPM	152	NOX, PPM	152
	CO,corr 3% O2, PPM	0	CO,corr 3% O2, PPM	0	CO,corr 3% O2, PPM	7	CO,corr 3% O2, PPM	0
	NOX, corr 3% O2, PPM	144	NOX, corr 3% O2, PPM	155	NOX, corr 3% O2, PPM	154	NOX, corr 3% O2, PPM	153
	NOX, Lb/Mbtu	0.197	NOX, Lb/Mbtu	0.213	NOX, Lb/Mbtu	0.211	NOX, Lb/Mbtu	0.210
M = 57"	O2, %	2.0	O2, %	2.2	O2, %	2.6	O2, %	2.5
	CO, PPM	20	CO, PPM	10	CO, PPM	7	CO, PPM	6
	NOX, PPM	147	NOX, PPM	157	NOX, PPM	154	NOX, PPM	153
	CO,corr 3% O2, PPM	19	CO,corr 3% O2, PPM	10	CO,corr 3% O2, PPM	7	CO,corr 3% O2, PPM	6
	NOX, corr 3% O2, PPM	139	NOX, corr 3% O2, PPM	150	NOX, corr 3% O2, PPM	151	NOX, corr 3% O2, PPM	149
	NOX, Lb/Mbtu	0.191	NOX, Lb/Mbtu	0.207	NOX, Lb/Mbtu	0.207	NOX, Lb/Mbtu	0.205
L = 95"	O2, %	2.6	O2, %	2.4	O2, %	2.7	O2, %	2.4
	CO, PPM	5	CO, PPM	0	CO, PPM	0	CO, PPM	0
	NOX, PPM	136	NOX, PPM	148	NOX, PPM	146	NOX, PPM	145
	CO,corr 3% O2, PPM	5	CO,corr 3% O2, PPM	0	CO,corr 3% O2, PPM	0	CO,corr 3% O2, PPM	0
	NOX, corr 3% O2, PPM	133	NOX, corr 3% O2, PPM	143	NOX, corr 3% O2, PPM	144	NOX, corr 3% O2, PPM	140
	NOX, Lb/Mbtu	0.183	NOX, Lb/Mbtu	0.197	NOX, Lb/Mbtu	0.197	NOX, Lb/Mbtu	0.193
<div><div>129"</div><div>195"</div><div>321"</div><div>389"</div></div> <div>WIDTH = 546"</div>								

DEPTH = 115"

Right

Grid Avg. O2, % = 2.7

Grid Avg. CO, PPM = 9

Grid Avg. NOX, PPM = 149

Grid Avg. CO corr 3% O2, PPM = 9

Grid Avg. NOX corr 3% O2, PPM = 146

Grid Avg. NOX, LB/MBtu = 0.201

Great River Energy  
Coal Creek #1  
Economizer Outlet

ALSTOM POWER, INC.  
PERFORMANCE SERVICES  
WINDSOR, CONNECTICUT

TEST DATA AND RESULTS  
FLUE GAS ANALYSIS - POINT BY POINT GRID DATA

Economizer Outlet Left Duct

TEST NUMBER: 1

DATE: 6/15/15

START TIME: 0947

F FACTOR: 9860

STOP TIME: 1028

LOAD:

S = 19"

M = 57"

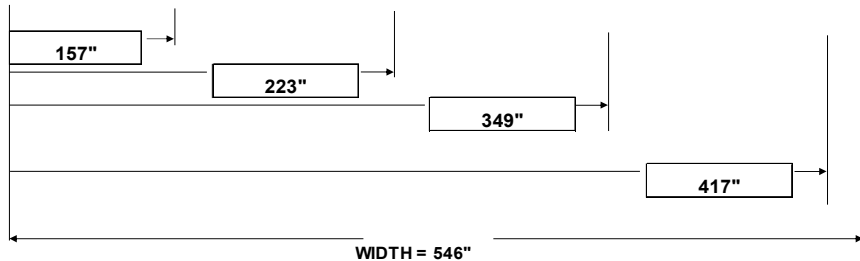
Left

L = 95"

DEPTH = 115"

Right

	TEST PORT		TEST PORT		TEST PORT		TEST PORT
	5		6		7		8
O <sub>2</sub> , %	3.5	O <sub>2</sub> , %	3.6	O <sub>2</sub> , %	3.0	O <sub>2</sub> , %	4.3
CO, PPM	26	CO, PPM	15	CO, PPM	28	CO, PPM	15
NOX, PPM	131	NOX, PPM	160	NOX, PPM	156	NOX, PPM	140
CO,corr 3% O <sub>2</sub> , PPM	27	CO,corr 3% O <sub>2</sub> , PPM	16	CO,corr 3% O <sub>2</sub> , PPM	28	CO,corr 3% O <sub>2</sub> , PPM	16
NOX, corr 3% O <sub>2</sub> , PPM	135	NOX, corr 3% O <sub>2</sub> , PPM	166	NOX, corr 3% O <sub>2</sub> , PPM	156	NOX, corr 3% O <sub>2</sub> , PPM	151
NOX, Lb/Mbtu	0.185	NOX, Lb/Mbtu	0.228	NOX, Lb/Mbtu	0.214	NOX, Lb/Mbtu	0.208
O <sub>2</sub> , %	3.3	O <sub>2</sub> , %	2.6	O <sub>2</sub> , %	2.6	O <sub>2</sub> , %	2.4
CO, PPM	28	CO, PPM	0	CO, PPM	23	CO, PPM	12
NOX, PPM	150	NOX, PPM	150	NOX, PPM	164	NOX, PPM	151
CO,corr 3% O <sub>2</sub> , PPM	28	CO,corr 3% O <sub>2</sub> , PPM	0	CO,corr 3% O <sub>2</sub> , PPM	22	CO,corr 3% O <sub>2</sub> , PPM	12
NOX, corr 3% O <sub>2</sub> , PPM	153	NOX, corr 3% O <sub>2</sub> , PPM	147	NOX, corr 3% O <sub>2</sub> , PPM	160	NOX, corr 3% O <sub>2</sub> , PPM	146
NOX, Lb/Mbtu	0.210	NOX, Lb/Mbtu	0.202	NOX, Lb/Mbtu	0.221	NOX, Lb/Mbtu	0.201
O <sub>2</sub> , %	3.0	O <sub>2</sub> , %	2.9	O <sub>2</sub> , %	2.5	O <sub>2</sub> , %	2.6
CO, PPM	12	CO, PPM	0	CO, PPM	9	CO, PPM	28
NOX, PPM	147	NOX, PPM	148	NOX, PPM	141	NOX, PPM	145
CO,corr 3% O <sub>2</sub> , PPM	12	CO,corr 3% O <sub>2</sub> , PPM	0	CO,corr 3% O <sub>2</sub> , PPM	9	CO,corr 3% O <sub>2</sub> , PPM	27
NOX, corr 3% O <sub>2</sub> , PPM	147	NOX, corr 3% O <sub>2</sub> , PPM	147	NOX, corr 3% O <sub>2</sub> , PPM	137	NOX, corr 3% O <sub>2</sub> , PPM	142
NOX, Lb/Mbtu	0.202	NOX, Lb/Mbtu	0.202	NOX, Lb/Mbtu	0.189	NOX, Lb/Mbtu	0.195



Grid Avg. O<sub>2</sub>, % = 3.0

Grid Avg. CO, PPM = 20

Grid Avg. NOX, PPM = 149

Grid Avg. CO corr 3% O<sub>2</sub>, PPM = 20

Grid Avg. NOX corr 3% O<sub>2</sub>, PPM = 149

Grid Avg. NOX, LB/MBtu = 0.205



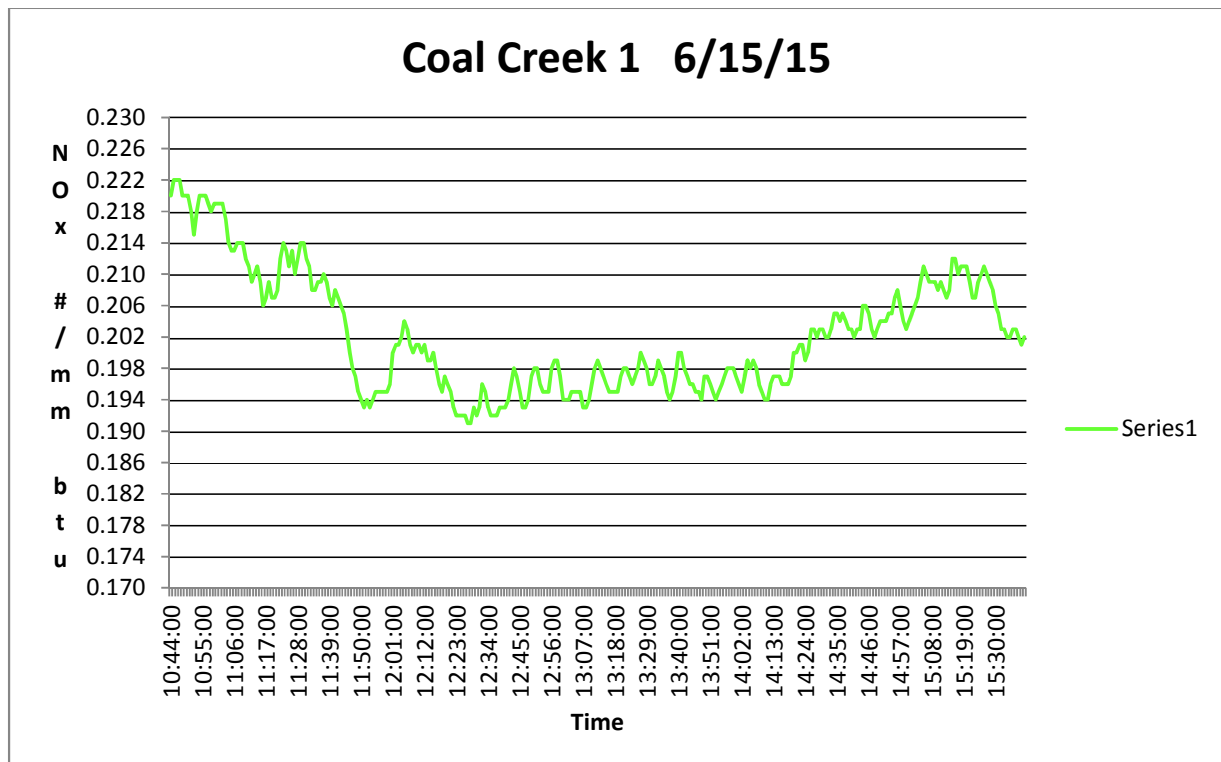
### 6/15/2015 Board Data (Unit #1)

- Load 606 MW
- Throttle Press 2522 psig
- SHO 1004/995 F
- RHO 1005/1002
- Mills in Service 6
- Burner Tilts 11/22 degrees up
- O<sub>2</sub> plant 2.6 % set point
- WB/F ΔP 5.2"
- NO<sub>x</sub> .216 #/MMBtu (CEMS)

### Alstom Test Grid

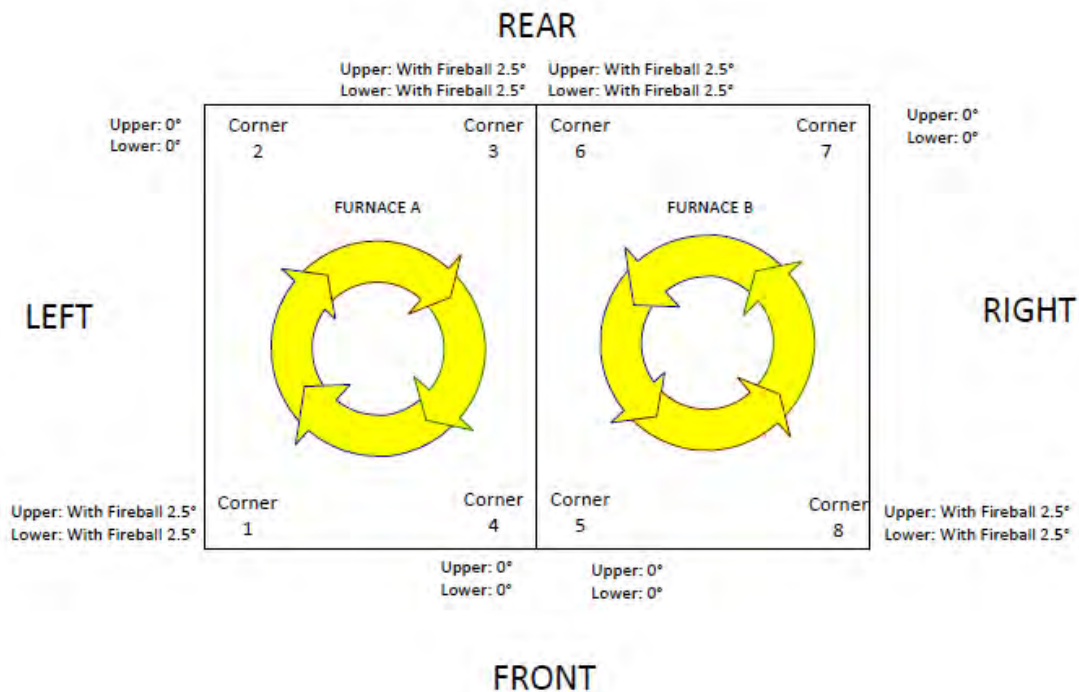
- O<sub>2</sub> 3.3 % (dry)
- CO 4 ppm
- NO<sub>x</sub> .217 #/MMBtu

Alstom began testing / tuning with several changes made to WB/F dP increases to impart a greater spin to the fireball. In addition, changes were made to the CCOFA air compartments, located just above the upper elevation burner compartment (Mill #8). See graph shown on next page.

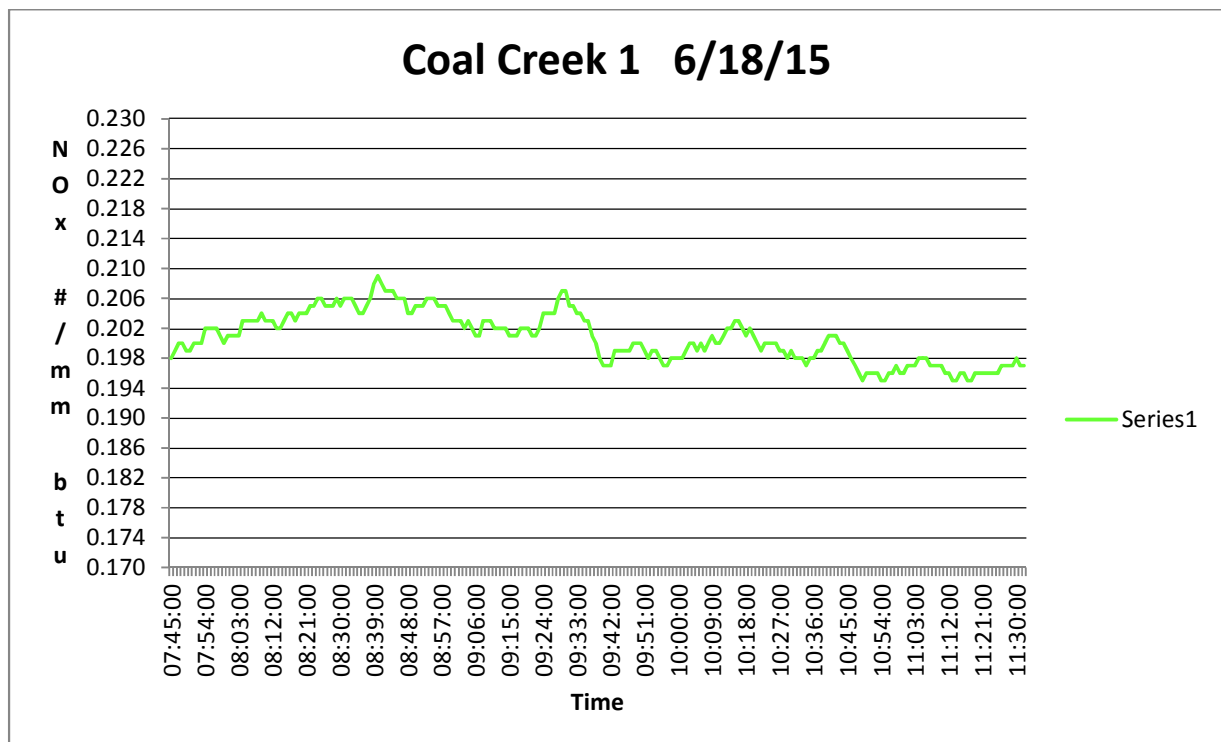


Graph showing results of parameters changes on NOx at beginning of tuning on 6/15/2015. Major change was from manual tilt decrease.

## GREAT RIVER ENERGY COAL CREEK #1 SOFA YAW POSTIONS



This diagram shows the optimum positioning of SOFA yaws on Unit #1, in a range of +15 to -15 degrees. As with Unit #2, these positions should not be modified. In addition, the SOFA damper control curves for the Upper and Lower SOFA compartments are working quite well and should not be modified.



The above graph indicates NOx emission on the Alstom grid after all changes / adjustments made to parameters. The low average of .198 #/MMBtu was the best NOx obtainable with the low Sodium fuel for that week. NOx at beginning of tuning was averaging .221 #/MMBtu

Parameters adjusted in matrix

- O<sub>2</sub>
- WB/F ΔP
- Burner tilts
- SOFA dampers
- SOFA Tilts



## CONCLUSIONS / RECOMMENDATIONS

GRE Coal Creek Units #1 and #2 NOx emissions were found to be below current State and Federal standards prior to Alstom making additional parameter adjustments. GRE has spent considerable effort to accomplish this goal in-house. These units are well maintained and operated. Based on our discovery during the tuning process, each unit required only minimal adjustments to certain parameters to improve overall NOx and CO emission reduction. The units SOFA system is so well tuned for full load operation that any deviance from the current in-place control curve will actually increase, rather than decrease, the NOx and CO output. Based on our testing and unit evaluation of operating controls, Coal Creek Units #1 and #2 have been optimized to its full potential for NOx and CO reduction.

To maintain the low NOx and CO output levels that GRE Coal Creek units #1 and #2 are capable of, Alstom's offers these recommendations:

- The current WB/F  $\Delta P$  curves work well as it is. Do not apply a negative bias to the controllers. Alstom removed the  $-.9''$  bias at the start of the tuning on Unit #1 and changed a bias to Unit #1 ( $+1.1''$ ). NOx was notably reduced.
- Alstom found a positive bias on 9 out of the 12 operating mill air flows (total for both units), ranging from 10 to 13%. It is believed that these biases were made during periods of pulverizing wet coal and were then not taken out when fuel conditions changed to dry. Excessive Primary Air through the mills typically increases the pulverized fuel ignition points and results in increased NOx and CO. If possible, limit the amount of air flow positive bias to 5 to 7%.





- During periods of low load operation, utilize the retract blowers to clean both the SH and RH pendant assemblies, including the back pass areas. The cleaner these surfaces remain, the lower the burner tilts may be operated from, which will further reduce NOx output.
- Coal fineness sampling was conducted on all mills and results showed that the % fineness through the 200 mesh screen was below design on all mills, with some as low as 54%. Design rating is 70% through the 200 mesh. GRE should continue to run performance evaluation on the mills, making adjustments where required, to obtain the design value.
- After concluding the MATS testing/tuning on Coal Creek Units 1 and 2, Alstom returned to the site to observe operating conditions on both boilers the week of 6/24. GRE informed Alstom that a higher level Sodium lignite had been delivered, with a Na content of 3.7% or higher. The operating results (NOx emissions) with this higher Sodium content fuel was significant. With all control parameter the same as the previous week, and at full load, the following data was observed on the plants CEMS.

Unit #1 NOx

.170 #/MMBtu

Unit #2 NOx

.122 #/MMBtu

The higher Na content produced additional slag/ash build up on both units Water Wall surfaces, which resulted in somewhat less heat absorption in the lower furnace. This in turn brought higher flue gas temperatures into the SH and RH Pendant sections, which allowed for the burner tilts to be lowered from +14/+22 degrees (avg.) to +3/+8 average. This reduced staging distance was responsible for the significantly lower NOx emission. Alstom recommends burning a fuel with a Sodium content average greater than 3%, if possible.



GRE Coal Creek Unit #2  
MATS Testing/Tuning  
Daily Report  
Wednesday, 6-10-2015

Unit Status – 10:50 am

Load – 606 mw Gross                      Throttle Pressure – 2510  
Tilts – 15/24 degrees (L-R)    CEMS NOx - .153 #/MMBtu  
SHO – 994/989                      RHO – 987/997  
6 mills in service (2-3-4-5-6-7). Mills 1 and 8 out.  
WB/F dP – 5.3” – but has -.9” bias.  
Air Flow – 97.8%  
Fuel Flow – 82.5%  
Stm Flow – 4024 Klbs/hr.  
Alstom Test Grid                      NOx - .147 #/MMBtu / 109 ppm.  
   CO – 8 ppm

12:55  
Began removing bias from WB/F dP. -.9” to -.6”.

NOx trending down. CEMS - .140                      Grid - .141

13:30  
Changed WB/F dP bias from -.6” to -.3”

CEMS - .138                      Grid - .142

14:05  
Removed all bias from WB/F dP

CEMS - .135                      Grid - .141. CO still low at 4 to 6 ppm.



15:10

CEMS - .135 #/MMBtu

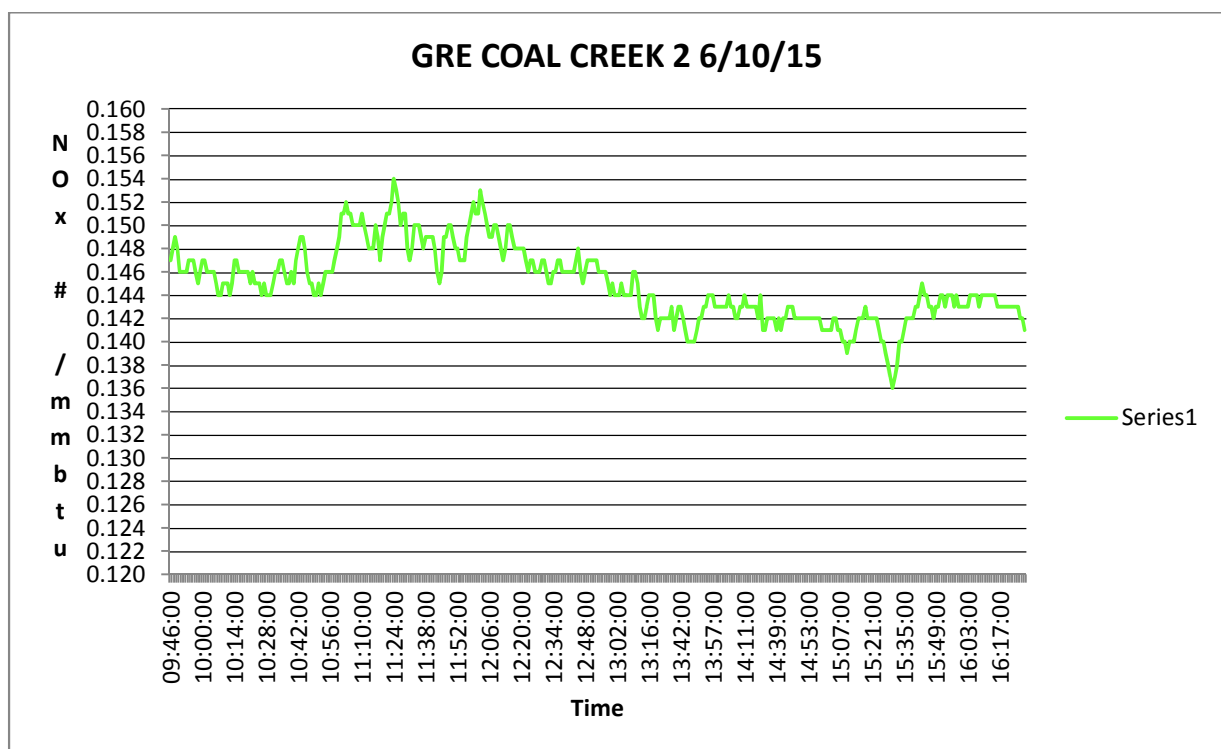
Grid - .141 #/MMBtu

16:30 Status

Load – 611 – NOTE: Increased steam temps gave us an additional 7MW.

SHO – 996/978      RHO – 1006/1004      NOx .138 NOx -= .143

Overall NOx did decrease, primarily due to removal of all bias on WB/F dP controller.





GRE Coal Creek Unit #2  
MATS Testing/Tuning  
Daily Report  
Thursday, 6-11-2015

Load remained steady at +600 MW through the night.

7:30 Status

Load – 610 MW                      CEMS NO<sub>x</sub> - .149 #/MMBtu                      Grid - .155  
Tilts – 15/25                      WB/F dP – 6.2” (no bias)                      O<sub>2</sub> sp at 2.6%

NOTE:

NO<sub>x</sub> higher this morning even though WB/F dP has no bias. GRE says we may have had a coal quality change. However, total TPH federate appears to be the same as 6/10. Tilts are raised more than yesterday as well and in auto, even though SH and RH temps are higher. Operator to blow some selected IK's to raise SH and RH outlet even more. This should result in tilts lowering.

NOTE:

After blowing 4 retracts in the Reheat area, NO<sub>x</sub> decreased some, from .149 to .145 on CEMS and .155 to .149 on Alstom grid. Will continue to blow a few more IK's.

Plan for today to remove mill air flow biases. According to GRE, these biases were placed on the mill air flow controllers when they received wet coal. Once drier fuel was provided, operators never took the biases back out. This mill air flow reduction (however slight) should decrease NO<sub>x</sub> somewhat.



09:00

Removed air flow bias from #7 mill 10% to 0.

9:35

Lowered RIGHT tilts (East) in manual from 24 to 20 degrees to lower NOx. By 9:50, had them down to 15 degrees. NOx slowly trending down.

10:00

Removed bias from #6 mill (13 to 0)

10:20

Removed bias from #5 mill (15 to 0)

11:00

Removed bias from #4 mill (10 to 0)

NOTE: #3 mill had no bias in controller.

11:20

Removed bias from #2 mill (20 to 0)

13:30

Placed LEFT tilts in manual and lowered from 11 to 8 degrees to see if NOx would decrease further.



GRE Coal Creek Unit #2  
MATS Testing/Tuning  
Daily Report  
Friday 6-12-2015

#### 7:30 Status

Unit ran at full or near full load all night. No problems reported.

Load – 612 MW                      CEMS NO<sub>x</sub> - .144 #/MMBtu

O<sub>2</sub> - 2.6% set point              WB/F dP – 6.2”

SHO – 992/985                      RHO – 1005/1004

Tilts – 9/18 degrees

#### 8:20

Began testing by manually closing down on Lower SFA dampers from 50% to 45% open. NO<sub>x</sub> increased from .145 to .151

#### 8:45

Closed back Lower SOFA dampers from 45% to 40% open. NO<sub>x</sub> increased again from .151 to .154

#### 9:00

Placed lower SOFA dampers back in auto. Within 15 minutes NO<sub>x</sub> decreased back to .147/

#### 9:05

Decreased O<sub>2</sub> set point from 2.6 to 2.5%. NO<sub>x</sub> to .144.

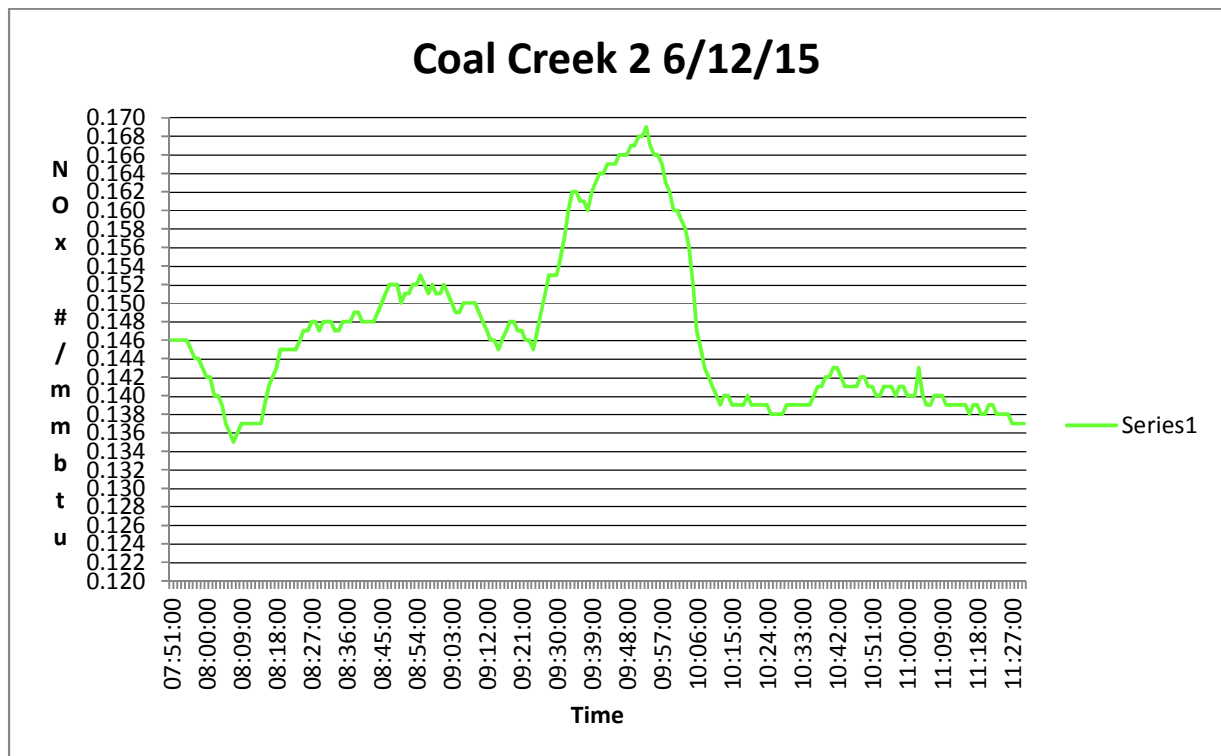
#### 9:20

Lowered SOFA tilts (manually) from +22 degree average to 10 degrees up. NO<sub>x</sub> immediately began to increase. By the time we had them all (8), NO<sub>x</sub> had increased up to .170 on CEMS and .169 on Alstom grid.

Brought all SOFA tilts to “as found” positions and NO<sub>x</sub> decreased back down to .139 to .140 #/MMBtu. No more testing conducted for day.



Began taking down test equipment from Unit #2 and moving it to Unit #1.  
Will pull probes and re-install on Monday.



Graph showing NOx fluctuations with small load drop in morning and then NOx increase with SOFA tilt manipulation (+22 degrees to +10 degrees up).



GRE Coal Creek Unit #1  
MATS Testing/Tuning  
Daily Report  
Monday 6-15-2015

8:00 Status

Load – 605 MW                      CEMS NOx .216 #/MMBtu  
6 mills in service 2-3-4-5-6-7      Mills 1 and 8 off  
O2 set point is 2.6%  
WB/F dP - 5.2" with a +.9" bias  
SHO 1004/995                      RHO – 1005/1002  
Tilts – 11/22 degrees.

NOTE:

NOx is higher today than last week at same load. GRE states this is due to change in coal quality. Will first work on increasing WB/F dP. Unit #1 has a plus bias installed. Unit #2 had a Minus bias installed. Difference is due to size of SOFA compartments on #2 being larger and more efficient for NOx reduction.

11:15

Increased WB/F dP bias from +.9 to +1.1"  
WB/F dP now 5.4". Slight improvement in NOx to .210

13:00

WB/F dP bias increase to +1.3". Now reading 5.5" Do not want to go any further for now.

NOTE:

Mills are swinging from 84% feeder speed up to 90%. This is continuous and has been since 8:00 am. This is a significant amount of coal input change with 6 mills in service.

14:20

Lowered Lower CCOFA dampers from 50% to 45% open for NOx change





14:25

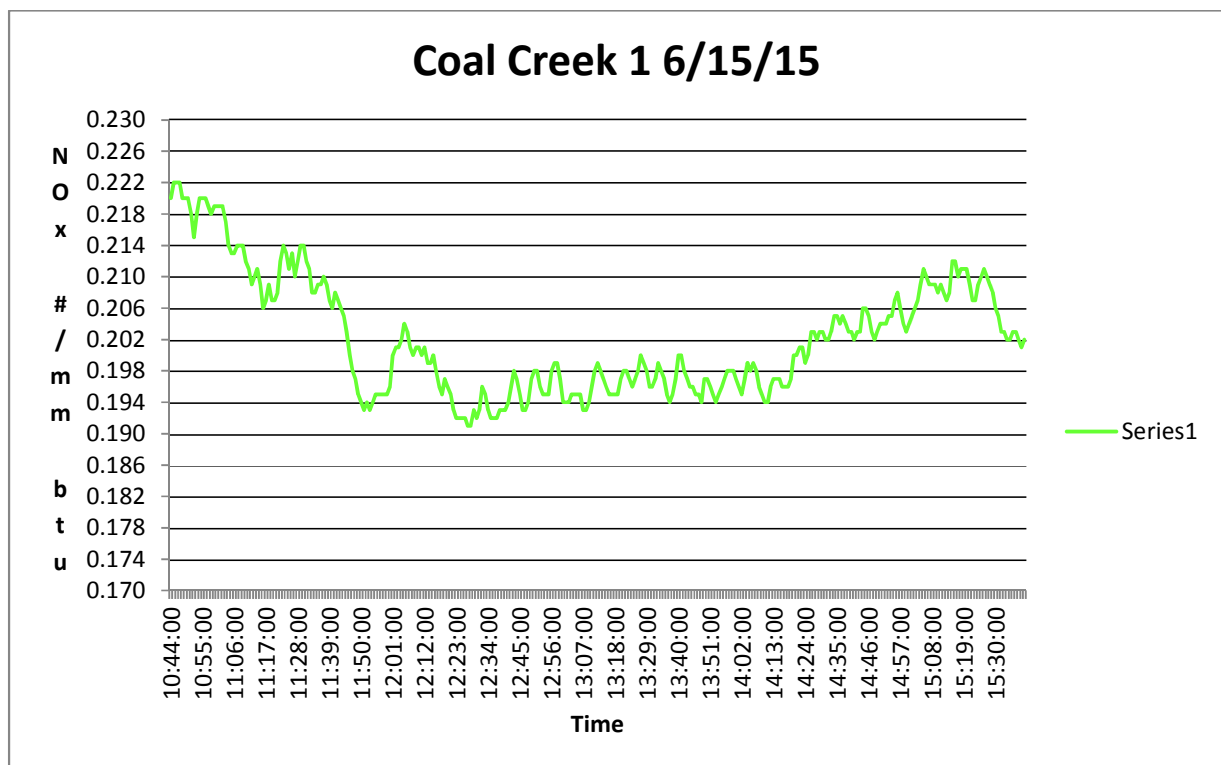
Changed Lower CCOFA dampers from 45 to 40% open . Have not seen any decrease in NOx.

14:35

Opened Lower CCOFA to 60%

15:15

Opened Lower CCOFA to 70% open. No real improvement in NOx reduction.





GRE Coal Creek Unit #1  
MATS Testing/Tuning  
Daily Report  
Tuesday 6-16-2015

7:00

Unit still down from last night load drop. 340 MW's. Dispatch bringing load up slow.

9:50

Load now at 603 MW                      NOx - .229  
WB/F dP – 5.2"   Night shift removed 1.3" bias.  
Tilts – 14/22 degrees. This is high and due to low RHO temps.  
SHO – 998/1005                      RHO – 1007/996

NOTE

Fuel quality down today, per GRE. 882 TPH total at 603 MW

10:15

Lowering Right side (A) tilts in manual from 22 then 18 then 15 degrees to effect NOx change.

10:30

NOx decreased from .228 to .214 #/MMBtu. Lowered Left side (B) tilts in manual from 14 to 10 degrees to effect NOx reduction.

10:40

Placed the 1.3" plus bias back into WB/F dP controller.

10:50

Now have both tilts in manual and at 11/12 degrees

SHO – 990/990

RHO – 996/977

NOx - .200 #/MMBtu

Will continue to allow SH and RH temps to drop to effect NOx reduction.



10:55

SHO – 980/986

RHO – 992/969

NOx - .194 #/MMBtu

11:00

SHO – 983/989

RHO – 991/969

NOx - .195 #/MMBtu

11:15

SHO – 984/989

RHO – 989/970

NOx - .195 #/MMBtu

11:20

Lowered O2 set point from 2.6 down to 2.5%

11:40

SHO – 980/985

RHO – 993/968

NOx - .188 #/MMBtu

11:50

SHO – 987/992

RHO – 994/973

NOx - .196 #/MMBtu

12:50

Raised Right side tilts back to 14 degrees up for additional temp

SHO – 992/995

RHO – 991/977

NOx - .199 #/MMBtu

12:55

Raising tilts back up to place in auto.



13:15

As a test, placing #8 mill in service. Hope to gain additional SH/RH temp so that tilts will come down. Even though adding an upper mill can hurt NOx, having the tilts lower is more than enough of an offset to help with total NOx.

15:50

#8 mill back off. SH and RH temps did not increase and Tilts remain high. End result was increased NOx...from .221 to .236 #/MMBtu.



GRE Coal Creek Unit #1  
MATS Testing/Tuning  
Daily Report  
Wednesday 6-17-2015

7:30 Status

Load – 603 MW                      CEMS NOx - .216

Tilts – 10/21 degrees

SHO – 989-987

RHO – 992-988

NOTE

Operator had Right side (East) tilts in manual and at a lower position that auto would have driven them. Requested tilts be placed back in auto to bring SH and RH temps back up. Will attempt WB/F dP change (less) today to see if temps may go up.

09:00

Tilts – 10/21

SHO – 1001-1003

RHO – 1008-1004

NOx - .215 #/MMBtu

NOTE.

RH – SH temps up after blowing selected IK's

09:10

Increased WB/F dP from 1.3" up to 1.8" + bias.

11:30

Tilts – 12/20

SHO – 1003-996

RHO – 1002-1003

NOx - .218

12:05

Lowered Right tilts to 18 degrees in manual.



12:35

Tilts – 12/18

SHO – 1001-997

RHO – 1004-1000

NOx - .214

13:45

Tilts – 13/16

SHO – 989-1001

RHO – 1005-987

NOx - .215

13:50

Changing WB/F dP from +1.8" to .9" bias for a test to see if temps increase.

14:00

Tilts – 15/16

SHO – 993-1003

RHO – 1005-985

NOx. - .236

14:05

NOx increased with lowered WB/F dP change. Increased bias back to 1.8"

14:25

Increased WB/F dP bias again to +2.0". WB/F dP now 6.2"

14:45

Tilts – 15/16

SHO – 992/1002

RHO – 1006/983

NOx - .225

15:35

Tilts – 12/16

SHO – 989/982

RHO – 981/969

NOx - .208 #/MMBtu

16:10

Tilts back in auto and raising back up to regain lost SH/RH temps.



GRE Coal Creek Unit #1  
MATS Testing/Tuning  
Daily Report  
Thursday 6-18-2015

7:45 Status

Load – 596 MW                      CEMS NOx .203 #/MMBtu  
Tilts – 13-22  
SHO – 978-967  
RHO – 968-961                      WB/F dP – 6.1”

NOTE:      Placed 2.0” bias back into WB/F dP controller.

NOTE:

Fuel quality down again today on both units. Neither can make or maintain SH and RH Outlet temps, even with tilts raised up. NOx values on both 1&2 are not too bad, but no temperatures. Waterwalls on both units are very clean. They appear to be exhibiting full heat absorption in the WW circuits, where is decreasing flue gas temps in the upper furnace and backpass areas, resulting in loss of SHO and RHO steam temperatures. Each unit is also losing about 8 MW's due to low steam temps.

09:00

Comparison of operating conditions with clean furnaces:

UNIT #1

Tilts – 12/22  
SHO – 989-979  
RHO – 971-972  
NOx - .210  
Load – 598 mw

UNIT #2

Tilts – 20/23  
SHO – 952-954  
RHO – 961-942  
NOx - .154  
Load – 598 – mw



NOx Limit .226

NOx Limit .165



Comparison indicates NOx output to be below limits on both units. However, both units cannot make or maintain SHO and RHO steam temperatures, even with tilts raised. Both units' waterwalls are very clean.

GRE has advised that fuel quality is good, but sodium content is low. This conditions results in less sticky ash and leaves the waterwall surfaces clean, allowing for better heat absorption.

11:15

Comparison

Unit #1

Unit #2

Tilts – 10-18

Tilts – 20-23

SHO – 974-963

SHO – 949-937

RHO – 956-956

RHO – 947-932

NOx - .196

NOx - .146

12:00

Complete tuning attempts on Unit #1.

## **Attachment B**

**Report "Cost Estimate for SNCR Impact to Fly Ash Disposal and Sales –  
Great River Energy – Coal Creek Station" March 1, 2019; Golder  
Associates Inc.**



## REPORT

# Cost Estimate for SNCR Impact to Fly Ash Disposal and Sales

*Great River Energy - Coal Creek Station*

Submitted to:

**Great River Energy**

Coal Creek Station  
2875 Third Street SW  
Underwood, North Dakota 58576

Submitted by:

**Golder Associates Inc.**

44 Union Boulevard, Suite 300 Lakewood, Colorado, USA 80228

+1 303 980-0540

19115185

March 1, 2019



# Table of Contents

<b>1.0 INTRODUCTION.....</b>	<b>1</b>
1.1 Qualifications.....	1
<b>2.0 SNCR IMPACT TO FLY ASH MARKETABILITY .....</b>	<b>2</b>
2.1 Ammonia Adsorption onto Fly Ash.....	2
2.2 Allowable Ammonia Present in Fly Ash .....	2
2.3 Marketability Conclusions .....	5
<b>3.0 AMMONIA SLIP MITIGATION.....</b>	<b>5</b>
3.1 Background .....	5
3.2 Process Description .....	6
3.3 Design and Limitations .....	10
3.4 ASM Application at CCS .....	11
3.4.1 Potential Design at CCS .....	11
3.5 Cost Estimate .....	12
3.5.1 System Engineering and Design.....	12
3.5.2 New Truck Load-Out Silo.....	12
3.5.3 Cal-Hypo Feed System.....	14
3.5.4 GRE Internal Costs .....	14
3.5.5 Project Contingency .....	14
3.5.6 Operational and Maintenance Costs.....	14
3.6 ASM Post-Processing Cost Summary .....	14
<b>4.0 FLY ASH DISPOSAL.....</b>	<b>15</b>
4.1 Fly Ash Disposal Scenarios .....	15
4.2 Landfill Design.....	16
4.2.1 Landfill Size .....	16
4.2.2 Infrastructure Development.....	17
4.2.3 Liner .....	17

4.2.4	Cover.....	18
4.3	Cost Estimate.....	19
4.3.1	Engineering, Design, and Permitting .....	19
4.3.2	Land Acquisition.....	20
4.3.3	Infrastructure Development.....	20
4.3.4	Liner Construction.....	20
4.3.5	Final Cover Construction .....	20
4.3.6	Post-Closure Care.....	21
4.3.7	Construction Management and Construction Quality Assurance .....	21
4.3.8	GRE Internal Costs .....	21
4.3.9	Project Contingency.....	21
4.3.10	Operational Costs .....	21
4.4	Disposal Cost Summary.....	22
4.5	Industry Ranges for CCR Disposal .....	22
<b>5.0</b>	<b>COST IMPACT.....</b>	<b>23</b>
5.1	Ammonia Slip Mitigation.....	23
5.2	Fly Ash Disposal .....	24
5.3	Lost Sales.....	24
5.4	Combined Impact to Fly Ash Management.....	25
<b>6.0</b>	<b>CLOSING .....</b>	<b>25</b>
<b>7.0</b>	<b>REFERENCES .....</b>	<b>27</b>

## TABLES

Table 1: Allowable Ammonia Content in Fly Ash .....	4
Table 2: Fly Ash Sales and Disposal Tons.....	15
Table 3: Scenario Landfill Sizes .....	17
Table 4: Disposal Cost Summary .....	22
Table 5: Fly Ash Sales and Disposal Tons.....	23
Table 6: ASM Post-Processing Costs .....	24

Table 7: Fly Ash Disposal Costs.....	24
Table 8: Cost Impact of Lost Fly Ash Sales.....	24
Table 9: Total Fly Ash Management Costs .....	25

## FIGURES

Figure 1: Allowable Ammonia Content in Fly Ash .....	4
Figure 2: Eastlake Station ASM Layout.....	7
Figure 3: Eastlake Station ASM Lab.....	8
Figure 4: Eastlake Station Silo 3, Silo 4, and ASM System Location.....	8
Figure 5: Eastlake Station ASM Control Panel.....	9
Figure 6: Eastlake Station ASM Mixing Hopper .....	10
Figure 7: Coal Creek Station ASM Layout.....	11
Figure 8: Typical Silo used in Cost Estimate .....	13
Figure 9: Potential Landfill Location (Scenario C) .....	16
Figure 10: Composite Liner Detail .....	18
Figure 11: Composite Cover Detail .....	19

## APPENDICES

### APPENDIX A

EASTLAKE ASM DESIGN DRAWINGS (HEADWATERS RESOURCES)

### APPENDIX B

COST ESTIMATE DETAILS

## 1.0 INTRODUCTION

Great River Energy (GRE) has requested that Golder Associates, Inc. (Golder) prepare a third-party cost evaluation to address the potential impact the installation of selective non-catalytic reduction (SNCR) control technology would have on the existing GRE fly ash disposal and sales at Coal Creek Station (CCS) located in Underwood, North Dakota. Evaluations were prepared in relation to the United States Environmental Protection Agency's (EPA's) approval of the North Dakota State Implementation Plan (SIP). Based on the proposed SIP, GRE is evaluating SNCR control technology to reduce nitrogen oxide (NO<sub>x</sub>) 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, as well as higher ammonia concentration in fly ash. Higher ammonia concentrations in fly ash are likely to affect beneficial use, sales, and disposal of fly ash at CCS. Due to the significant impact of ammonia concentrations in fly ash on current beneficial use and sales, GRE is evaluating a potential ammonia slip mitigation (ASM) technology patented by Boral Resources (Boral) that would allow for treatment of fly ash for beneficial use and sales.

Golder performed a third-party review and estimated costs associated with implementation of Boral's 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 Boral has not conducted any field scale assessment on application of this technology to lignite-derived fly ash, nor has Boral implemented this technology commercially at a size comparable to CCS (total tons of fly ash and tons per day of fly ash). The limited experience in commercial application and lack of field trials is not adequate for Boral to be able to provide any guarantee that the process can be successfully applied to treat lignite ash at the Coal Creek.

Based on the potential impacts of ammonia concentrations to fly ash sales, and the evaluation of the ASM technology, Golder prepared a cost comparison for three fly ash management scenarios at CCS:

- Scenario A: CCS's current fly ash sale rate (approximately 80% of fly ash produced is sold);
- Scenario B: No fly ash sales;
- Scenario C: Application of ASM technology (approximately 60% of fly ash produced is sold).

The cost evaluation includes a comparison of capital and O&M costs for each scenario assuming a new facility for each scenario meets EPA Coal Combustion Residual (CCR) regulations (EPA 2015).

### 1.1 Qualifications

Golder Associates Corporation is a global, employee-owned organization providing consulting, design, and construction services in our specialist areas of earth, environment, and energy through technical excellence, innovative solutions, and award-winning client service. Since our founding in 1960, our more than 6,500 people operating from 165 offices worldwide deliver deep technical understanding, cross-disciplinary thinking, and a passion to help our clients succeed. The United States operating company, Golder Associates, Inc., employs approximately 1,200 people in 50 offices and 5 laboratories.

This project was conducted by a team based in our Lakewood, Colorado office. The project team was well-suited to perform the proposed services for CCS because of the experience of our technical staff on comparable projects and our familiarity with the geotechnical and engineering properties of EPA CCR Rule landfill designs.

Additionally, our team has a firm understanding of the engineering practice and regulatory environment surrounding coal-fired power plants, both in North Dakota and nationwide.

## 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 end users.

### 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.

GRE recently contracted with a Fuel Tech, Inc. (Fuel Tech) to evaluate the potential for implementing SNCR technology at CCS and potential ammonia slip adsorption onto the fly ash (Fuel Tech 2019). As a part of that study, Fuel Tech indicated that ammonia slip is difficult to predict but was assumed to be between 5 ppm and 10 ppm, as this range is typical for units burning coal with sulfur content below 1%. In addition, Fuel Tech stated that “...an ammonia slip of 2 ppm is not really viable, as this concentration is within instrument error” due to non-linear instrument calibration issues. Fuel Tech indicated that under steady state operation if the ammonia slip is 5 ppm, the ammonia adsorbed onto fly ash should not be expected to exceed 50 ppm. Similarly, if the ammonia slip is 10 ppm, the ammonia adsorbed onto fly ash should not be expected to exceed 100 ppm.

### 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. Boral, 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 Energy Services indicated (January 11, 2010) that they “...quit shipping anything over 100 ppm...” in reference to the Eastlake facility, which 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 100 ppm is the approximate maximum “acceptable” ammonia level in fly ash (Bittner et al. 2001, Giampa 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:

$$NH_{3\text{ ash}} = \frac{(NH_{3\text{ water}})(\text{Water} - \text{to} - \text{Cement ratio})}{(\text{Fly Ash Content})}$$

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 away as California. In a review of fly ash uses in North Dakota, the Energy & Environmental Research Center (EERC) stated:

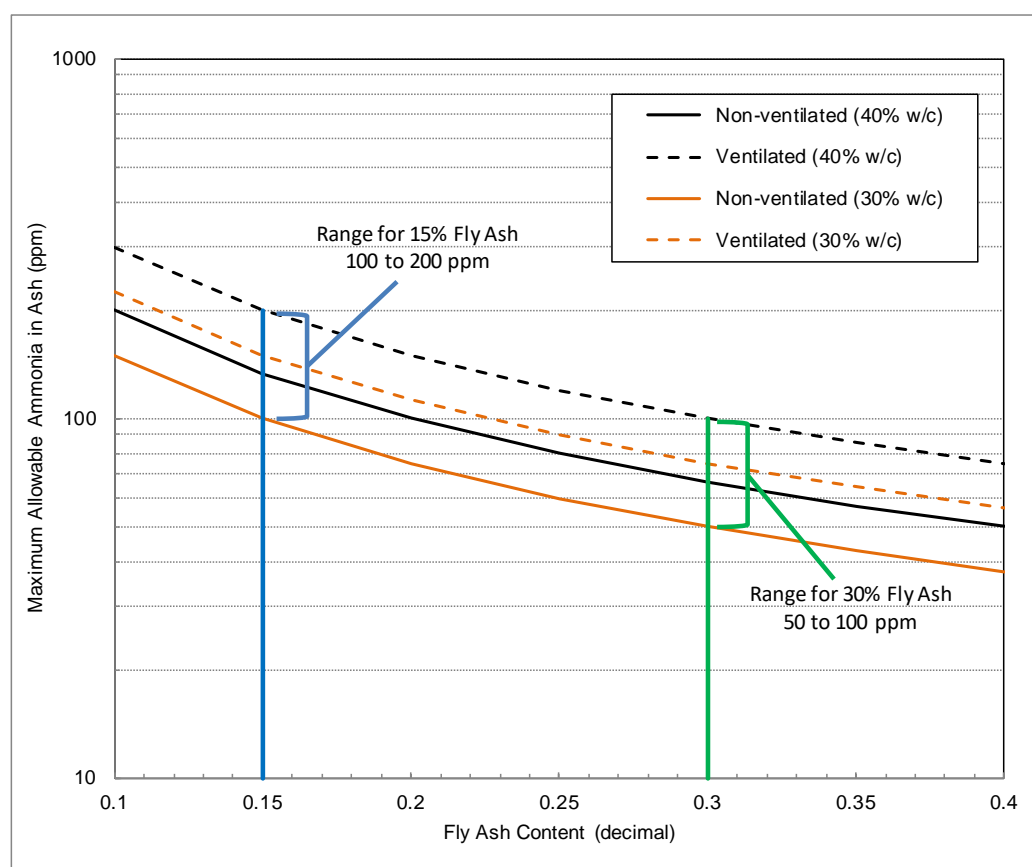
“NDDOT uses fly ash in almost all concrete projects at a replacement rate of 30%. A replacement rate between 15% and 30% is specified by most state DOTs (if they specify fly ash use at all), making NDDOT’s specification on the higher end compared to other states. For mass pours, a replacement rate of 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 Table 1 and Figure 1 below.

**Table 1: Allowable Ammonia Content in Fly Ash**

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)

**Figure 1: Allowable Ammonia Content in Fly Ash**

## 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. As previously stated, Fuel Tech indicated that ammonia slip between 5 ppm and 10 ppm is reasonable for CCS and that the ammonia adsorbed onto fly ash may range between 50 and 100 ppm under steady state conditions (slip and ammonia adsorbed onto fly ash would be higher during load swings or upset conditions). 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.

Definitive information is not available for the levels of ammonia that will 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 cost 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 AMMONIA SLIP MITIGATION

### 3.1 Background

Boral has developed an ASM technology to manage ammonia levels in the fly ash, allowing a portion of the fly ash produced to be sold as a concrete additive. The Boral ASM technology was initially developed in 2001 with the first US patent issued in 2004. The first commercial installation of ASM technology was completed at RG&E Russell Station in Rochester, New York, in 2004. Russell Station used an SNCR and burned eastern bituminous coal. This power plant has since been closed and deconstructed.

The second commercial installation was performed at Eastlake Station in Ohio. Eastlake Station was a 600-megawatt (MW) unit that was fired with a 50/50 blend of Powder River Basin (PRB) and eastern bituminous coal while generating approximately 100,000 tons per year of fly ash during full operation. Headwaters (acquired by Boral in 2017) was able to blend, treat, and market approximately 85% of the fly ash produced at Eastlake Station. Fly ash was not treated during periods of highly variable ammonia concentrations, typically occurring during SNCR upset or plant load swings. This power plant is currently closed.

Boral is currently in the process of installing ASM technology at the Monroe Power Plant in Michigan and anticipates ASM system startup later in 2019. Monroe Power Plant has an SCR and the ASM plant is expected to run on demand rather than full time. The plant can burn petcoke, PRB, and eastern bituminous coals. The ASM system is designed to treat fly ash with ammonia concentrations up to between 150 and 200 ppm with a treated fly ash ammonia limit of 75 ppm or lower for sales.

Currently, there are no commercial applications of ASM technology at a lignite-fired power plant, and Boral 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, Boral cannot provide a guarantee that the ASM technology can be successfully applied.

### 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. The 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 following treatment of approximately 35 to 80 ppm. The dosage is affected by other potential chemical demands for Cal-Hypo depending on fly ash chemistry. Additional testing of CCS fly ash is required to confirm the effectiveness of Cal-Hypo and the appropriate dosage.

Golder visited the commercial application of ASM technology at Eastlake Station in 2011 at a time it was operational (Figure 2). Fly ash from the electrostatic precipitator (ESP) was sent to one of two fly ash silos where the fly ash was tested daily to determine ammonia concentrations (Figure 3). If the ammonia concentrations were above 150 ppm, the fly ash was diverted for disposal. Fly ash with ammonia concentrations less than 150 ppm were sent to a third silo, after which the fly ash was “dosed” with Cal-Hypo and sent to a fourth silo (Figure 4 through Figure 6). The SNCR at Eastlake could not keep the ammonia slip consistent, and often over-treated 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 was 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 was able to market approximately 85% of the produced fly ash as this fly ash was considered “treatable” (i.e., ammonia concentration levels were below 150 ppm). Diagrams of the Eastlake Station system provided by Headwaters (Boral) are shown in Appendix A.

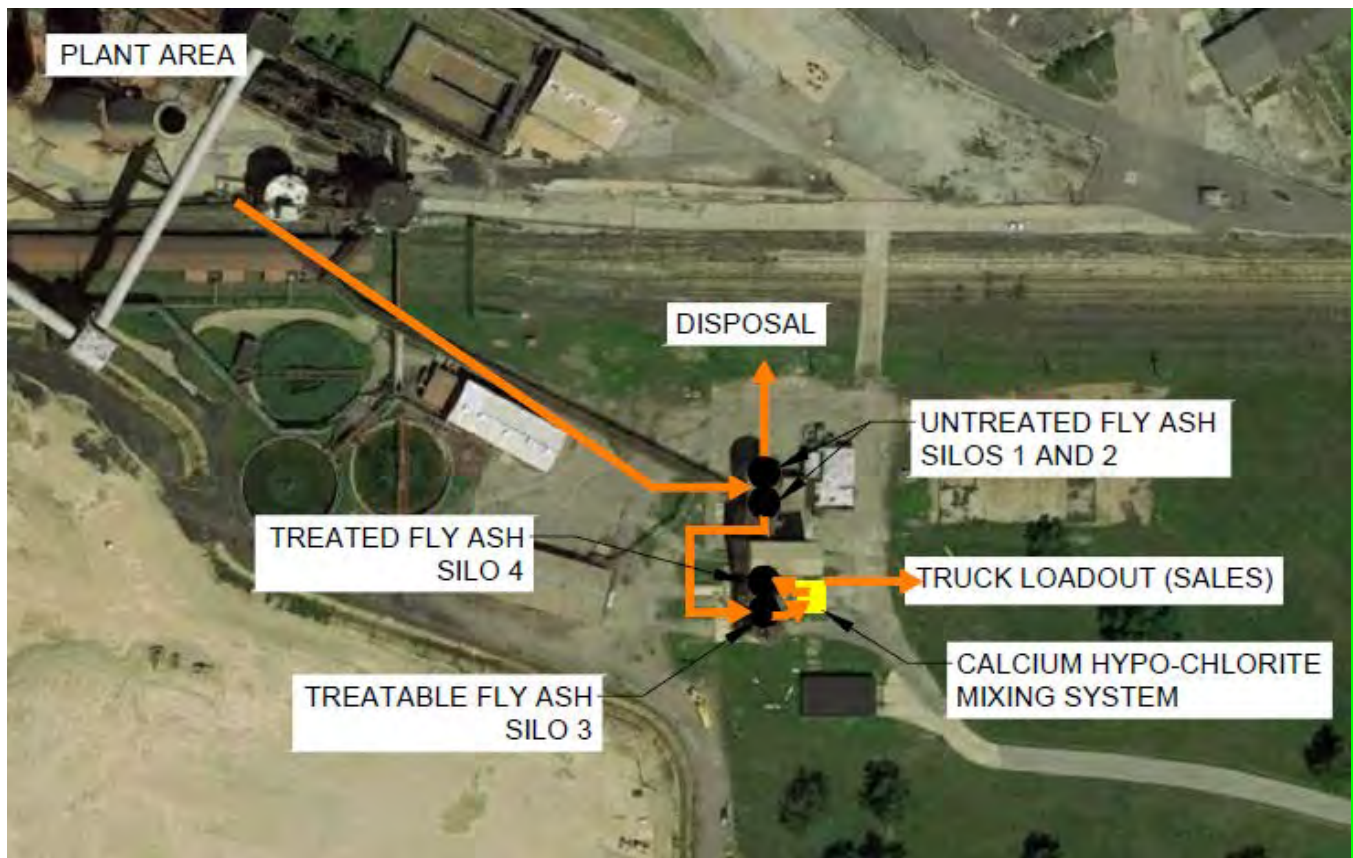


Figure 2: Eastlake Station ASM Layout





Figure 3: Eastlake Station ASM Lab



Figure 4: Eastlake Station Silo 3, Silo 4, and ASM System Location



Figure 5: Eastlake Station ASM Control Panel



**Figure 6: 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”, properly adjusting the amount of ammonia injected into the flue gas can be difficult, resulting in varying concentrations of ammonia in the fly ash. In the event of a plant upset condition, several days may pass until the fly ash is produced with ammonia concentrations at “treatable” levels. The concerns are two-fold. First, 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. Low concentrations of ammonia gas are an irritant, while high concentrations of ammonia gas can be dangerous to health. Second, if too much Cal-Hypo is added to the fly ash, chlorine gas will be released when the fly ash is mixed with water. Chlorine gas, even at low concentrations, is dangerous to health.

In addition to the impacts of load “swings” on the treatment effectiveness, Boral has indicated that the amount of fly ash produced at CCS may also cause issues. At Eastlake Station, the low production of fly ash allowed for significant time between fly ash being produced to fly ash being loaded for sales (fly ash could wait in silos, and trucks could wait to be loaded). This time allowed for testing of the untreated fly ash, dosage testing, and then full-scale dosage and testing. At CCS, approximately 1,500 tons of fly ash are produced daily and there are limits to fly ash storage and load-out rates for beneficial use and sales. Therefore, Boral has indicated that a robust quality assurance and quality control program would be required to understand the concentration of ammonia in the



untreated fly ash, the dosage rates, and the ammonia concentrations in the treated fly ash. In addition, the rate of production and load-out may cause some treated fly ash to be disposed rather than sold.

### 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 7. This potential layout utilizes the existing fly ash infrastructure including the truck load-out silos (Fly Ash Silos 91 and 92), the rail load-out silo (Rail Loadout Silo 93), and the fly ash storage dome (Fly Ash Dome 94). To use ASM technology, 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 (Silo 93). The general flow of material is treatable fly ash being routed to either the new truck load-out silo, Fly Ash Dome 94, or the rail load-out silo. From these locations, the fly ash is tested and then mixed with Cal-Hypo while being 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 existing truck load-out Silos (Silos 91 and 92) where the fly ash will be loaded into haul trucks and disposed at on-site disposal facilities.

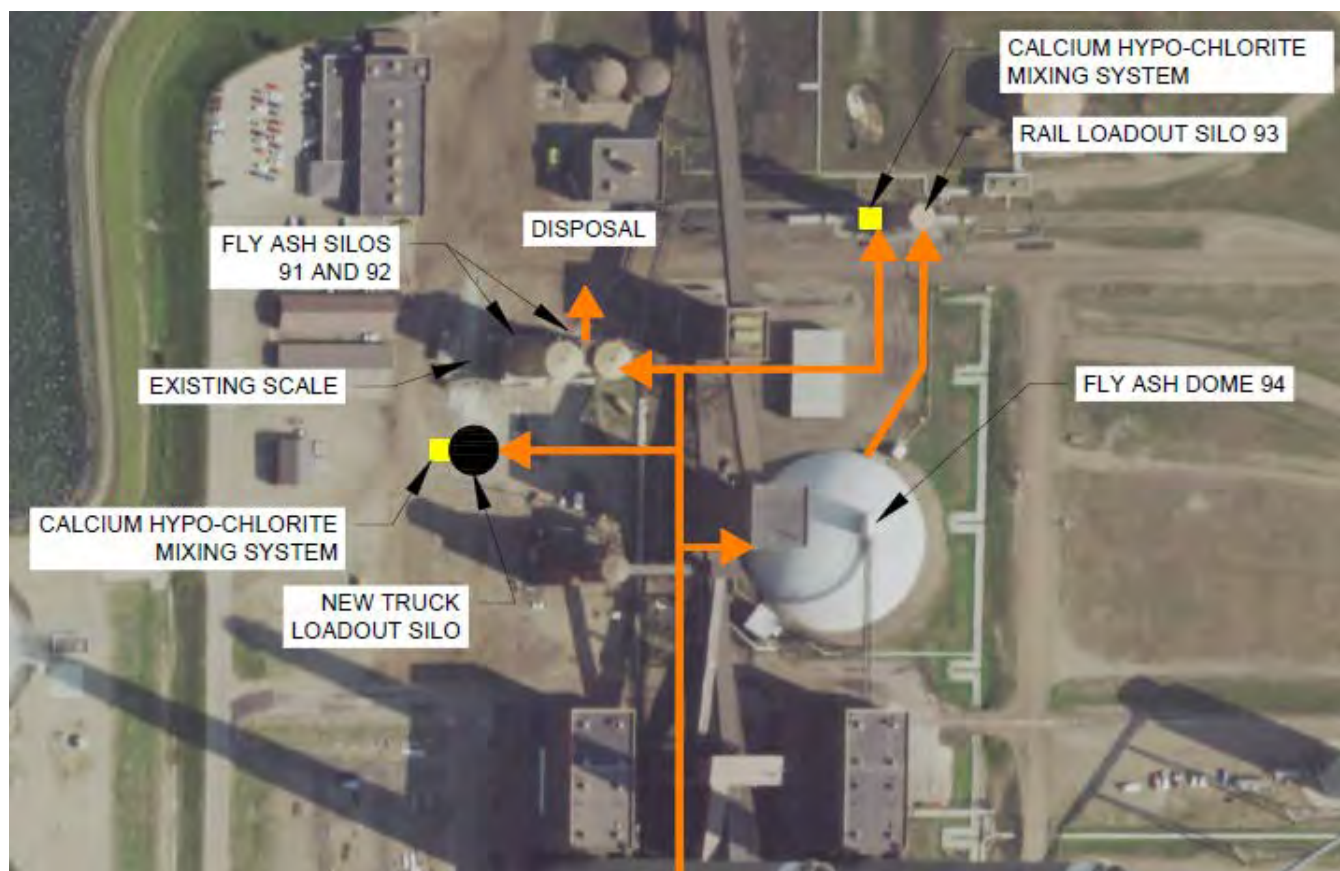


Figure 7: Coal Creek Station ASM Layout

As discussed in Section 3.2, not all fly ash coming from the precipitators is expected to have “treatable” concentrations of ammonia. Generally, when the power generation units are operating at steady load and the SNCR ammonia injection system is operating properly, the produced fly ash should be “treatable” using the ASM system and will be collected in Rail Loadout Silo 93, Fly Ash Dome 94, or the new truck loadout silo. Conditions under which the ammonia content of the produced fly ash will be questionable include:

- Unit load swings causing variations in ash ammonia concentrations (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 resulting in oily ash.

Golder anticipates that when any of these conditions occur, the produced fly ash will automatically be directed to Fly Ash Silos 91 and 92 for disposal. Fly ash will not be directed to Rail Loadout Silo 93, Fly Ash Dome 94, or the new truck loadout silo for sale of the fly ash until the upset condition is over and the fly ash collected in the first two rows of the electrostatic precipitator (ESP) has been tested and proven to contain less than 150 ppm of ammonia.

Currently, approximately 80% of the fly ash produced annually at CCS is sold. The remaining 20% is disposed due to market conditions, storage/transportation issues, and unit startup and shutdown resulting in oily ash. Based on a review of the recent and anticipated load profile at CCS, and concerns described by Boral in operating ASM technology on the amount of fly ash produced at CCS, an additional 20% of the fly ash produced annually is expected to be disposed due to ammonia concentrations which will make the fly ash untreatable or unmarketable after treatment.

## 3.5 Cost Estimate

Included in the cost estimate are costs for the ASM infrastructure, including engineering and design, construction, and operations and maintenance. Golder used actual costs from similar projects and professional judgement 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 2019 dollars.
- Capital costs are annualized based on a 20-year life and 5.25% interest rate.
- Existing fly ash sales infrastructure (silos, scales, and rail facilities) and operations and maintenance thereof are not included.

### 3.5.1 System Engineering and Design

Costs for system engineering, design, and permitting are estimated at 10% of the total construction costs to develop new facilities, based on Golder's professional judgement.

### 3.5.2 New Truck Load-Out Silo

The costs for the new truck load-out silo include site preparation, permit application, silo and handling equipment, dust collection equipment, and feed piping. 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 8). The total estimated cost for this item is \$2.02 million (in 2019 dollars) and includes the following:

- Silo and truck scale similar to the Irondale, CO unit:
  - Silo slab on grade;
  - Starvac reclaimer;
  - Truck scale beside the silo on grade;
  - Screw conveyor from discharge of the Starvac reclaimer;
  - Bucket elevator to overhead;
  - Air slide; and
  - 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; and
  - Higher capacity dust collectors to handle the high air flow from the ESP.

Details for this cost estimate are included in Appendix B.



Figure 8: Typical Silo used in Cost Estimate

### 3.5.3 Cal-Hypo Feed System

The costs for the Cal-Hypo feed systems are estimated at \$680,000 (in 2019 dollars) 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:
  - Weigh hopper above truck loadout spot;
  - Cal-Hypo storage and conveying building;
  - Day storage hopper for Cal-Hypo on the silo weight bin floor;
  - Conveying system from the storage building to the day storage hopper;
  - Variable speed screw conveyor to feed Cal-Hypo into existing weight hopper;
  - ASM system controls.

### 3.5.4 GRE Internal Costs

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

### 3.5.5 Project Contingency

Due to the order-of-magnitude scope of this cost estimate, a contingency of 20% on the construction costs was added to the cost estimate.

### 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 Rail Loadout Silo 93 and the new truck loadout silo.

The estimated cost for this item, based on annual sale/processing of 308,000 tons, is approximately \$1.67 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 \$6.40 per ton of fly ash treated.

## 4.0 FLY ASH DISPOSAL

Fly ash that cannot be marketed for beneficial use is disposed 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 2 through Table 4 and Figure 9 through Figure 11, 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 fly ash at CCS. These scenarios are as follows:

- Scenario A – This scenario is the base case, with fly ash sales equal to the average fly ash sales at CCS between 2014 and 2018 (approximately 80% of fly ash produced). The scenario assumes that fly ash will be disposed in a new landfill with a design based on EPA CCR Rules with 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 in a new landfill with a design based on EPA CCR Rules with a 20-year disposal capacity.
- Scenario C – This scenario assumes that Boral's ASM technology will be viable for ammonia-impacted fly ash at CCS. However, sales will be reduced from current sales due to load swings, outages, ASM system upsets, market conditions, and other factors previously identified within this report (assume 60% of fly ash produced can be sold). The scenario also assumes that fly ash will be disposed in a new landfill with a design based on EPA CCR Rules with a 20-year disposal capacity.

A summary of the fly ash production, sales, and disposal annual tonnages for these scenarios is provided in Table 2.

**Table 2: Fly Ash Sales and Disposal Tons**

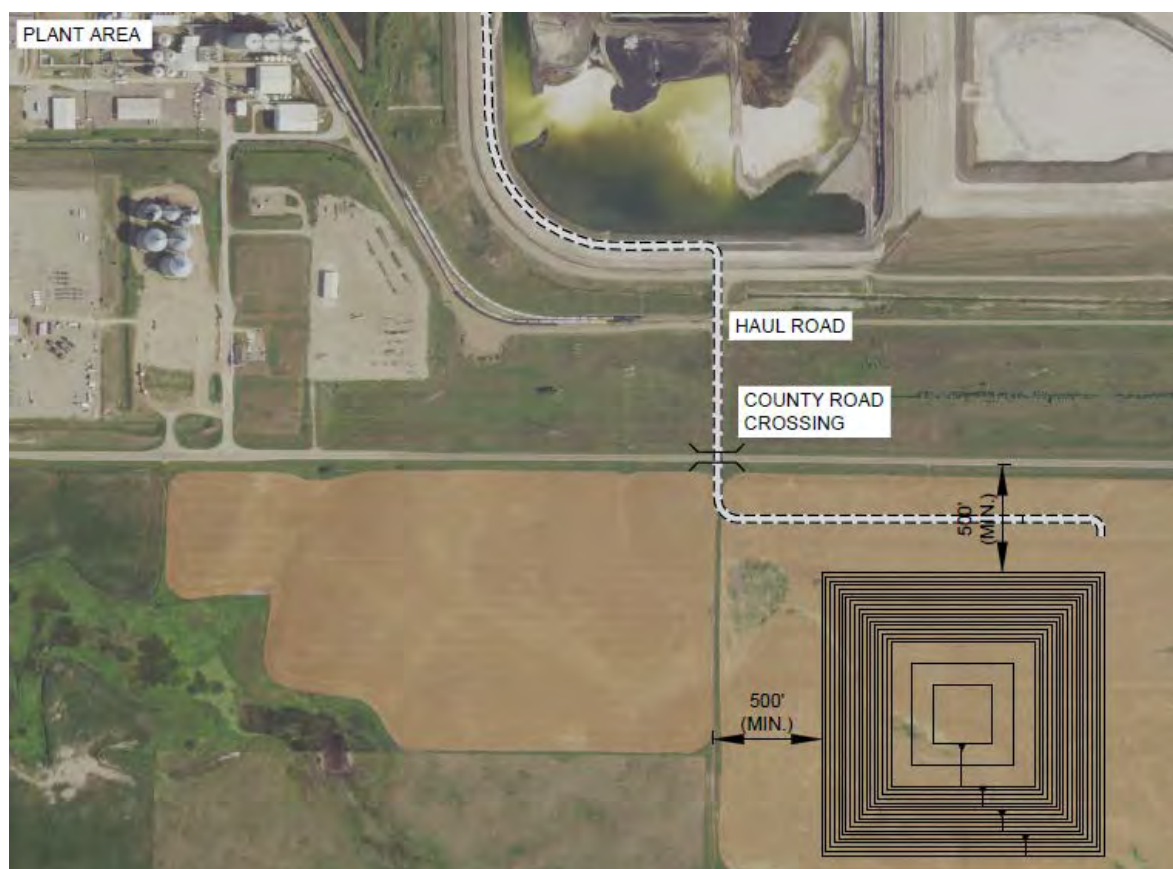
	Scenario A (Current Sales)	Scenario B (No Sales)	Scenario C (Reduced Sales & ASM)
Fly Ash Produced (tons/year)	513,000	513,000	513,000
Fly Ash Sold (tons/year)	400,000	0	308,000
Fly Ash Disposed (tons/year)	113,000	513,000	205,000

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 an average of the actual tonnage produced, sold, and disposed at CCS between 2014 and 2018.



## 4.2 Landfill Design

For all three scenarios a 20-year disposal capacity and a design in accordance with EPA CCR Rules is assumed. Further, the landfill is assumed to be built on property not currently owned by GRE. This cost estimate assumes that property just south of the plant property would be purchased for the new facility. Figure 9 shows a potential location for these new facilities just south of the plant property and represents the approximate footprint required for Scenario C.



**Figure 9: Potential Landfill Location (Scenario C)**

### 4.2.1 Landfill Size

Landfill size is based on a 20-year fly ash disposal capacity. For the three scenarios, size varies between 2.3 million and 10.3 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, a 12-foot high soil perimeter 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 80,000 and 120,000 cubic yards (cy) per lined acre due to the increased height capacity of a larger footprint facility. Figures showing the approximate 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 the lined footprint to allow for access roads, fencing, support structures, and groundwater monitoring. For the land acquisition purchase estimate, the nearest eighth section of land to the required footprint was assumed.

Table 3 provides a summary of the estimated facility liner area, cover area, and site area for the three scenarios.

**Table 3: Scenario Landfill Sizes**

	Scenario A (Current Sales)	Scenario B (No Sales)	Scenario C (Reduced Sales & ASM)
Liner Area (acres)	24.5	72.0	36.5
Cover Area (acres)	27.0	79.0	40.0
Site Area (acres)	160	240	160

## 4.2.2 Infrastructure Development

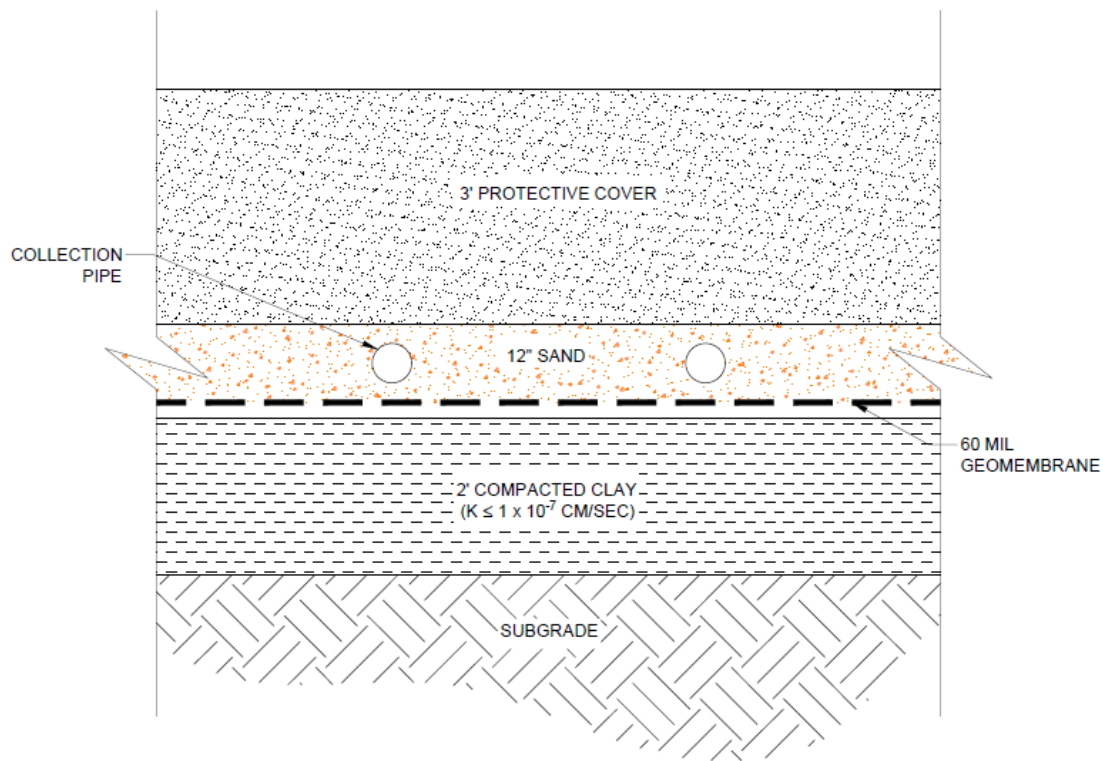
Since the landfill would be constructed on new property, considerable site development is required. Such site development may include:

- Haul truck access road;
- Fencing and gates around the property;
- Power to the new site;
- Monitoring wells upgradient and downgradient of the facility; and
- Water return pipeline to allow for pumping of excess contact water from the site to the ash water tanks within the plant.

Additionally, 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 county road bridge should be constructed to allow haul truck traffic to pass 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 is based on EPA CCR Rules. The assumed liner system is shown in Figure 10 and consists of (from bottom to top) a compacted clay liner ( $1 \times 10^{-7}$  centimeters per second, cm/sec, maximum permeability), a geomembrane, a leachate collection layer consisting of drainage material, piping and sumps, and a protective cover layer.

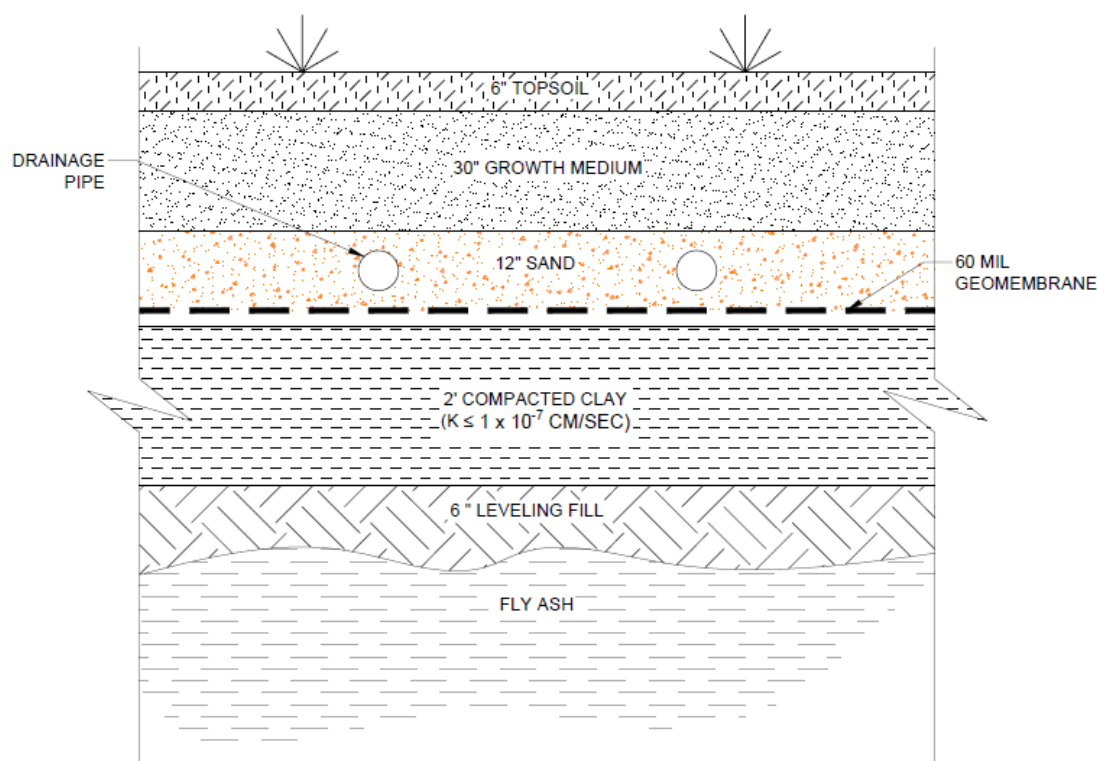


**Figure 10: Composite Liner Detail**

#### 4.2.4 Cover

The final cover design is also based on EPA CCR Rules. The assumed cover system is shown in Figure 11 and consists of (from bottom to top) a leveling fill layer, a compacted clay liner ( $1 \times 10^{-7}$  cm/sec maximum permeability), a 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. Additionally, the cover will use terrace channels and armored down-chute channels to manage surface water runoff and reduce erosion.





**Figure 11: 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, crew analyses based on local contractor rates, RS Means manuals (RS Means 2019), and professional judgement to develop this cost estimate. Sources and assumptions are documented. Some general assumptions for the cost estimate include:

- All costs are estimated in 2019 dollars.
- Capital costs are annualized based on a 20-year life and 5.25% 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 thereof are not included.
- Disposal costs only include fly ash disposal and not facility airspace or operations and maintenance costs for other CCRs produced at CCS.

### 4.3.1 Engineering, Design, and Permitting

Costs for engineering, design, and permitting are estimated at 10% of the total construction costs to develop new facilities, based on Golder's experience with coal combustion residuals facilities in 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 and associated permit renewals, submittal of air permits and NPDES permits, and creation of construction and bid packages for the facility.

The siting evaluation may include a hydrogeological characterization of the site, including 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, and other evaluations as required.

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

Permitting may include the solid waste landfill permit, air permits, and an NPDES permit, including 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 required 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 of the property. Currently, crop land near CCS is selling for \$3,000 to \$5,000 per acre. A unit cost of \$4,000 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 infrastructure development include fencing, monitoring well installation, power from the plant to the 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 \$2,740,000 and \$2,910,000 for the various 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 liner, a geomembrane layer, a leachate collection system, and protective cover. Additionally, the 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, compaction of the liner and cover, and application of site controls such as erosion controls. The costs for construction are estimated to be between \$239,000 and \$243,000 per acre for the different scenarios. Details for the quantities and unit rates applied to this work are included in Appendix B.

#### **4.3.5 Final Cover Construction**

Final cover construction includes leveling fill, a compacted soil layer, a geomembrane liner, a drainage collection system, growth medium, topsoil, armored down-chute channels, and vegetation of the site. Costs for this construction are estimated to be between \$183,000 and \$201,000 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 (for the state and the EPA CCR Rule), annual site inspections, additional compliance requirements associated with the EPA CCR Rule, repair and maintenance of the final cover (soil, seeding, mowing, surface water structures), maintenance of the facility access roads and fencing, and 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. Costs for post-closure care are estimated to be between \$106,000 and \$154,000 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. Costs for construction management and construction quality assurance are estimated as 10% of the total construction costs to develop the facility, based on Golder's experience with coal combustion residuals facilities in the Midwest.

### 4.3.8 GRE Internal Costs

Internal costs for GRE to manage consultants, contractors, and in-house staff are estimated at 10% of the total costs (construction, engineering, permitting, CQA), 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 20% 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 reporting (for the state and the EPA CCR Rule), additional compliance requirements associated with the EPA CCR Rule, and an annual survey. Site operations include the ownership and operation of site haul and placement equipment, full-time site staff, and material expenses. Since ammonia concentrations in the fly ash to be contained in site landfills may be an irritant, operational modifications may be required to handling and placement methods. Costs associated with these potential operational changes have not been included.

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

Haul costs were estimated at \$3.30 per ton based on haul distance, equipment capacity, operator costs, and equipment costs. Placement costs were estimated at \$2.30 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 \$196,000 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 4.

**Table 4: Disposal Cost Summary**

	Scenario A (Current Sales)	Scenario B (No Sales)	Scenario C (Reduced Sales & ASM)
Fly Ash Disposal (ton/year)	113,000	513,000	205,000
Disposal Cost (\$/ton)	\$26.00	\$15.80	\$20.60
Annual Disposal Cost (\$/year)	\$2,940,000	\$8,100,000	\$4,220,000
Annual Increase in Disposal Cost Compared to Scenario A (\$/year)	-	\$5,160,000	\$1,280,000

The disposal cost per ton is reduced with increased disposal quantity due to the efficiency of the landfill footprint (a 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 \$5.2 million per year if fly ash is no longer marketable or an additional \$1.3 million per year if the ASM technology proves successful.

## 4.5 Industry Ranges for CCR Disposal

Disposal costs of \$16 to \$26 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 2010, the EPA estimated baseline (i.e. current) CCR disposal costs in their Regulatory Impact Analysis for EPA's Proposed RCRA Regulation of Coal Combustion Residuals 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 per ton to \$80 per ton with an average of \$59 per ton. In discussion of these results, the report indicates that \$2 per ton is reflective of unlined, near-plant impoundments in states with low regulatory requirements, and the high end of \$80 per ton is reflective of off-site commercial disposal in landfills. The proposed fly ash disposal facilities at CCS are composite-lined (per EPA rule requirements), engineered landfills located at varying distances from the plant.

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 2012)

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 \$16 to \$26 per ton appears well within the EPA’s cost estimate and industry practice (particularly when accounting for inflation and new regulatory requirements since the 2010 estimates).

## 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 5 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 5: Fly Ash Sales and Disposal Tons**

	Scenario A (Current Sales)	Scenario B (No Sales)	Scenario C (Reduced Sales & ASM)
Fly Ash Produced (tons/year)	513,000	513,000	513,000
Fly Ash Sold (tons/year)	400,000	0	308,000
Fly Ash Disposed (tons/year)	113,000	513,000	205,000
Lost Fly Ash Sales (tons/year)	0	400,000	92,000

### 5.1 Ammonia Slip Mitigation

Post-processing of ammonia slip impacted fly ash by Boral’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 on the plant power profile and how the fly ash distribution system is set up, additional tons of fly ash will likely be treated and disposed, but these potential cost impacts are not included. The cost impact for ASM post-processing is shown in Table 6.

**Table 6: 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	\$6.40
ASM Annual Capital and O&M (\$/year)	\$0	\$0	\$1,980,000

## 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 7.

**Table 7: Fly Ash Disposal Costs**

	Scenario A (Current Sales)	Scenario B (No Sales)	Scenario C (Reduced Sales & ASM)
Unit Rate Capital and O&M (\$/ton disposed)	\$26.00	\$15.80	\$20.60
Annual Capital and O&M (\$/year)	\$2,940,000	\$8,100,000	\$4,220,000

## 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 management 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 to GRE is based on the 2014 to 2018 average revenue per ton of \$12.40. The cost impact of the potential loss in fly ash sales is shown in Table 8.

**Table 8: Cost Impact of 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)	\$12.40	\$12.40	\$12.40
Annual Lost Fly Ash Sales Revenue (\$/year)	\$0	\$4,960,000	\$1,140,000

## 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 9. This table also shows the additional cost impact of Scenario B and Scenario C in comparison with the current sales (Scenario A).

**Table 9: Total Fly Ash Management Costs**

	Scenario A (Current Sales)	Scenario B (No Sales)	Scenario C (Reduced Sales & ASM)
<b>Total (Disposal + Post-Processing + Lost Sales)</b>			
Annual Cost (\$/year)	\$2,940,000	\$13,060,000	\$7,340,000
Unit Cost (\$/ton produced)	\$5.70	\$25.50	\$14.30
<b>Additional Cost (Scenario B/C – Scenario A)</b>			
Fly Ash Management Cost (\$/year)	-	\$10,120,000	\$4,400,000
Fly Ash Management Cost (\$/ton produced)	-	\$19.70	\$8.60

The total additional cost impact to fly ash management as a result of an SNCR is estimated between \$4.4 and \$10.1 million per year.

## 6.0 CLOSING

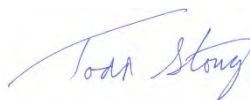
We appreciate the opportunity to provide this third-party review of Boral's ASM technology, and an estimate of the potential impact of SNCR on fly ash management costs including disposal and sales. Please contact us if you have any questions about the information provided.

## Signature Page

### Golder Associates Inc.



Craig Schuettpelz, PE  
*Senior Project Engineer*



Todd Stong, PE  
*Associate and Senior Consultant*

TJS/CCS/cm

Golder and the G logo are trademarks of Golder Associates Corporation

[https://golderassociates.sharepoint.com/sites/102406/deliverables/reports/rpt\\_fly\\_ash\\_sncr\\_01mar19/19115185\\_flyashevaluation\\_fnl\\_01mar19.docx](https://golderassociates.sharepoint.com/sites/102406/deliverables/reports/rpt_fly_ash_sncr_01mar19/19115185_flyashevaluation_fnl_01mar19.docx)



## 7.0 REFERENCES

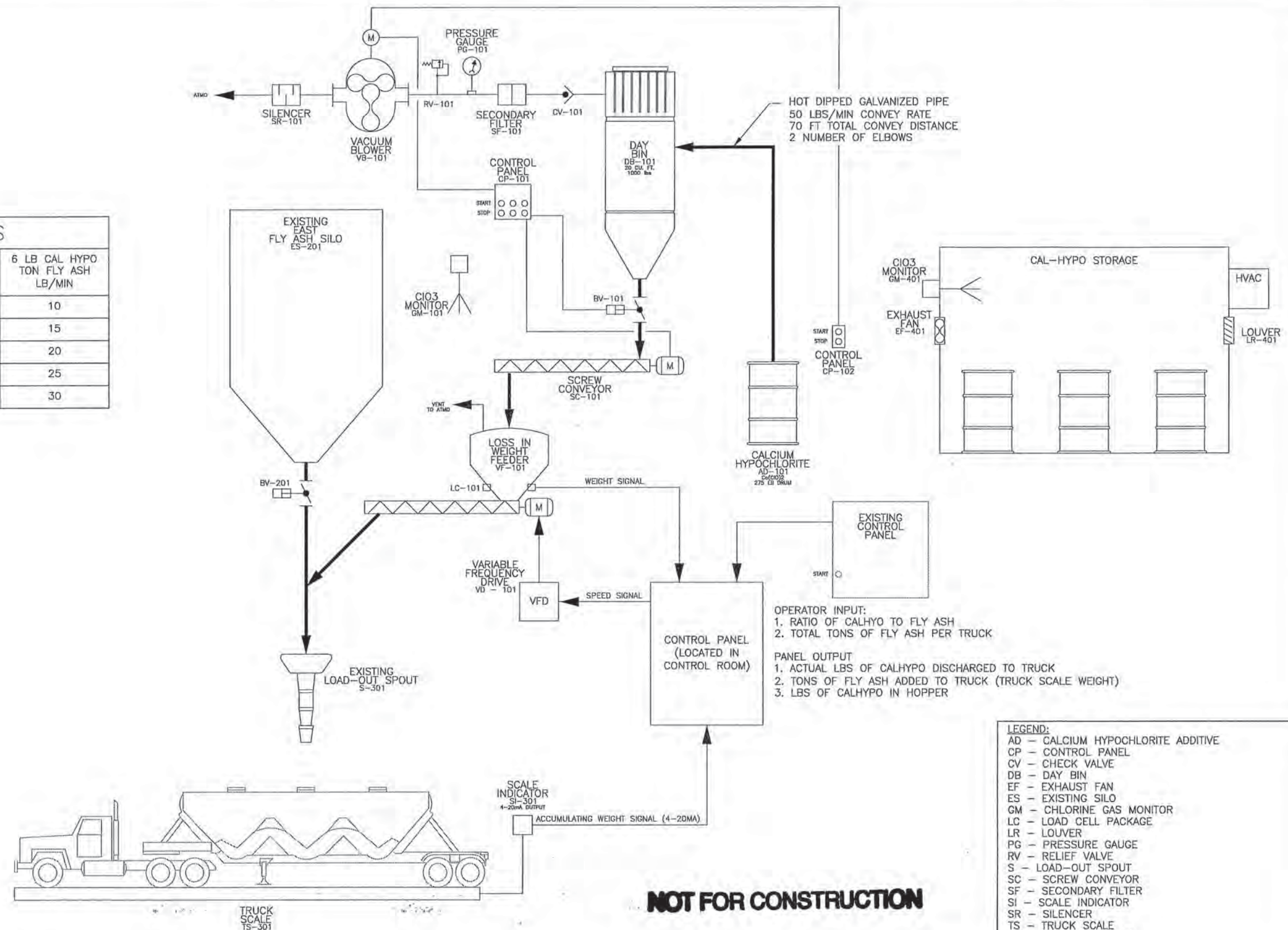
- ACAA, American Coal Ash Association, Frequently Asked Questions nr. 13, Retrieved March 22, 2012 from <http://acaa.affiniscape.com/displaycommon.cfm?an=1&subarticlenbr=5#Q13>
- Bittner, J.D., Gasiorowski, S.A., and Hrach F. (2001). Removing Ammonia from Fly Ash, 2001 International Ash Utilization Symposium.
- Bittner, J.D. and Gasiorowski, S.A. (2005). Triboelectrostatic Fly Ash Beneficiation: An Update on Separation Technologies' International Operations, 2005 Conference on Unburned Carbon on Utility Fly Ash.
- Brendel, G.F., Bonetti, J.E., Rathbone, R.F., and Frey, R.N. (2000). Investigation of Ammonia Adsorption on Fly Ash Due to Installation of Selective Catalytic Reduction Systems – Final Technical Report, Department of Energy Cooperative Agreement No. DE-FC26-98FT40028.
- EERC, Energy & Environmental Research Center (2011). Market Development, Education, and Outreach to Encourage Fly Ash Use in Roads, Parking Lots, and Other Construction, 2011-EERC-03-03.
- EPA (2015). Environmental Protection Agency, Code of Federal Regulations Title 40 Part 257: Hazardous and Solid Waste Management System; *Disposal of Coal Combustion Residuals from Electric Utilities*.
- EPA (2010). Regulatory Impact Analysis For EPA's Proposed RCRA Regulation Of Coal Combustion Residues (CCR) Generated by the Electric Utility Industry, EPA.
- EPRI (2007). Experience with Ammoniated Fly Ash, EPRI, Palo Alto, CA 2006. 1014269
- Fuel Tech, Inc. (2019). SNCR CFD and CKM Modeling Report, Great River Energy Coal Creek Unit #2.
- Giampa, V.M. (2000). Ammonia Removal from Fly Ash by Carbon Burn-Out, 2000 Conference on Selective Catalytic Reduction (SCR) and Selective Non-Catalytic Reduction (SNCR) for NO<sub>x</sub> Control.
- Hinton, W.S. & Associates. Fly Ash Behavior, Retrieved March 22, 2012 from <http://www.wshinton.com/FlyAsh.html>
- Larrimore, L. (2002). Effects of Ammonia from Post-Combustion NO<sub>x</sub> Control on Ash Handling and Use, Fuel Chemistry Division Reprints 2002, 47(2), 833.
- Murarka, I.P., Hassett, D.J., Plughoeft-Hassett, D.F., and Heebink, L.V. (2003). Leaching of Selected Constituents from Ammoniated Fly Ash from a Coal-Fired Power Plant, 2003 International Ash Utilization Symposium.
- NIOSH Pocket Guide to Chemical Hazards, National Institute for Occupational Safety and Health – Education and Information Division, 2011. (NIOSH 2011).
- Rathbone, R. and Robl, T. (2001). A Study of the Effects of Post-Combustion Ammonia Injection on Fly Ash Quality: Characterization of Ammonia Release from Concrete and Mortars Containing Fly Ash as a Pozzolanic Admixture, University of Kentucky Technical Progress Report, Department of Energy Cooperative Agreement No. DE-FC26-00NT40908.
- RSMeans, Heavy Construction Cost Data, Retrieved February 2019 from [rsmeansonline.com](http://rsmeansonline.com).
- Sahu, Ranajit. (2011). Focused Comments on Proposed NO<sub>x</sub> BART Limits for Selected North Dakota Coal-Fired Power Plant Units by EPA, printed on behalf of The National Parks Conservation Association (NPCA).

**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



**HEADWATERS**  
RESOURCES

"THIS DRAWING IS THE PROPERTY OF HEADWATERS RESOURCES, INC AND IS LOANED UPON CONDITION THAT IT IS NOT TO BE REPRODUCED OR COPIED, IN WHOLE OR IN PART, OR USED FOR FURNISHING INFORMATION TO ANY PERSON WITHOUT WRITTEN CONSENT OF HEADWATERS, OR FOR ANY PURPOSE DETRIMENTAL TO THEIR INTEREST, AND IS TO BE RETURNED UPON REQUEST."

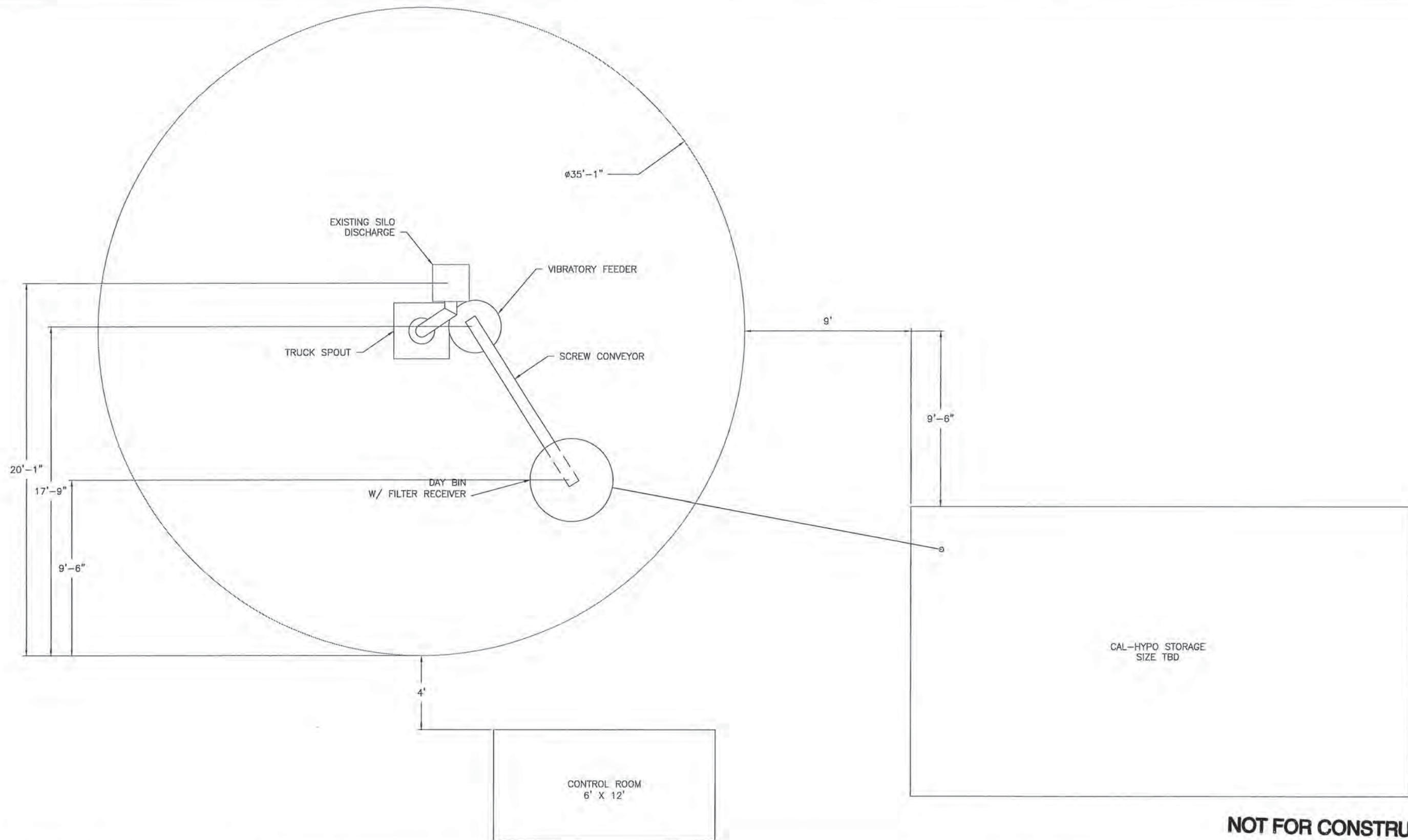
HEADWATERS RESOURCES, INC.  
10653 S. RIVER FRONT PARKWAY  
SUITE 300  
SOUTH JORDAN, UT 84095  
(801) 984-9400  
FAX (801) 984-9419  
www.headwaters.com

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





NOT FOR CONSTRUCTION



HEADWATERS RESOURCES, INC.  
10653 S. RIVER FRONT PARKWAY  
SUITE 300  
SOUTH JORDAN, UT 84095  
(801) 984-9400  
FAX (801) 984-9419  
www.headwaters.com

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

EAST LAKE  
AMMONIA SLIP MITIGATION  
PLAN VIEW  
EAST LAKE, OH

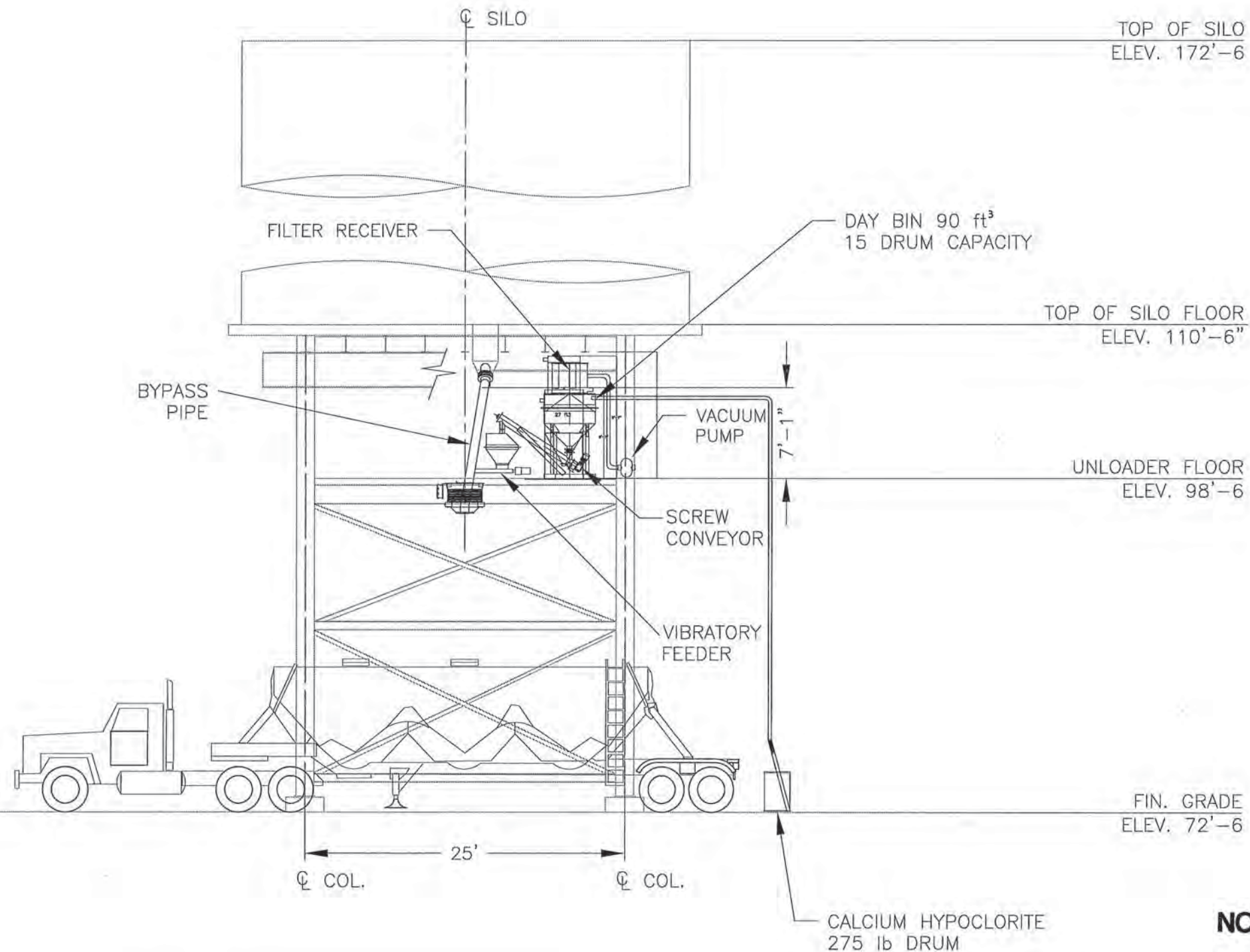
SCALE: 3/16" = 1'  
DATE: 07-18-07  
DESIGN BY: LAS  
DRAWN BY: DCB  
CHECKED BY:  
APPROVED BY:

SHEET NO.

M100

REVISION NO.  
A  
PROJECT NO.  
R070H0

"THIS DRAWING IS THE PROPERTY OF HEADWATERS RESOURCES, INC AND IS LOANED UPON CONDITION THAT IT IS NOT TO BE REPRODUCED OR COPIED, IN WHOLE OR IN PART, OR USED FOR FURNISHING INFORMATION TO ANY PERSON WITHOUT WRITTEN CONSENT OF HEADWATERS, OR FOR ANY PURPOSE DETRIMENTAL TO THEIR INTEREST, AND IS TO BE RETURNED UPON REQUEST."



**NOT FOR CONSTRUCTION**

**HEADWATERS**  
RESOURCES

"THIS DRAWING IS THE PROPERTY OF HEADWATERS RESOURCES, INC AND IS LOANED UPON CONDITION THAT IT IS NOT TO BE REPRODUCED OR COPIED, IN WHOLE OR IN PART, OR USED FOR FURNISHING INFORMATION TO ANY PERSON WITHOUT WRITTEN CONSENT OF HEADWATERS, OR FOR ANY PURPOSE DETRIMENTAL TO THEIR INTEREST, AND IS TO BE RETURNED UPON REQUEST."

HEADWATERS RESOURCES, INC.  
10653 S. RIVER FRONT PARKWAY  
SUITE 300  
SOUTH JORDAN, UT 84095  
(801) 984-9400  
FAX (801) 984-9419  
www.headwaters.com

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

**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.

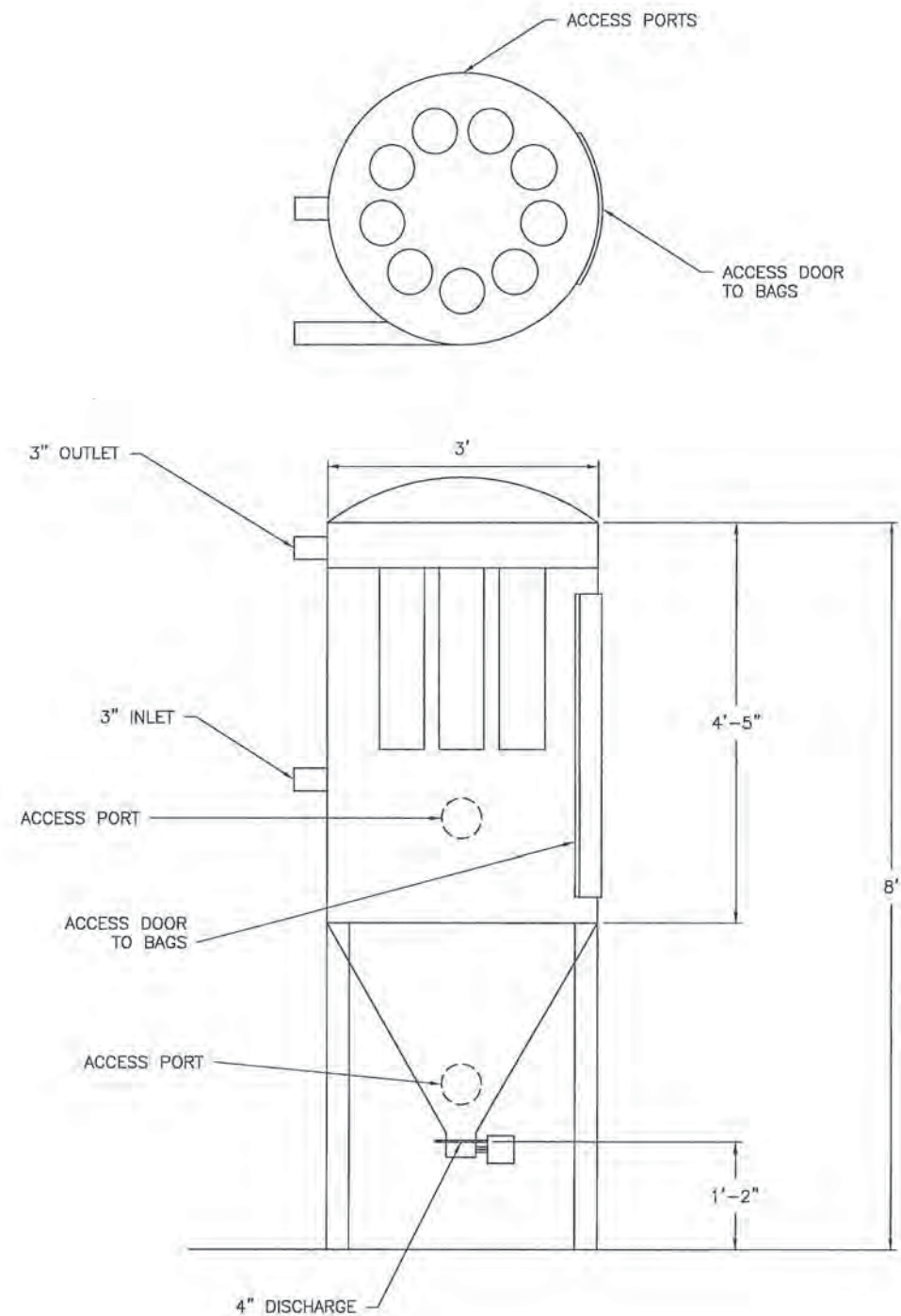
A

PROJECT NO.

R070H0



- NOTE:
- 1. EPOXY PAINT INSIDE AND OUT
  - 2. TOTAL CAPACITY - 17 FT<sup>3</sup>
  - 3. USE 2' TEFLON-COATED BAGS



NOT FOR CONSTRUCTION

**HEADWATERS**  
RESOURCES

"THIS DRAWING IS THE PROPERTY OF HEADWATERS RESOURCES, INC AND IS LOANED UPON CONDITION THAT IT IS NOT TO BE REPRODUCED OR COPIED, IN WHOLE OR IN PART, OR USED FOR FURNISHING INFORMATION TO ANY PERSON WITHOUT WRITTEN CONSENT OF HEADWATERS, OR FOR ANY PURPOSE DETRIMENTAL TO THEIR INTEREST, AND IS TO BE RETURNED UPON REQUEST."

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
8/6/07	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.

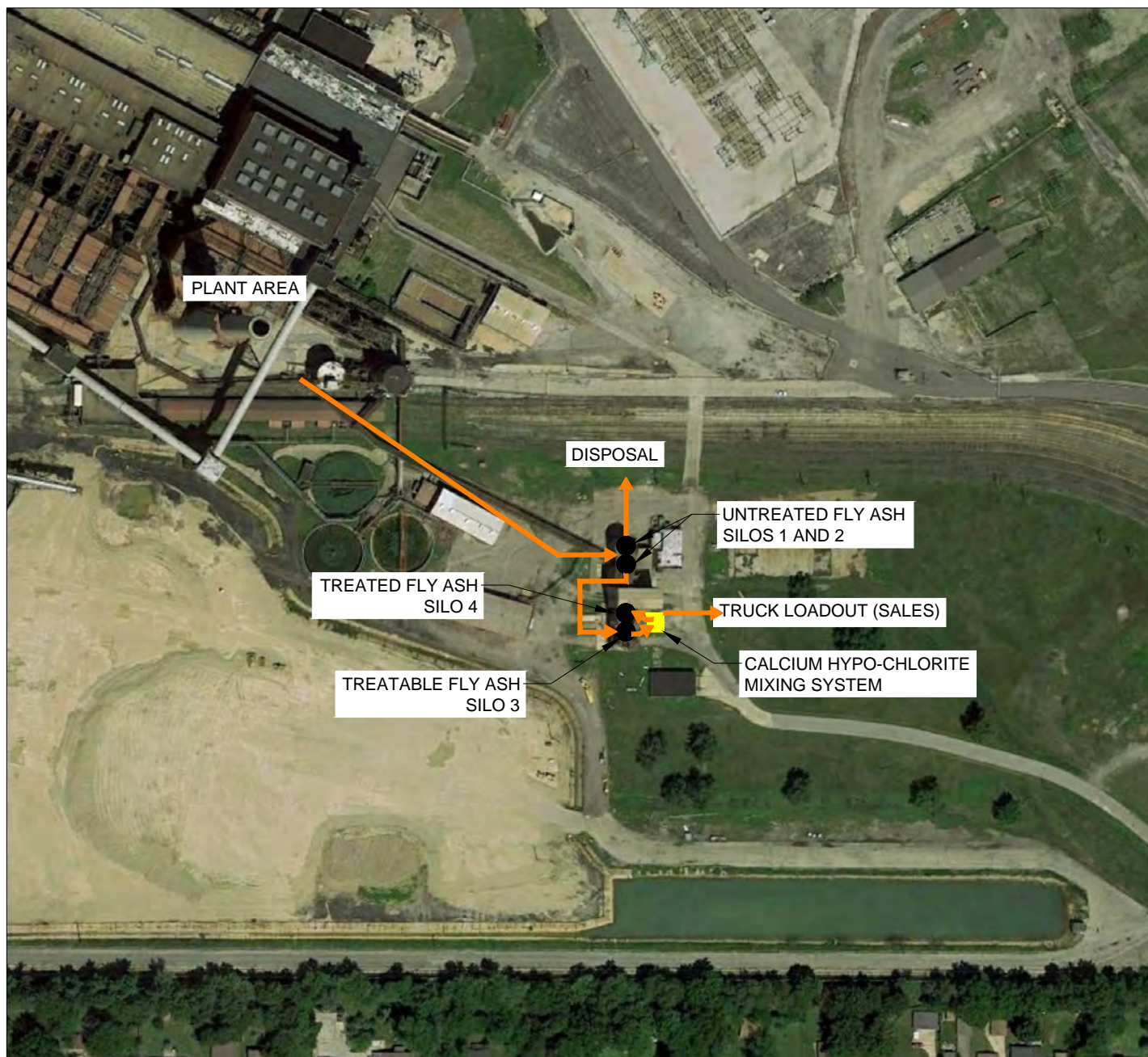
B

PROJECT NO.



R070H0

## APPENDIX B

# COST ESTIMATE DETAILS

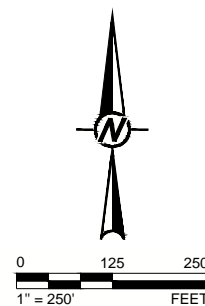


#### LEGEND

-  FLY ASH STREAM
-  CALCIUM HYPO-CHLORITE MIXING SYSTEM

#### NOTE(S)

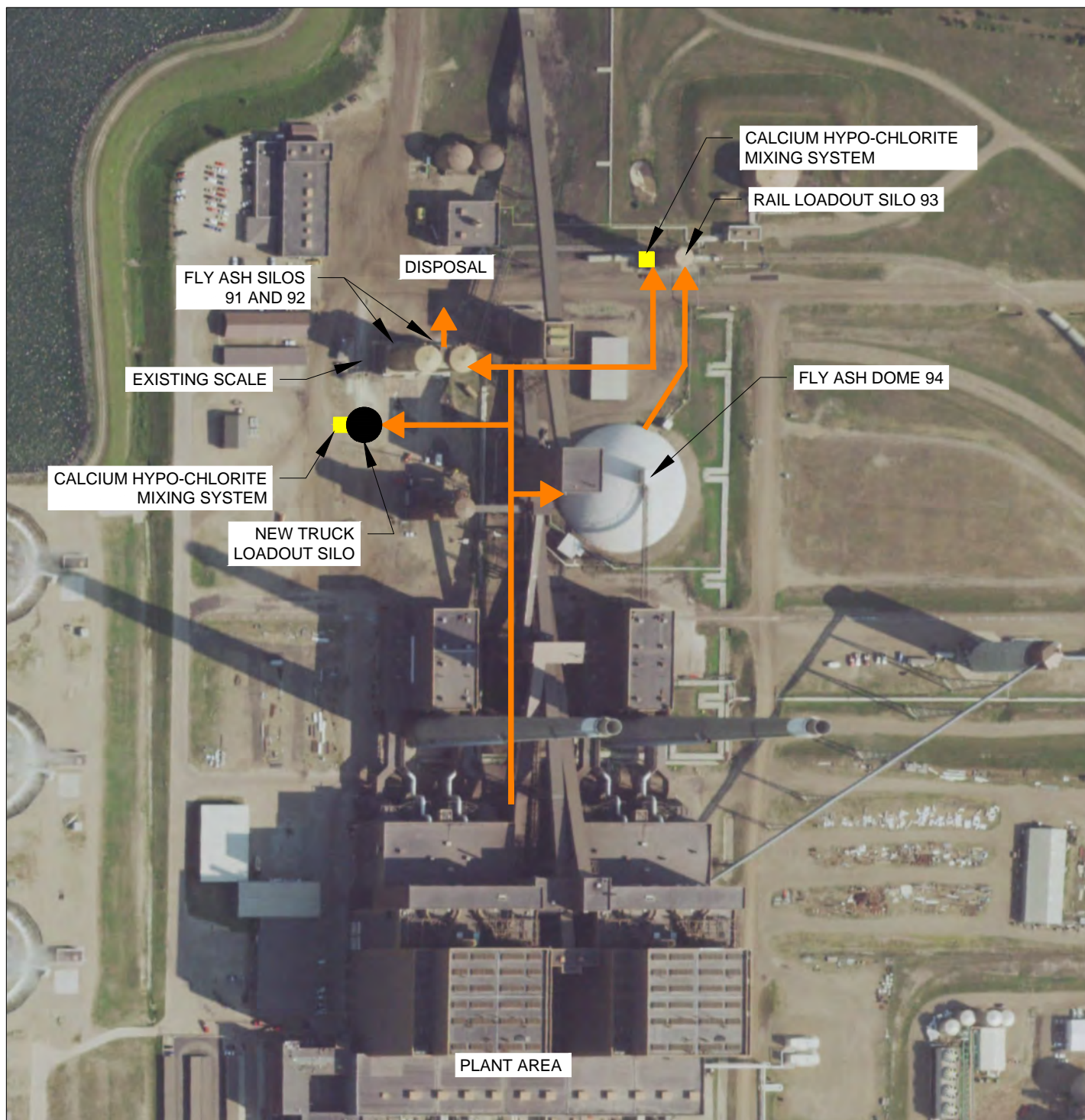
1. EASTLAKE GENERATING PLANT HAS A TRUCK LOADOUT FOR BOTH UNTREATABLE FLY ASH DESTINED FOR DISPOSAL (SILOS 1 AND 2) AND TREATED FLY ASH (SILO 4).





**FLY ASH LOADOUT LAYOUT  
EASTLAKE GENERATING PLANT**

**FIGURE 1**



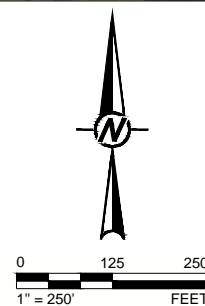


#### LEGEND

-  FLY ASH STREAM
-  CALCIUM HYPO-CHLORITE MIXING SYSTEM

#### NOTE(S)

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.



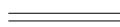


**FLY ASH LOADOUT LAYOUT  
COAL CREEK STATION**

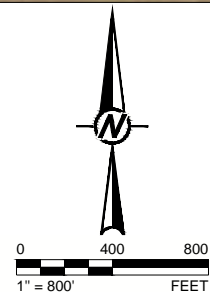
**FIGURE 2**





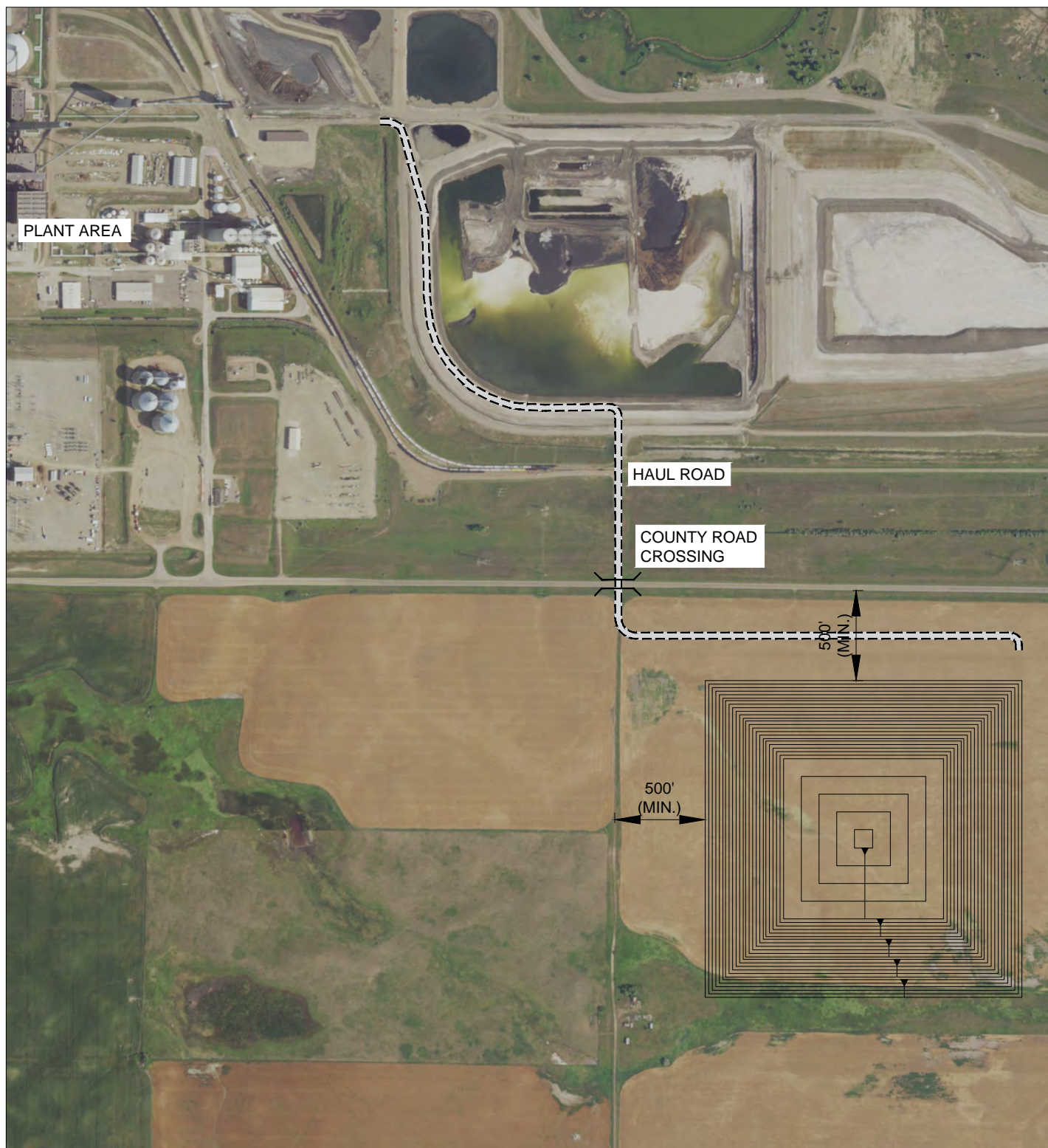
**LEGEND**

-  TOP OF CONTAINMENT FACILITY CONTOURS
-  HAUL ROAD TO BE CONSTRUCTED
-  COUNTY ROAD CROSSING TO BE CONSTRUCTED



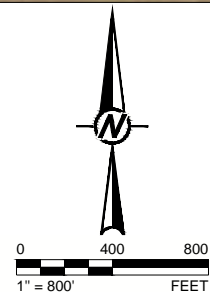
**SCENARIO A  
FLY ASH CONTAINMENT FACILITY**





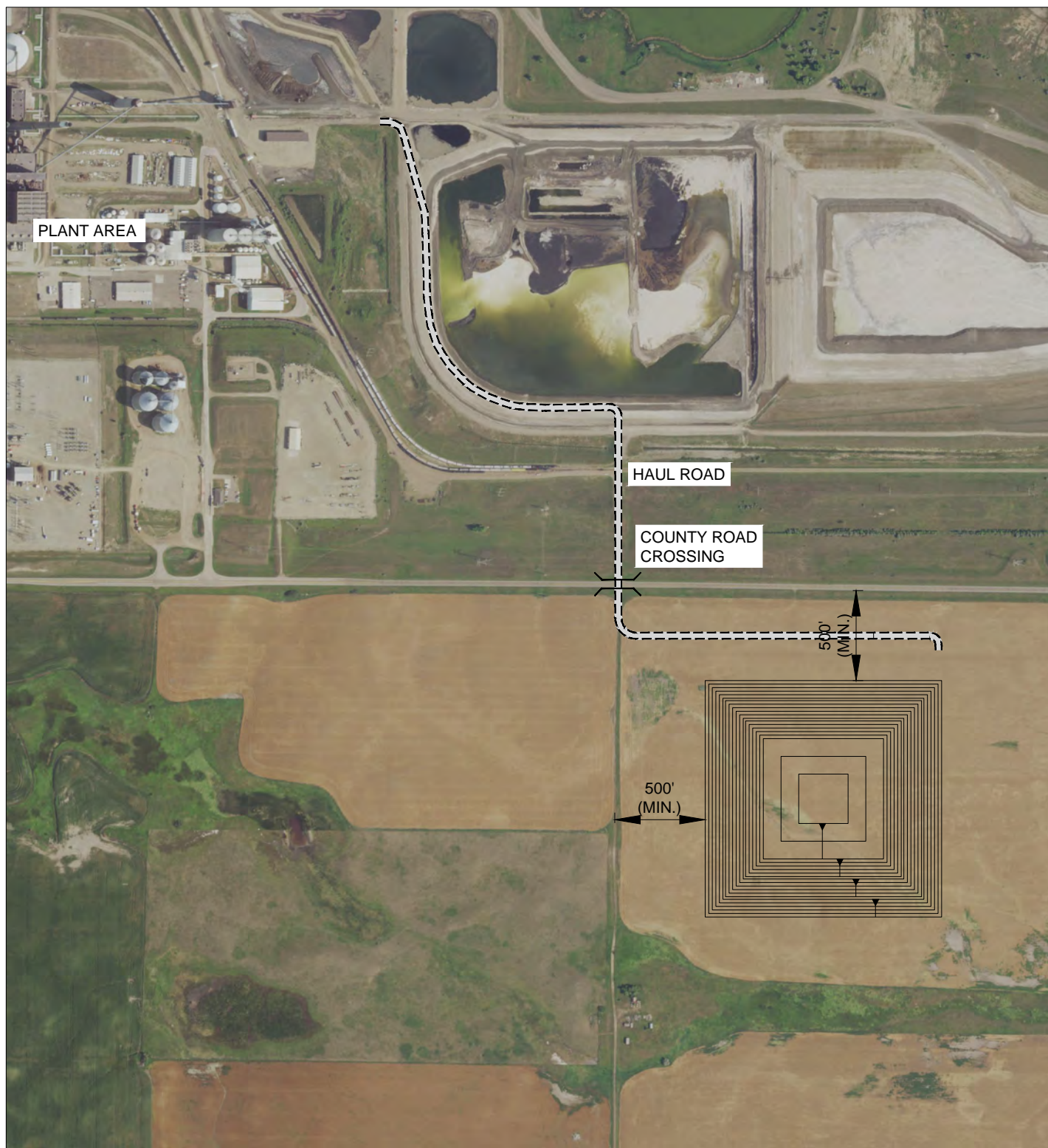
LEGEND

- TOP OF CONTAINMENT FACILITY CONTOURS
- HAUL ROAD TO BE CONSTRUCTED
- COUNTY ROAD CROSSING TO BE CONSTRUCTED

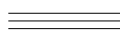




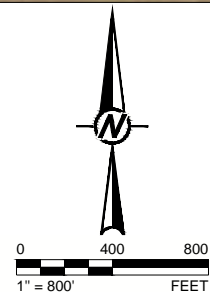
SCENARIO B  
FLY ASH CONTAINMENT FACILITY



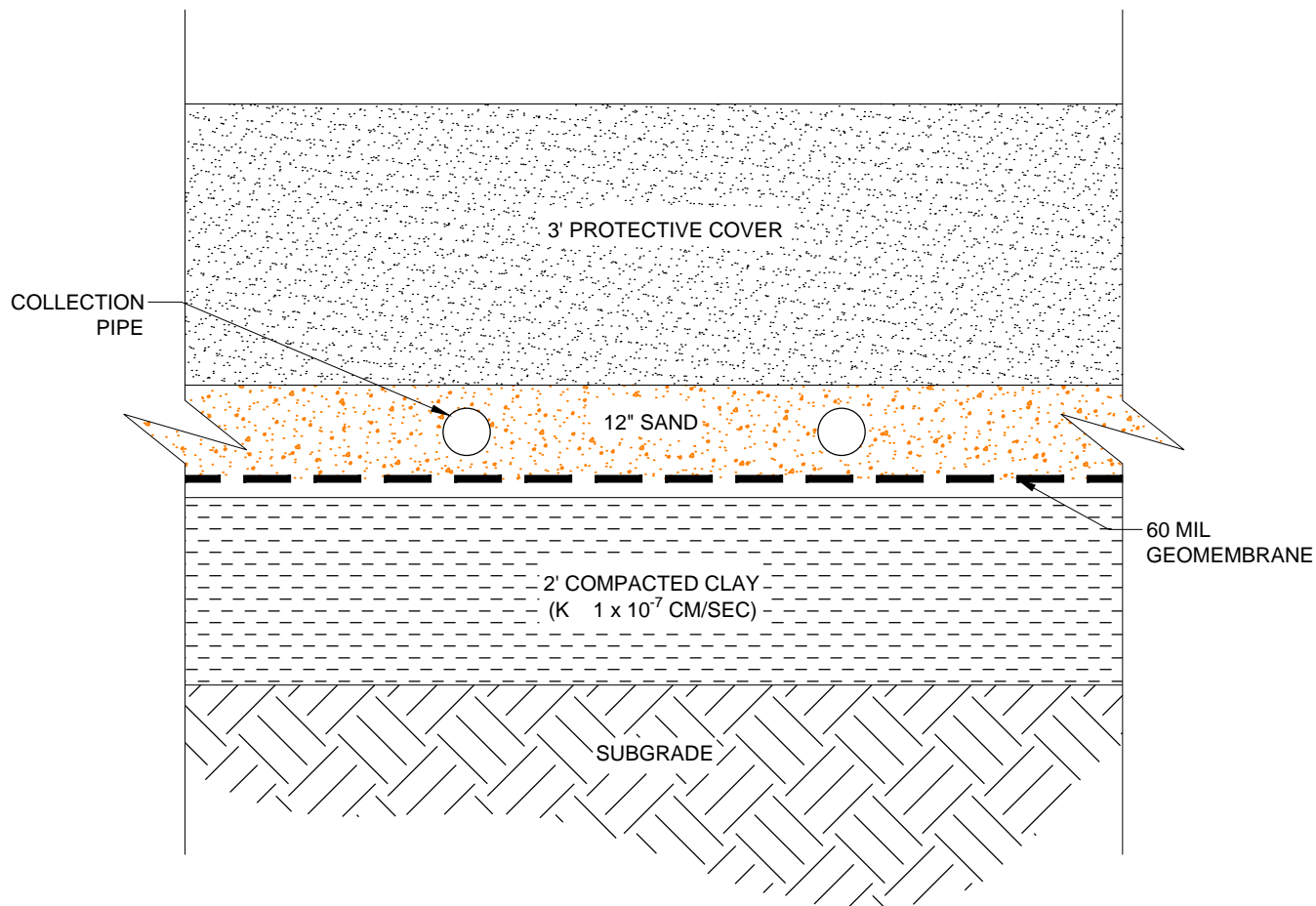


**LEGEND**

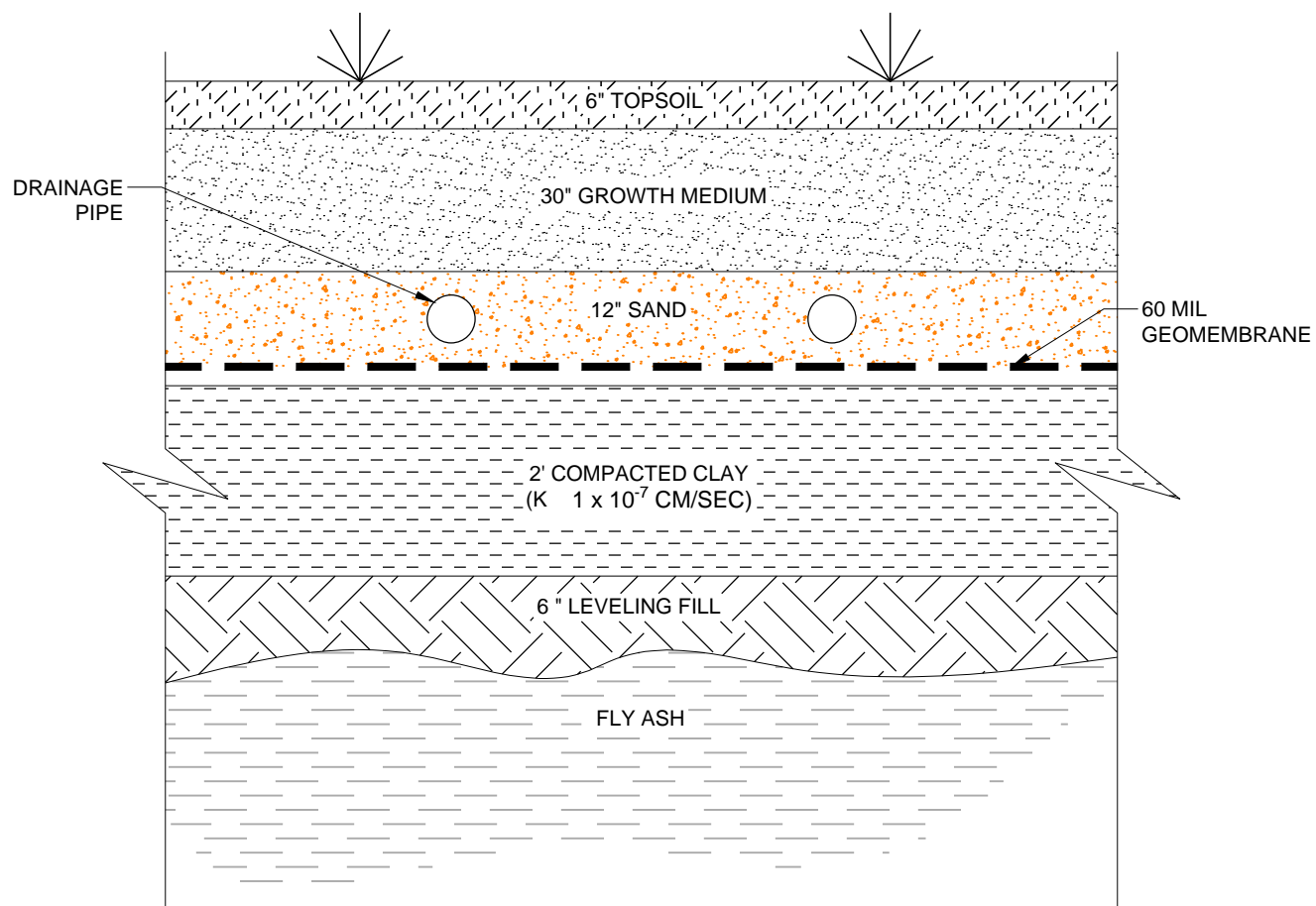
-  TOP OF CONTAINMENT FACILITY CONTOURS
-  HAUL ROAD TO BE CONSTRUCTED
-  COUNTY ROAD CROSSING TO BE CONSTRUCTED



**SCENARIO C**  
**FLY ASH CONTAINMENT FACILITY**



COMPOSITE LINER DETAIL



COMPOSITE COVER DETAIL

FIGURE 7

### Fly Ash Management Impact Evaluation Summary (March 1, 2019)

	Scenario A	Scenario B	Scenario C
	Current fly ash sales with new EPA CCR Rule landfill	No fly ash sales with new EPA CCR Rule landfill	ASM technology to allow reduced fly ash sales with new EPA CCR Rule landfill
<b>Fly Ash Quantities</b>			
Fly Ash production (ton/yr)	513,000	513,000	513,000
Fly Ash Sales (ton/yr)	400,000	0	308,000
Fly Ash Disposal (ton/yr)	113,000	513,000	205,000
Lost Fly Ash Sales (ton/yr)	0	400,000	92,000
<b>ASM Fly Ash Post Processing</b>			
ASM Unit Rate Capital and O&M (\$/ton sold)	\$ -	\$ -	\$ 6.40
ASM Annual Capital and O&M (\$/yr)	\$ -	\$ -	\$ 1,980,000
<b>Fly Ash Disposal</b>			
Lined Footprint (acres)	24.5	72.0	36.5
Unit Rate Capital and O&M (\$/ton disposed)	\$ 26.00	\$ 15.80	\$ 20.60
Annual Capital and O&M (\$/yr)	\$ 2,940,000	\$ 8,100,000	\$ 4,220,000
<b>Lost Fly Ash Sales</b>			
Lost Fly Ash Sales Revenue (\$/ton lost sales)	\$ 12.40	\$ 12.40	\$ 12.40
Annual Lost Fly Ash Sales Revenue (\$/yr)	\$ -	\$ 4,960,000	\$ 1,140,000
<b>Total (Disposal + Post Processing + Lost Sales)</b>			
Annual Cost (\$/yr)	\$ 2,940,000	\$ 13,060,000	\$ 7,340,000
Unit Cost (\$/ton produced)	\$ 5.70	\$ 25.50	\$ 14.30
<b>Additional Cost (Scenario B/C - Scenario A)</b>			
Fly Ash Management Cost (\$/yr)	-	\$ 10,120,000	\$ 4,400,000
Fly Ash Management Cost (\$/ton produced)	-	\$ 19.70	\$ 8.60

**Notes:**

Capital costs annualized based on 20-year life and 5.25% interest rate.

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

EPA CCR Rule compliant 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 2019 dollars.

Lost fly ash sales revenue based on average per ton revenue to GRE between 2014 and 2018.

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

## Scenario A - Current Sales

### Sizing Information

Annual Fly Ash Disposal	113,000	tn	
20yr Fly Ash Disposal	2,260,000	tn	
Fly Ash Dry Density (in-situ)	90	pcf	
20yr Fly Ash Quantity	1,860,000	cy	
Lined Footprint	24.5	ac	80,000 cy/ac
Disturbance Footprint	35.0	ac	100' offset on liner footprint
Berm Length	4,300	ft	20' offset on liner footprint
Total Footprint	160	ac	500' offset on liner footprint, nearest 1/8 section
Total Cover Area	27.0	ac	1.1 ration of cover area to liner area

Project	19115185
Date	3/1/2019
By	PDS
Checked	CCS

### Direct/Capital Costs

Item	Rate	#		Total Cost
Land Acquisition	\$ 4,000 /ac	160.0	ac	\$ 640,000
Infrastructure Development	\$ 851,000 ea	1.0	LS	\$ 850,000
County Road Crossing	\$ 1,887,000 ea	1.0	LS	\$ 1,890,000
Liner Construction	\$ 243,000 /ac	24.5	ac	\$ 5,950,000
Final Cover Construction	\$ 201,000 /ac	27.0	ac	\$ 5,430,000
Post-Closure Care	\$ 106,000 /yr	30.0	yr	\$ 3,180,000
Facility Design & Permitting (on construction)	10.0% -	\$ 14,120,000	LS	\$ 1,410,000
Construction Quality Assurance (on construction)	10.0% -	\$ 14,120,000	LS	\$ 1,410,000
GRE Internal Costs (on construction, design, CQA, & land purchase)	10.0% -	\$ 20,760,000	-	\$ 2,080,000
Project Contingency (on construction & land)	20.0% -	\$ 14,760,000	-	\$ 2,950,000
Total Direct/Capital Costs				\$ 25,790,000
Annualized Capital Cost*				\$ 2,110,000 /yr
Capital Costs				\$ 18.70 /tn

### Operational Costs

Hauling Costs	\$ 3.30 /tn	113,000 tn/yr	\$ 370,000 /yr
Placement Costs	\$ 2.30 /tn	113,000 tn/yr	\$ 260,000 /yr
Maintenance Costs	\$ 196,000 /yr	1 yr	\$ 200,000 /yr
Annual Operational Costs			\$ 830,000 /yr
Operational Costs			\$ 7.30 /tn

### TOTAL DISPOSAL COSTS

Annual Costs	\$ 2,940,000 /yr
20-Year Total Costs	\$ 58,800,000
Per Ton Cost	\$ 26.00 /tn

### Notes:

\*Annualized capital cost based on 20-year life and 5.25% interest rate.

All costs are in 2019 dollars.



## Scenario B - No Fly Ash Sales

### Sizing Information

Annual Fly Ash Disposal	513,000	tn	
20yr Fly Ash Disposal	10,260,000	tn	
Fly Ash Dry Density (in-situ)	90	pcf	
20yr Fly Ash Quantity	8,444,000	cy	
Lined Footprint	72.0	ac	120,000 cy/ac
Disturbance Footprint	89.0	ac	100' offset on liner footprint
Berm Length	7,240	ft	20' offset on liner footprint
Total Footprint	240	ac	500' offset on liner footprint, nearest 1/8 section
Total Cover Area	79.0	ac	1.1 ration of cover area to liner area

Project	19115185
Date	3/1/2019
By	PDS
Checked	CCS

### Direct/Capital Costs

Item	Rate	#		Total Cost
Land Acquisition	\$ 4,000 /ac	240.0	ac	\$ 960,000
Infrastructure Development	\$ 1,020,000 ea	1.0	LS	\$ 1,020,000
County Road Crossing	\$ 1,887,000 ea	1.0	LS	\$ 1,890,000
Liner Construction	\$ 239,000 /ac	72.0	ac	\$ 17,210,000
Final Cover Construction	\$ 183,000 /ac	79.0	ac	\$ 14,460,000
Post-Closure Care	\$ 154,000 /yr	30.0	yr	\$ 4,620,000
Facility Design & Permitting (on construction)	10.0% -	\$ 34,580,000	LS	\$ 3,460,000
Construction Quality Assurance (on construction)	10.0% -	\$ 34,580,000	LS	\$ 3,460,000
GRE Internal Costs (on construction, design, CQA, & land purchase)	10.0% -	\$ 47,080,000	-	\$ 4,710,000
Project Contingency (on construction & land)	20.0% -	\$ 35,540,000	-	\$ 7,110,000
Total Direct/Capital Costs				\$ 58,900,000
Annualized Capital Cost*				\$ 4,830,000 /yr
Capital Costs				\$ 9.40 /tn

### Operational Costs

Hauling Costs	\$ 3.30 /tn	513,000 tn/yr	\$ 1,690,000 /yr
Placement Costs	\$ 2.30 /tn	513,000 tn/yr	\$ 1,180,000 /yr
Maintenance Costs	\$ 396,000 /yr	1 yr	\$ 400,000 /yr
An. Operational Costs			\$ 3,270,000 /yr
Operational Costs			\$ 6.40 /tn

### TOTAL DISPOSAL COSTS

Annual Costs	\$ 8,100,000 /yr
20-Year Total Costs	\$ 162,000,000
Per Ton Cost	\$ 15.80 /tn

### Notes:

\*Annualized capital cost based on 20-year life and 5.25% interest rate.

All costs are in 2019 dollars.

## Scenario C - Partial Fly Ash Sales with ASM

### Sizing Information

Annual Fly Ash Disposal	205,000	tn	
20yr Fly Ash Disposal	4,100,000	tn	
Fly Ash Dry Density (in-situ)	90	pcf	
20yr Fly Ash Quantity	3,374,000	cy	
Lined Footprint	36.5	ac	90,000 cy/ac
Disturbance Footprint	49.0	ac	100' offset on liner footprint
Berm Length	5,200	ft	20' offset on liner footprint
Total Footprint	160	ac	500' offset on liner footprint, nearest 1/8 section
Total Cover Area	40.0	ac	1.1 ration of cover area to liner area

Project	19115185
Date	3/1/2019
By	PDS
Checked	CCS

### Direct/Capital Costs

Item	Rate	#		Total Cost
Land Acquisition	\$ 4,000 /ac	160.0	ac	\$ 640,000
Infrastructure Development	\$ 865,000 ea	1.0	LS	\$ 870,000
County Road Crossing	\$ 1,887,000 ea	1.0	LS	\$ 1,890,000
Liner Construction	\$ 241,000 /ac	36.5	ac	\$ 8,800,000
Final Cover Construction	\$ 198,000 /ac	40.0	ac	\$ 7,920,000
Post-Closure Care	\$ 120,000 /yr	30.0	yr	\$ 3,600,000
Facility Design & Permitting (on construction)	10.0% -	\$ 19,480,000	LS	\$ 1,950,000
Construction Quality Assurance (on construction)	10.0% -	\$ 19,480,000	LS	\$ 1,950,000
GRE Internal Costs (on construction, design, CQA, & land purchase)	10.0% -	\$ 27,620,000	-	\$ 2,760,000
Project Contingency (on construction & land)	20.0% -	\$ 20,120,000	-	\$ 4,020,000
Total Direct/Capital Costs				\$ 34,400,000
Annualized Capital Cost*				\$ 2,820,000 /yr
Capital Costs				\$ 13.80 /tn

### Operational Costs

Hauling Costs	\$ 3.30 /tn	205,000 tn/yr	\$ 680,000 /yr
Placement Costs	\$ 2.30 /tn	205,000 tn/yr	\$ 470,000 /yr
Maintenance Costs	\$ 246,000 /yr	1 yr	\$ 250,000 /yr
An. Operational Costs			\$ 1,400,000 /yr
Operational Costs			\$ 6.80 /tn

### TOTAL DISPOSAL COSTS

Annual Costs	\$ 4,220,000 /yr
20-Year Total Costs	\$ 84,400,000
Per Ton Cost	\$ 20.60 /tn

### Notes:

\*Annualized capital cost based on 20-year life and 5.25% interest rate.

All costs are in 2019 dollars.

## ASM Post-Processing

### Sizing Information

Annual Fly Ash Sales 308,000 tn

Project	19115185
Date	3/1/2019
By	PDS
Checked	TJS

### Direct/Capital Costs

Item	Rate	#	Total Cost
New Truck Load-out Silo	\$ 2,021,000 ea	1.0 LS	\$ 2,020,000
Cal-Hypo Feed Systems (Rail silo)	\$ 288,000 ea	1.0 LS	\$ 290,000
Cal-Hypo Feed Systems (New silo)	\$ 385,000 ea	1.0 LS	\$ 390,000
System Design & Engineering (on construction)	10.0% -	\$ 2,700,000 -	\$ 270,000
GRE Internal Costs (on all)	10.0% -	\$ 2,970,000 -	\$ 300,000
Project Contingency (on construction)	20.0% -	\$ 2,700,000 -	\$ 540,000
Total Direct/Capital Costs			\$ 3,810,000

Annualized Capital Cost\* \$ 310,000 /yr

Capital Costs \$ 1.00 /tn

### Operational Costs

Maintenance	\$ 90.00 \$/hr	4,600 hr	\$ 410,000 /yr
Maintenance Materials	50% -	\$ 410,000 -	\$ 210,000 /yr
Operations Materials	\$ 90.00 \$/hr	5,750 hr	\$ 520,000 /yr
Operations Materials (Cal-Hypo)	\$ 0.70 /tn	308,000 tn/yr	\$ 220,000 /yr
Technology Royalty	\$ 1.00 /tn	308,000 tn/yr	\$ 310,000 /yr
An. Operational Costs			\$ 1,670,000 /yr
Operational Costs			\$ 5.40 /tn

### TOTAL ASM COSTS

Annual Costs \$ 1,980,000 /yr

20-Year Total Costs \$ 39,600,000

Per Ton Cost \$ 6.40 /tn

### Notes:

\*Annualized capital cost based on 20-year life and 5.25% interest rate.

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

Assumed calcium hypo-chlorite cost of \$1.25/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	\$ 850,500	\$	851,000
<b>General</b>						
Mobilize/Demobilize	5%	%	\$ -	\$ 38,659.11		
Miscellaneous Site Work & Materials	5%	%	\$ -	\$ 38,659.11		Erosion controls, offices, toilets, temporary roads, survey control, etc.
<b>Civil</b>						
Road Topsoil Stripping and Stockpiling	3,200	CY	\$ 2.64	\$ 8,448	Crew analysis, dozer work	18" topsoil
Access Road Construction	186,200	SF	\$ 1.47	\$ 273,714	32 11 23.23 RS Means 2019 Bismarck	8" thick, Crushed 1-1/2"stone base, compacted to 4" deep, 5,320' x 35'
Return Water Pipeline						
Trench Excavation	8,300	CY	\$ 2.94	\$ 24,439	Crew analysis	
6" Pipeline	5,600	LF	\$ 12.00	\$ 67,200	33 14 13.35 RS Means 2019 Bismarck	DR25 PVC
Misc. Appurtenances	1	EA	\$ 10,000.00	\$ 10,000		
Pipe Bedding & Embedment	1,700	CY	\$ 4.99	\$ 8,475	Crew analysis	
Trench Backfill	5,700	CY	\$ 3.59	\$ 20,485	Crew analysis	
Topsoil	900	CY	\$ 3.52	\$ 3,168	Crew analysis	
Marking Tape	5,600	LF	\$ 0.10	\$ 560	Underground Warning tape - via web search	
Tracer Wire	5,600	LF	\$ 0.20	\$ 1,120	14 gauge burial wire - via web search	
Fence	8,132	LF	\$ 28.23	\$ 229,574	32 31 13.20 RS Means 2019 Bismarck	6' Chain link fence, 3 strands barb wire
Overhead Power (Plant to Landfill)	1	EA	\$ 90,000	\$ 90,000	RS Means 2019 Bismarck 33.71.39.13.0150 33.71.16.33.5060	Pipeline length + 20% One utility pole every 200 feet
Monitoring Well Installation	6	EA	\$ 6,000	\$ 36,000	Golder Estimate	
County Road Crossing			Total	\$ 1,886,520	\$	1,887,000
<b>General</b>						
Mobilize/Demobilize	5%	%	\$ -	\$ 85,751		
Misc. (erosion controls, toilets, etc)	5%	%	\$ -	\$ 85,751		Erosion controls, offices, toilets, temporary roads, survey control, etc.
<b>Civil</b>						
Topsoil Stripping and Stockpiling	4,577	CY	\$ 2.64	\$ 12,083	Crew analysis, dozer work	18" topsoil
Embankment Fill	5,776	CY	\$ 6.49	\$ 37,510	Crew analysis	
County Road Base Course	32,200	SF	\$ 2.13	\$ 68,586	32 11 23.23 RS Means 2019 Bismarck	12" Gravel base course Crushed 1-1/2"stone base, compacted to 4" deep
County Road Asphalt Pavement	3,578	SY	\$ 35.45	\$ 126,838	RSMeans 2019, Bismarck 32 12 16.13.1595 32.12.16.13.1460 31.23.23.20.1114	2" Binder Course 4" Wearing Course
Bridge Deck Construction	4,900	SF	\$ 300	\$ 1,470,000	2016 California DOT cost range	140 ft bridge deck, 35 ft wide
Liner Construction			Total	\$ 5,962,218	Cost Per Acre of Liner	\$ 243,000
<b>General</b>						
Mobilize/Demobilize	5%	%	\$ -	\$ 271,010		
Miscellaneous Site Work & Materials	5%	%	\$ -	\$ 271,010		Erosion controls, offices, toilets, temporary roads, survey control, etc.
<b>Civil</b>						
Clearing and Grubbing	35	AC	\$ 4,500.00	\$ 157,500	31 11 10.10 RS Means 2019 Bismarck	Clear & grub brush including stumps
Topsoil Stripping & Stockpiling (18")	-	CY	\$ 2.64		Crew analysis	
	35	AC	\$ 6,389	\$ 223,608		
Subgrade Cut to Stockpile	297,800	CY	\$ 5.62	\$ 1,674,165	Crew analysis	10' deep cut across liner area: for liner, berms and cover
Subgrade Cut/Embankment Fill	97,467	CY	\$ 6.49	\$ 632,930	Crew analysis	612 ft2 cross section area
	-	CY	\$ 6.56		Crew analysis	
Low Permeability Soil Liner (24")	25	AC	\$ 21,161	\$ 518,456		
60-mil HDPE Liner	-	SF	\$ 0.75		Recent construction	Materials, waste, conformance testing, installation
	25	AC	\$ 32,670	\$ 800,415		
Leachate Collection Layer, Sand (12")		CY	\$ 29.70		Crew analysis for haul/place from Bismarck	
	25	AC	\$ 47,916	\$ 1,173,942		
Protective Cover (3')	-	CY	\$ 6.33		Crew analysis	Fly ash as protective cover
	6	AC	\$ 30,626	\$ 187,584		Contractor place 25% of liner area (side slopes, haul routes)
<b>Piping</b>						
LCS 4" Piping	4,570	LF	\$ 3.92	\$ 17,914	33 42 11.50 RS Means 2019 Bismarck	4" Corrugated HDPE
LCS 8" Piping	910	LF	\$ 7.78	\$ 7,080	33 42 11.50 RS Means 2019 Bismarck	8" Corrugated HDPE
LCS Sump/Riser	1	EA	\$ 20,000	\$ 20,000	Golder Estimate	
<b>Equipment and Electrical</b>						
Power Posts at Pumps/Sumps	1	EA	\$ 1,605	\$ 1,605	26 24 16.30-0150 RS Means 2019 Bismarck	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	\$ 5,415,669	Cost Per Acre of Cover	\$ 201,000
General						
Mobilize/Demobilize	5%	%	\$ -	\$ 246,167		
Miscellaneous Site Work & Materials	5%	%	\$ -	\$ 246,167		Erosion controls, offices, toilets, temporary roads, survey control, etc.
Civil						
Leveling Fill (6")	-	CY	\$ 6.49		Crew analysis	Stockpile cut to embankment fill
	27	AC	\$ 5,238	\$ 141,435		
Compacted Low Permeability Soil Liner (24")	-	CY	\$ 6.56		Crew analysis	Stockpile cut to embankment fill
	27	AC	\$ 21,161	\$ 571,360		
60-mil HDPE Liner	-	SF	\$ 0.75		Recent construction	Materials, waste, conformance testing, installation
	27	AC	\$ 32,670	\$ 882,090		
Drainage Layer, Sand (12")		CY	\$ 29.70		Crew analysis for haul/place from Bismarck	
	27	AC	\$ 47,916	\$ 1,293,732		
Growth Medium (30")		CY	\$ 6.34		Crew analysis	
	27	AC	\$ 25,578	\$ 690,599		
Topsoil (6")		CY	\$ 6.34		Crew analysis	
	27	AC	\$ 5,116	\$ 138,120		
Downchute Channels	57,600	SF	\$ 20.00	\$ 1,152,000	Golder Estimate	36' wide, 4 downchutes
Seed and Mulch	27	AC	\$ 2,000	\$ 54,000	32 92 19.14-4600 RS Means 2019 Bismarck	Seed, mulch & fertilizer, hydro or air seeding
Post Closure Care			Total	\$ 105,500	\$	106,000
CCR Groundwater Monitoring & Reporting	1	EA	\$ 25,000	\$ 25,000	Golder Estimate	
Update CCR Baseline, Network Cert., and Statistical Method Cert. As Needed	1	EA	\$ 24,000	\$ 24,000	Golder Estimate	
Annual Site Inspection	1	EA	\$ 10,000	\$ 10,000	Golder Estimate	
Annual Dust Control Report	1	EA	\$ 2,000	\$ 2,000	Golder Estimate	
Other CCR Requirements	1	EA	\$ 4,600	\$ 4,600	Golder Estimate	
Final Cover Repair	1	EA	\$ 5,500	\$ 5,500	Golder Estimate	2% of cover area, 12" growth medium/topsoil fill
Seeding Repair	1	EA	\$ 5,400	\$ 5,400	Golder Estimate	10% of cover area
Mowing and/or rodent, weed, & tree control	1	EA	\$ 2,200	\$ 2,200	Golder Estimate	\$2,000 per 25 acres
Surface Water Controls Maintenance	1	EA	\$ 17,500	\$ 17,500	Golder Estimate	1% of armored channel replaced + other repairs
Gate and/or fence Maintenance	1	EA	\$ 2,300	\$ 2,300	Golder Estimate	1% of fence
Recordkeeping	1	EA	\$ 1,600	\$ 1,600	Golder Estimate	\$1,500 per 25 acres
Direct Expenses	1	EA	\$ 5,400	\$ 5,400	Golder Estimate	\$5,000 per 25 acres
Annual Operations & Maintenance Costs (not haul and place)			Total	\$ 195,800	\$	196,000
CCR Groundwater Monitoring & Reporting	1	EA	\$ 25,000	\$ 25,000	Golder Estimate	
Update CCR Baseline, Network Cert., and Statistical Method Cert. As Needed	1	EA	\$ 24,000	\$ 24,000	Golder Estimate	
Annual Site Inspection	1	EA	\$ 10,000	\$ 10,000	Golder Estimate	
Annual Dust Control Report	1	EA	\$ 2,000	\$ 2,000	Golder Estimate	
Other CCR Requirements	1	EA	\$ 4,600	\$ 4,600	Golder Estimate	
Engineering Support	1	EA	\$ 49,000	\$ 49,000	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	\$ 2,300	\$ 2,300	Golder Estimate	1% of fence
Recordkeeping	1	EA	\$ 4,900	\$ 4,900	Golder Estimate	\$5,000 per 25 acres
Misc Work (contact water, dust, erosion, grading, etc)	1	EA	\$ 49,000	\$ 49,000	Golder Estimate	\$50,000 per 25 acres
Haul & Place Costs						
Haul Cost	1	CY	\$ 3.30	\$ 3.30	31 23 23.20-8180 RSMeans 2019 Bismarck	60cy Off-road, 20 min wait, 15 mph, 2 mile cycle
Haul Cost	1	TON	\$ 3.30	\$ 3.30	Golder Estimate	75pcf haul density (1 ton/cy)
Place Cost	1	CY	\$ 1.90	\$ 1.90	31 23 23.17-0020 RSMeans 2019 Bismarck	Dozer, no compaction
Place Cost	1	TON	\$ 2.30	\$ 2.30	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	\$ 1,019,878	\$	1,020,000
<b>General</b>						
Mobilize/Demobilize	5%	%	\$ -	\$ 46,358		
Miscellaneous Site Work & Materials	5%	%	\$ -	\$ 46,358		Erosion controls, offices, toilets, temporary roads, survey control, etc.
<b>Civil</b>						
Road Topsoil Stripping and Stockpiling	4,700	CY	\$ 2.64	\$ 12,408	Crew analysis, dozer work	18" topsoil
Access Road Construction	213,500	SF	\$ 1.47	\$ 313,845	32 11 23.23 RS Means 2019 Bismarck	8" thick, Crushed 1-1/2"stone base, compacted to 4" deep, 6,100' x 35'
Return Water Pipeline						
Trench Excavation	9,400	CY	\$ 2.94	\$ 27,677	Crew analysis	
6" Pipeline	6,340	LF	\$ 12.00	\$ 76,080	33 14 13.35 RS Means 2019 Bismarck	
Misc. Appurtenances	1	EA	\$ 10,000.00	\$ 10,000		
Pipe Bedding & Embedment	1,900	CY	\$ 4.99	\$ 9,472	Crew analysis	
Trench Backfill	6,500	CY	\$ 3.59	\$ 23,360	Crew analysis	
Topsoil	1,000	CY	\$ 3.52	\$ 3,520	Crew analysis	
Marking Tape	6,340	LF	\$ 0.10	\$ 634	Underground Warning tape - via web search	
Tracer Wire	6,340	LF	\$ 0.20	\$ 1,268	14 gauge burial wire - via web search	
Fence	11,084	LF	\$ 28.23	\$ 312,897	32 31 13.20 RS Means 2019 Bismarck	6' Chain link fence, 3 strands barb wire
Overhead Power (Plant to Landfill)	1	EA	\$ 100,000	\$ 100,000	RS Means 2019 Bismarck 33.71.39.13.0150 33.71.16.33.5060	Pipeline length + 20% One utility pole every 200 feet
Monitoring Well Installation	6	EA	\$ 6,000	\$ 36,000	Golder Estimate	
County Road Crossing			Total	\$ 1,886,520	\$	1,887,000
<b>General</b>						
Mobilize/Demobilize	5%	%	\$ -	\$ 85,751		
Misc. (erosion controls, toilets, etc)	5%	%	\$ -	\$ 85,751		Erosion controls, offices, toilets, temporary roads, survey control, etc.
<b>Civil</b>						
Topsoil Stripping and Stockpiling	4,577	CY	\$ 2.64	\$ 12,083	Crew analysis, dozer work	18" topsoil
Embankment Fill	5,776	CY	\$ 6.49	\$ 37,510	Crew analysis	
County Road Base Course	32,200	SF	\$ 2.13	\$ 68,586	32 11 23.23 RS Means 2019 Bismarck	12" Gravel base course Crushed 1-1/2"stone base, compacted to 4" deep
County Road Asphalt Pavement	3,578	SY	\$ 35.45	\$ 126,838	RSMeans 2019, Bismarck 32 12 16.13.1595 32.12.16.13.1460 31.23.23.20.1114	2" Binder Course 4" Wearing Course
Bridge Deck Construction	4,900	SF	\$ 300	\$ 1,470,000	2016 California DOT cost range	140 ft bridge deck, 35 ft wide
Liner Construction			Total	\$ 17,224,249	Cost Per Acre of Liner	\$ 239,000
<b>General</b>						
Mobilize/Demobilize	5%	%	\$ -	\$ 782,920.39		
Miscellaneous Site Work & Materials	5%	%	\$ -	\$ 782,920.39		Erosion controls, offices, toilets, temporary roads, survey control, etc.
<b>Civil</b>						
Clearing and Grubbing	89	AC	\$ 4,500.00	\$ 400,500	31 11 10.10 RS Means 2019 Bismarck	Clear & grub brush including stumps
Topsoil Stripping & Stockpiling (18")	-	CY	\$ 2.64		Crew analysis	
	89	AC	\$ 6,389	\$ 568,603		
Subgrade Cut to Stockpile	997,493	CY	\$ 5.62	\$ 5,607,683	Crew analysis	10' deep cut across liner area: for liner, berms and cover
Subgrade Cut/Embankment Fill	164,107	CY	\$ 6.49	\$ 1,065,677	Crew analysis	612 ft2 cross section area
Low Permeability Soil Liner (24")	-	CY	\$ 6.56		Crew analysis	
	72	AC	\$ 21,161	\$ 1,523,626		
60-mil HDPE Liner	-	SF	\$ 0.75		Recent construction	Materials, waste, conformance testing, installation
	72	AC	\$ 32,670	\$ 2,352,240		
Leachate Collection Layer, Sand (12")	-	CY	\$ 29.70		Crew analysis for haul/place from Bismarck	
	72	AC	\$ 47,916	\$ 3,449,952		
Protective Cover (3')	-	CY	\$ 6.33		Crew analysis	Fly ash as protective cover
	18	AC	\$ 30,626	\$ 551,267		Contractor place 25% of liner area (side slopes, haul routes)
<b>Piping</b>						
LCS 4" Piping	15,280	LF	\$ 3.92	\$ 59,898	33 42 11.50 RS Means 2019 Bismarck	4" Corrugated HDPE
LCS 8" Piping	3,310	LF	\$ 7.78	\$ 25,752	33 42 11.50 RS Means 2019 Bismarck	8" Corrugated HDPE
LCS Sump/Riser	2	EA	\$ 20,000	\$ 40,000	Golder Estimate	
<b>Equipment and Electrical</b>						
Power Posts at Pumps/Sumps	2	EA	\$ 1,605	\$ 3,210	26 24 16.30-0150 RS Means 2019 Bismarck	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	\$ 14,419,074	Cost Per Acre of Cover	\$ 183,000
<b>General</b>						
Mobilize/Demobilize	5%	%	\$ -	\$ 655,412		
Miscellaneous Site Work & Materials	5%	%	\$ -	\$ 655,412		Erosion controls, offices, toilets, temporary roads, survey control, etc.
<b>Civil</b>						
Leveling Fill (6")	-	CY	\$ 6.49		Crew analysis	Stockpile cut to embankment fill
	79	AC	\$ 5,238	\$ 413,828.74		
Compacted Low Permeability Soil Liner (24")	-	CY	\$ 6.56		Crew analysis	Stockpile cut to embankment fill
	79	AC	\$ 21,161	\$ 1,671,756		
60-mil HDPE Liner	-	SF	\$ 0.75		Recent construction	Materials, waste, conformance testing, installation
	79	AC	\$ 32,670	\$ 2,580,930		
Drainage Layer, Sand (12")	-	CY	\$ 29.70		Crew analysis for haul/place from Bismarck	
	79	AC	\$ 47,916	\$ 3,785,364		
Growth Medium (30")	-	CY	\$ 6.34		Crew analysis	
	79	AC	\$ 25,578	\$ 2,020,642		
Topsoil (6")	-	CY	\$ 6.34		Crew analysis	
	79	AC	\$ 5,116	\$ 404,128		
Downchute Channels	103,680	SF	\$ 20.00	\$ 2,073,600	Golder Estimate	36' wide, 4 downchutes
Seed and Mulch	79	AC	\$ 2,000	\$ 158,000	32 92 19.14-4600 RS Means 2019 Bismarck	Seed, mulch & fertilizer, hydro or air seeding
<b>Post Closure Care</b>						
			Total	\$ 154,200	\$	154,000
CCR Groundwater Monitoring & Reporting	1	EA	\$ 25,000	\$ 25,000	Golder Estimate	
Update CCR Baseline, Network Cert., and Statistical Method Cert. As Needed	1	EA	\$ 24,000	\$ 24,000	Golder Estimate	
Annual Site Inspection	1	EA	\$ 10,000	\$ 10,000	Golder Estimate	
Annual Dust Control Report	1	EA	\$ 2,000	\$ 2,000	Golder Estimate	
Other Potential CCR Reporting Requirements/Updates	1	EA	\$ 4,600	\$ 4,600	Golder Estimate	
Final Cover Repair	1	EA	\$ 16,200	\$ 16,200	Golder Estimate	2% of cover area, 12" growth medium/topsoil fill
Seeding Repair	1	EA	\$ 15,800	\$ 15,800	Golder Estimate	10% of cover area
Mowing and/or rodent, weed, & tree control	1	EA	\$ 6,300	\$ 6,300	Golder Estimate	\$2,000 per 25 acres
Surface Water Controls Maintenance	1	EA	\$ 26,700	\$ 26,700	Golder Estimate	1% of armored channel replaced + other repairs
Gate and/or fence Maintenance	1	EA	\$ 3,100	\$ 3,100	Golder Estimate	1% of fence
Recordkeeping	1	EA	\$ 4,700	\$ 4,700	Golder Estimate	\$1,500 per 25 acres
Direct Expenses	1	EA	\$ 15,800	\$ 15,800	Golder Estimate	\$5,000 per 25 acres
<b>Annual Operations &amp; Maintenance Costs (not haul and place)</b>						
			Total	\$ 396,130	\$	396,000
CCR Groundwater Monitoring & Reporting	1	EA	\$ 25,000	\$ 25,000	Golder Estimate	
Update CCR Baseline, Network Cert., and Statistical Method Cert. As Needed	1	EA	\$ 24,000	\$ 24,000	Golder Estimate	
Annual Site Inspection	1	EA	\$ 10,000	\$ 10,000	Golder Estimate	
Annual Dust Control Report	1	EA	\$ 2,000	\$ 2,000	Golder Estimate	
Other Potential CCR Reporting Requirements/Updates	1	EA	\$ 4,600	\$ 4,600	Golder Estimate	
Engineering Support	1	EA	\$ 144,000	\$ 144,000	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	\$ 3,130	\$ 3,130	Golder Estimate	1% of fence
Recordkeeping	1	EA	\$ 14,400	\$ 14,400	Golder Estimate	\$5,000 per 25 acres
Misc Work (contact water, dust, erosion, grading, etc)	1	EA	\$ 144,000	\$ 144,000	Golder Estimate	\$50,000 per 25 acres
<b>Haul &amp; Place Costs</b>						
Haul Cost	1	CY	\$ 3.30	\$ 3.30	31 23 23.20-8180 RSMeans 2019 Bismarck	60cy Off-road, 20 min wait, 15 mph, 2 mile cycle
Haul Cost	1	TON	\$ 3.30	\$ 3.30	Golder Estimate	75pcf haul density (1 ton/cy)
Place Cost	1	CY	\$ 1.90	\$ 1.90	31 23 23.17-0020 RSMeans 2019 Bismarck	Dozer, no compaction
Place Cost	1	TON	\$ 2.30	\$ 2.30	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	\$ 864,616	\$	865,000
<b>General</b>						
Mobilize/Demobilize	5%	%	\$ -	\$ 20,340		
Miscellaneous Site Work & Materials	5%	%	\$ -	\$ 20,340		Erosion controls, offices, toilets, temporary roads, survey control, etc.
<b>Civil</b>						
Road Topsoil Stripping and Stockpiling	3,800	CY	\$ 2.64	\$ 10,032	Crew analysis, dozer work	18" topsoil
Access Road Construction	197,400	SF	\$ 1.47	\$ 290,178	32 11 23.23 RS Means 2019 Bismarck	8" thick, Crushed 1-1/2"stone base, compacted to 4" deep, 5,640' x 35'
Return Water Pipeline						
Trench Excavation	8,800	CY	\$ 2.94	\$ 25,911	Crew analysis	
6" Pipeline	5,890	LF	\$ 12.00	\$ 70,680	33 14 13.35 RS Means 2019 Bismarck	
Misc. Appurtenances	1	EA	\$ 10,000.00	\$ 10,000		
Pipe Bedding & Embedment	1,800	CY	\$ 4.99	\$ 8,974	Crew analysis	
Trench Backfill	6,100	CY	\$ 3.59	\$ 21,922	Crew analysis	
Topsoil	900	CY	\$ 3.52	\$ 3,168	Crew analysis	
Marking Tape	5,890	LF	\$ 0.10	\$ 589	Underground Warning tape - via web search	
Tracer Wire	5,890	LF	\$ 0.20	\$ 1,178	14 gauge burial wire - via web search	
Fence	9,044	LF	\$ 28.23	\$ 255,304	32 31 13.20 RS Means 2019 Bismarck	6' Chain link fence, 3 strands barb wire
Overhead Power (Plant to Landfill)	1	EA	\$ 90,000	\$ 90,000	RS Means 2019 Bismarck 33.71.39.13.0150 33.71.16.33.5060	Pipeline length + 20% One utility pole every 200 feet
Monitoring Well Installation	6	EA	\$ 6,000	\$ 36,000	Golder Estimate	
County Road Crossing			Total	\$ 1,886,520	\$	1,887,000
<b>General</b>						
Mobilize/Demobilize	5%	%	\$ -	\$ 85,751		
Misc. (erosion controls, toilets, etc)	5%	%	\$ -	\$ 85,751		Erosion controls, offices, toilets, temporary roads, survey control, etc.
<b>Civil</b>						
Topsoil Stripping and Stockpiling	4,577	CY	\$ 2.64	\$ 12,083	Crew analysis, dozer work	18" topsoil
Embankment Fill	5,776	CY	\$ 6.49	\$ 37,510	Crew analysis	
County Road Base Course	32,200	SF	\$ 2.13	\$ 68,586	32 11 23.23 RS Means 2019 Bismarck	12" Gravel base course Crushed 1-1/2"stone base, compacted to 4" deep
County Road Asphalt Pavement	3,578	SY	\$ 35.45	\$ 126,838	RSMeans 2019, Bismarck 32 12 16.13.1595 32.12.16.13.1460 31.23.23.20.1114	2" Binder Course 4" Wearing Course
Bridge Deck Construction	4,900	SF	\$ 300	\$ 1,470,000	2016 California DOT cost range	140 ft bridge deck, 35 ft wide
Liner Construction			Total	\$ 8,803,611	Cost Per Acre of Liner	\$ 241,000
<b>General</b>						
Mobilize/Demobilize	5%	%	\$ -	\$ 400,164		
Miscellaneous Site Work & Materials	5%	%	\$ -	\$ 400,164		Erosion controls, offices, toilets, temporary roads, survey control, etc.
<b>Civil</b>						
Clearing and Grubbing	49	AC	\$ 4,500.00	\$ 220,500	31 11 10.10 RS Means 2019 Bismarck	Clear & grub brush including stumps
Topsoil Stripping & Stockpiling (18")	-	CY	\$ 2.64		Crew analysis	
	49	AC	\$ 6,389	\$ 313,051		
Subgrade Cut to Stockpile	471,000	CY	\$ 5.62	\$ 2,647,856	Crew analysis	10' deep cut across liner area: for liner, berms and cover
Subgrade Cut/Embankment Fill	117,867	CY	\$ 6.49	\$ 765,404	Crew analysis	612 ft2 cross section area
Low Permeability Soil Liner (24")	-	CY	\$ 6.56		Crew analysis	
	37	AC	\$ 21,161	\$ 772,394		
60-mil HDPE Liner	-	SF	\$ 0.75		Recent construction	Materials, waste, conformance testing, installation
	37	AC	\$ 32,670	\$ 1,192,455		
Leachate Collection Layer, Sand (12")	-	CY	\$ 29.70		Crew analysis for haul/place from Bismarck	
	37	AC	\$ 47,916	\$ 1,748,934		
Protective Cover (3')	-	CY	\$ 6.33		Crew analysis	Fly ash as protective cover
	9	AC	\$ 30,626	\$ 279,462		Contractor place 25% of liner area (side slopes, haul routes)
<b>Piping</b>						
LCS 4" Piping	7,060	LF	\$ 3.92	\$ 27,675	33 42 11.50 RS Means 2019 Bismarck	4" Corrugated HDPE
LCS 8" Piping	1,150	LF	\$ 7.78	\$ 8,947	33 42 11.50 RS Means 2019 Bismarck	8" Corrugated HDPE
LCS Sump/Riser	1	EA	\$ 20,000	\$ 20,000	Golder Estimate	
<b>Equipment and Electrical</b>						
Power Posts at Pumps/Sumps	1	EA	\$ 1,605	\$ 1,605	26 24 16.30-0150 RS Means 2019 Bismarck	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	\$ 7,919,961	Cost Per Acre of Cover	\$ 198,000
General						
Mobilize/Demobilize	5%	%	\$ -	\$ 359,998		
Miscellaneous Site Work & Materials	5%	%	\$ -	\$ 359,998		Erosion controls, offices, toilets, temporary roads, survey control, etc.
Civil						
Leveling Fill (6")	-	CY	\$ 6.49		Crew analysis	Stockpile cut to embankment fill
	40	AC	\$ 5,238	\$ 209,534		
Compacted Low Permeability Soil Liner (24")	-	CY	\$ 6.56		Crew analysis	Stockpile cut to embankment fill
	40	AC	\$ 21,161	\$ 846,459		
60-mil HDPE Liner	-	SF	\$ 0.75		Recent construction	Materials, waste, conformance testing, installation
	40	AC	\$ 32,670	\$ 1,306,800		
Drainage Layer, Sand (12")		CY	\$ 29.70		Crew analysis for haul/place from Bismarck	
	40	AC	\$ 47,916	\$ 1,916,640		
Growth Medium (30")		CY	\$ 6.34		Crew analysis	
	40	AC	\$ 25,578	\$ 1,023,110		
Topsoil (6")		CY	\$ 6.34		Crew analysis	
	40	AC	\$ 5,116	\$ 204,622		
Downchute Channels	80,640	SF	\$ 20.00	\$ 1,612,800	Golder Estimate	36' wide, 4 downchutes
Seed and Mulch	40	AC	\$ 2,000	\$ 80,000	32 92 19.14-4600 RS Means 2019 Bismarck	Seed, mulch & fertilizer, hydro or air seeding
Post Closure Care			Total	\$ 120,100	\$	120,000
CCR Groundwater Monitoring & Reporting	1	EA	\$ 25,000	\$ 25,000	Golder Estimate	
Update CCR Baseline, Network Cert., and Statistical Method Cert. As Needed	1	EA	\$ 24,000	\$ 24,000	Golder Estimate	
Annual Site Inspection	1	EA	\$ 10,000	\$ 10,000	Golder Estimate	
Annual Dust Control Report	1	EA	\$ 2,000	\$ 2,000	Golder Estimate	
Other Potential CCR Reporting Requirements/Updates	1	EA	\$ 4,600	\$ 4,600	Golder Estimate	
Final Cover Repair	1	EA	\$ 8,200	\$ 8,200	Golder Estimate	2% of cover area, 12" growth medium/topsoil fill
Seeding Repair	1	EA	\$ 8,000	\$ 8,000	Golder Estimate	10% of cover area
Mowing and/or rodent, weed, & tree control	1	EA	\$ 3,200	\$ 3,200	Golder Estimate	\$2,000 per 25 acres
Surface Water Controls Maintenance	1	EA	\$ 22,100	\$ 22,100	Golder Estimate	1% of armored channel replaced + other repairs
Gate and/or fence Maintenance	1	EA	\$ 2,600	\$ 2,600	Golder Estimate	1% of fence
Recordkeeping	1	EA	\$ 2,400	\$ 2,400	Golder Estimate	\$1,500 per 25 acres
Direct Expenses	1	EA	\$ 8,000	\$ 8,000	Golder Estimate	\$5,000 per 25 acres
Annual Operations & Maintenance Costs (not haul and place)			Total	\$ 246,450	\$	246,000
CCR Groundwater Monitoring & Reporting	1	EA	\$ 25,000	\$ 25,000	Golder Estimate	
Update CCR Baseline, Network Cert., and Statistical Method Cert. As Needed	1	EA	\$ 24,000	\$ 24,000	Golder Estimate	
Annual Site Inspection	1	EA	\$ 10,000	\$ 10,000	Golder Estimate	
Annual Dust Control Report	1	EA	\$ 2,000	\$ 2,000	Golder Estimate	
Other Potential CCR Reporting Requirements/Updates	1	EA	\$ 4,600	\$ 4,600	Golder Estimate	
Engineering Support	1	EA	\$ 73,000	\$ 73,000	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	\$ 2,550	\$ 2,550	Golder Estimate	1% of fence
Recordkeeping	1	EA	\$ 7,300	\$ 7,300	Golder Estimate	\$5,000 per 25 acres
Misc Work (contact water, dust, erosion, grading, etc)	1	EA	\$ 73,000	\$ 73,000	Golder Estimate	\$50,000 per 25 acres
Haul & Place Costs						
Haul Cost	1	CY	\$ 3.30	\$ 3.30	31 23 23.20-8180 RSMeans 2019 Bismarck	60cy Off-road, 20 min wait, 15 mph, 2 mile cycle
Haul Cost	1	TON	\$ 3.30	\$ 3.30	Golder Estimate	75pcf haul density (1 ton/cy)
Place Cost	1	CY	\$ 1.90	\$ 1.90	31 23 23.17-0020 RSMeans 2019 Bismarck	Dozer, no compaction
Place Cost	1	TON	\$ 2.30	\$ 2.30	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	\$	2,021,053	\$	2,021,000
	Miscellaneous Site Work & Materials	10%	%	\$ -	\$ 183,732		Erosion controls, offices, toilets, temporary roads, survey control, etc.
	Silo slab on grade	1	EA	\$ 827,470	\$ 827,470	2003 Irondale CO Unit less RR & land	Site prep, silo & handling equipment, permit
	Starvac reclaimers	1	EA	\$ 90,439	\$ 90,439		
	Truck scale	1	EA	\$ 88,293	\$ 88,293		Beside the silo on grade
	Screw conveyor	1	EA	\$ 26,687	\$ 26,687		From Starvac reclaimers to bucket elevator
	Bucket Elevator	1	EA	\$ 96,370	\$ 96,370		From screw conveyor to overhead airslide
	Air Slide	1	EA	\$ 29,158	\$ 29,158		From bucket elevator to new weigh hopper
	Truck load-out spout	1	EA	\$ 49,420	\$ 49,420		From new weigh hopper to truck
	Building	1	EA	\$ 12,355	\$ 12,355		With scales and ASM controls
	Feed piping & valves	1	EA	\$ 385,713	\$ 385,713	Golder Estimate	From each of the four fly ash conveying lines
	Dust collectors	1	EA	\$ 231,417	\$ 231,417	Golder Estimate	Higher capacity to handle high air flow from ESP
Cal-Hypo Feed System (Rail Load-out Silo)			Total	\$	288,181	\$	288,000
	Miscellaneous Site Work & Materials	10%	%	\$ -	\$ 26,198		
	Storage & Conveying Building	1,000	SF	\$ 58.58	\$ 58,583	GRE 2009 Construction Project	\$35/sf for large insulated bldg, use \$50/sf
	Building Foundation	62	CY	\$ 351.50	\$ 21,793	Worley Parsons Jul09	12' x 40' x 1' thick plus 1' x 5' perimeter
	Day Storage Hopper	1	EA	\$ 17,575	\$ 17,575	Golder Estimate	On the silo weigh bin floor
	Conveying System	1	EA	\$ 23,433	\$ 23,433	Golder Estimate	From storage building to the day storage hopper
	Variable speed conveyor	1	EA	\$ 23,433	\$ 23,433	Golder Estimate	To feed cal-hypo into the existing weigh hopper
	ASM System Controls	1	EA	\$ 117,166	\$ 117,166	Golder Estimate	
Cal-Hypo Feed System (New Truck Load-out Silo)			Total	\$	384,843	\$	385,000
	Miscellaneous Site Work & Materials	10%	%	\$ -	\$ 34,986		
	Weigh Hopper	1	EA	\$ 87,874	\$ 87,874	Golder Estimate	Above truck load-out spout
	Storage & Conveying Building	1,000	SF	\$ 58.58	\$ 58,583	GRE 2009 Construction Project	\$35/sf for large insulated bldg, use \$50/sf for 25'x40'
	Building Foundation	62	CY	\$ 351.50	\$ 21,793	Worley Parsons Jul09	25' x 40' x 1' thick plus 1' x 5' perimeter
	Day Storage Hopper	1	EA	\$ 17,575	\$ 17,575	Golder Estimate	On the silo weigh bin floor
	Conveying System	1	EA	\$ 23,433	\$ 23,433	Golder Estimate	From storage building to the day storage hopper
	Variable speed conveyor	1	EA	\$ 23,433	\$ 23,433	Golder Estimate	To feed cal-hypo into the existing weigh hopper
	ASM System Controls	1	EA	\$ 117,166	\$ 117,166	Golder Estimate	

Historic prices have been escalated 2% per year from original price date to 2019.



**[golder.com](http://golder.com)**

## Attachment C

Report "Ammonia Slip Mitigation for SNCR Impacted Ash at the Coal Creek Station" March 22, 2019; Boral Resources

March 22, 2019

## **Ammonia Slip Mitigation for SNCR Impacted Ash at the Coal Creek Station**

### **Introduction**

The contamination of fly ash with ammonia is a major concern for the marketability of ash for beneficial use in concrete. Although, ammoniated fly ash causes no detrimental effects to the durability of concrete, it poses safety concerns for workers pouring, placing and finishing fresh concrete. When placed in the high alkaline concrete slurry, ammoniated fly ash creates unpleasant and noxious ammonia gas odor that impacts the workers handling fresh concrete and concrete products. Exposure to ammonia in high concentrations is considered a health hazard to concrete workers as it can irritate or burn skin, mouth, throat, lungs and eyes. In very high dosages, ammonia gas can damage lungs or cause death. The presence of ammonia in ash at coal-fired plants and their disposal facilities can also create the potential for exposing power plant workers to this noxious gas. It also creates the potential for its release to air and water.

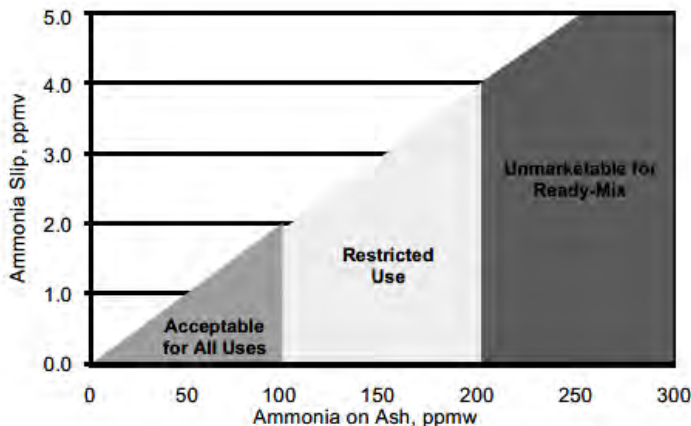
### **Ammonia in Ash from SNCR Systems**

Ammonia-based environmental control technologies such as SCR and SNCR's are used to reduce NOx emissions from coal-fired power units. Ammonia/NOx redox reactions are not 100% complete and result in excess ammonia in flue gas. The excess ammonia gas, known as ammonia slip, reacts with other flue gas species, primarily SO<sub>3</sub>, to form an ammonium salt solid deposit (NH<sub>4</sub>SO<sub>3</sub>) that is collected with the fly ash. The ammonium salt content of the ash depends on the ammonia slip, the SO<sub>3</sub> levels and other flue gas parameters such as acidity, temperature, etc. Typically, SNCR units have resulted in higher levels of ammonia in ash than SCR units.

A study performed by EPRI in 2007 reviewed eight units fueled with PRB/eastern bituminous coal blends where SNCRs systems had been installed and were in operation. The units were small and had ammonia slip up to 5 ppm. Four of the units had ammonia in the fly ash data ranging from less than 100 ppm to over 200 ppm. (EPRI 2007). Other studies suggest that 2 ppm ammonia slip may result in fly ash ammonia levels from less than 50 to several hundred mg/kg (Murarka 2003, Bittner 2001, Hinton 2012, Larrimore 2002). There is no published information for SNCR ammonia gas slip levels from lignite powered units.

For the Coal Creek units, Fuel Tech is quoting ammonia in ash levels at less than 20 mg/kg for 2 ppm slip and less than 100 mg/kg for 10 ppm slip for full load steady state operations. These estimated ammonia-in-ash levels relative to slip in flue gas do not correspond to literature values. In fact, the chart included herein, created by Larrimore (2002) and based on literature reviews and operating plant data, indicates that ammonia slip levels of 2 ppm can lead up to 100 mg/kg of ammonia in ash while a slip of 10 ppm could lead up to 500 mg/kg making the ash “unmarketable” for use in ready mix concrete.

The ammonia slip level from SNCR systems is highly dependent on the ammonia injection rate, NO<sub>x</sub> reduction efficiency, plant load, reaction zone temperature and other unit specific flue gas parameters. Although the coal fired units at the Coal Creek station were designed for baseload service, they are expected to cycle depending on electric power demand and economic dispatch. Load cycling which includes ramping up or down and heat-up and cool-down of the units impart significant variability to the performance of the reaction-temperature sensitive SNCR. Load cycling is expected to result in significant variability in ammonia slip and ammonia in ash levels. Accurate and reliable ammonia slip and ash contamination levels can only be determined by a full scale SNCR demonstration and modeling of the specific fuel/unit.



### Acceptable Levels of Ammonia in Ash

The ammonium salt present in the ash is rapidly converted to ammonia gas once the ash is exposed to the high pH concrete mixture. Ammonium salts are converted to ammonia gas at high pH (>10). Concrete mixtures can easily reach a pH of 12-13 within seconds of adding water to hydrate the cement. Mixing of concrete containing ammoniated ash will result in ammonia gas evolution from the mixer and during concrete pouring, placing and finishing. Ammonia gas evolution continues after placement of fresh concrete. Undesirable ammonia odor can linger after the hardening of concrete products in enclosed applications.

Exposure to ammonia gas evolving from concrete mixers or job sites is a health and safety risk. Exposure to mild levels of ammonia odors can generate unpleasant conditions for concrete workers that can result in undesirable finish and poor workmanship. The presence of even milder ammonia odor in residential/commercial concrete (indoor walls or slabs) would expose concrete producers, contractors, fly ash marketers and source utilities to potential product quality and health risk claims. Such claims of “poor” quality or potential long risk exposure from mild unpleasant odors would significantly impact ash sales in residential concrete markets.

There is no definitive ammonia limit for fly ash used in concrete since the factors affecting workers exposure are highly dependent on the amount of ash used in concrete and the environment where fly ash concrete is produced, placed and finished. When ammoniated fly ash concrete is placed in an open environment, personnel are rarely subjected to a time-weighted-average-permissible exposure limit exceeding 50 ppm if the ammonia in ash is less than 100 mg/kg. However, in a closed environment with restricted ventilation the same ammonia in ash level can result in exceeding both OSHA and NIOSH time-weighted-average-permissible exposure limits 50 ppm/20 ppm respectively. (Schert 2013)

Based on studies from the University of Kentucky funded by DOE, Electric Power Research Institute (EPRI) suggests the recommended limit of  $\text{NH}_3$  is 200 mg/kg for fly ash used in concrete placed in well vented areas, in non-vented areas, the recommended limit is 100 mg/kg (Rathbone 2003). These limits are based on 15% ash replacement of cement, which is typical for ash derived from the combustion of eastern bituminous coal. When doubling the fly ash replacement to 30%, which is common with high quality ash such as the Coal Creek ash, the allowable ammonia content in fly ash will need to be reduced by 50% to 100 mg/kg and 50 mg/kg, respectively.

FDOT and other state agencies have concluded, if specifications are needed, an upper limit of 100 mg/kg would be protective of human health for most situations, and achievable under most circumstances (Schert 2012). It is Boral Resources policy to reject fly ash containing more than 100 mg/kg. However, fly ash products are marketed for use in various concrete products and applications. The amount of ash used in a concrete mixture also varies depending on the ash pozzolanic reactivity, specified concrete mixture, ambient temperature and other concrete product parameters.

Boral Resources and its concrete-producing customers do not know the intended application of all concrete products or the environment where the concrete is placed. Ammonia in ash contents of less than 100 mg/kg are sometimes requested by customers for the purpose of protecting their workers environment or to reduce the risk of customers' claims. Boral Resources complies with special customers request and periodically notifies customers with  $\text{NH}_3$  in ash tests

results. Although, the 100 mg/kg threshold has been established based on research and general practice, in some ash markets such as MI/OH, Boral had to lower acceptable ammonia concentration to 75 mg/kg based on market feedback and customers' requests (concrete producers).

Rejected fly ash contaminated with unacceptable levels of ammonia is typically discarded in the landfill. Risks associated with the release and exposure at the utility fly ash landfill and handling systems are discussed elsewhere.

### **Economic impact of ammoniated ash**

The direct cost impacts resulting from ammoniated ash include: lost revenue to GRE from fly ash sales by Boral, incremental ash disposal costs and the costs of long-term monitoring associated with the disposed ash. The direct cost impacts are discussed elsewhere. Other economic impacts include externalities of lost opportunity values related to; carbon emissions offset, additional sustainability benefits of reduced cement content Concrete durability benefits for using fly ash.

The Environmental impact of carbon emissions offset equal to 0.72 metric tons of avoided CO<sub>2</sub> equivalent emissions per ton of ash replacing cement in concrete. This is based on U.S. Environmental Protection Agency Report to Congress EPA530-R-08-007, June 3, 2008, page 3-11. Assuming potential future adoption of an accessible carbon tax or cap and trade program, the monetary value of carbon offsets is \$16.30 per ton. This value is based on California Carbon Allowance Futures pricing on January 15, 2019, for 2018 vintage offsets deliverable December 2019. Based on the same EPA Report to Congress, the other sustainability benefits of using fly ash to replace cement in concrete include; reduced water use by 379 liters per ton of ash and reduced energy consumption by 4,695 megajoules per ton of ash.

The benefits of fly ash use in concrete include; increasing higher ultimate strength, reducing permeability and corrosion of embedded steel, mitigating deleterious alkali aggregate reactions and increase concrete resistance to sulfate and other chemical attacks.

The Economic Impacts of Prohibiting Coal Fly Ash Use in Transportation Infrastructure Construction was evaluated by the American Road and Transportation Builders Association. Based on their September 2011 report, the economic impact of durability was estimated at \$478 per ton of ash replacing cement in concrete for transportation projects.



**Beneficiation of ammoniated fly ash**

Boral has a chemical treatment technology that was developed to address moderate levels (<200 mg/kg) of ammonia in ash. The chemical treatment process, known as Ammonia Slip Mitigation (ASM), has been deployed at two power plants 1) the eastern bituminous fired units (4@ 253 MW total nameplate capacity) of Rochester Gas & Electric Russell Station – in this plant, ASM was used to treat an average of 3 truck-loads of ash per day with a total annual marketable ash production of about 10,000 tons; and 2) The East Lake station in Ohio - ASM was deployed to treat fly ash generated from a 600 MW unit burning a 50/50 blend of powder River Basin and Eastern Bituminous Coals. These plants used ASM to lower the ammonia in ash levels from up to 150 ppm to less than 50 ppm. Ammonia concentrations over 150 ppm were diverted to disposal. Higher levels of ammonia were also accompanied by wide variability, an issue that could not be solved by ASM.

The ASM technology requires robust quality control efforts to frequently test the ammonia in ash level to assure adequate treatment. Heightened quality control efforts were relatively simple to deploy at the above referenced small plants with low ash load-out rates.

ASM consists of adding a strong oxidizer, calcium hypochlorite, in powder form to the ash during load-out from the silo into a truck. The reagent is used to neutralize (oxidize) the ammonia once the ash gets wet in a concrete mixer. This approach works well with consistent and moderate ammonia levels. Higher ammonia levels and associated high reagent additions would lead to high levels of chlorides in concrete which is limited by many specifications. The ASM technology has not been demonstrated to deal with ammoniated ash at large power plant units requiring potentially complex quality control program.

Another commercially proven approach was developed by STI. It consists of wetting the ash and adding  $\text{Ca}(\text{OH})_2$  to rapidly raise the pH to strip the ammonia then dry the ash. This approach has been deployed for low CaO eastern bituminous derived ash at a powerplant in Tampa. However, this chemical stripping of ammonia is not feasible for Coal Creek ash since it would increase the ash CaO content limiting its use in the market. It would require about 10% of lime by weight of ash to raise the pH to 12 for effective stripping. The 10% lime addition will drive the CaO content of the Coal Creek above 20%, making it not suitable for use in DOT specified projects to enhance durability of concrete.

Inconsistent and high levels of ammonia in ash from SNCR units can be thermally removed from the ash to maintain an effectively safe program for the beneficial use of ash in concrete. The state-of-the art thermal removal of ammonia from ash has not been commercially demonstrated. It requires a

significant capital investment for the thermal reactor, cooler, bag house and other ancillary equipment. Energy from the boiler or natural gas will be needed to raise the ash temperature for effective stripping of ammonia. The operating temperature will depend the ammonium salt species found in the ash. Temperatures ranging from 800 to 1400 °F have been cited as effective to remove ammonia from fly ash. Pilot scale testing will be required to confirm ammonia stripping temperature and retention time. The stripped ammonia can be returned to the boiler or scrubbed. Balance of plant issues much also be evaluated.

The costs to deploy the Ammonia Slip Mitigation technology at GRE Coal Creek Station was developed by Golder Associates in 2011 and updated in March 2019. The estimates were based on their review of the East Lake installation scaled up for deployment at the Coal Creek Station. The 2019 updates adequately cover the costs of ASM system installations and ancillary equipment such as a new truck load out silo dedicated for the ASM system and installing a second ASM system at the existing rail loadout silo. The ASM system at Coal Creek would be used to treat ash containing less than 150 mg/kg. Fly ash containing more than 150 mg/kg would be diverted to disposal via existing silos. The Golder 2019 updated study also includes the operating and maintenance costs associated with the use of the ASM technology to treat the ash.

It's very difficult to estimate the annual quantity of fly ash that would contain less than 150 mg/kg of ammonia and be suitable for treatment using ASM. This is due to the inherent site-specific performance capabilities of SNCR and variabilities expected by load cycling.

## **References**

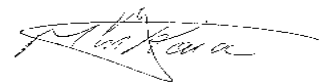
L. Larrimore, "Effects of ammonia from post-combustion NOx control on ash handling and use," Southern Company, Birmingham, 2002.

J. Schert, "Emerging worker safety concerns associated with the recycling of fly ash from coal-fired power plant in concrete mixtures," Transportation Research Information Services, 29 01 2013. [Online]. Available: <https://rms.trb.org/details/dproject.aspx?n=33398>.

R. Rathbone and T. Robl, "A study of the effects of post-combustion ammonia injection on fly ash quality: Characterization of ammonia release from concrete and mortars containing fly ash as a pozzolanic admixture," University of Kentucky Center for Applied Energy Research, Lexington, 2003.

J. Schert, T. Townsend and W. Chang-Yu, "Identification of potential concerns associated with FDOT use of ammoniated fly ash," Department of Environmental Engineering Science University of Florida, Gainesville, 2012.

ESI Inc of Tennessee, PMI Ash Technology Ammonia Reduction Facility. 2010



Rafic Minkara, Ph.D., P.E.



## Attachment D

Letter "Coal Creek Station Unit 2 NOx Emissions" March 5 2018 from  
GRE to the NDDEQ



12300 Elm Creek Boulevard  
Maple Grove, Minnesota 55369-4718  
763-445-5000  
greatriverenergy.com

March 5, 2018

**VIA ELECTRONIC**  
**AND U.S. MAIL**

Terry O'Clair  
Director, Division of Air Quality  
North Dakota Department of Health  
918 E. Divide Ave, 2nd Floor  
Bismarck, ND 58501-1947

RE: Coal Creek Station Unit 2 NOx Emissions

Dear Mr. O'Clair:

We understand that you have been working with the U.S. Environmental Protection Agency ("EPA") to finalize the phase I regional haze state implementation plan ("SIP") for North Dakota. In connection with these efforts, you asked Great River Energy to discuss the NOx emission rates at Coal Creek Station, Unit 2 ("CCS2"), particularly the relatively lower NOx emission rates that CCS2 has achieved in the last 12-24 months. This letter responds to that request.

In its amended SIP, the North Dakota Department of Health ("NDDH") proposed a best available retrofit technology ("BART") limit of 0.17 lbs/mmBtu on a 30-day rolling average for NOx at CCS2. This limit was based on Great River Energy's use of our DryFining™ process for the coal and the installation of LNC3+ low NOx burners on CCS2. Great River Energy is pleased with the performance of CCS2 following the application of these technologies. These technologies allowed us to appreciably reduce our NOx emission rate.

Great River Energy continues to believe that NDDH's proposed BART limit is appropriate for CCS2 and hopes that EPA will concur with NDDH's determination. Based on our experience with these technologies and expectations of future operation, we are concerned that NOx emission rates will continue to have high variability and increase in the future.

There are two primary factors that affect the NOx emission rate at CCS2: the sodium content of the coal and the load variability of the boiler. In recent months, the NOx emission rate has benefitted from higher sodium coal and relatively steady-state generation. As discussed in detail below, Great River Energy cannot depend on the continuation of these trends because we have little control over coal sodium content or load variability. Thus, the proposed NOx emission rate, 0.17 lbs/mmBtu over 30 days, remains appropriate for CCS2.

## **Lignite Sodium Content**

Lignite sodium content is a key variable that affects boiler operation and, as a result, NOx performance. CCS2 was designed for the use of local lignite coal. The design anticipated a certain amount of slagging on the boiler walls which affects the rate of heat absorption by the boiler walls in the area of the main fireball. The quantity of sodium in the coal has a pronounced impact on the amount of slagging: as sodium levels drop, less slagging occurs. When CCS2 burns low-sodium coal and less slagging occurs, there is much greater heat absorption in the lower zone of the boiler and less heat reaches the upper reheat and superheat zones of the boiler. This lowers unit efficiency and raises the heat rate. As a result, CCS2 must burn more coal to produce the same amount of electricity.

Great River Energy has little ability to counter the loss of efficiency caused by the combustion of lower sodium coal. First, Great River Energy cannot dictate different coal specifications because CCS2 is a mine-mouth facility and designed to burn the coal from that mine. The mine's ability to blend coal for various constituents is limited because it typically operates only one or two pits. While the sodium content varies across the seam, it is logistically impractical for the mine to stockpile coal from the same mine to achieve a consistently higher sodium content. Second, because CCS2 is designed to maximize efficiency, the burners automatically adjust in response to an imbalance in the heat distribution. Low temperatures in the super heat section of the boiler automatically cause the burners to tilt upwards to move more heat to the upper sections of the boiler. When this happens, the fireball is extended upwards within the boiler, changing the fuel-air mixture in that section of the boiler and increasing NOx emissions. The boiler operators have little ability to limit these automatic adjustments. Efforts to override the burner tilt controls adversely affect unit efficiency and emissions of NOx and other pollutants.

Figure 1, attached, demonstrates the impact of sodium on the NOx emission rate at CCS2. Figure 1 shows the sodium content of coal and the NOx emissions over a four-year period (2014-2017). The green line shows short-term sodium concentration; the blue line shows the long-term average sodium concentration; and the red line reflects the 30-day rolling average NOx emission rate. When sodium levels were low, particularly in the 2014-2015 time frame, the NOx emission rate was significantly higher, with several periods exceeding 0.17 lbs/mmBtu. As sodium levels increased starting in early 2016, the NOx emission rate began trending lower.

Even during periods when the average sodium levels were relatively high – above 3 percent – Great River Energy still observed significant short-term NOx variability, including several very high NOx spikes. This is because even short-term sodium variability impacts NOx emissions; even a one- or two-week pocket of low-sodium coal will drive up the NOx emission rate.

## **Load Variability**

Load variability also is a key factor that affects NOx rates at CCS2. CCS2 was designed as a baseload generating unit, operating in a steady-state, high-capacity mode. At a constant load, it is easier to manage and minimize NOx emissions. NOx emissions increase when CCS2 is required to ramp up and down based on demands from our independent system operator, Midcontinent Independent System Operator ("MISO").

When Great River Energy proposed the CCS2 BART limit to NDDH, we did not envision CCS2 becoming a load-following unit. However, the last decade has seen dramatic increases in renewable energy penetration in the MISO region. As a result, MISO has been increasingly requiring CCS2 to "chase load"

over extended periods. As an example, between 2012 and 2014 CCS2 operated in "low load" mode (30 - 40 percent of maximum capacity) less than 10 hours per year. In 2016, that increased to 249 hours. The amount of planned and announced wind development in the MISO region promises to increase this trend.

The impact of load shifts on NOx emission rates, particularly low-load and ramping operation, is demonstrated in Figures 2 and 3, also attached. Figure 2 depicts the direct, inverse relationship between load levels and NOx emission rates over a five-day period when sodium levels in the coal were low (<2 percent). The red line shows the hourly load levels; the dark blue line shows the hourly NOx emission rate; and the light blue line shows the 24-hr rolling average NOx rate over the period. The NOx emission rates (hourly and 24-hr average) were consistently above 0.2 lbs/mmBtu over this five-day period due to the combination of low sodium and high load variability.

Figure 3 shows a different period when the sodium levels were above 3 percent, where we would have expected NOx rates to be correspondingly lower. Instead, CCS2 experienced higher than expected NOx emission rates because of the highly variable load demands, with the 24-hr average rate hovering at or above 0.17 lbs/mmBtu. It takes only a few periods like that reflected in Figure 3 to drive the 30-day rolling average NOx emission rate above 0.17 lbs/mmBtu.

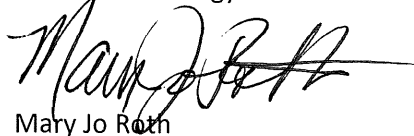
## Conclusion

CCS2 has achieved significant improvement in its NOx performance as a result of Great River Energy's DryFining™ process and the installation of LNC3+ burners. As Great River Energy works to ensure that we can achieve the proposed BART emission rate of 0.17 lbs/mmBtu, two variables – sodium content and load variability – will continue to be impediments and these variables are largely out of Great River Energy's control. Accordingly, Great River Energy hopes that EPA will concur with NDDH's determination that 0.17 lbs/mmBtu is an appropriate BART limit.

Please contact me at (763-445-5212) if you have any questions or wish to discuss any of the above.

Sincerely,

Great River Energy

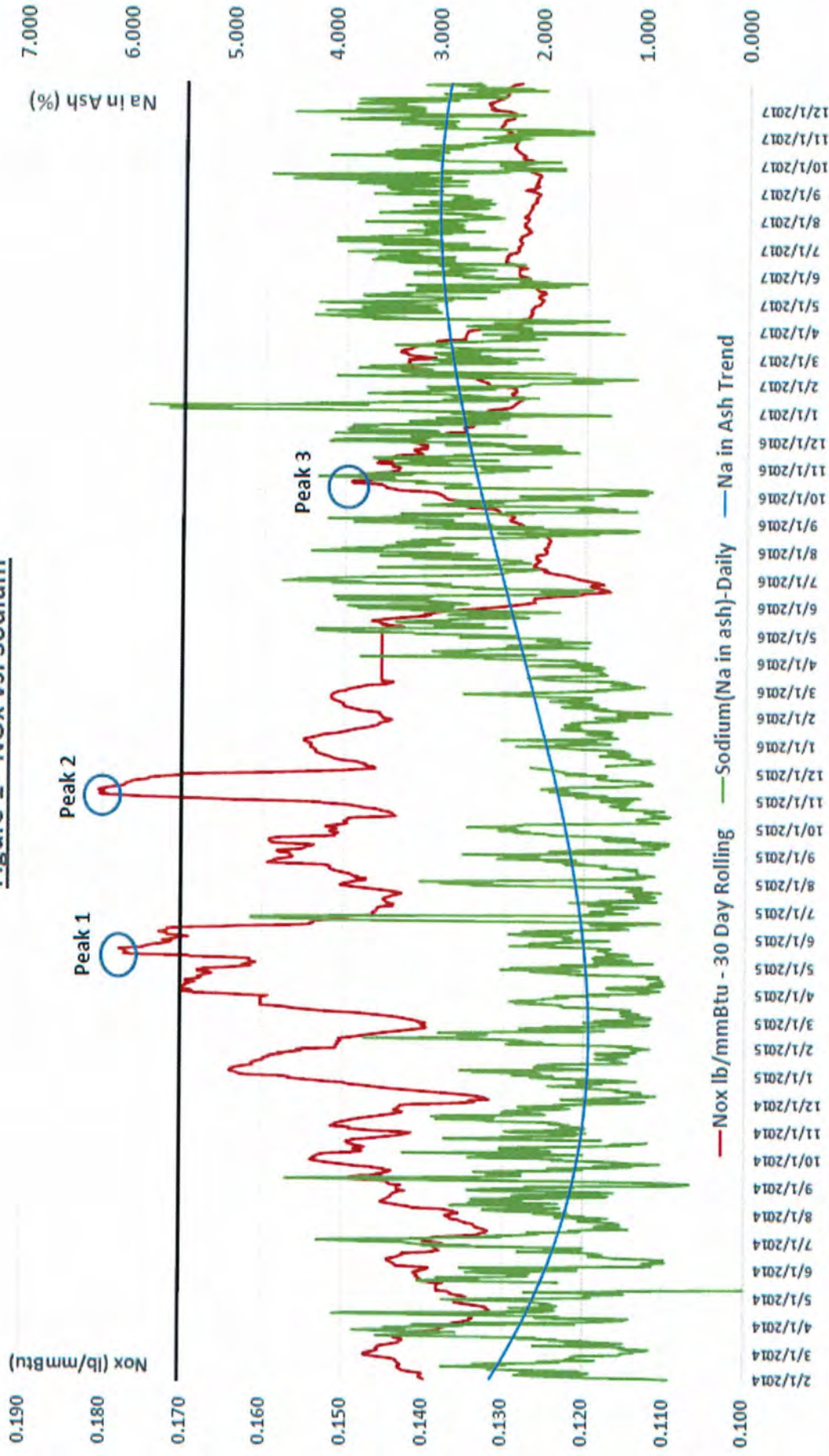


Mary Jo Roth  
Manager, Environmental Services

Attachments

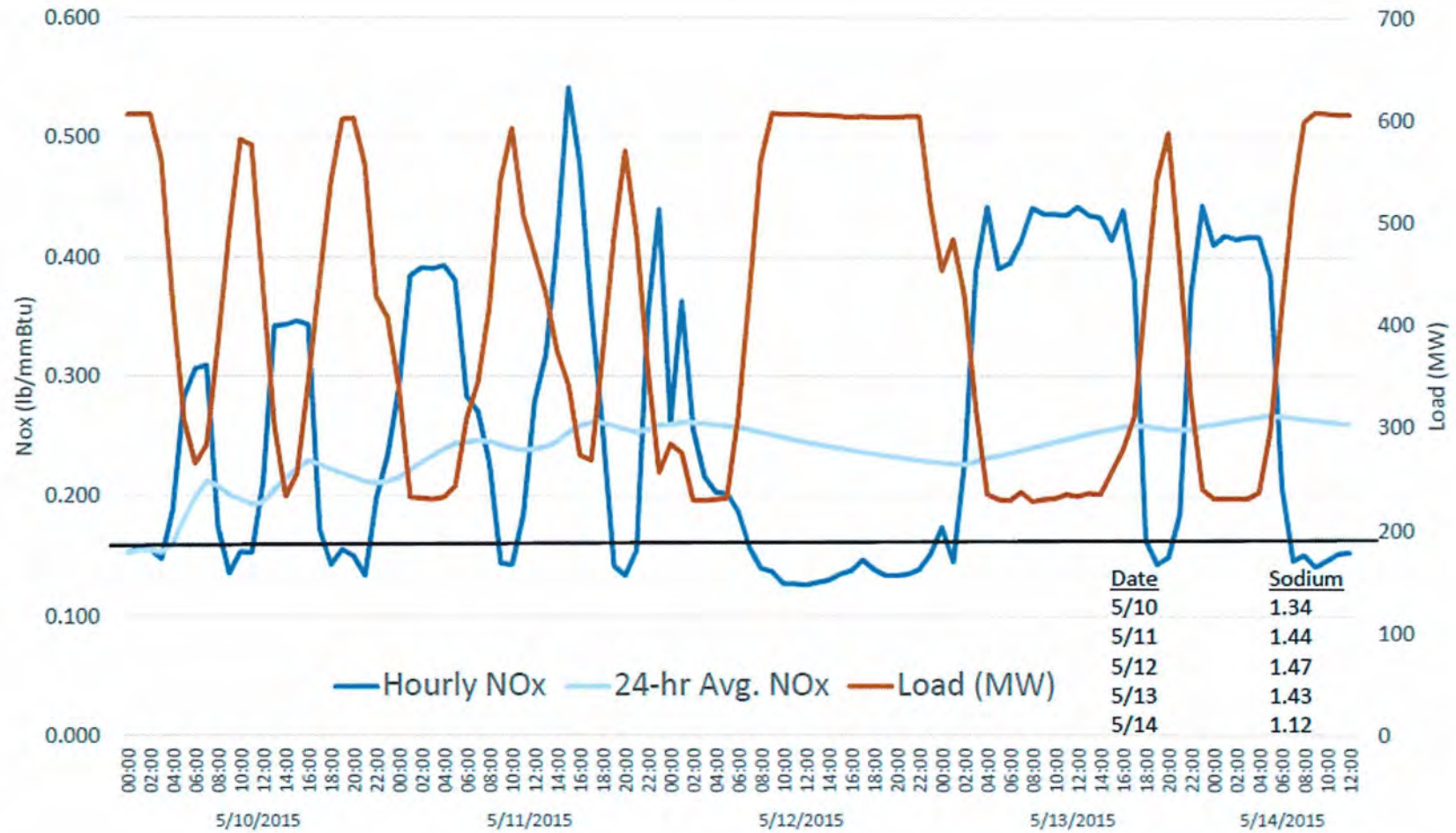


Figure 1 - NOx vs. Sodium

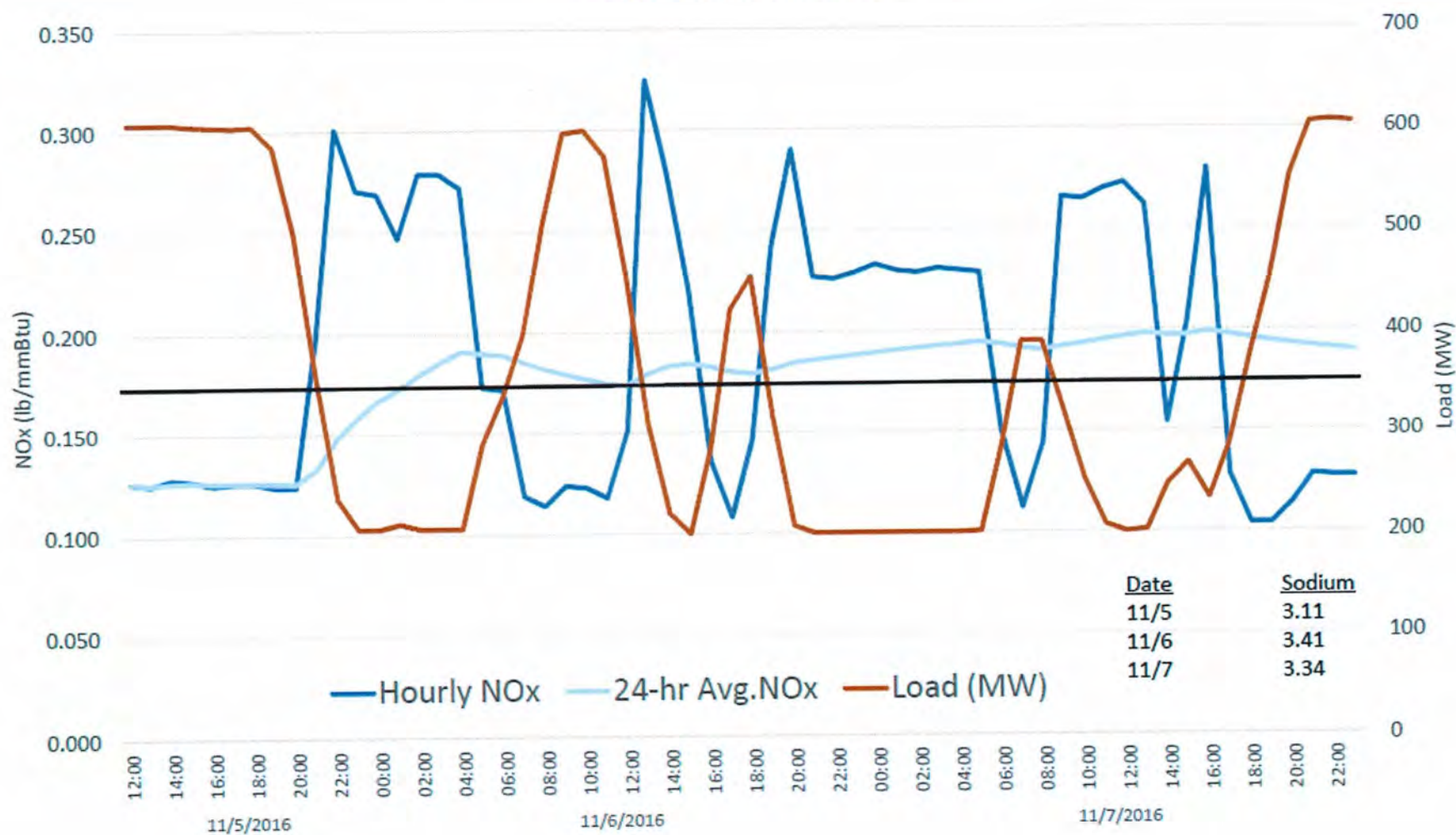




**Figure 2**  
**Peak 1 - NOx vs. Variable Load**  
**Low Sodium Coal**



**Figure 3**  
**Peak 3 - NOx vs. Variable Load**  
**High Sodium Coal**





## **Attachment E-1**

**Report "Protocol for BART-Related Visibility Impairment Modeling  
Analysis – Great River Energy – Coal Creek Station" July 2019; Barr  
Engineering Company**



**UNITED STATES ENVIRONMENTAL PROTECTION AGENCY  
REGION 8**

1595 Wynkoop Street  
Denver, CO 80202-1129  
Phone 800-227-8917  
[www.epa.gov/region8](http://www.epa.gov/region8)

Ref: 8ARD-PM

Mr. James L. Semerad  
Director, Division of Air Quality  
North Dakota Department of Environmental Quality  
918 E. Divide Avenue, 2nd Floor  
Bismarck, North Dakota 58501-1947

Dear Mr. Semerad:

On March 21, 2019, the North Dakota Department of Environmental Quality (NDDEQ) shared the *Protocol for BART-Related Visibility Impairment Modeling Analysis, Great River Energy Coal Creek Station (March 2019)* with the Environmental Protection Agency (EPA) by email for our review. The EPA provided comments on the protocol to NDDEQ in our letter dated April 8, 2019. Subsequently, on July 8, 2019, NDDEQ provided a revised protocol that addressed the concerns raised by the EPA, with the exception of the modeled scenarios and several other items detailed in the email sent by Aaron Worstell, of my staff, on July 10, 2019. On July 26, 2019, after further coordination between Great River Energy, NDDEQ, and the EPA, a final protocol was submitted to the EPA addressing these remaining concerns. With this letter, the EPA is approving the modeling methods and assumptions contained in the final modeling protocol.

In our comments of April 8, 2019, the EPA stated that the protocol did not provide enough detail to explain how the emission units and control scenarios will be combined in POSTUTIL and subsequently in CALPUFF (see item 31). The final protocol has largely addressed this concern. To ensure that the concern is fully addressed during implementation, we request that NDDEQ provide us with sample POSTUTIL input files prior to running the module to ensure that the configuration aligns with our preferred approach.

We understand that the protocol is intended to support a future State Implementation Plan (SIP) revision addressing Best Available Retrofit Technology requirements for nitrogen oxides at Coal Creek Station. Please note that we will only reach a final conclusion regarding the adequacy of the SIP revision when we act on the SIP submittal through notice and comment rulemaking.

We appreciate the opportunity to provide input on the modeling protocol. If you have any additional questions, please contact Aaron Worstell, of my staff, at 303-312-6073 or [worstell.aaron@epa.gov](mailto:worstell.aaron@epa.gov).

Sincerely,

8/7/2019

 Carl Daly

Signed by: CARL DALY

Carl Daly  
Acting Director  
Air and Radiation Division



## Attachment E-2

Approval Correspondence from US EPA Region 8 and NDDEQ for the  
BART Modeling Protocol; August 7 and 8, 2019



**From:** Stroh, David E. <[deStroh@nd.gov](mailto:deStroh@nd.gov)>  
**Sent:** Thursday, August 8, 2019 7:23 AM  
**To:** Archer, Gregory GRE-MG <[garcher@GREnergy.com](mailto:garcher@GREnergy.com)>  
**Cc:** Roth, Mary Jo GRE-MG <[mjroth@GREnergy.com](mailto:mjroth@GREnergy.com)>; Nelson, Debra GRE-MG <[dnelson@greenergy.com](mailto:dnelson@greenergy.com)>; Semerad, Jim L. <[jsemerad@nd.gov](mailto:jsemerad@nd.gov)>; Bachman, Tom A. <[tbachman@nd.gov](mailto:tbachman@nd.gov)>; Seligman, Angela N. <[aseligman@nd.gov](mailto:aseligman@nd.gov)>; Thorton, Rhannon T. <[rThorton@nd.gov](mailto:rThorton@nd.gov)>  
**Subject:** FW: Coal Creek Modeling Protocol

**EXTERNAL**

Morning Greg,

Attached you will find EPA's approval of the modeling protocol for the revised NOx BART analysis.

GRE CCS can proceed forward with the modeling as outlined. Let me know if you have any questions or comments.

Thanks,

**David Stroh**  
*Environmental Engineer*

701-328-5188 • [destroh@nd.gov](mailto:destroh@nd.gov)



918 E. Divide Ave. • Bismarck, ND 58501

---

**From:** Daly, Carl <[Daly.Carl@epa.gov](mailto:Daly.Carl@epa.gov)>  
**Sent:** Wednesday, August 7, 2019 4:40 PM  
**To:** Semerad, Jim L. <[jsemerad@nd.gov](mailto:jsemerad@nd.gov)>  
**Cc:** Worstell, Aaron <[Worstell.Aaron@epa.gov](mailto:Worstell.Aaron@epa.gov)>; Morales, Monica <[Morales.Monica@epa.gov](mailto:Morales.Monica@epa.gov)>  
**Subject:** Coal Creek Modeling Protocol

**CAUTION:** This email originated from an outside source. Do not click links or open attachments unless you know they are safe.

Jim

Please see attached, our letter approving the July 26, 2019 CALPUFF modeling protocol for the Coal Creek station.

Regards

Carl Daly, Acting Director  
Air and Radiation Division  
303-312-6416

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.



## Attachment F

### EPA RBLC Database Tables

Coal Creek Station Updated BART Review  
EPA RACT BACT LAER Clearinghouse Data Jan 2000 - Aug 2019  
NOx Controls on Large Coal Fired Boilers (>250 MMBtu/hr)  
NOx limts in lb/MMBtu

Highlighting Key	Average	Max	Min	Count
No Emission Controls Specified				
Comb Cont, LNB,OFA, etc	0.22	0.30	0.15	6
SNCR (PC Boiler)	0.36	0.36	0.35	2
CFB w SNCR	0.09	0.16	0.07	15
All SNCR	0.12	0.36	0.07	17
SCR	0.07	0.12	0.05	24

NOTE: Draft determinations are marked with a " \* " beside the RBLC ID.

RBLC ID	Facility Name	Corporate or Company Name	Facility State	Permit Number	NAICS Code	Permit Date	Facility Description	Process Name	Fuel	Through-put	Units	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	Case-by-Case Basis	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
AR-0074	PLUM POINT ENERGY	PLUM POINT ASSOCIATES, LLC	AR	1995-AOP-R0	221112	08/20/2003 ACT		BOILER - UNIT 1 - SN-01	SUB-BITUMINOUS COAL	800	MW	Nitrogen Oxides (NOx)	LOW NOX BURNERS + SCR (SCR not listed in RBLC, but specified in permit for facility 0.09 lb/MMBtu specified with SCR)	0.09	LB/MMBTU		BACT-PSD	0			0.09	LB/MMBTU	
AR-0079	PLUM POINT ENERGY	PLUM POINT ASSOCIATES, LLC	AR	1995-AOP-R0	221112	08/20/2003 ACT	PLUM POINT ENERGY ASSOCIATES, LLC (PERMITTEE) PROPOSES TO CONSTRUCT AND OPERATE A NOMINAL 550-800 MW COAL FIRED GENERATING STATION	BOILER - SN-01	SUB-BITUMINOUS COAL	800	MW	Nitrogen Oxides (NOx)	LOW NOX BURNERS + SCR (SCR not listed in RBLC, but specified in permit for facility 0.09 lb/MMBtu specified with SCR)	0.09	LB/MMBTU		BACT-PSD	0.09	LB/MMBTU		0		
AR-0094	JOHN W. TURK JR. POWER PLANT	SOUTHWEST ELECTRIC POWER COMPANY	AR	2123-AOP-R0	221112	11/05/2008 ACT	600 MW POWDER RIVER BASIN SUB-BITUMINOUS PULVERIZED COAL FIRED POWER PLANT	PC BOILER	PRB SUB-BIT COAL	6000	MMBTU/H	Nitrogen Oxides (NOx)	SELECTIVE CATALYTIC REDUCTION (SCR)	0.067	LB/MMBTU	24 HOUR ROLLING	BACT-PSD	0.05	LB/MMBTU	12 MONTH ROLLING	0		
AZ-0055	NAVAJO GENERATING STATION	SALT RIVER PROJECT AGRICULTURAL AND POWER DISTRICT	AZ	AZ 08-01	221112	02/06/2012 ACT	2,250 MW COAL FIRED POWER PLANT	PULVERIZED COAL FIRED BOILER	COAL	7725	MMBTU/H	Nitrogen Oxides (NOx)	LOW NOX BURNER (LNB), SEPARATED OVERFIRE AIR (SOFA) SYSTEM,	0.24	LB/MMBTU	30-DAY ROLLING AVG	BACT-PSD	0			0		
IA-0067	WALTER SCOTT JR. ENERGY CENTER	MIDAMERICAN ENERGY COMPANY	IA	PROJECT 02-528	221112	06/17/2003 ACT	utility	CBEC 4 BOILER	PRB COAL	7675	MMBTU/H	Nitrogen Oxides (NOx)	LOW NOX BURNERS, OVERFIRE AIR, AND SELECTIVE CATALYTIC REDUCTION	0.07	LB/MMBTU	30 DAY ROLLING AVERAGE	BACT-PSD	2353	T/YR		0.07	LB/MMBTU	30 DAY ROLLING AVERAGE
KS-0026	HOLCOMB UNIT #2	SAND SAGE POWER, LLC	KS	0550087/C-3855	221112	10/08/2002 ACT		BOILER, PULVERIZED COAL	COAL	660	MW	Nitrogen Oxides (NOx)	SCR, LOW NOX BURNERS, SEPARATED OVERFIRE AIR (SOFA)	0.12	LB/MMBTU	initial 18 months	Other Case-by-Case	0.08	LB/MMBTU	after initial 18 months	0.08	LB/MMBTU	
KY-0079	KENTUCKY MOUNTAIN POWER, LLC	KENTUCKY MOUNTAIN POWER, LLC	KY	V-00-045	221112	05/04/2001 ACT	ELECTRIC GENERATING STATION	BOILER, CIRCULATING FLUIDIZED BED UNITS 1 & 2	COAL	2550	MMBTU/H	Nitrogen Oxides (NOx)	SNCR	0.07	LB/MMBTU		Other Case-by-Case	0			0.07	LB/MMBTU	
KY-0084	THOROUGHbred GENERATING STATION	THOROUGHbred GENERATING COMPANY, LLC	KY	V-02-001	221112	10/11/2002 ACT	POWER PLANT	BOILER, COAL, (2)	COAL	7446	MMBTU/H	Nitrogen Oxides (NOx)	PROPER BOILER DESIGN, LOW NOX BURNERS, AND SCR	0.08	LB/MMBTU	30 day rolling avg	BACT-PSD	0			0.08	LB/MMBTU	
KY-0086	EAST KENTUCKY POWER COOP., INC./SPURLOCK POWER STA	EAST KENTUCKY POWER COOP., INC.	KY	V-97-050 (REVISION 1)	221112	08/04/2002 ACT	POWER PLANT	BOILER, CFB, COAL	COAL	2500	MMBTU/H	Nitrogen Oxides (NOx)	SELECTIVE NON CATALYTIC REDUCTION (SNCR) SYSTEM	0.07	LB/MMBTU	30 day rolling avg	BACT-PSD	0			0.07	LB/MMBTU	
MI-0389	KARN WEADOCK GENERATING COMPLEX	CONSUMERS ENERGY	MI	341-07	221112	12/29/2009 ACT	ELECTRICITY GENERATING FACILITY, EXISTING CAPACITY GREATER THAN 2,000 MW.	BOILER	PRB COAL OR 50/50 BLEND	8190	MMBTU/H	Nitrogen Oxides (NOx)	LOW NOX BURNER, OVER-FIRED AIR, SELECTIVE CATALYTIC REDUCTION.	0.05	LB/MMBTU	30-DAY ROLLING	BACT-PSD	409.5	LB/H	24-HOUR ROLLING	0		
MI-0399	DETROIT EDISON--MONROE	DETROIT EDISON	MI	93-09A	221112	12/21/2010 ACT	Utility--Coal fired power plant	Boiler Units 1, 2, 3 and 4	Coal	7624	MMBTU/H	Nitrogen Oxides (NOx)	Staged combustion, low-NOx burners, overfire air, and SCR.	0.08	LB/MMBTU	EACH, 12-MONTH ROLLING AVG.	BACT-PSD	222.6	T/MO	EACH, 12-MONTH ROLLING AVG.	0		
MI-0400	WOLVERINE POWER	WOLVERINE POWER SUPPLY COOPERATIVE, INC.	MI	317-07	221112	06/29/2011 ACT	Coal-fired power plant.	2 Circulating Fluidized Bed Boilers (CFB1 & CFB2) -	Petcoke/coal	3030	MMBTU/H each	Nitrogen Oxides (NOx)	SNCR (Selective Non-Catalytic Reduction)	0.07	LB/MMBTU	EACH, 30 D ROLLING AVG; BACT	BACT-PSD	0			0		
MO-0060	CITY UTILITIES OF SPRINGFIELD - SOUTHWEST POWER STATION	CITY UTILITIES OF SPRINGFIELD	MO	122004-007	221111	12/15/2004 ACT	CITY UTILITIES OF SPRINGFIELD HAS APPLIED FOR THE AUTHORITY TO INSTALL A 275 MW (2,724 MMBTU/H) PULVERIZED COAL BOILER AND ASSOCIATED MATERIAL HANDLING EQUIPMENT AT THEIR EXISTING SOUTHWEST POWER STATION. THE EXISTING	PULVERIZED COAL FIRED BOILER	COAL	2724	MMBTU/H	Nitrogen Oxides (NOx)	IT WAS DETERMINED THAT THE BACT FOR NOX FROM THE PULVERIZED COAL FIRED BOILER IS GOOD COMBUSTION PRACTICES ALONG WITH SCR HAVING A NOX EMISSION	0.08	LB/MMBTU	30-DAYS ROLLING AVERAGE	BACT-PSD	0			0		NOT AVAILABLE- *SEE NOTES
MO-0071	KANSAS CITY POWER & LIGHT COMPANY - IATAN STATION	GREAT PLAINS ENERGY	MO	012006-019	221112	01/27/2006 ACT	KCPH HAS APPLIED FOR THE AUTHORITY TO INSTALL A PULVERIZED COAL BOILER, AN AUXILIARY BOILER, ASSOCIATED STORAGE, HANDELING AND POLLUTION CONTROL EQUIPMENT, A FUEL OIL STORAGE TANK AND A LANDFILL, ALL ADJACENT TO THE EXISTING	PULVERIZED COAL BOILER - UNIT 2	PULVERIZED COAL	4000	T/H	Nitrogen Oxides (NOx)	KCPH SHALL INSTALL SCR UNIT FOR THE UNIT 2 BOILER TO REDUCE NOX EMISSIONS AND ALSO SHALL INSTALL WET SCRUBBER TO REDUCE SOX EMISSIONS. BOTH CONTROLS	0.08	LB/MMBTU	30 DAYS ROLLING AVERAGE	BACT-PSD	0			0		
MO-0071	KANSAS CITY POWER & LIGHT COMPANY - IATAN STATION	GREAT PLAINS ENERGY	MO	012006-019	221112	01/27/2006 ACT	KCPH HAS APPLIED FOR THE AUTHORITY TO INSTALL A PULVERIZED COAL BOILER, AN AUXILIARY BOILER, ASSOCIATED STORAGE, HANDELING AND POLLUTION CONTROL EQUIPMENT, A FUEL OIL STORAGE TANK AND A LANDFILL, ALL ADJACENT TO THE EXISTING	PULVERIZED COAL BOILER - UNIT 1	COAL	4000	T/H	Nitrogen Oxides (NOx)		0.1	LB/MMBTU	30 DAYS ROLLING AVERAGE	N/A	0			0		
MO-0077	NORBORNE POWER PLANT	ASSOCIATED ELECTRIC COOPERATIVE, INC	MO	022008-010	221121	02/22/2008 ACT	TO CONSTRUCT A NEW SUPERCRITICAL PULVERIZED COAL-FIRED BOILER WITH RELATED MATERIAL HANDLING AND POLLUTION CONTROL EQUIPMENT AND A STEAM TURBINE GENERATOR WITH A NET ELECTRICAL OUTPUT OF 689 MEGAWATTS (780 MW GROSS	MAIN BOILER	COAL	3762420	T/YR	Nitrogen Oxides (NOx)	SCR - SELECTIVE CATALYTIC REDUCTION LNB - LOW NOX BURNERS OFA - OVERFIRE AIR	0.065	LB/MMBTU	30 DAYS ROLLING AVERAGE	BACT-PSD	0.05	LB/MMBTU	12 MONTH ROLLING AVERAGE	0		
MT-0027	HARDIN GENERATOR PROJECT	ROCKY MOUNTAIN POWER, INC.	MT	3185-00	221112	06/11/2002 ACT	COAL-FIRED POWER PLANT	BOILER, PULVERIZED COAL-FIRED	COAL	1304	MMBTU/H	Nitrogen Oxides (NOx)	SELECTIVE CATALYTIC REDUCTION	0.09	LB/MMBTU	30-day rolling average	Other Case-by-Case	0			0.09	LB/MMBTU	30-day rolling average
ND-0024	SPIRITWOOD STATION	GREAT RIVER ENERGY	ND	PTC07026	221112	09/14/2007 ACT	LIGNITE FIRED COMBINED HEAT AND POWER PLANT RATED AT A NOMINAL 99 MWGE (NET) AND A MAXIMUM OF 112 MWGE (GROSS). BOILER IS RATED AT 1280.	ATMOSPHERIC CIRCULATING FLUIDIZED BED BOILER	LIGNITE	1280	MMBTU/H	Nitrogen Oxides (NOx)	FLUIDIZED BED COMBUSTION AND SELECTIVE NON-CATALYTIC REDUCTION	0.09	LB/MMBTU	30 D ROLLING	BACT-PSD	114.9	LB/H	24 H BLOCK	0		
ND-0026	M.R. YOUNG STATION	MINNKOTA POWER COOPERATIVE	ND	PTC12003	221112	03/08/2012 ACT	Two lignite fired cyclone boilers.	Cyclone Boilers, Unit 2	Lignite	6300	MMBTU/H	Nitrogen Oxides (NOx)	SNCR plus separated over fire air	0.35	LB/MMBTU	30 DAY ROLLING AVERAGE	BACT-PSD	3995.6	LB/H	24 HOUR AV DURING STARTUP	0		
ND-0026	M.R. YOUNG STATION	MINNKOTA POWER COOPERATIVE	ND	PTC12003	221112	03/08/2012 ACT	Two lignite fired cyclone boilers.	Cyclone Boilers, Unit 1	Lignite	3200	MMBTU/H	Nitrogen Oxides (NOx)	SNCR plus separated over fire air	0.36	LB/MMBTU	30 DAY ROLLING AVERAGE	BACT-PSD	2070.2	LB/H	24 HOUR AV DURING STARTUP	0		
NE-0018	WHELAN ENERGY CENTER	HASTINGS UTILITIES	NE	58048	221112	03/30/2004 ACT	ADDITION OF A 220 MW COAL-FIRED UTILITY BOILER & 75 MMBTU/HR AUX BOILER TO AN EXISTING 80 MW FACILITY	BOILER, UNIT 2 UTILITY	SUBBITUMINOUS COAL	2210	MMBTU/H	Nitrogen Oxides (NOx)	SELECTIVE CATALYTIC REDUCTION	0.08	LB/MMBTU	30-day rolling ave.	BACT-PSD	0			0.08	LB/MMBTU	
NE-0031	OPPD - NEBRASKA CITY STATION	OMAHA PUBLIC POWER DISTRICT	NE	58343C01	221112	03/09/2005 ACT	EXISTING ELECTRICAL GENERATING PLANT, CONSTRUCTING A NEW 660 (NET) MW UNIT.	UNIT 2 BOILER	SUBBITUMINOUS COAL			Nitrogen Oxides (NOx)	SELECTIVE CATALYTIC REDUCTION (SCR)	0.07	LB/MMBTU	30 DAY ROLLING AVERAGE	BACT-PSD	0			0.07	LB/MMBTU	
NE-0049	OPPD NEBRASKA CITY STATION	OMAHA PUBLIC POWER DISTRICT	NE	CP07-0049	221112	02/26/2009 ACT	COAL-FIRED POWER PLANT CONSISTING OF TWO ~650MW ELECTRIC STEAM GENERATING UNITS. UNIT 1 INSTALLED IN THE 1970S, UNIT 2 CONSTRUCTED/OPERATIONAL IN 2009.	NCS UNIT 1	POWDER RIVER BASIN COAL	370	T/YR	Nitrogen Oxides (NOx)	LNB W/OVERFIRE AIR PORT SYSTEM	0.23	LB/MMBTU	30-DAY ROLLING AV	BACT-PSD	0			0		

Coal Creek Station Updated BART Review  
EPA RACT BACT LAER Clearinghouse Data Jan 2000 - Aug 2019  
NOx Controls on Large Coal Fired Boilers (>250 MMBtu/hr)  
NOx lmits in lb/MMBtu

Highlighting Key	Average	Max	Min	Count
No Emission Controls Specified				
Comb Cont, LNB,OFA, etc	0.22	0.30	0.15	6
SNCR (PC Boiler)	0.36	0.36	0.35	2
CFB w SNCR	0.09	0.16	0.07	15
All SNCR	0.12	0.36	0.07	17
SCR	0.07	0.12	0.05	24

NOTE: Draft determinations are marked with a " \* " beside the RBLC ID.

RBLC ID	Facility Name	Corporate or Company Name	Facility State	Permit Number	NAICS Code	Permit Date	Facility Description	Process Name	Fuel	Through-put	Units	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	Case-by-Case Basis	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
NV-0036	TS POWER PLANT	NEWMONT NEVADA ENERGY INVESTMENT, LLC	NV	AP4911-1349	221112	05/05/2005	200 MW PC COAL FIRED ELECTRICAL GENERATION UNIT	200 MW PC COAL BOILER	POWDER RIVER BASIN COAL	2030	MMBTU/H	Nitrogen Oxides (NOx)	SCR & LOW NOX BURNERS	0.067	LB/MMBTU	24-HOUR ROLLING	BACT-PSD	0			0.067	LB/MMBTU	24-HOUR ROLLING
OK-0118	HUGO GENERATING STA	WESTERN FARMERS ELECTRIC COOP	OK	97-058-C M-2 PSD	335999	02/09/2007	ACT GENERATING STATION	COAL-FIRED STEAM EGU BOILER (HU-UNIT 2)		750	MW	Nitrogen Oxides (NOx)	LOW NOX BURNERS (LNB) W/ OVERFIRE AIR (OFA) AND SELECTIVE CATALYTIC REDUCTION (SCR)	0.07	LB/MMBTU	30 DAY ROLLING AVERAGE	BACT-PSD	0.05	LB/MMBTU	12 MONTH ROLLING AVERAGE	0		
OK-0151	SOONER GENERATING STATION	O G AND E	OK	2010-338-C(M-1)PSD	221112	01/17/2013	ACT The facility is an electricity generation plant (SIC Code 4911) located in an attainment area. The facility is currently operating under Permit No. 2010-338-TRR2 issued November 21, 2011.	COAL-FIRED BOILERS	COAL	550	MW	Nitrogen Oxides (NOx)	LOW-NOx BURNERS AND OVERFIRE AIR.	0.15	LB/MMBTU	30-DAY AVG	BART	0			0		
OK-0152	MUSKOGEE GENERATING STATION	O G AND E	OK	2005-271-C(M-5)PSD	221112	01/30/2013	ACT The Muskogee Generating Station utilizes sub-bituminous coal, natural gas, and some waste products (used oil-sorb, used antifreeze, used solvents, used oil, chemical cleaning wastes, hazardous waste fuel, activated carbon, demineralizer resin, and waste water	COAL-FIRED BOILER	COAL	550	MW	Nitrogen Oxides (NOx)	LOW-NOx BURNERS AND OVERFIRE AIR	0.15	LB/MMBTU	30-DAY AVG	BART	0			0		
PA-0182	RELIANT ENERGY SEWARD POWER	RELIANT ENERGY	PA	PA-32-040B	221112	08/26/2003	ACT ELECTRIC GENERATING FACILITY	BOILER, CIRCULATING FLUIDIZED BED, (2)	COAL	2532	MMBTU/H	Nitrogen Oxides (NOx)	SELECTIVE NON CATALYTIC REDUCTION (SNCR)	0.15	LB/MMBTU		BACT-PSD	0			0.15	LB/MMBTU	
PA-0247	BEECH HOLLOW POWER PROJECT	ROBINSON POWER COMPANY LLC	PA	63-00922A	221112	04/01/2005	ACT PA FOR INSTALLATION OF 272 (NET) MEGAWATT WASTE COAL FIRED CFB AND ASSOCIATED AIR SOURCES CONTROLLED BY A LIMESTONE INJECTION ,SNCR AND BAGHOUSE.	COAL FIRED CFB	WASTE COAL			Nitrogen Oxides (NOx)	SNCR EMPLOYED TO MINIMIZE NOX EMISSIONS. FACILITY WILL BE EQUIPPED WITH NOX CEM TO MONITOR EXHAUST GAS STREAM.	0.08	LB/MMBTU		LAER	972	T/YR		0.08	LB/MMBTU	
PA-0248	GREENE ENERGY RESOURCE RECOVERY PROJECT	WELLINGTON DEV/GREENE ENERGY	PA	30-00150A	221119	07/08/2005	ACT THIS PA IS FOR THE CONSTRUCTION OF A NEW 525 NET MW (580 GROSS) ELECTRIC GENERATING FACILITY. THE FACILITY CONSISTS OF 2 WASTE COAL FIRED CFB BOILERS, EACH RATED AT 2756 MMBTU/HR, CFB'S WILL DRIVE A SINGLE TURBINE/GENERATOR.	2 CFB BOILERS	WASTE COAL	358	T/H (each)	Nitrogen Oxides (NOx)	SNCR, NOX CEM	0.08	LB/MMBTU	30 DAY ROLLING AVERAGE	LAER	0.1	LB/MMBTU	24 HR AVERAGE	0		
PA-0257	SUNNYSIDE ETHANOL,LLC	SUNNYSIDE ETHANOL,LLC	PA	17-313-001	325193	05/07/2007	ACT THIS PA IS FOR A 88 MILLION GALLON PER YEAR ETHANOL PRODUCTION PLANT POWERED BY A 24.7 MW COAL FIRED COGENERATION PLANT. THE PLANT IS LOCATED AT CURWENSVILLE BOROUGH IN CLEARFIELD COUNTY.	CFB BOILER	COAL	496.8	MMBTU/H	Nitrogen Oxides (NOx)	SNCR	0.1	LB/MMBTU	24 HR AVERAGE	LAER	34.78	LB/H		0		
SC-0104	SANTEE COOPER CROSS GENERATING STATION	SANTEE COOPER	SC	0420-0030-CI	221112	02/05/2004	ACT ELECTRIC UTILITY	BOILER, NO. 3 AND NO. 4	BITUMINOUS COAL	5700	MMBTU/H	Nitrogen Oxides (NOx)	LOW NOX BURNERS AND SCR	0.08	LB/MMBTU		Other Case-by-Case	2278	T/YR	Each Boiler	0.08	LB/MMBTU	
TX-0489	SOUTHWESTERN PUBLIC SERVICE COMPANY- HARRINGTON STATION	SOUTHWESTERN PUBLIC SERVICE COMPANY	TX	P017M1	221112	10/17/2006	ACT COAL-FIRED ELECTIONAL GENERATING FACILITY	UNIT 3 BOILER	PBR COAL	3870	MMBtu/h	Nitrogen Oxides (NOx)	LOW NOX BURNERS, SEPARATED OVERFIRE AIR WINDBOX, WITH ADDITIONAL VAW CONTROL OF THE BURNERS FOR ADDITIONAL NOX CONTROL	0.3	LB/MMBTU		Other Case-by-Case	0			0		
TX-0554	COLETO CREEK UNIT 2	COLETO CREEK	TX	PSDTX1118	221112	05/03/2010	ACT Coal-fired boiler	Coal-fired Boiler Unit 2	PRB coal	6670	MMBTU/H	Nitrogen Oxides (NOx)	low-NOx burners with OFA, Selective Catalytic Reduction	0.06	LB/MMBTU	ROLLING 30 DAY AVG	BACT-PSD	0.05	LB/MMBTU	ROLLING 12 MONTH AVG	0		
TX-0557	LIMESTONE ELECTRIC GENERATING STATION	NRG TEXAS POWER LLC	TX	PSDTX371M4	221112	02/01/2010	ACT NRG Texas Power LLC (NRG) operates two coal and petroleum coke-fired steam/electric units, otherwise known as Limestone Units 1 and 2, which were originally permitted to operate in September 1981. These units are Combustion Engineering tangentially-fired, controlled	LMS Units 1 and 2	Coal	9061	MMBTU/H	Nitrogen Oxides (NOx)	Tuning of existing low-NOx firing system to induce deeper state combustion.	0.25	LB/MMBTU	30-DAY	BACT-PSD	0			0		
TX-0577	WHITE STALLION ENERGY CENTER	WHITE STALLION ENERGY CENTER, LLC	TX	86088	221112	12/16/2010	ACT WSEC proposes to construct and operate new steam-electric utility generating facilities using four circulating fluidized bed (CFB) boilers, each with a design maximum heat input of 3,300 million British thermal units per hour (MMBTU/hr) and 300 MW net electric output.	CFB BOILER	COAL & PET COKE	3300	MMBTU/H	Nitrogen Oxides (NOx)	CFB AND SNCR	0.07	LB NOX/MMBTU	30-DAY ROLLING	BACT-PSD	0.1	LB NOX/MMBTU	1-HR	0		
TX-0585	TENASKA TRAILBLAZER ENERGY CENTER	TENASKA TRAILBLAZER PARTNERS LLC	TX	PSDTX1123	221112	12/30/2010	ACT Coal-fired electric generating facility	Coal-fired Boiler	Sub-bituminous coal	8307	MMBTU/H	Nitrogen Oxides (NOx)	Selective Catalytic Reduction	0.05	LB/MMBTU	12-MONTH ROLLING	BACT-PSD	0.06	LB/MMBTU	30-DAY ROLLING	0		
UT-0064	SEVIER POWER COMPANY	NEVCO - SEVIER POWER COMPANY	UT	DAQE-AN2529001-04	221112	10/12/2004	ACT 270 MW COAL-FIRED CIRCULATING FLUIDIZED BED STEAM ELECTRIC PLANT (BOILER). USES LOW-NOX BURNERS (DRY LOW NOX), LIMESTONE INJECTION SNCR, AMMONIUS INJECTION, DRY LIME SCRUBBER, BAGHOUSE ALL AS CONTROLS	LOW-NOX BURNERS WITH SNCR	WESTERN COAL	270	MW	Nitrogen Oxides (NOx)	LOW NOX BURNERS WITH SNCR WITH AMMONIA INJECTION	0.1	LB/MMBTU	24-HOUR ROLLING	BACT-PSD	0			0.1	LB/MMBTU	
UT-0065	INTERMOUNTAIN POWER GENERATING STATION - UNIT #3	INTERMOUNTAIN POWER SERVICE CORPORATION	UT	DAQE-AN0327010-04	221112	10/15/2004	ACT NEW PULVERIZED COAL FIRED ELECTRIC GENERATING UNIT #3, DESIGNED AT 950-GROSS MW (900-NETMW) WITH A DRY BOTTOM, TANGENTIALLY FIRED OR WALL-FIRED BOILER. UNIT #3 BOILER WILL BE EQUIPPED WITH WET FLUE GAS DESULPHURIZATION, LNB, OVER	PULVERIZED COAL FIRED ELECTRIC GENERATING	BITUMINOUS OR BLEND	950	MW-gross	Nitrogen Oxides (NOx)	LOW NOX BURNERS, OVER FIRE AIR, SCR	0.07	LB/MMBTU	30-DAY ROLLING AVERAGE	BACT-PSD	633.5	LB/H	24-BLOCK AVERAGE	0.07	LB/MMBTU	
UT-0070	BONANZA POWER PLANT WASTE COAL FIRED UNIT	DESERET POWER ELECTRIC COOPERATIVE	UT	PSD-OU-0002-04.00	221112	08/30/2007	ACT 110 MW WASTE COAL FIRED UNIT	CIRCULATING FLUIDIZED BED BOILER, 1445 MMBTU/HR	WASTE COAL/BITUMINOUS BLEND			Nitrogen Oxides (NOx)	SNCR	0.088	LB/MMBTU	30-DAY ROLLING	BACT-PSD	0			0		
UT-0070	BONANZA POWER PLANT WASTE COAL FIRED UNIT	DESERET POWER ELECTRIC COOPERATIVE	UT	PSD-OU-0002-04.00	221112	08/30/2007	ACT 110 MW WASTE COAL FIRED UNIT	CIRCULATING FLUIDIZED BED BOILER, 1445 MMBTU/HR	WASTE COAL/BITUMINOUS BLEND			Nitrogen Oxides (NOx)	SNCR	0.08	LB/MMBTU	30-DAY ROLLING	BACT-PSD	0			0		
VA-0311	VIRGINIA CITY HYBRID ENERGY CENTER	VIRGINIA ELECTRIC AND POWER CO	VA	11526	221112	06/30/2008	ACT ELECTRIC POWER GENERATING FACILITY	2 CIRCULATING FLUIDIZED BED BOILERS	COAL AND COAL REFUSE	3132	MMBTU/H	Nitrogen Oxides (NOx)	SELECTIVE NON-CATALYTIC REDUCTION AND GOOD COMBUSTION PRACTICES AND CEM SYSTEM	0.07	LB/MMBTU	30 DAY ROLLING AVERAGE	BACT-PSD	0.07	LB/MMBTU	30 DAY ROLLING AVERAGE	0		
WI-0225	MANITOWOC PUBLIC UTILITIES	MANITOWOC PUBLIC UTILITIES	WI	02-RV-147	22	12/03/2003	ACT PUBLIC ELECTRIC UTILITY	CIRCULATING FLUIDIZED BED BOILER (ELECTRIC	COAL / PET COKE	650	MMBTU/H	Nitrogen Oxides (NOx)	SNCR NETTED OUT OF PSD BACT BY ELIMINATING COAL FROM BOILER #5	0.155	LB/MMBTU		N/A	24.62	T/MO	12 MO. ROLLING AVERAGE	0		
WI-0228	WPS - WESTON PLANT	WISCONSIN PUBLIC SERVICE	WI	04-RV-248	22	10/19/2004	ACT ELECTRICAL UTILITY	SUPER CRITICAL PULVERIZED COAL ELECTRIC STEAM BOILER	PRB COAL	5173.07	MMBTU/H	Nitrogen Oxides (NOx)	LOW NOX BURNERS, GOOD COMBUSTION PRACTICES SELECTIVE CATALYTIC REDUCTION (SCR)	0.07	LB/MMBTU	30 DAY AVG. EXCL. STARTUP/SHUTDOWN	BACT-PSD	0.06	LB/MMBTU	12 MO. AVG. INCL. STARTUP / SHUTDOWN	0		
WV-0024	WESTERN GREENBRIER CO-GENERATION, LLC	WESTERN GREENBRIER CO-GENERATION, LLC	WV	R14-0028	221112	04/26/2006	ACT NOMINAL 98 NET MEGAWATT WASTE COAL-FIRED STEAM ELECTRIC CO-GENERATION FACILITY. BOILER IS CFB TECHNOLOGY. FACILITY INCLUDES KILN TO PRODUCE CEMENTITIOUS MATERIAL FROM ASH GENERATED IN BOILER.	CIRCULATING FLUIDIZED BED BOILER (CFB)	WASTE COAL	1070	mmbtu/h	Nitrogen Oxides (NOx)	SNCR	0.1	LB/MMBTU	30-DAY	BACT-PSD	0			0.1	LB/MMBTU	30-DAY
WY-0057	WYGEN 2	BLACK HILLS CORPORATION	WY	CT-3030	221112	09/25/2002	ACT 300 MW PC POWER PLANT	BOILER, 500 MW PC	SUBBITUMINOUS COAL	5145.7	MMBTU/H	Nitrogen Oxides (NOx)	LOW NOX BURNERS/SCR	0.07	LB/MMBTU	30 DAY ROLLING	BACT-PSD	0			0.07	LB/MMBTU	
WY-0063	WYGEN 3	BLACK HILLS CORPORATION	WY	CT-4517	221112	02/05/2007	ACT 100 MW PULVERIZED COAL FIRED ELECTRIC UTILITY	PC BOILER	SUBBITUMINOUS COAL	1300	MMBTU/H	Nitrogen Oxides (NOx)	SCR/LNB/OVERFIRE AIR	0.05	LB/MMBTU	12 MONTH ROLLING	BACT-PSD	65	LB/H	30 DAY ROLLING	0		
WY-0064	DRY FORK STATION	BASIN ELECTRIC POWER COOPERATIVE	WY	CT-4631	237130	10/15/2007	ACT ONE PC BOILER RATED A 385 MW (NET)	PC BOILER (E51-01)	COAL			Nitrogen Oxides (NOx)	LOW NOX BURNERS AND SCR	0.05	LB/MMBTU	12 MONTH ROLLING	BACT-PSD	190.1	LB/H	30-DAY ROLLING	832.4	T/YR	ANNUAL



## Attachment G

EPA Control Cost Manual SCR and SNCR Spreadsheets for Units 1 and 2



## Data Inputs

Coal Creek SCR Cost Estimate for 2019 BART - 0.06 lb NOx/MMBtu EPA calculations for flue gas flow and catalyst volume. Use anhydrous ammonia Meth 2 Cat Rep Cost EPA Default Cat Cost.

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler?

Utility ▼

What type of fuel does the unit burn?

Coal ▼

Is the SCR for a new boiler or retrofit of an existing boiler?

Retrofit ▼

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty.

1

Complete all of the highlighted data fields:

EPA default value used

Site specific data entered

What is the MW rating at full load capacity (Bmw)?

605 MW

What is the higher heating value (HHV) of the fuel?

6,685 Btu/lb

\*HHV value of 6685 Btu/lb is a default value. See below for data source. Enter actual HHV for fuel burned, if known.

What is the estimated actual annual MWhs output?

4,610,826 MWhs

87% capacity factor

Enter the net plant heat input rate (NPHR)

10 MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation

1980

Feet above sea level

Provide the following information for coal-fired boilers:

Type of coal burned:

Lignite ▼

Enter the sulfur content (%S) =

0.82 percent by weight

CCS data sulfur content

For units burning coal blends:

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the **Cost Estimate** tab. Please select your preferred method:

- ☐ Method 1  
☒ Method 2  
☐ Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates ( $t_{SCR}$ )

365 days

Number of days the boiler operates ( $t_{plant}$ )

365 days

Inlet NO<sub>x</sub> Emissions (NO<sub>x,in</sub>) to SCR

0.13 lb/MMBtu

Outlet NO<sub>x</sub> Emissions (NO<sub>x,out</sub>) from SCR

0.06 lb/MMBtu

Stoichiometric Ratio Factor (SRF)

1.050

\*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Number of SCR reactor chambers ( $n_{SCR}$ )

1

Number of catalyst layers ( $R_{layer}$ )

3 Replace all catalyst every 3 years

Number of empty catalyst layers ( $R_{empty}$ )

1

Ammonia Slip (Slip) provided by vendor

2 ppm

Volume of the catalyst layers ( $Vol_{catalyst}$ )  
(Enter "UNK" if value is not known)

UNK Cubic feet (confidential)

Flue gas flow rate ( $Q_{fluegas}$ )  
(Enter "UNK" if value is not known)

UNK acfm

Estimated operating life of the catalyst ( $H_{catalyst}$ )

24,000 hours

Estimated SCR equipment life

30 Years\*

\* For utility boilers, the typical equipment life of an SCR is at least 30 years.

Concentration of reagent as stored ( $C_{stored}$ )

29 percent\*

Density of reagent as stored ( $\rho_{stored}$ )

56 lb/cubic feet\*

Number of days reagent is stored ( $t_{storage}$ )

14 days

\*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Gas temperature at the SCR inlet (T)

650 °F

Base case fuel gas volumetric flow rate factor ( $Q_{fuel}$ )

547 ft<sup>3</sup>/min-MMBtu/hour

Select the reagent used

Ammonia

Densities of typical SCR reagents:

50% urea solution71 lbs/ft<sup>3</sup>

29.4% aqueous NH<sub>3</sub>56 lbs/ft<sup>3</sup>

Enter the cost data for the proposed SCR:

Desired dollar-year

2018

CEPCI for 2018

615.3 Enter the CEPCI value for 2018541.72016 CEPCI

Annual Interest Rate (i)

5.25 Percent

Reagent (Cost<sub>reag</sub>)

0.293 \$/gallon for 29% ammonia\*

Electricity (Cost<sub>elect</sub>)

0.0361 \$/kWh

Catalyst cost (CC<sub>replace</sub>)

227.00 \$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst)

Operator Labor Rate

60.00 \$/hour (including benefits)\*

Operator Hours/Day

4.00 hours/day\*

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

CEPCI = Chemical Engineering Plant Cost Index

\* \$0.293/gallon is a default value for 29% ammonia. User should enter actual value, if known.

\* \$0.0361/kWh is a default value for electricity cost. User should enter actual value, if known.

\* \$227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.

\* \$60/hour is a default value for the operator labor rate. User should enter actual value, if known.

\* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

**Data Sources for Default Values Used in Calculations:**

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost (\$/gallon)	\$0.293/gallon 29% ammonia solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 ( <a href="https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf">https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf</a> )	
Electricity Cost (\$/kWh)	0.0361	U.S. Energy Information Administration. Electric Power Annual 2016. Table 8.4. Published December 2017. Available at: <a href="https://www.eia.gov/electricity/annual/pdf/epa.pdf">https://www.eia.gov/electricity/annual/pdf/epa.pdf</a> .	
Percent sulfur content for Coal (% weight)	0.82	Average sulfur content based on U.S. coal data for 2016 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at <a href="http://www.eia.gov/electricity/data/eia923/">http://www.eia.gov/electricity/data/eia923/</a> .	
Higher Heating Value (HHV) (Btu/lb)	6,685	2016 coal data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at <a href="http://www.eia.gov/electricity/data/eia923/">http://www.eia.gov/electricity/data/eia923/</a> .	
Catalyst Cost (\$/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: <a href="https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6">https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6</a> .	
Operator Labor Rate (\$/hour)	\$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: <a href="https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6">https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6</a> .	
Interest Rate (Percent)	5.5	Default bank prime rate Use 5.25 per ND Dept of Health Guidance	

## SCR Design Parameters

Coal Creek SCR Cost Estimate for 2019 BART - 0.06 lb NO<sub>x</sub>/MMBtu EPA calculations for flue gas flow and catalyst volume. Use anhydrous ammonia Meth 2 Cat Rep Cost EPA Default Cat Cost.

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units
Maximum Annual Heat Input Rate ( $Q_B$ ) =	Bmw x NPHR =	6,050	MMBtu/hour
Maximum Annual MW Output (Bmw) =	Bmw x 8760 =	5,299,800	MWhs
Estimated Actual Annual MWhs Output (Boutput) =		4,610,826	MWhs
Heat Rate Factor (HRF) =	NPHR/10 =	1.00	
Total System Capacity Factor ( $CF_{total}$ ) =	(Boutput/Bmw)*(tscr/tplant) =	0.870	fraction
Total operating time for the SCR ( $t_{op}$ ) =	$CF_{total} \times 8760 =$	7621	hours
NO <sub>x</sub> Removal Efficiency (EF) =	$(NO_{x_{in}} - NO_{x_{out}})/NO_{x_{in}} =$	53.8	percent
NO <sub>x</sub> removed per hour =	$NO_{x_{in}} \times EF \times Q_B =$	423.50	lb/hour
Total NO <sub>x</sub> removed per year =	$(NO_{x_{in}} \times EF \times Q_B \times t_{op})/2000 =$	1,613.79	tons/year
NO <sub>x</sub> removal factor (NRF) =	$EF/80 =$	0.67	
Volumetric flue gas flow rate ( $q_{flue\ gas}$ ) =	$Q_{fuel} \times Q_B \times (460 + T)/(460 + 700)n_{scr} =$	3,166,706	acfm
Space velocity ( $V_{space}$ ) =	$q_{flue\ gas}/Vol_{catalyst} =$	181.21	/hour
Residence Time	$1/V_{space}$	0.01	hour
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.07	
SO <sub>2</sub> Emission rate =	$(\%S/100) \times (64/32) \times 1 \times 10^6 / HHV =$	< 3	lbs/MMBtu
Elevation Factor (ELEVf) =	$14.7\ psia/P =$	1.07	
Atmospheric pressure at sea level (P) =	$2116 \times [(59 - (0.00356 \times h) + 459.7)/518.6]^{5.256} \times (1/144)^* =$	13.7	psia
Retrofit Factor (RF)	Retrofit to existing boiler	1.00	

\* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at <https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html>.

#### Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	$(\text{interest rate}) / (1 / ((1 + \text{interest rate})^Y - 1))$ , where $Y = H_{\text{catalyst}} / (t_{\text{SCR}} \times 24 \text{ hours})$ rounded to the nearest integer	0.3164	Fraction
Catalyst volume ( $Vol_{\text{catalyst}}$ ) =	$2.81 \times Q_G \times EF_{\text{adj}} \times Slip_{\text{adj}} \times NOx_{\text{adj}} \times S_{\text{adj}} \times (T_{\text{adj}} / N_{\text{scr}})$	17,475.38	Cubic feet
Cross sectional area of the catalyst ( $A_{\text{catalyst}}$ ) =	$Q_{\text{flue gas}} / (16 \text{ ft/sec} \times 60 \text{ sec/min})$	3,299	ft <sup>2</sup>
Height of each catalyst layer ( $H_{\text{layer}}$ ) =	$(Vol_{\text{catalyst}} / (R_{\text{layer}} \times A_{\text{catalyst}})) + 1$ (rounded to next highest integer)	3	feet

#### SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor ( $A_{\text{SCR}}$ ) =	$1.15 \times A_{\text{catalyst}}$	3,793	ft <sup>2</sup>
Reactor length and width dimensions for a square reactor =	$(A_{\text{SCR}})^{0.5}$	61.6	feet
Reactor height =	$(R_{\text{layer}} + R_{\text{empty}}) \times (7 \text{ ft} + h_{\text{layer}}) + 9 \text{ ft}$	48	feet

#### Reagent Data:

Type of reagent used	Ammonia	Molecular Weight of Reagent (MW) =	17.03 g/mole
		Density =	56 lb/ft <sup>3</sup>

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ( $m_{\text{reagent}}$ ) =	$(NOx_{\text{in}} \times Q_G \times EF \times SRF \times MW_R) / MW_{NOx}$	165	lb/hour
Reagent Usage Rate ( $m_{\text{sol}}$ ) =	$m_{\text{reagent}} / C_{\text{sol}}$	568	lb/hour
	$(m_{\text{sol}} \times 7.4805) / \text{Reagent Density}$	76	gal/hour
Estimated tank volume for reagent storage =	$(m_{\text{sol}} \times 7.4805 \times t_{\text{storage}} \times 24) / \text{Reagent Density}$	25,500	gallons (storage needed to store a 14 day reagent supply rounded to the ne

#### Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i (1 + i)^n / ((1 + i)^n - 1)$ Where n = Equipment Life and i= Interest Rate	0.0669

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	$A \times 1,000 \times 0.0056 \times (\text{CoalF} \times \text{HRF})^{0.43}$ where A = Bmw for utility boilers	3488.02	kW

## Cost Estimate

Coal Creek SCR Cost Estimate for 2019 BART - 0.06 lb NOx/MMBtu EPA calculations for flue gas flow and catalyst volume. Use anhydrous ammonia Meth 2 Cat Rep Cost EPA Default Cat Cost.

### Total Capital Investment (TCI)

#### TCI for Coal-Fired Boilers

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SCR_{cost} + RPC + APHC + BPC)$$

Capital costs for the SCR ( $SCR_{cost}$ )** =	\$134,743,323	in 2018 dollars
Reagent Preparation Cost (RPC) =	\$2,906,167	in 2018 dollars
Air Pre-Heater Costs (APHC)* =	\$0	in 2018 dollars
Balance of Plant Costs (BPC) =	\$9,781,799	in 2018 dollars
Total Capital Investment (TCI) =	\$191,660,675	in 2018 dollars

\* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 3lb/MMBtu of sulfur dioxide.

\*\* Cost estimate for SCR Reactor from Version 10 spreadsheet at 0.04 lb NOx/MMBtu was \$141.8M. Size and cost of reactor is not reduced at performance rating of 0.06 lb NOx/MMBtu. A 0.06 lb NOx/MMBtu performance rating reflects an optimistic estimate of the 3-year average performance of the SCR catalyst in this service based actual performance of the best performing power plant of two plants firing Texas Lignite. Actual performance could be lower based on the higher sodium content of North Dakota lignite versus Texas lignite

#### SCR Capital Costs ( $SCR_{cost}$ )

For Coal-Fired Utility Boilers >25 MW:

$$SCR_{cost} = 310,000 \times (NRF)^{0.2} \times (B_{MW} \times HRF \times CoalF)^{0.92} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$SCR_{cost} = 310,000 \times (NRF)^{0.2} \times (0.1 \times Q_B \times CoalF)^{0.92} \times ELEVF \times RF$$

SCR Capital Costs ( $SCR_{cost}$ ) =

\$134,743,323 in 2018 dollars

#### Reagent Preparation Costs (RPC)

For Coal-Fired Utility Boilers >25 MW:

$$RPC = 564,000 \times (NO_{x,in} \times B_{MW} \times NPHR \times EF)^{0.25} \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$RPC = 564,000 \times (NO_{x,in} \times Q_B \times EF)^{0.25} \times RF$$

Reagent Preparation Costs (RPC) =

\$2,906,167 in 2018 dollars

#### Air Pre-Heater Costs (APHC)\*

For Coal-Fired Utility Boilers >25MW:

$$APHC = 69,000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$APHC = 69,000 \times (0.1 \times Q_B \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs ( $APH_{cost}$ ) =

\$0 in 2018 dollars

\* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 3lb/MMBtu of sulfur dioxide.

#### Balance of Plant Costs (BPC)

For Coal-Fired Utility Boilers >25MW:

$$BPC = 529,000 \times (B_{MW} \times HRF \times CoalF)^{0.42} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$BPC = 529,000 \times (0.1 \times Q_B \times CoalF)^{0.42} \times ELEVF \times RF$$

Balance of Plant Costs ( $BOP_{cost}$ ) =

\$9,781,799 in 2018 dollars

## Annual Costs

### Total Annual Cost (TAC)

$$\text{TAC} = \text{Direct Annual Costs} + \text{Indirect Annual Costs}$$

Direct Annual Costs (DAC) =	\$3,868,611 in 2018 dollars
Indirect Annual Costs (IDAC) =	\$12,836,227 in 2018 dollars
Total annual costs (TAC) = DAC + IDAC	\$16,704,838 in 2018 dollars

### Direct Annual Costs (DAC)

$$\text{DAC} = (\text{Annual Maintenance Cost}) + (\text{Annual Reagent Cost}) + (\text{Annual Electricity Cost}) + (\text{Annual Catalyst Cost})$$

Annual Maintenance Cost =	$0.005 \times \text{TCI} =$	\$958,303 in 2018 dollars
Annual Reagent Cost =	$m_{\text{sol}} \times \text{Cost}_{\text{reag}} \times t_{\text{op}} =$	\$169,294 in 2018 dollars
Annual Electricity Cost =	$P \times \text{Cost}_{\text{elect}} \times t_{\text{op}} =$	\$959,641 in 2018 dollars
Annual Catalyst Replacement Cost =		\$1,781,373 in 2018 dollars
For coal-fired boilers, the following methods may be used to calculate the catalyst replacement cost.		
Method 1 (for all fuel types):	$n_{\text{scr}} \times \text{Vol}_{\text{cat}} \times (\text{CC}_{\text{replace}} / R_{\text{layer}}) \times \text{FWF}$	* Calculation Method 2 selected.
Method 2 (for coal-fired utility boilers):	$B_{\text{MW}} \times 0.4 \times (\text{CoalF})^{2.9} \times (\text{NRF})^{0.71} \times (\text{CC}_{\text{replace}}) \times 35.3$	
Direct Annual Cost =		\$3,868,611 in 2018 dollars

### Indirect Annual Cost (IDAC)

$$\text{IDAC} = \text{Administrative Charges} + \text{Capital Recovery Costs}$$

Administrative Charges (AC) =	$0.03 \times (\text{Operator Cost} + 0.4 \times \text{Annual Maintenance Cost}) =$	\$14,128 in 2018 dollars
Capital Recovery Costs (CR)=	$\text{CRF} \times \text{TCI} =$	\$12,822,099 in 2018 dollars
Indirect Annual Cost (IDAC) =	$\text{AC} + \text{CR} =$	\$12,836,227 in 2018 dollars

## Cost Effectiveness

$$\text{Cost Effectiveness} = \text{Total Annual Cost} / \text{NOx Removed/year}$$

Total Annual Cost (TAC) =	\$16,704,838 per year in 2018 dollars
NOx Removed =	1,614 tons/year
Cost Effectiveness =	\$10,351 per ton of NOx removed in 2018 dollars



## Data Inputs

Coal Creek SCR Cost Estimate for 2019 BART - 0.08 lb NOx/MMBtu EPA calculations for flue gas flow and catalyst volume. Use anhydrous ammonia Meth 2 Cat Rep Cost EPA Default Cat Cost.

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler?

Utility ▼

What type of fuel does the unit burn?

Coal ▼

Is the SCR for a new boiler or retrofit of an existing boiler?

Retrofit ▼

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty.

1

Complete all of the highlighted data fields:

What is the MW rating at full load capacity (Bmw)?

605 MW

What is the higher heating value (HHV) of the fuel?

6,685 Btu/lb

What is the estimated actual annual MWhs output?

4,610,826 MWhs

87% capacity factor

Enter the net plant heat input rate (NPHR)

10 MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation

1980

Feet above sea level

Provide the following information for coal-fired boilers:

Type of coal burned:

Lignite ▼

Enter the sulfur content (%S) =

0.82 percent by weight

CCS data sulfur content and HHV

For units burning coal blends:

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the **Cost Estimate** tab. Please select your preferred method:

- ☐ Method 1  
☒ Method 2  
☐ Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates ( $t_{SCR}$ )	365 days	Number of SCR reactor chambers ( $n_{SCR}$ )	1
Number of days the boiler operates ( $t_{plant}$ )	365 days	Number of catalyst layers ( $R_{layer}$ )	3 Replace all catalyst every 3 years
Inlet NO <sub>x</sub> Emissions (NO <sub>x,in</sub> ) to SCR	0.13 lb/MMBtu	Number of empty catalyst layers ( $R_{empty}$ )	1
Outlet NO <sub>x</sub> Emissions (NO <sub>x,out</sub> ) from SCR	0.08 lb/MMBtu	Ammonia Slip (Slip) provided by vendor	2 ppm
Stoichiometric Ratio Factor (SRF)	1.050	Volume of the catalyst layers (Vol <sub>catalyst</sub> ) (Enter "UNK" if value is not known)	UNK Cubic feet (confidential)
*The SRF value of 1.05 is a default value. User should enter actual value, if known.		Flue gas flow rate (Q <sub>fluegas</sub> ) (Enter "UNK" if value is not known)	UNK acfm

Estimated operating life of the catalyst (H <sub>catalyst</sub> )	24,000 hours	Gas temperature at the SCR inlet (T)	650 °F
Estimated SCR equipment life	30 Years*	Base case fuel gas volumetric flow rate factor (Q <sub>fuel</sub> )	547 ft <sup>3</sup> /min-MMBtu/hour
* For utility boilers, the typical equipment life of an SCR is at least 30 years.			

Concentration of reagent as stored (C <sub>stored</sub> )	29 percent*	*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.
Density of reagent as stored (ρ <sub>stored</sub> )	56 lb/cubic feet*	
Number of days reagent is stored (t <sub>storage</sub> )	14 days	

Select the reagent used 

Ammonia ▼

Densities of typical SCR reagents:

50% urea solution	71 lbs/ft <sup>3</sup>
29.4% aqueous NH <sub>3</sub>	56 lbs/ft <sup>3</sup>

Enter the cost data for the proposed SCR:

Desired dollar-year	2018	
CEPCI for 2018	615.3 Enter the CEPCI value for 2018	541.7 2016 CEPCI
Annual Interest Rate (i)	5.25 Percent	
Reagent (Cost <sub>reag</sub> )	0.293 \$/gallon for 29% ammonia*	* \$0.293/gallon is a default value for 29% ammonia. User should enter actual value, if known.
Electricity (Cost <sub>elect</sub> )	0.0361 \$/kWh	* \$0.0361/kWh is a default value for electricity cost. User should enter actual value, if known.
Catalyst cost (CC <sub>replace</sub> )	227.00 \$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst)	* \$227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.
Operator Labor Rate	60.00 \$/hour (including benefits)*	* \$60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00 hours/day*	* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

**Data Sources for Default Values Used in Calculations:**

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost (\$/gallon)	\$0.293/gallon 29% ammonia solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 ( <a href="https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf">https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf</a> )	
Electricity Cost (\$/kWh)	0.0361	U.S. Energy Information Administration. Electric Power Annual 2016. Table 8.4. Published December 2017. Available at: <a href="https://www.eia.gov/electricity/annual/pdf/epa.pdf">https://www.eia.gov/electricity/annual/pdf/epa.pdf</a> .	
Percent sulfur content for Coal (% weight)	0.82	Average sulfur content based on U.S. coal data for 2016 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at <a href="http://www.eia.gov/electricity/data/eia923/">http://www.eia.gov/electricity/data/eia923/</a> .	
Higher Heating Value (HHV) (Btu/lb)	6,685	2016 coal data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at <a href="http://www.eia.gov/electricity/data/eia923/">http://www.eia.gov/electricity/data/eia923/</a> .	
Catalyst Cost (\$/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: <a href="https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6">https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6</a> .	
Operator Labor Rate (\$/hour)	\$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: <a href="https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6">https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6</a> .	
Interest Rate (Percent)	5.5	Default bank prime rate Use 5.25 per ND Dept of Health Guidance	

## SCR Design Parameters

Coal Creek SCR Cost Estimate for 2019 BART - 0.08 lb NO<sub>x</sub>/MMBtu EPA calculations for flue gas flow and catalyst volume. Use anhydrous ammonia Meth 2 Cat Rep Cost EPA Default Cat Cost.

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units
Maximum Annual Heat Input Rate ( $Q_B$ ) =	$Bmw \times NPHR =$	6,050	MMBtu/hour
Maximum Annual MW Output (Bmw) =	$Bmw \times 8760 =$	5,299,800	MW <sub>h</sub>
Estimated Actual Annual MW <sub>h</sub> Output (Boutput) =		4,610,826	MW <sub>h</sub>
Heat Rate Factor (HRF) =	$NPHR/10 =$	1.00	
Total System Capacity Factor ( $CF_{total}$ ) =	$(Boutput/Bmw) \times (tscr/tplant) =$	0.870	fraction
Total operating time for the SCR ( $t_{op}$ ) =	$CF_{total} \times 8760 =$	7621	hours
NO <sub>x</sub> Removal Efficiency (EF) =	$(NO_{x_{in}} - NO_{x_{out}})/NO_{x_{in}} =$	38.5	percent
NO <sub>x</sub> removed per hour =	$NO_{x_{in}} \times EF \times Q_B =$	302.50	lb/hour
Total NO <sub>x</sub> removed per year =	$(NO_{x_{in}} \times EF \times Q_B \times t_{op})/2000 =$	1,152.71	tons/year
NO <sub>x</sub> removal factor (NRF) =	$EF/80 =$	0.48	
Volumetric flue gas flow rate ( $q_{flue\ gas}$ ) =	$Q_{fuel} \times QB \times (460 + T)/(460 + 700)n_{scr} =$	3,166,706	acfm
Space velocity ( $V_{space}$ ) =	$q_{flue\ gas}/Vol_{catalyst} =$	223.72	/hour
Residence Time	$1/V_{space}$	0.00	hour
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.07	
SO <sub>2</sub> Emission rate =	$(\%S/100) \times (64/32) \times 1 \times 10^6 / HHV =$	< 3	lbs/MMBtu
Elevation Factor (ELEV) =	$14.7\ psia/P =$	1.07	
Atmospheric pressure at sea level (P) =	$2116 \times [(59 - (0.00356 \times h) + 459.7)/518.6]^{5.256} \times (1/144) =$	13.7	psia
Retrofit Factor (RF)	Retrofit to existing boiler	1.00	

\* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at <https://spaceflight systems.grc.nasa.gov/education/rocket/atmos.html>.

#### Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	$(\text{interest rate}) / (1 / ((1 + \text{interest rate})^Y - 1))$ , where $Y = H_{\text{catalyst}} / (t_{\text{SCR}} \times 24 \text{ hours})$ rounded to the nearest integer	0.3164	Fraction
Catalyst volume ( $Vol_{\text{catalyst}}$ ) =	$2.81 \times Q_G \times EF_{\text{adj}} \times Slip_{\text{adj}} \times NOx_{\text{adj}} \times S_{\text{adj}} \times (T_{\text{adj}} / N_{\text{scr}})$	14,154.71	Cubic feet
Cross sectional area of the catalyst ( $A_{\text{catalyst}}$ ) =	$Q_{\text{flue gas}} / (16 \text{ ft/sec} \times 60 \text{ sec/min})$	3,299	ft <sup>2</sup>
Height of each catalyst layer ( $H_{\text{layer}}$ ) =	$(Vol_{\text{catalyst}} / (R_{\text{layer}} \times A_{\text{catalyst}})) + 1$ (rounded to next highest integer)	2	feet

#### SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor ( $A_{\text{SCR}}$ ) =	$1.15 \times A_{\text{catalyst}}$	3,793	ft <sup>2</sup>
Reactor length and width dimensions for a square reactor =	$(A_{\text{SCR}})^{0.5}$	61.6	feet
Reactor height =	$(R_{\text{layer}} + R_{\text{empty}}) \times (7 \text{ ft} + h_{\text{layer}}) + 9 \text{ ft}$	47	feet

#### Reagent Data:

Type of reagent used	Ammonia	Molecular Weight of Reagent (MW) =	17.03 g/mole
		Density =	56 lb/ft <sup>3</sup>

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ( $m_{\text{reagent}}$ ) =	$(NOx_{\text{in}} \times Q_G \times EF \times SRF \times MW_R) / MW_{NOx}$	118	lb/hour
Reagent Usage Rate ( $m_{\text{sol}}$ ) =	$m_{\text{reagent}} / C_{\text{sol}}$	405	lb/hour
	$(m_{\text{sol}} \times 7.4805) / \text{Reagent Density}$	54	gal/hour
Estimated tank volume for reagent storage =	$(m_{\text{sol}} \times 7.4805 \times t_{\text{storage}} \times 24) / \text{Reagent Density}$	18,200	gallons (storage needed to store a 14 day reagent supply rounded to the ne

#### Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i (1 + i)^n / ((1 + i)^n - 1)$ Where n = Equipment Life and i = Interest Rate	0.0669

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	$A \times 1,000 \times 0.0056 \times (\text{CoalF} \times \text{HRF})^{0.43}$ where A = Bmw for utility boilers	3488.02	kW

## Cost Estimate

Coal Creek SCR Cost Estimate for 2019 BART - 0.08 lb NOx/MMBtu EPA calculations for flue gas flow and catalyst volume. Use anhydrous ammonia Meth 2 Cat Rep Cost EPA Default Cat Cost.

### Total Capital Investment (TCI)

#### TCI for Coal-Fired Boilers

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SCR_{cost} + RPC + APHC + BPC)$$

Capital costs for the SCR ( $SCR_{cost}$ ) =	\$125,974,211	in 2018 dollars
Reagent Preparation Cost (RPC) =	\$2,671,705	in 2018 dollars
Air Pre-Heater Costs (APHC)* =	\$0	in 2018 dollars
Balance of Plant Costs (BPC) =	\$9,781,799	in 2018 dollars
Total Capital Investment (TCI) =	\$179,956,029	in 2018 dollars

\* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 3lb/MMBtu of sulfur dioxide.

#### SCR Capital Costs ( $SCR_{cost}$ )

For Coal-Fired Utility Boilers >25 MW:

$$SCR_{cost} = 310,000 \times (NRF)^{0.2} \times (B_{MW} \times HRF \times CoalF)^{0.92} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$SCR_{cost} = 310,000 \times (NRF)^{0.2} \times (0.1 \times Q_b \times CoalF)^{0.92} \times ELEVF \times RF$$

SCR Capital Costs ( $SCR_{cost}$ ) =	\$125,974,211 in 2018 dollars
--------------------------------------	-------------------------------

#### Reagent Preparation Costs (RPC)

For Coal-Fired Utility Boilers >25 MW:

$$RPC = 564,000 \times (NO_{x,in} \times B_{MW} \times NPHR \times EF)^{0.25} \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$RPC = 564,000 \times (NO_{x,in} \times Q_b \times EF)^{0.25} \times RF$$

Reagent Preparation Costs (RPC) =	\$2,671,705 in 2018 dollars
-----------------------------------	-----------------------------

#### Air Pre-Heater Costs (APHC)\*

For Coal-Fired Utility Boilers >25MW:

$$APHC = 69,000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$APHC = 69,000 \times (0.1 \times Q_b \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs ( $APH_{cost}$ ) =	\$0 in 2018 dollars
---	---------------------

\* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 3lb/MMBtu of sulfur dioxide.

#### Balance of Plant Costs (BPC)

For Coal-Fired Utility Boilers >25MW:

$$BPC = 529,000 \times (B_{MW} \times HRF \times CoalF)^{0.42} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$BPC = 529,000 \times (0.1 \times Q_b \times CoalF)^{0.42} \times ELEVF \times RF$$

Balance of Plant Costs ( $BOP_{cost}$ ) =	\$9,781,799 in 2018 dollars
---	-----------------------------

## Annual Costs

### Total Annual Cost (TAC)

$$\text{TAC} = \text{Direct Annual Costs} + \text{Indirect Annual Costs}$$

Direct Annual Costs (DAC) =	\$3,383,172 in 2018 dollars
Indirect Annual Costs (IDAC) =	\$12,052,484 in 2018 dollars
Total annual costs (TAC) = DAC + IDAC	\$15,435,656 in 2018 dollars

### Direct Annual Costs (DAC)

$$\text{DAC} = (\text{Annual Maintenance Cost}) + (\text{Annual Reagent Cost}) + (\text{Annual Electricity Cost}) + (\text{Annual Catalyst Cost})$$

Annual Maintenance Cost =	$0.005 \times \text{TCI} =$	\$899,780 in 2018 dollars
Annual Reagent Cost =	$m_{\text{sol}} \times \text{Cost}_{\text{reag}} \times t_{\text{op}} =$	\$120,924 in 2018 dollars
Annual Electricity Cost =	$P \times \text{Cost}_{\text{elect}} \times t_{\text{op}} =$	\$959,641 in 2018 dollars
Annual Catalyst Replacement Cost =		\$1,402,826 in 2018 dollars
For coal-fired boilers, the following methods may be used to calculate the catalyst replacement cost.		
Method 1 (for all fuel types):	$n_{\text{scr}} \times \text{Vol}_{\text{cat}} \times (\text{CC}_{\text{replace}} / R_{\text{layer}}) \times \text{FWF}$	* Calculation Method 2 selected.
Method 2 (for coal-fired utility boilers):	$B_{\text{MW}} \times 0.4 \times (\text{CoalF})^{2.9} \times (\text{NRF})^{0.71} \times (\text{CC}_{\text{replace}}) \times 35.3$	
Direct Annual Cost =		\$3,383,172 in 2018 dollars

### Indirect Annual Cost (IDAC)

$$\text{IDAC} = \text{Administrative Charges} + \text{Capital Recovery Costs}$$

Administrative Charges (AC) =	$0.03 \times (\text{Operator Cost} + 0.4 \times \text{Annual Maintenance Cost}) =$	\$13,425 in 2018 dollars
Capital Recovery Costs (CR)=	$\text{CRF} \times \text{TCI} =$	\$12,039,058 in 2018 dollars
Indirect Annual Cost (IDAC) =	$\text{AC} + \text{CR} =$	\$12,052,484 in 2018 dollars

## Cost Effectiveness

$$\text{Cost Effectiveness} = \text{Total Annual Cost} / \text{NOx Removed/year}$$

Total Annual Cost (TAC) =	\$15,435,656 per year in 2018 dollars
NOx Removed =	1,153 tons/year
Cost Effectiveness =	\$13,391 per ton of NOx removed in 2018 dollars



## Data Inputs

Coal Creek SNCR w MNL Cost Estimate for 2019 BART - 0.10 lb NOx/MMBtu

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler?

Utility ▼

What type of fuel does the unit burn?

Coal ▼

Is the SNCR for a new boiler or retrofit of an existing boiler?

Retrofit ▼

Please enter a retrofit factor equal to or greater than 0.84 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty.

1

Complete all of the highlighted data fields:

EPA default value used

Site specific data entered

What is the MW rating at full load capacity (Bmw)?

605 MW

What is the higher heating value (HHV) of the fuel?

6,626 Btu/lb

What is the estimated actual annual MWh output?

4,610,826 MWh

87% capacity factor

Is the boiler a fluid-bed boiler?

No ▼

Enter the net plant heat input rate (NPHR)

10 MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Provide the following information for coal-fired boilers:

Type of coal burned:

Lignite ▼

Enter the sulfur content (%S) = 0.82 percent by weight  
or

Select the appropriate SO<sub>2</sub> emission rate:

Not Applicable ▼

\*The sulfur content of 0.82% is a default value. See below for data source. Enter actual value, if known.

Ash content (%Ash):

13.6 percent by weight

\*The ash content of 13.6% is a default value. See below for data source. Enter actual value, if known.

For units burning coal blends:

Note: The table below is pre-populated with default values for HHV, %S, %Ash and cost. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

	Fraction in Coal Blend	%S	%Ash	HHV (Btu/lb)	Fuel Cost (\$/MMBtu)
Bituminous	0	1.84	9.23	11,841	2.4
Sub-Bituminous	0	0.41	5.84	8,826	1.89
Lignite	0	0.82	13.6	6,626	1.74

Please click the calculate button to calculate weighted values based on the data in the table above.

### Enter the following design parameters for the proposed SNCR:

Number of days the SNCR operates ( $t_{\text{SNCR}}$ )

365 days

Plant Elevation

1980 Feet above sea level

Inlet  $\text{NO}_x$  Emissions ( $\text{NO}_{x,\text{in}}$ ) to SNCR

0.13 lb/MMBtu

Outlet  $\text{NO}_x$  Emissions ( $\text{NO}_{x,\text{out}}$ ) from SNCR

0.10 lb/MMBtu

Estimated Normalized Stoichiometric Ratio (NSR)

3.00

\*The NSR for a urea system may be calculated using equation 1.17 in Section 4, Chapter 1 of the Air Pollution Control Cost Manual (as updated March 2019).

Concentration of reagent as stored ( $C_{\text{stored}}$ )

50 Percent

Density of reagent as stored ( $\rho_{\text{stored}}$ )

71 lb/ft<sup>3</sup>

Concentration of reagent injected ( $C_{\text{inj}}$ )

50 percent

Number of days reagent is stored ( $t_{\text{storage}}$ )

14 days

Estimated equipment life

20 Years

#### Densities of typical SNCR reagents:

50% urea solution	71 lbs/ft <sup>3</sup>
29.4% aqueous $\text{NH}_3$	56 lbs/ft <sup>3</sup>

Select the reagent used

Urea

### Enter the cost data for the proposed SNCR:

Desired dollar-year

2018

CEPCI for 2018

615.3 Enter the CEPCI value for 2018

541.7

2016 CEPCI

CEPCI = Chemical Engineering Plant Cost Index

Annual Interest Rate (i)

5.25 Percent

Fuel ( $\text{Cost}_{\text{fuel}}$ )

1.74 \$/MMBtu\*

Reagent ( $\text{Cost}_{\text{reag}}$ )

1.66 \$/gallon for a 50 percent solution of urea\*

Water ( $\text{Cost}_{\text{water}}$ )

0.0042 \$/gallon\*

Electricity ( $\text{Cost}_{\text{elect}}$ )

0.0361 \$/kWh\*

Ash Disposal (for coal-fired boilers only) ( $\text{Cost}_{\text{ash}}$ )

48.80 \$/ton\*

\* The values marked are default values. See the table below for the default values used and their references. Enter actual values, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

### Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =

0.015

Administrative Charges Factor (ACF) =

0.03

## Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost (\$/gallon)	\$1.66/gallon of 50% urea solution	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6, Using the Integrated Planning Model, Updates to the Cost and Performance for APC Technologies, SNCR Cost Development Methodology, Chapter 5, Attachment 5-4, January 2017. Available at: <a href="https://www.epa.gov/sites/production/files/2018-05/documents/attachment_5-4_sncr_cost_development_methodology.pdf">https://www.epa.gov/sites/production/files/2018-05/documents/attachment_5-4_sncr_cost_development_methodology.pdf</a> .	
Water Cost (\$/gallon)	0.00417	Average water rates for industrial facilities in 2013 compiled by Black & Veatch. (see 2012/2013 "50 Largest Cities Water/Wastewater Rate Survey." Available at <a href="http://www.saws.org/who_we_are/community/RAC/docs/2014/50-largest-cities-brochure-water-wastewater-rate-survey.pdf">http://www.saws.org/who_we_are/community/RAC/docs/2014/50-largest-cities-brochure-water-wastewater-rate-survey.pdf</a> .	
Electricity Cost (\$/kWh)	0.0361	U.S. Energy Information Administration. Electric Power Annual 2016. Table 8.4. Published December 2017. Available at: <a href="https://www.eia.gov/electricity/annual/pdf/epa.pdf">https://www.eia.gov/electricity/annual/pdf/epa.pdf</a> .	
Fuel Cost (\$/MMBtu)	1.74	U.S. Energy Information Administration. Electric Power Annual 2016. Table 7.4. Published December 2017. Available at: <a href="https://www.eia.gov/electricity/annual/pdf/epa.pdf">https://www.eia.gov/electricity/annual/pdf/epa.pdf</a> .	
Ash Disposal Cost (\$/ton)	48.8	Waste Business Journal. The Cost to Landfill MSW Continues to Rise Despite Soft Demand. July 11, 2017. Available at: <a href="http://www.wastebusinessjournal.com/news/wbj20170711A.htm">http://www.wastebusinessjournal.com/news/wbj20170711A.htm</a> .	
Percent sulfur content for Coal (% weight)	0.82	Average sulfur content based on U.S. coal data for 2016 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at <a href="http://www.eia.gov/electricity/data/eia923/">http://www.eia.gov/electricity/data/eia923/</a> .	
Percent ash content for Coal (% weight)	13.60	Average ash content based on U.S. coal data for 2016 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at <a href="http://www.eia.gov/electricity/data/eia923/">http://www.eia.gov/electricity/data/eia923/</a> .	
Higher Heating Value (HHV) (Btu/lb)	6,685	2016 coal data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at <a href="http://www.eia.gov/electricity/data/eia923/">http://www.eia.gov/electricity/data/eia923/</a> .	
Interest Rate (%)	5.5	Default bank prime rate	

## SNCR Design Parameters

Coal Creek SNCR w MNL Cost Estimate for 2019 BART - 0.10 lb NO<sub>x</sub>/MMBtu

The following design parameters for the SNCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units
Maximum Annual Heat Input Rate (Q <sub>B</sub> ) =	Bmw x NPHR =	6,050	MMBtu/hour
Maximum Annual MWh Output =	Bmw x 8760 =	5,299,800	MWh
Estimated Actual Annual MWh Output (Boutput) =		4,610,826	MWh
Heat Rate Factor (HRF) =	NPHR/10 =	1.00	
Total System Capacity Factor (CF <sub>total</sub> ) =	(Boutput/Bmw)*(tsncr/365) =	0.87	fraction
Total operating time for the SNCR (t <sub>op</sub> ) =	CF <sub>total</sub> x 8760 =	7621	hours
NO <sub>x</sub> Removal Efficiency (EF) =	(NO <sub>x</sub> <sub>in</sub> - NO <sub>x</sub> <sub>out</sub> )/NO <sub>x</sub> <sub>in</sub> =	23	percent
NO <sub>x</sub> removed per hour =	NO <sub>x</sub> <sub>in</sub> x EF x Q <sub>B</sub> =	181.50	lb/hour
Total NO <sub>x</sub> removed per year =	(NO <sub>x</sub> <sub>in</sub> x EF x Q <sub>B</sub> x t <sub>op</sub> )/2000 =	691.62	tons/year
Coal Factor (Coal <sub>F</sub> ) =	1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.07	
SO <sub>2</sub> Emission rate =	(%S/100)x(64/32)*(1x10 <sup>6</sup> )/HHV =	< 3	lbs/MMBtu
Elevation Factor (ELEVF) =	14.7 psia/P =	1.07	
Atmospheric pressure at 1980 feet above sea level (P) =	$2116 \times [(59 - (0.00356 \times h)) + 459.7] / 518.6^{5.256} \times (1/144)^*$ =	13.7	psia
Retrofit Factor (RF) =	Retrofit to existing boiler	1.00	

\* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at <https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html>.

**Reagent Data:**

Type of reagent used

Urea

Molecular Weight of Reagent (MW) =

60.06 g/mole

Density =

71 lb/gallon

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ( $m_{\text{reagent}}$ ) =	$(\text{NOx}_{\text{in}} \times Q_{\text{B}} \times \text{NSR} \times \text{MW}_{\text{R}}) / (\text{MW}_{\text{NOx}} \times \text{SR}) =$ (whre SR = 1 for $\text{NH}_3$ ; 2 for Urea)	1540	lb/hour
Reagent Usage Rate ( $m_{\text{sol}}$ ) =	$m_{\text{reagent}} / C_{\text{sol}} =$	3,080	lb/hour
	$(m_{\text{sol}} \times 7.4805) / \text{Reagent Density} =$	324.5	gal/hour
Estimated tank volume for reagent storage =	$(m_{\text{sol}} \times 7.4805 \times t_{\text{storage}} \times 24 \text{ hours/day}) / \text{Reagent Density} =$	109,100	gallons (storage needed to store a 14 day reagent supply rounded up to the nearest 100 gallons)

**Capital Recovery Factor:**

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i (1+i)^n / ((1+i)^n - 1) =$ Where n = Equipment Life and i= Interest Rate	0.0820

Parameter	Equation	Calculated Value	Units
<b>Electricity Usage:</b> Electricity Consumption (P) =	$(0.47 \times \text{NOx}_{\text{in}} \times \text{NSR} \times Q_{\text{B}}) / \text{NPHR} =$	110.9	kW/hour
<b>Water Usage:</b> Water consumption ( $q_{\text{w}}$ ) =	$(m_{\text{sol}} / \text{Density of water}) \times ((C_{\text{stored}} / C_{\text{inj}}) - 1) =$	0	gallons/hour
<b>Fuel Data:</b> Additional Fuel required to evaporate water in injected reagent ( $\Delta \text{Fuel}$ ) =	$H_v \times m_{\text{reagent}} \times ((1/C_{\text{inj}}) - 1) =$	1.39	MMBtu/hour
<b>Ash Disposal:</b> Additional ash produced due to increased fuel consumption ( $\Delta \text{ash}$ ) =	$(\Delta \text{fuel} \times \% \text{Ash} \times 1 \times 10^6) / \text{HHV} =$	28.4	lb/hour

## Cost Estimate

Coal Creek SNCR w MNL Cost Estimate for 2019 BART - 0.10 lb NO<sub>x</sub>/MMBtu

### Total Capital Investment (TCI)

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + APH_{cost} + BOP_{cost})$$

For Fuel Oil and Natural Gas-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + BOP_{cost})$$

Capital costs for the SNCR ( $SNCR_{cost}$ ) =	\$4,230,857 in 2018 dollars
Air Pre-Heater Costs ( $APH_{cost}$ )* =	\$0 in 2018 dollars
Balance of Plant Costs ( $BOP_{cost}$ ) =	\$5,617,234 in 2018 dollars
<b>Total Capital Investment (TCI) =</b>	<b>\$12,802,518 in 2018 dollars</b>

\* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 0.3lb/MMBtu of sulfur dioxide.

### SNCR Capital Costs ( $SNCR_{cost}$ )

For Coal-Fired Utility Boilers:

$$SNCR_{cost} = 220,000 \times (B_{MW} \times HRF)^{0.42} \times \text{CoalF} \times \text{BTF} \times \text{ELEV} \times \text{RF}$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$SNCR_{cost} = 147,000 \times (B_{MW} \times HRF)^{0.42} \times \text{ELEV} \times \text{RF}$$

For Coal-Fired Industrial Boilers:

$$SNCR_{cost} = 220,000 \times (0.1 \times Q_B \times HRF)^{0.42} \times \text{CoalF} \times \text{BTF} \times \text{ELEV} \times \text{RF}$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$SNCR_{cost} = 147,000 \times ((Q_B/NPHR) \times HRF)^{0.42} \times \text{ELEV} \times \text{RF}$$

SNCR Capital Costs ( $SNCR_{cost}$ ) =	\$4,230,857 in 2018 dollars
--	-----------------------------

### Air Pre-Heater Costs ( $APH_{cost}$ )\*

For Coal-Fired Utility Boilers:

$$APH_{cost} = 69,000 \times (B_{MW} \times HRF \times \text{CoalF})^{0.78} \times \text{AHF} \times \text{RF}$$

For Coal-Fired Industrial Boilers:

$$APH_{cost} = 69,000 \times (0.1 \times Q_B \times HRF \times \text{CoalF})^{0.78} \times \text{AHF} \times \text{RF}$$

Air Pre-Heater Costs ( $APH_{cost}$ ) =	\$0 in 2018 dollars
---	---------------------

\* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 3lb/MMBtu of sulfur dioxide.

### Balance of Plant Costs ( $BOP_{cost}$ )

For Coal-Fired Utility Boilers:

$$BOP_{cost} = 320,000 \times (B_{MW})^{0.33} \times (\text{NO}_x\text{Removed/hr})^{0.12} \times \text{BTF} \times \text{RF}$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$BOP_{cost} = 213,000 \times (B_{MW})^{0.33} \times (\text{NO}_x\text{Removed/hr})^{0.12} \times \text{RF}$$

For Coal-Fired Industrial Boilers:

$$BOP_{cost} = 320,000 \times (0.1 \times Q_B)^{0.33} \times (\text{NO}_x\text{Removed/hr})^{0.12} \times \text{BTF} \times \text{RF}$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$BOP_{cost} = 213,000 \times (Q_B/NPHR)^{0.33} \times (\text{NO}_x\text{Removed/hr})^{0.12} \times \text{RF}$$

Balance of Plant Costs ( $BOP_{cost}$ ) =	\$5,617,234 in 2018 dollars
---	-----------------------------

## Annual Costs

### Total Annual Cost (TAC)

$$\text{TAC} = \text{Direct Annual Costs} + \text{Indirect Annual Costs}$$

Direct Annual Costs (DAC) =	\$4,351,631 in 2018 dollars
Indirect Annual Costs (IDAC) =	\$1,055,568 in 2018 dollars
Total annual costs (TAC) = DAC + IDAC	\$5,407,198 in 2018 dollars

### Direct Annual Costs (DAC)

$$\text{DAC} = (\text{Annual Maintenance Cost}) + (\text{Annual Reagent Cost}) + (\text{Annual Electricity Cost}) + (\text{Annual Water Cost}) + (\text{Annual Fuel Cost}) + (\text{Annual Ash Cost})$$

Annual Maintenance Cost =	$0.015 \times \text{TCI} =$	\$192,038 in 2018 dollars
Annual Reagent Cost =	$q_{\text{sol}} \times \text{Cost}_{\text{reag}} \times t_{\text{op}} =$	\$4,105,413 in 2018 dollars
Annual Electricity Cost =	$P \times \text{Cost}_{\text{elect}} \times t_{\text{op}} =$	\$30,510 in 2018 dollars
Annual Water Cost =	$q_{\text{water}} \times \text{Cost}_{\text{water}} \times t_{\text{op}} =$	\$0 in 2018 dollars
Additional Fuel Cost =	$\Delta \text{Fuel} \times \text{Cost}_{\text{fuel}} \times t_{\text{op}} =$	\$18,380 in 2018 dollars
Additional Ash Cost =	$\Delta \text{Ash} \times \text{Cost}_{\text{ash}} \times t_{\text{op}} \times (1/2000) =$	\$5,290 in 2018 dollars
Direct Annual Cost =		\$4,351,631 in 2018 dollars

### Indirect Annual Cost (IDAC)

$$\text{IDAC} = \text{Administrative Charges} + \text{Capital Recovery Costs}$$

Administrative Charges (AC) =	$0.03 \times \text{Annual Maintenance Cost} =$	\$5,761 in 2018 dollars
Capital Recovery Costs (CR) =	$\text{CRF} \times \text{TCI} =$	\$1,049,806 in 2018 dollars
Indirect Annual Cost (IDAC) =	$\text{AC} + \text{CR} =$	\$1,055,568 in 2018 dollars

## Cost Effectiveness

$$\text{Cost Effectiveness} = \text{Total Annual Cost} / \text{NOx Removed/year}$$

Total Annual Cost (TAC) =	\$5,407,198 per year in 2018 dollars
NOx Removed =	692 tons/year
Cost Effectiveness =	\$7,818 per ton of NOx removed in 2018 dollars

## Attachment H-1

Report "Estimating Total Sulfuric Acid Emissions from Stationary Power Plants" 2018 Update; Electric Power Research Institute



# **Estimating Total Sulfuric Acid Emissions from Stationary Power Plants**

*2018 Update*

**3002012398**

---

# **Estimating Total Sulfuric Acid Emissions from Stationary Power Plants**

*2018 Update*

3002012398

Technical Update, March 2018

EPRI Project Manager

N. Goodman

## **DISCLAIMER OF WARRANTIES AND LIMITATION OF LIABILITIES**

THIS DOCUMENT WAS PREPARED BY THE ORGANIZATION(S) NAMED BELOW AS AN ACCOUNT OF WORK SPONSORED OR COSPONSORED BY THE ELECTRIC POWER RESEARCH INSTITUTE, INC. (EPRI). NEITHER EPRI, ANY MEMBER OF EPRI, ANY COSPONSOR, THE ORGANIZATION(S) BELOW, NOR ANY PERSON ACTING ON BEHALF OF ANY OF THEM:

(A) MAKES ANY WARRANTY OR REPRESENTATION WHATSOEVER, EXPRESS OR IMPLIED, (I) WITH RESPECT TO THE USE OF ANY INFORMATION, APPARATUS, METHOD, PROCESS, OR SIMILAR ITEM DISCLOSED IN THIS DOCUMENT, INCLUDING MERCHANTABILITY AND FITNESS FOR A PARTICULAR PURPOSE, OR (II) THAT SUCH USE DOES NOT INFRINGE ON OR INTERFERE WITH PRIVATELY OWNED RIGHTS, INCLUDING ANY PARTY'S INTELLECTUAL PROPERTY, OR (III) THAT THIS DOCUMENT IS SUITABLE TO ANY PARTICULAR USER'S CIRCUMSTANCE; OR

(B) ASSUMES RESPONSIBILITY FOR ANY DAMAGES OR OTHER LIABILITY WHATSOEVER (INCLUDING ANY CONSEQUENTIAL DAMAGES, EVEN IF EPRI OR ANY EPRI REPRESENTATIVE HAS BEEN ADVISED OF THE POSSIBILITY OF SUCH DAMAGES) RESULTING FROM YOUR SELECTION OR USE OF THIS DOCUMENT OR ANY INFORMATION, APPARATUS, METHOD, PROCESS, OR SIMILAR ITEM DISCLOSED IN THIS DOCUMENT.

REFERENCE HEREIN TO ANY SPECIFIC COMMERCIAL PRODUCT, PROCESS, OR SERVICE BY ITS TRADE NAME, TRADEMARK, MANUFACTURER, OR OTHERWISE, DOES NOT NECESSARILY CONSTITUTE OR IMPLY ITS ENDORSEMENT, RECOMMENDATION, OR FAVORING BY EPRI.


THE FOLLOWING ORGANIZATION, UNDER CONTRACT TO EPRI, PREPARED THIS REPORT:

**Fossil Energy Research Corporation**

**This is an EPRI Technical Update report. A Technical Update report is intended as an informal report of continuing research, a meeting, or a topical study. It is not a final EPRI technical report.**

## **NOTE**

For further information about EPRI, call the EPRI Customer Assistance Center at 800.313.3774 or e-mail [askepri@epri.com](mailto:askepri@epri.com).

Electric Power Research Institute, EPRI, and TOGETHER  SHAPING THE FUTURE OF ELECTRICITY are registered service marks of the Electric Power Research Institute, Inc.

Copyright © 2018 Electric Power Research Institute, Inc. All rights reserved.

# ACKNOWLEDGMENTS

The following organization, under contract to the Electric Power Research Institute (EPRI), prepared this report:

Fossil Energy Research Corporation  
23342C South Pointe  
Laguna Hills, Ca 92653

Principal Investigator  
J. Muncy

This report describes research sponsored by EPRI.

The methodology described in this document was developed by Southern Company Services and modified, with permission, by EPRI. Individuals responsible for the development of the original Southern Company sulfuric acid model are Keith E. Harrison and Larry S. Monroe, Ph.D. of the Southern Company.

---

This publication is a corporate document that should be cited in the literature in the following manner:

*Estimating Total Sulfuric Acid Emissions from Stationary Power Plants: 2018 Update.* EPRI, Palo Alto, CA: 2018. 3002012398.

## ABSTRACT

The U. S. Environmental Protection Agency's (EPA's) Toxics Release Inventory (TRI) program requires electric utilities to estimate and report annual emissions of 682 chemicals and chemical categories. Sulfuric acid ( $\text{H}_2\text{SO}_4$ ) is one of the chemicals included in the TRI reporting requirement, when it is present in an aerosol form. The EPA defines sulfuric acid aerosols as "includ[ing] mists, vapors, gas, fog, and other airborne forms of any particle size." The objective of this report is to provide a method for predicting the sulfuric acid manufactured during fuel combustion, removed by air pollution control equipment or flue gas treatment, and released to the environment in stack gases. The estimation method is an empirical model, whereby emissions are predicted from factors derived from sulfuric acid measurements at full-scale power plants. The power generation units considered in the report include coal, oil and natural gas-fired boilers, as well as both simple and combined cycle gas turbines. The procedures presented here can be used to estimate sulfuric acid manufacture from combustion, operation of nitrogen oxide reduction control equipment and flue gas conditioning, and the removal of  $\text{SO}_3$  or  $\text{H}_2\text{SO}_4$  from the flue gas stream by air heaters, particulate control devices such as electrostatic precipitators (ESPs) and fabric filters, sulfur dioxide control equipment, and nitrogen oxide control equipment.

### Keywords

Air emissions

Coal combustion

Natural gas combustion

Sulfuric acid

Toxics Release Inventory (TRI)

**Deliverable Number:** 3002012398

**Product Type:** Technical Update

**Product Title:** Estimating Total Sulfuric Acid Emissions from Stationary Power Plants: 2018 Update

---

**PRIMARY AUDIENCE:** Power company environmental staff responsible for Toxics Release Inventory reporting and air permitting.

**SECONDARY AUDIENCE:** Air quality agencies and other organizations with an interest in power plant emissions.

### **KEY RESEARCH QUESTION**

The U. S. Environmental Protection Agency's (EPA's) Toxics Release Inventory (TRI) program requires owners of some coal-, oil-, and natural gas-fired power plants to estimate and report annual emissions of 682 chemicals and chemical categories. Sulfuric acid ( $\text{H}_2\text{SO}_4$ ) is one of the chemicals included in the TRI reporting requirement, when it is present in an aerosol form. The objective of this report is to provide a method for predicting the sulfuric acid manufactured during fuel combustion, removed by air pollution control equipment or flue gas treatment, and released to the environment in stack gases.

### **RESEARCH OVERVIEW**

The sulfuric acid estimation method is an empirical model, whereby emissions are predicted from factors derived from sulfuric acid measurements at full-scale power plants. The power generation units considered in the report include coal, oil, and natural gas-fired boilers, as well as both simple and combined cycle gas turbines. The procedures presented here can be used to estimate sulfuric acid manufacture from combustion, operation of nitrogen oxide reduction control equipment and flue gas conditioning, and the removal of  $\text{SO}_3$  or  $\text{H}_2\text{SO}_4$  from the flue gas stream by air heaters, particulate control devices such as electrostatic precipitators (ESPs) and fabric filters, sulfur dioxide control equipment, and nitrogen oxide control equipment. The 2018 update to this report incorporates modifications to the methodology for estimating emissions from coal plants with hot-side electrostatic precipitators (ESPs), and plants that add magnesium oxide to inhibit conversion of sulfur dioxide to sulfur trioxide.

### **KEY FINDINGS**

- The principal sources of sulfuric acid emissions from fossil fuel-fired power plants are 1) oxidation of sulfur during fuel combustion, 2) injection of sulfur trioxide for flue gas conditioning to improve the efficiency of ESPs, and 3) increased conversion of sulfur dioxide to sulfur trioxide when flue gas passes through selective catalytic reduction (SCR) NOx control equipment.
- Sulfuric acid is removed from flue gas when it reacts with ammonia to form solids that are not reportable to TRI, and are also removed when the flue gas passes through wet or dry scrubber equipment.
- Measurements of sulfuric acid before and after power plant process equipment were used to develop factors representing the impact of fuel type and pollution control devices on formation and removal of sulfuric acid.

**WHY THIS MATTERS**

Sulfuric acid is emitted from power plants that burn coal, and to a lesser extent, those that burn oil or natural gas for electricity production. For some U.S. power plants, the quantities emitted must be reported annually to the Environmental Protection Agency TRI program, as well as to state agencies. This report provides power plant owners with a methodology to estimate the impact of fuel changes or new equipment on sulfuric acid emissions.

**HOW TO APPLY RESULTS**

The equations in this report provide a complete methodology for estimating emissions from most common fossil fuel-fired power plant configurations. The equations may be calculated by entering them into a spreadsheet. The Electric Power Research Institute (EPRI) also incorporates the equations into the Toxics Release Inventory for Power Plants software, designed to assist power plant owners with annual TRI reporting.

**LEARNING AND ENGAGEMENT OPPORTUNITIES**

- Toxics Release Inventory for Power Plants User's Group

**EPRI CONTACTS:** Naomi Goodman, Senior Technical Leader, [ngoodman@epri.com](mailto:ngoodman@epri.com)

**PROGRAM:** Program 59: Power Plant Multimedia Emissions Characterization

---

*Together...Shaping the Future of Electricity®*

**Electric Power Research Institute**

3420 Hillview Avenue, Palo Alto, California 94304-1338 • PO Box 10412, Palo Alto, California 94303-0813 USA  
[800.313.3774](tel:800.313.3774) • [650.855.2121](tel:650.855.2121) • [askepri@epri.com](mailto:askepri@epri.com) • [www.epri.com](http://www.epri.com)

© 2018 Electric Power Research Institute (EPRI), Inc. All rights reserved. Electric Power Research Institute, EPRI, and TOGETHER...SHAPING THE FUTURE OF ELECTRICITY are registered service marks of the Electric Power Research Institute, Inc.

# ACRONYMS AND ABBREVIATIONS

APH	air preheater
ABS	ammonium bisulfate
AS	ammonium sulfate
Btu	British thermal units
CCS	controlled condensation system
CEMS	continuous emissions monitoring system
EDTA	ethylenediamine tetraacetic acid
EGU	electric generation unit
EPA	U.S. Environmental Protection Agency
EPCRA	Emergency Planning and Community Right-To-Know Act
EPRI	Electric Power Research Institute
ESP	electrostatic precipitator
FGC	flue gas conditioning
FGD	flue gas desulfurization
lb	pound
HV	heating value
MBtu	million Btu
Mcf	thousand cubic feet (of natural gas)
mmBtu	million Btu (of natural gas)
mol	mole
MW	molecular weight
PCD	pollution control device
ppm	parts per million
ppmv	parts per million by volume
PRB	Powder River Basin
scf	standard cubic feet
SBS	sodium bisulfate
SCR	selective catalytic reduction
SCS	Southern Company Services
SNCR	selective non-catalytic reduction



TRI	Toxics Release Inventory
TSAM	total sulfuric acid manufactured
TSAR	total sulfuric acid release
WAF	wall adjustment factor
yr	year

## SI CONVERSION FACTORS

	English (US) units	X	Factor	=	SI units
Area:	1 ft <sup>2</sup>	X	$9.29 \times 10^{-2}$	=	m <sup>2</sup>
Flow Rate:	1 gal/min	X	$6.31 \times 10^{-5}$	=	m <sup>3</sup> /s
	1 gal/min	X	$6.31 \times 10^{-2}$	=	L/s
Length:	1 ft	X	0.3048	=	m
	1 in	X	2.54	=	cm
	1 yd	X	0.9144	=	m
Mass:	1 lb	X	454	=	g
	1 lb	X	0.454	=	kg
	1 gr	X	0.0648	=	g
	1 ton	X	0.907		tonne
Volume:	1 ft <sup>3</sup>	X	28.3	=	L
	1 ft <sup>3</sup>	X	0.0283	=	m <sup>3</sup>
	1 gal	X	3.785	=	L
	1 gal	X	$3.785 \times 10^{-3}$	=	m <sup>3</sup>
Temperature:	°F-32	X	0.556	=	°C
Energy:	Btu	X	1055.1	=	joule

# CONTENTS

<b>ABSTRACT .....</b>	<b>V</b>
<b>EXECUTIVE SUMMARY .....</b>	<b>VII</b>
<b>1 INTRODUCTION .....</b>	<b>1-1</b>
Background .....	1-1
Objective .....	1-2
Report Organization .....	1-2
<b>2 MEASUREMENT UNCERTAINTY .....</b>	<b>2-1</b>
CCS Measurement Uncertainty .....	2-1
Representativeness .....	2-2
<b>3 BACKGROUND AND METHODOLOGY OVERVIEW .....</b>	<b>3-1</b>
Description of General Methodology .....	3-1
Sulfuric Acid Manufacture from Combustion .....	3-1
Sulfuric Acid Manufacture from SCR/SNCR NO <sub>x</sub> Control .....	3-2
Sulfuric Acid Manufacture from Flue Gas Conditioning .....	3-3
Methodology to Estimate Release .....	3-3
Ammonia from SCR/SNCR NO <sub>x</sub> Control .....	3-7
Ammonia from Flue Gas Conditioning .....	3-8
Estimating Release with Alkali Injection .....	3-8
Estimating Sulfuric Acid with Partial-Year SNCR or SCR Operation .....	3-10
<b>4 ESTIMATING GUIDELINE: STEAM BOILERS .....</b>	<b>4-1</b>
Sulfuric Acid Manufacture .....	4-1
Sulfuric Acid Manufactured by Combustion (EM <sub>Comb</sub> ) .....	4-1
Sulfuric Acid Manufactured from SCR (EM <sub>SCR</sub> ) .....	4-8
Sulfuric Acid Manufactured from FGC (EM <sub>FGC</sub> ) .....	4-9
Total Manufacture from All Sources .....	4-12
Sulfuric Acid Release .....	4-12
Ammonia Slip from SCR and SNCR (NH <sub>3</sub> <sub>SCR</sub> ) .....	4-14
Ammonia Injection from FGC (NH <sub>3</sub> <sub>FGC</sub> ) .....	4-15
Total Release Calculation for Sources Employing Alkali Injection .....	4-16
Technology Impact Factors (F <sub>2</sub> ) .....	4-18
Air Heater .....	4-18
Particulate and SO <sub>3</sub> Control Processes .....	4-20
FGD .....	4-22
<b>5 ESTIMATING GUIDELINE: MULTIPLE FUEL OR BLENDED FUEL BOILERS .....</b>	<b>5-1</b>
<b>6 ESTIMATING GUIDELINE: COMBUSTION TURBINES .....</b>	<b>6-1</b>
Manufacture and Release for Simple Cycle Units .....	6-1
Combined Cycle Units .....	6-4
Sulfuric Acid Manufactured .....	6-4

<b>7 REFERENCES .....</b>	<b>7-1</b>
<b>A EXAMPLE CALCULATIONS.....</b>	<b>A-1</b>
Example 1: Conventional Coal-Fired Boiler with an ESP .....	A-1
Solution .....	A-1
Example 2: SCR Added to Example 1 .....	A-2
Solution .....	A-2
Example 3: Alkali Injection Added to Example 1 .....	A-4
Solution .....	A-4
Example 4: 500 MW PRB-fired Boiler with ESP, SCR.....	A-7
Solution .....	A-7
Example 5: FGC Added to Example 1 .....	A-9
Solution .....	A-9
Example 6: SCR and FGC Added to Example 1 .....	A-11
Solution .....	A-11
Example 7: SCR and Downstream FGC Added to Example 1 .....	A-12
Solution .....	A-12
Example 8: Coal-Fired Boiler with FGC, NG Startup Fuel, and Used Oil Co-Firing.....	A-13
Solution .....	A-13
Coal fuel calculations .....	A-13
Natural gas fuel calculations .....	A-13
Used oil fuel calculations.....	A-14
Example 9: Natural Gas Combined Cycle Plant .....	A-16
Solution .....	A-16
Example 10: SCR and CO catalyst added to Example 9 .....	A-17
Solution .....	A-17
<b>B CHRONOLOGY OF CHANGES TO THE EPRI SULFURIC ACID ESTIMATION MODEL..</b>	<b>B-1</b>

# LIST OF FIGURES

Figure 3-1 Schematic of Methodology Used to Estimate Sulfuric Acid Releases .....3-6

Figure 4-1 Relationship between Boiler SO<sub>3</sub> Production and Flue Gas SO<sub>2</sub> (corrected to 3% O<sub>2</sub>) .....4-5

Figure 4-2 Removal of Sulfuric Acid by Ljungstrom-Type Air Heaters .....4-19

Figure 4-3 Removal of Sulfuric Acid by Cold-Side ESPs and One Hot-Side ESP .....4-21

Figure 4-4 Removal of Sulfuric Acid by Flue Gas Desulfurization Equipment: Various FGD Designs, Coals .....4-23

## LIST OF TABLES

Table 4-1 Summary of Fuel Impact (F1) Factors for Steam Generating Units .....	4-7
Table 4-2 F3 <sub>SCR</sub> Technology Impact Factors for SCR.....	4-9
Table 4-3 Summary of F2 Factors for Air Heater Removal of Sulfuric Acid .....	4-20
Table 4-4 Summary of F2 Factors for Particulate Control Devices (ESP, Baghouse) .....	4-22
Table 4-5 Summary of F2 Factors for Wet and Dry FGD Equipment and Additives.....	4-24
Table 6-1 Fuel Impact (F1) Factors for a Simple CT .....	6-3



# 1

## INTRODUCTION

### Background

Estimation of sulfuric acid emissions from power plants is a topic of increasing importance to the U.S. electric utility industry. Most significantly, Section 313 of the Emergency Planning and Community Right-to-Know Act (EPCRA), also known as the Toxics Release Inventory (TRI), requires facilities that “manufacture,” “process,” or “otherwise use” a listed chemical above certain threshold amounts to report their annual releases of the chemical to EPA and state agencies. For sulfuric acid, the TRI reporting requirements are triggered if a facility “manufactures” or “processes” more than 25,000 pounds of this chemical or “otherwise uses” more than 10,000 pounds of it in a given calendar year.

In June 1995, the U. S. Environmental Protection Agency (EPA) modified the list of chemicals subject to the EPCRA § 313 reporting requirements so that only aerosol forms of sulfuric acid would be subject to the TRI reporting requirements (EPA, 1995a). EPA defines sulfuric acid aerosols as “includ[ing] mists, vapors, gas, fog, and other airborne forms of any particle size.” Although initially it appeared that only liquid droplets of sulfuric acid needed to be reported, the present method estimates the sulfuric acid emissions regardless of the physical state of the molecules.

Beginning on July 1, 1999, certain coal- and oil-fired electric power plants have been required to report annual releases of TRI chemicals that they manufacture, process or otherwise use above threshold amounts. Under EPA’s EPCRA § 313 regulations, coal- and oil-fired electric utilities are deemed to “manufacture” sulfuric acid. Thus, electric utilities have to submit TRI reports on sulfuric acid aerosol releases if they “manufacture” more than 25,000 pounds of the chemical in a given reporting year (EPA, 1997).

Emissions of sulfuric acid received considerable attention in with the broad application of selective catalytic reduction (SCR) NO<sub>x</sub> control technology. The use of SCR unavoidably contributes to production of sulfur trioxide (SO<sub>3</sub>), the precursor of sulfuric acid. Several notable incidents have been witnessed where an increase in sulfuric acid emissions, as manifested by an increase in stack plume visibility, was attributed to the addition of SCR process equipment to an existing power plant. The deployment of approximately 115 GW of selective catalytic reduction (SCR) from 1997 through 2009 prompted power plant owners to conduct extensive measurements documenting the fate of SO<sub>3</sub> and sulfuric acid in power plants.

The methodology described in this report was developed by Southern Company Services (SCS). Between 2000 and 2005, SCS developed several versions of the estimation methodology and released draft reports informally (Hardman, 1998; Hardman, 1999; Monroe, 2001, Harrison, 2004, and Harrison, 2005). The SCS model was widely used in the electrical power generation industry for TRI reporting and other emissions estimation purposes. In 2007, EPRI received permission from Southern Company Services to modify the SCS estimation method to include additional data and improvements, and to publish this method under EPRI sponsorship. The 2008



version of the model added the ability to estimate emissions based on a specified sulfuric acid flue gas concentration at the stack, which can be used when alkali injection is employed to reduce sulfuric acid emissions. The 2010 version updated several of the “technology impact factors” (F2 factors, used to reflect the impact of pollution control devices on sulfuric acid releases) with new SO<sub>3</sub> measurements. The 2012 version of the model (EPRI, 2012) made minor changes to the calculation procedure to more accurately represent flow through from the boiler and control devices, changed the approach used to account for sulfuric acid from flue gas conditioning (FGC), and made several corrections and clarifications to technology factors, including a new technology factor for units with a wet electrostatic precipitator (ESP) and the addition of a new sulfuric acid source through the oxidation of sulfur dioxide across a carbon monoxide catalyst in combined cycle units.

The current version of the model makes minor changes to the application of the sulfuric acid removal factors (Technology Impact Factors, F2) for configurations that include a hot-side ESP or magnesium oxide addition to the fuel or furnace. This version also incorporates methodology for the calculation of releases when SCR or SCNR is only injected on a partial-year basis (previously published in 2014 as an erratum to the 2012 report).

## **Objective**

The objective of this report is to present a methodology for estimating sulfuric acid emissions from power generating facilities, for use in Toxics Release Inventory reporting and other applications. The scope of units considered includes coal- and oil-fired steam generating units, as well as simple cycle and combined cycle natural gas- and oil-fired combustion turbines. To date, the most authoritative and documented data describe sulfuric acid emissions from coal-fired steam generators. The focus on this category of units is due to the increased availability of measurements describing the fate of sulfuric acid attributable to the retrofit of SCR process equipment on coal-fired steam generators.

## **Report Organization**

Section 2 of this report addresses the uncertainty in measuring SO<sub>3</sub> concentration using the preferred controlled condensation system (CCS) method, and the accuracy and representativeness of the available data. Section 3 outlines the general methodology adopted in this model while Section 4 describes the details of the methodology, focusing on data that can be used to predict sulfuric acid manufacture by combustion. This section also summarizes data describing the removal of sulfuric acid across air heaters, ESPs, and wet flue gas desulfurization (FGD) process equipment. Section 5 outlines how to conduct the calculation for steam boilers firing a mixture of fuels. Section 6 addresses simple cycle and combined cycle combustion turbine applications. Example calculations for various power plant configurations are presented in Appendix A. A chronology of changes to the sulfuric acid model is presented in Appendix B.

# 2

## MEASUREMENT UNCERTAINTY

A predictive method for sulfuric acid emissions requires knowledge of sulfuric acid production and the fate of emissions from specific boilers and combustion turbines, to an acceptable degree of measurement accuracy. In addition, a large database of measurements from many electric generating units (EGUs) is desired to obtain a robust predictive method. Both the size and the representativeness of the measurement database are critical to the accuracy of a predictive method.

The predictive correlations presented in this report are based on data obtained from field tests conducted predominantly within the last 10 years, with some estimates conducted in the 1990s. The quality of the data is thought to vary widely. It was not possible to obtain quality control information for all of the available measurements; thus, it was not possible to critically review all data used in this model.

The technique used to measure  $\text{SO}_3/\text{H}_2\text{SO}_4$  is not known for all data sources, but most measurements were conducted using the controlled condensate system (CCS), a widely used technique that is generally considered the most accurate method for measuring  $\text{SO}_3/\text{H}_2\text{SO}_4$  in stack gases from stationary combustion sources. EPA Method 8 is sometimes used for this purpose, but that method has a known positive bias from oxidation of  $\text{SO}_2$  to  $\text{SO}_3$  in the impinger solution.

### CCS Measurement Uncertainty

A series of field and laboratory trials conducted by EPRI evaluated the measurement bias of the CCS technique by comparing results from both laboratory tests and field trials (EPRI, 2001).  $\text{SO}_3/\text{H}_2\text{SO}_4$  measurements at similar gas compositions were compared in a 1) clean, ash-free laboratory environment; 2) simulated ash environment, and 3) actual field duty. The findings of the EPRI tests conducted under high-ash conditions are applicable to much of the field data used to derive removal factors in the current estimation model. The results showed that, when fly ash was present in the flue gas stream, the technique imposed a low bias (e.g., indicated lower  $\text{SO}_3/\text{H}_2\text{SO}_4$  than measured in the ash-free laboratory environment), due to reactions of  $\text{SO}_3$  or sulfuric acid with fly ash in the filter thimble holder upstream of the CCS condenser. Conversely, the EPRI tests indicated that use of CCS downstream of the particulate control device produces unbiased measurements, as long as appropriate procedures are followed.

The extent of bias observed in the EPRI study depended on the sampling location, which could be the air heater inlet, air heater outlet, or flue gas desulfurization outlet. Furthermore, the bias depended on the quantity of ash collected, the alkalinity of the ash, and the coal sulfur content (e.g.,  $\text{SO}_2$  content in the sample gas). Measurement bias in the simulated ash environment was observed for both high sulfur coal and low sulfur Powder River Basin (PRB) coal; however biasing in the PRB coal tests can generally be considered non-significant in light of already low  $\text{SO}_3$  concentrations and the expected absorption of sulfuric acid with the alkaline ash in actual field tests. Data for high sulfur coal suggested a low bias of 20-25% could occur in measurement

locations upstream of a particulate control device with typical ash loadings, and no significant bias downstream of the particulate control device.

The precision of the CCS data used in this estimation model can be estimated from the variability among duplicate measurements believed to be conducted under the same process conditions. Data from recent field trials with experienced test crews suggest a precision of up to  $\pm 20\%$  is realistic for most conditions. The repeatability of the CCS measurements depends on avoiding stratification within the gas stream (traversing is very difficult), maintaining correct temperatures in the sampling train, and having well trained sampling personnel. Therefore, the precision of the entire data set used in this model, which includes data from older studies of unknown quality, is expected to be closer to  $\pm 50\%$ .

### **Representativeness**

The accuracy of the correlations presented in this report depends on the representativeness of the constituent data points. For some power plant configurations, only a few measurements are available, and the correlations provide only rough approximations of the flue gas  $\text{SO}_3/\text{H}_2\text{SO}_4$  releases for similar units. The category with the largest number of data points is dry-bottom boilers, firing low sulfur, eastern bituminous coal. In general, the number of  $\text{SO}_3$  measurements for various power plant configurations are proportional to the occurrence of those configurations among the total population of U.S. EGUs. The number of measurements in each power plant category should be considered when applying this model; factors based on one measurement have much higher uncertainty than factors based on dozens of measurements.

As a consequence of the uncertainty in  $\text{SO}_3/\text{H}_2\text{SO}_4$  measurements and the limited number of data points that comprise the relevant correlations, the predictive technique should be assumed to provide estimates within a  $\pm 50\%$  relative accuracy.

# 3

## BACKGROUND AND METHODOLOGY OVERVIEW

This section provides a brief overview of sulfuric acid production mechanisms in power plants and presents the basic equations for estimating sulfuric acid releases. A detailed review of this topic has been provided by Srivastava (2004) and more recently by Monroe (2006).

The production or manufacture of  $\text{SO}_3$ , and ultimately sulfuric acid, is determined initially by processes occurring directly within the flame zone of a boiler, the convective heat transfer sections, or environmental control components. These production or manufacturing processes can be gas phase or can be induced by catalysis on the surface of fly ash particles or heat removal surfaces.

Mechanisms that remove sulfuric acid from the flue gas also can occur both in the gas phase and on heat transfer surfaces, usually promoted by ash-derived deposits. The amount of sulfuric acid released from the stack is the aggregate result of production mechanisms, generally occurring at temperatures above  $650^\circ\text{F}$ , and removal mechanisms, including alkali-based sorbent injection, occurring at lower temperatures.

### Description of General Methodology

The method estimates the manufacture and the subsequent release of sulfuric acid from the power generation process. The *manufacture* of sulfuric acid is defined as any process step that increases the flue gas content of sulfuric acid, regardless of its ultimate fate. To estimate the *release* of sulfuric acid, the manufacture estimate is corrected by a factor or series of factors to account for sulfuric acid removal within the system.

Three process steps ultimately lead to the manufacture of sulfuric acid in a fossil fuel-fired electricity generation unit: the combustion process, selective catalytic reduction (SCR) for  $\text{NO}_x$  control, and flue gas conditioning. All remaining steps in the power generation process reduce sulfuric acid. Therefore, the total sulfuric acid released (TSAR) is the cumulative sum of the total sulfuric acid manufactured (TSAM), adjusted by sulfuric acid losses.

### Sulfuric Acid Manufacture from Combustion

A detailed analytical study by Senior (2002) explored details of  $\text{SO}_2$  oxidation to  $\text{SO}_3$ . Specifically, the author modeled the relevant reaction sets employing the temperature-time history of a typical utility boiler, considering gas phase events only and ignoring catalytic effects. The results showed that insignificant  $\text{SO}_3$  formed in the early stage of the flame, but  $\text{SO}_3$  production increased as the gases exited the flame zone and cooled. The author reported production of  $\text{SO}_3$  to be essentially complete prior to flue gas entering the economizer section. The observation that most  $\text{SO}_3$  forms during cooling from post-flame temperatures ( $2,900$ - $3,100^\circ\text{F}$ ) to temperatures typical of the economizer entrance was also noted by Buckley (2002). Senior further quantified the relationship between coal sulfur content, excess air, and  $\text{SO}_3$  production that has been empirically observed by previous investigators. Specifically, the results showed that after four seconds of residence time,  $\text{SO}_3$  production could range from between 0.3 - 0.6% of the flue gas  $\text{SO}_2$  concentration.

In the absence of SCR NO<sub>x</sub> control or FGC, the boiler or turbine combustion process comprises the only source of sulfuric acid. The sulfuric acid manufacture by the combustion process (EM<sub>Comb</sub>) is expressed as follows:

$$EM_{Comb} = K \bullet F1 \bullet E2 \quad \text{Eq. 3-1}$$

Where K is a constant, F1 is a Fuel Impact Factor describing the SO<sub>3</sub> production associated with combustion for a specific fuel type, and E2 is the annual rate of SO<sub>2</sub> production. Further details of this relationship and the derivation of constants and other terms are presented in Section 4. There are two situations where the TSAR equations must be modified to reflect reduction or removal of sulfuric acid from combustion: 1) the use of a hot-side ESP and 2) magnesium oxide (Mag-Ox) addition to the boiler or fuel. All other sources of sulfuric acid (SCR or FGC) are manufactured downstream of these two technologies and require no modifications. The derivation and use of technology impact factors for hot-side ESP and Mag-Ox addition are discussed in Section 4.

### ***Sulfuric Acid Manufacture from SCR/SNCR NO<sub>x</sub> Control***

The SCR process increases the production of SO<sub>3</sub>, and therefore, H<sub>2</sub>SO<sub>4</sub>, as a percentage of SO<sub>2</sub>. SO<sub>3</sub> production can range from as low as 0.3%, for the most recent catalyst technology, to as high as 3% of the SO<sub>2</sub> concentration.

The production of SO<sub>3</sub> from SO<sub>2</sub> is a well-known consequence of SCR, and the degree of SO<sub>2</sub> oxidation is a performance variable that should be part of catalyst procurement specifications. To a degree, SO<sub>3</sub> production can be mitigated by reducing the content of vanadium pentoxide and compensating with other catalyst oxides such as tungsten or molybdenum, which offer improved selectivity (e.g., lower SO<sub>2</sub> oxidation) but also lower activity for NO<sub>x</sub> removal. Alternatively, advanced catalyst formulations can be used that concentrate the vanadium-containing active ingredients on the catalyst surface and minimize content within the substrate, lowering SO<sub>2</sub> oxidation. To achieve an equivalent level of NO<sub>x</sub> and residual ammonia slip, a low SO<sub>2</sub> oxidation catalyst may require a larger volume of catalyst than one for which SO<sub>2</sub> conversion is not constrained. In general, the degree of SO<sub>2</sub> oxidation ranges from about 0.2% to 1.5% for most SCR process reactors designed for bituminous coals. If SCR is applied to extremely low sulfur, high alkalinity coals such as PRB, higher SO<sub>2</sub> oxidation is acceptable. Depending on how the measurement of SO<sub>2</sub> oxidation is performed, the oxidation can be 3% or higher.

In many instances, owners and catalyst suppliers prefer that measurements to quantify SO<sub>2</sub> oxidation for the purpose of commercial guarantees be conducted not with authentic flue gas but in a laboratory-scale test facility, without fly ash present. This approach has the advantage of improved accuracy and repeatability of the SO<sub>3</sub> concentration. The measurements are generally conducted using CCS. However, particularly for PRB coals, this method will over-predict SO<sub>3</sub> manufactured by the SCR, as the mitigating role of high fly ash alkalinity is not considered. Consequently, the role of fly ash alkalinity must be considered in predicting SO<sub>3</sub> manufactured by SCR.

The observation that calculated laboratory-scale SO<sub>3</sub> values at the exit of an SCR reactor exceed measurements in the field has been witnessed on numerous occasions. Specifically, Lindenhoff (2004) reported that the measured SO<sub>2</sub> oxidation rate for PRB-generated flue gas of 1.25% was below the 1.6% value predicted based on the boiler and SCR catalyst specifications. Further,

tests conducted by this catalyst manufacturer noted significant absorption of SO<sub>3</sub> generated within the SCR reactor prior to the air heater. Sufficient data was accumulated to derive both a mathematical model and to project a graphical relationship describing SO<sub>3</sub> removal within an SCR reactor as a function of both ash content and the number of alkaline sites available in the flue gas stream.

An alternative NO<sub>x</sub> control process, selective non-catalytic reduction (SNCR), does not use a catalyst and does not promote the oxidation of SO<sub>2</sub> to SO<sub>3</sub>. Accordingly, there is no manufacture of sulfuric acid attributable to SNCR.

The following relationship describes the total H<sub>2</sub>SO<sub>4</sub> manufactured from an SCR equipped utility boiler or steam generator:

$$EM_{SCR} = K \bullet S2 \bullet f_{sops} \bullet E2 \bullet F3_{SCR} \quad \text{Eq. 3-2}$$

Where K is a constant, S2 is the catalyst SO<sub>2</sub> oxidation rate,  $f_{sops}$  is the fraction of the coal burn in which flue gas is directed through the SCR, E2 is the annual rate of SO<sub>2</sub> production, and F3<sub>SCR</sub> is the Technology Impact Factor for SCR used to adjust for the presence of alkaline fly ash. Further details of this relationship and the derivation of constants and other terms are presented in Section 4.

### ***Sulfuric Acid Manufacture from Flue Gas Conditioning***

Flue gas conditioning (FGC) is a process that is typically used in power plants to assist in particulate control in an ESP or baghouse. The conditioning additives can be any of the following: SO<sub>3</sub>, SO<sub>3</sub> plus NH<sub>3</sub>, or NH<sub>3</sub> alone. In SO<sub>3</sub>-based FGC, SO<sub>3</sub> is introduced into the flue gas either preceding or following the air heater. The SO<sub>3</sub> is typically produced on-site from sulfurous fuel that is burned to produce SO<sub>2</sub>, which is then catalytically oxidized to SO<sub>3</sub> with a conversion rate typically exceeding 95%. When injected into the flue gas, the SO<sub>3</sub> immediately reacts with water vapor to create sulfuric acid, thus resulting in the manufacture of sulfuric acid. Estimating the manufacture source requires knowledge of the concentration of SO<sub>3</sub> injected and the associated oxygen content of the flue gas.

Equation 3-3 estimates the manufacture of sulfuric acid from FGC, where  $K_e$  is a constant, B is the coal burn,  $f_e$  is the FGC operating factor, and  $I_s$  the SO<sub>3</sub> injection rate. F3<sub>FGC</sub> is the Technology Impact Factor for FGC that is used to adjust for the presence of alkaline fly ash in PRB coals. Further details and derivation of the constant are provided in Section 4.

$$EM_{FGC} = K_e \bullet B \bullet f_e \bullet I_s \bullet F3_{FGC} \quad \text{Eq. 3-3}$$

### **Methodology to Estimate Release**

Sources of sulfuric acid manufactured upstream of the air preheater are calculated separately (modified for hot-side ESP or Mag-Ox if necessary), then summed. The combined SO<sub>3</sub> is modified to reflect reactions of SO<sub>3</sub> with residual equivalent NH<sub>3</sub> slip from SCR/SNCR equipment and/or FGC ammonia injection to form ABS, and then adjusted by removal in applicable downstream equipment such as the air preheater, electrostatic precipitator or other particulate control device (PCD) and flue gas desulfurization (FGD) equipment. In the calculations to determine the amount of ABS formation, ammonia slip is subtracted from sulfuric acid. However, the 1:1 ratio of H<sub>2</sub>SO<sub>4</sub> to NH<sub>3</sub> is on a molar basis. Therefore, all the following

calculations of ammonia slip are actually the amount of ammonia slip that is equivalent to sulfuric acid based on a 1:1 molar ratio, as determined through the use of the constant K. The adjustments are made using Technology Impact Factors (F2) which describe the fraction of sulfuric acid that penetrates each component.

The methodology employs the follow steps, combined into a single release equation, which is shown in Equation 3-4, and illustrated schematically in Figure 3-1:

1. Calculate the sources of sulfuric acid upstream of the APH from combustion, SCR and FGC
2. If applicable, apply the technology factor for sulfuric acid removal to the sulfuric acid manufactured from combustion only, for hot-side ESP and/or Mag-Ox addition
3. Sum the resulting sources of sulfuric acid upstream of the APH from combustion, SCR and FGC
4. Calculate residual equivalent ammonia slip from the SCR/SNCR and FGC and subtract this ammonia from the sum of the sources upstream of the APH to account for ABS formation which is not reportable
5. If the result of Steps 1) and 2) is a positive value, apply the technology factor for APH removal of SO<sub>3</sub> (F2<sub>APH</sub>)
6. Add downstream sources of sulfuric acid (from FGC, if injected downstream), and subtract downstream ammonia injection (from FGC, if injected downstream) to account for ABS, which is not reportable
7. Apply all remaining relevant downstream technology factors

In equation form, the methodology is expressed as shown in Equation 3-4.

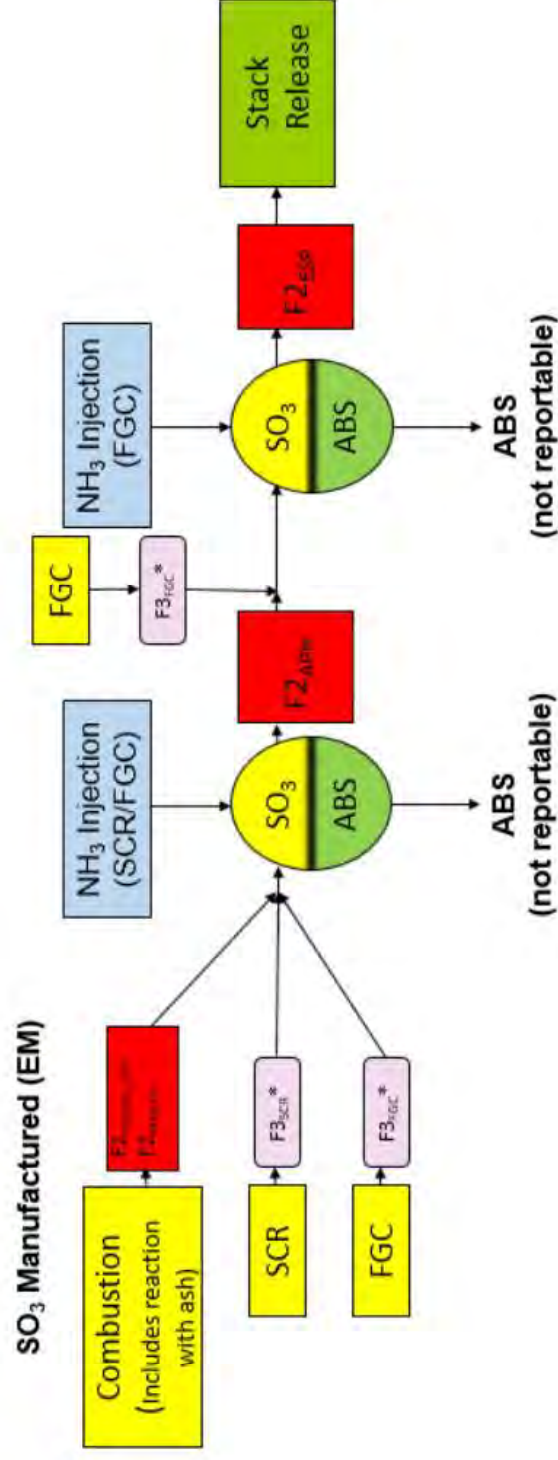
$$\text{TSAR} = \{ [ ( ( \text{EM}_{\text{Comb}} * F2_{\text{Hotside\_ESP}} * F2_{\text{Mag-ox}} ) + \text{EM}_{\text{SCR/SNCR}} + \text{EM}_{\text{FGC\_beforeAPH}} ) - ( \text{NH3}_{\text{SCR}} + \text{NH3}_{\text{FGC\_beforeAPH}} ) ] * F2_{\text{APH}} + ( \text{EM}_{\text{FGC\_afterAPH}} - \text{NH3}_{\text{FGC\_afterAPH}} ) \} * F2_x \quad \text{Eq. 3-4}$$

where,

TSAR	= Total sulfuric acid released
EM <sub>Comb</sub>	= Sulfuric acid manufactured through combustion
EM <sub>SCR/SNCR</sub>	= Sulfuric acid manufactured from SCR or SNCR
EM <sub>FGC\_beforeAPH</sub>	= Sulfuric acid manufactured from FGC injected upstream of the air preheater (APH)
EM <sub>FGC\_afterAPH</sub>	= Sulfuric acid manufactured from FGC injected downstream of the APH
NH <sub>3</sub> Slip	= Calculated equivalent ammonia slip that reacts with H <sub>2</sub> SO <sub>4</sub> to form ammonium bisulfate (ABS) from SCR/SNCR and/or FGC
F2 <sub>APH</sub>	= Technology Impact Factor for APH
F2 <sub>Hotside\_ESP</sub>	= Technology Impact Factor for hot-side ESP

	= 0.63 if hot-side ESP is present
	= 1.0 if hot-side ESP is <u>not</u> present (optional)
$F2_{Mag-Ox}$	= Technology Impact Factor for magnesium oxide addition in fuel or furnace
	= 0.25 (or custom) if Mag-Ox is sprayed into furnace
	= 0.50 (or custom) if Mag-Ox is mixed with fuel
	= 1.0 if Mag-Ox is <u>not</u> applied (optional)
$F2_x$	= Technology Impact Factors, all others that apply (downstream of APH)





\*F3 factor accounting for alkalinity of PRB ash

Figure 3-1  
Schematic of Methodology Used to Estimate Sulfuric Acid Releases

### ***Ammonia from SCR/SNCR NO<sub>x</sub> Control***

Both SCR and SNCR can introduce residual ammonia (NH<sub>3</sub>), also called ammonia slip, into the flue gas. This residual ammonia can react with SO<sub>3</sub> or sulfuric acid to form ammonium sulfate and/or ammonium bisulfate, thereby removing from the flue gas some of the SO<sub>3</sub> that is a precursor to sulfuric acid, and reducing the amount released.

For an SCR, ammonia slip is expected to usually range between 0 and 2 parts per million (ppm) for bituminous coal cases. Higher values of ammonia slip are possible if the unit has not been recently tuned, the boiler or SCR process operates under upset, or as the catalyst ages. Higher ammonia slip may be tolerable in PRB coal applications, since ammonia is not readily absorbed by the highly alkaline PRB ash and adverse operational impacts (air preheater pluggage and ash contamination by ammonia) are avoided. Reactions between the residual ammonia and SO<sub>3</sub> or H<sub>2</sub>SO<sub>4</sub> occur in the air preheater and result in a solid product that may deposit or accumulate on the surface of the fly ash. Any SO<sub>3</sub> or H<sub>2</sub>SO<sub>4</sub> that participates in these reactions is no longer present as sulfuric acid and is not required to be reported to the EPA TRI program as a release of sulfuric acid.

SNCR employs ammonia or urea injection in the upper furnace for NO<sub>x</sub> reduction. The higher temperatures characteristic of the upper furnace zone (1,800 to 2,400°F, as compared to 700°F for SCR) do not require reduction catalyst so there is no additional manufacture of SO<sub>3</sub> or sulfuric acid. Typically, SNCR systems operate with higher levels of residual ammonia (5 to 10 ppm), so any sulfuric acid that is present from combustion is reduced through reaction with the ammonia. Consequently, SNCR systems will always *reduce* the overall amount of sulfuric acid released, while SCR systems can *reduce* but will likely *increase* the amount of sulfuric acid released.

The reactions between SO<sub>3</sub> and/or H<sub>2</sub>SO<sub>4</sub> and ammonia produce ammonium sulfate [(NH<sub>4</sub>)<sub>2</sub>SO<sub>4</sub>] and/or ammonium bisulfate (NH<sub>4</sub>HSO<sub>4</sub>). While both chemicals are solids, the bisulfate pairs one molecule of ammonia with one of sulfuric acid, while the sulfate requires two ammonia molecules for each sulfuric acid. Which reaction product is present is usually determined by the stoichiometry, or the relative amount of each substance on a mole basis, that is present in the flue gas. When ammonia is present in an amount over twice the mole content of sulfuric acid, the reaction product will always be ammonium sulfate (AS). Conversely, when sulfuric acid is present in an amount on a mole basis greater than ammonia, the product will be ammonium bisulfate (ABS). Between these two extremes, a mixture of ammonium sulfate and bisulfate is produced.

A SCR-equipped unit firing bituminous coals with low-to-medium sulfur content will always produce an excess of sulfuric acid over ammonia slip. Accordingly, ammonium bisulfate is the primary byproduct anticipated. For subbituminous and lignite coals, any sulfuric acid produced is typically adsorbed by the ash and it is likely that residual ammonia will exceed sulfuric acid content on a mole basis. Under these conditions, ammonium sulfate is the likely product.

For SNCR-equipped units, ammonia slip levels of 5 ppm and possibly higher will favor ammonium sulfate, particularly for western U.S. coals where the alkaline fly ash will reduce the SO<sub>3</sub> content. For eastern bituminous coals, which have generally higher sulfur content and lower ash alkalinity, ammonium bisulfate will likely predominate.

For the purpose of predicting sulfuric acid emissions, these distinctions are not important. A single molecule of sulfuric acid will capture a single molecule of ammonia, producing ammonium bisulfate. If additional ammonia is available, the ammonium bisulfate can react with another ammonia molecule to form ammonium sulfate. It can be assumed that all sulfuric acid forms ammonium bisulfate before any further reaction to the ammonium sulfate form occurs. This assumption leads to the calculation strategy that ammonia captures all of the sulfuric acid it can as ammonium bisulfate, and since the bisulfate form is no longer reportable, the sulfuric acid disappears from the release calculation. Additional ammonia reacting with the ammonium bisulfate is of no consequence to the sulfuric acid calculation – although this reaction is important when estimating ammonia releases.

The total sulfuric acid released is reduced by the residual equivalent ammonia, or ammonia slip, from SCR or SNCR. This equivalent ammonia slip is calculated as follows, and is added to any ammonia injection from FGC before it is subtracted from the sum of the sulfuric acid manufactured.

$$\text{NH3}_{\text{SCR}} = K_s \bullet B \bullet f_{\text{sreagent}} \bullet \text{SNH3} \quad \text{Eq. 3-5}$$

Where  $K_s$  is a constant,  $B$  is the coal burn in TBtu/yr,  $f_{\text{sreagent}}$  is the fraction of SCR operation with reagent injection, and  $\text{SNH3}$  is the  $\text{NH}_3$  slip for the SCR/SCNR. This calculation and factors are described further in Section 4.

### ***Ammonia from Flue Gas Conditioning***

Flue gas conditioning may involve injection of  $\text{NH}_3$  alone or  $\text{NH}_3$  with  $\text{SO}_3$ . Thus, FGC can result in sulfuric acid manufacture or may result in sulfuric acid removal, if  $\text{NH}_3$  is injected alone or in quantities greater than the sulfuric acid. The following equation describes the calculation of equivalent ammonia that is used to reduce sulfuric acid. If ammonia is injected upstream of the APH, this value would be added to the residual ammonia from SCR/SNCR. If added downstream of the APH, the value would be subtracted from any downstream  $\text{SO}_3$  injection introduced by FGC.

$$\text{NH3}_{\text{FGC}} = K_e \bullet B \bullet f_e \bullet \text{INH3} \quad \text{Eq. 3-6}$$

Where  $K_e$  is a constant,  $B$  is the coal burn in TBtu/yr,  $f_e$  is the fraction of coal burn with FGC operation, and  $\text{INH3}$  is the  $\text{NH}_3$  injected. This calculation and factors are described further in Section 4.

### ***Estimating Release with Alkali Injection***

Many utility operators inject alkali into the flue gas to control  $\text{SO}_3$ . A wide variety of alkali materials based on calcium, sodium, or in some cases magnesium compounds, have been used with varying degrees of effectiveness to remove  $\text{SO}_3$ . These alkali materials include sodium bisulfate, trona, and various types of lime (conventional, hydrated, and magnesium enhanced).

Sodium bisulfate (SBS) is the most widely used reagent for control of  $\text{SO}_3$ . SBS is introduced into the flue gas, usually at the air heater exit, but in some units at the air heater inlet, to maximize residence time and improve  $\text{SO}_3$  removal. SBS can be highly effective in removing  $\text{SO}_3$ . Additional sodium can be added to the flue gas to compensate for any compromise in ESP

performance due to increased ash resistivity associated with SO<sub>3</sub> reduction. A detailed summary of experience with SBS usage has recently been published (Moser, 2007).

Trona is another sodium-containing reagent that is used to control SO<sub>3</sub>. Trona can be injected at several locations within the boiler, but most applications introduce trona at the air heater exit, prior to the particulate collector (Ritzenthaler, 2006). As with SBS, additional sodium introduced into flue gas is advantageous to compensate for the reduction in ESP performance.

Several forms of calcium-based sorbents can be utilized. These are injected at various locations in the flue gas, including the economizer inlet, economizer outlet (e.g., air heater inlet), and the air heater outlet. A survey of recent experience with lime-derived sorbents addressed the advantages of this approach (Benson, 2006a). Hydrated lime has been shown to be an effective calcium-based reagent for SO<sub>3</sub> control (Gale, 2006), as has lime supplemented with magnesium hydroxide (Benson, 2006b). Calcium-based sorbents can be very effective in reducing SO<sub>3</sub>, but may compromise ESP performance, as the reduced SO<sub>3</sub> content in flue gas increases the electrical resistivity of the ash on the collecting plate. For this reason, some operators have proposed using both calcium- and sodium-based sorbents, the latter to both augment SO<sub>3</sub> removal and promote ESP performance. In summary, any of several alkali materials can be used to control SO<sub>3</sub>, with the least cost solution depending on the plant and access to low cost sorbent.

Plant units that deploy alkali injection will generally have conducted field tests to determine the SO<sub>3</sub> concentration in flue gas for a specified sorbent injection rate. In most cases, these tests will be conducted at the stack. The alkali injection system usually is operated to reduce SO<sub>3</sub> emissions to between 5 and 15 ppm, an optimal range to prevent formation of a visible plume. A procedure to convert measured sulfuric acid concentration in flue gas to a mass emission rate is summarized below and described in more detail in Section 4. An example application of this procedure is provided in Appendix A.

$$ER_{ALKINJ} = K_{alkali} \bullet B \bullet S_{SO_3} \bullet F_{2x} \bullet F_{alkali} \quad \text{Eq. 3-7}$$

Where  $K_{alkali}$  is a constant, B is the coal burn,  $S_{SO_3}$  is the measured SO<sub>3</sub> content with injection,  $F_{alkali}$  is the fraction of time alkali injection is in operation, and F<sub>2</sub> are any applicable downstream Technology Impact Factors.

Users of this approach should be cautioned that the current EPA-approved test method for SO<sub>3</sub> (EPA Method 8) has a significant positive bias, and that corrections for this bias may be needed to accurately assess flue gas concentrations. A more accurate method is the controlled condensate system (CCS). Although no general-purpose, EPA-approved CCS method is currently available, it is widely used by stack test contractors for sulfuric acid measurement and is more accurate than Method 8, if performed correctly.

Some units will not have measured stack emissions. This version of the model adds an alternate approach to estimate releases with alkali injection if stack SO<sub>3</sub> measurements are not available. Instead of using Equation 3-7 for  $ER_{ALKINJ}$ , the total sulfuric acid release is calculated by estimating total releases using Equation 3-4. An alkali injection factor,  $F_{3ALKINJ}$ , is then applied to the total release as shown in Equation 3-8. This  $F_{3ALKINJ}$  is either the expected fractional reduction in SO<sub>3</sub> (generally as guaranteed by the vendor) or a default of 0.2. The basis of the 0.2 value is test results indicating that 80% removal is easily achievable (EPRI, 2010b). This method is explained in further detail in Section 4.

$$TSAR_{ALKINJ} = (TSAR_{Comb+SCR+FGC}) \bullet F3_{ALKINJ}$$

Eq. 3-8

To estimate SO<sub>3</sub> manufacture with alkali injection, plant owners should use the standard approaches given in Section 4 for the appropriate plant configuration. At this time, EPRI does not have sufficient information to estimate the impact on SO<sub>3</sub> formation of adding alkali at various points in the fuel combustion and stack gas treatment process. Assuming that there is no reduction of SO<sub>3</sub> formation is conservative for a threshold determination for TRI reporting purposes.

### ***Estimating Sulfuric Acid with Partial-Year SNCR or SCR Operation***

When ammonia or urea is employed in SCR or SNCR during only part of a year, the methodology outlined in this report may not provide an accurate estimate of total sulfuric acid released through the stack. The reason is that the model calculates the pounds of ammonia injected on an annual basis, and uses that quantity to subtract an equivalent quantity of sulfuric acid as non-reportable ammonia salt. However, if there is an excess of ammonia slip present during SCR/SNCR operation above the amount of SO<sub>3</sub> available to react, the model is in effect borrowing SO<sub>3</sub> from periods when the SCR/SNCR is not operating. As a result, the annual release of sulfuric acid will be underestimated for that unit. Underestimation of sulfuric acid releases is most likely to when the following conditions are met:

- SNCR (more likely) or SCR (less likely) operated partial-year
- Sulfuric acid emissions are calculated from fuel sulfur, not CEMS
- The operating factor for reagent addition in the SCR/SNCR system ( $f_{sreagent}$ ) is small
- The unit burns a fuel that inherently manufactures low levels of SO<sub>3</sub> from combustion, such as PRB coal
- The unit has high ammonia slip levels when ammonia is injected

To determine whether the model is underestimating releases for a unit with SCR or SNCR partial-year operation, the user should perform separate calculations for the SCR/SNCR “Ammonia On” condition and SCR/SNCR “Ammonia Off” condition, allocating the amount of fuel burned during the two conditions appropriately. If the sum of the sulfuric acid releases for these two conditions is greater than for the full-year calculation, separate calculations should be employed going forward.

# 4

## ESTIMATING GUIDELINE: STEAM BOILERS

This section describes an estimation procedure for calculating the manufacture and release of sulfuric acid from coal-fired steam generators. The topics addressed are (a) formation within the furnace; (b) the role of SCR, (c) flue gas conditioning (FGC), and (d) alkali injection; and (e) removal by downstream equipment such as air heaters, ESPs or other particulate control devices, and FGD process equipment. Each of the subsequent sections in this chapter provides the information to conduct this stepwise calculation.

### Sulfuric Acid Manufacture

#### *Sulfuric Acid Manufactured by Combustion ( $EM_{Comb}$ )*

The premise of the methodology is that the amount of sulfuric acid manufactured by the boiler is a function of the amount of  $SO_2$  produced – which may be determined either from coal usage (amount burned and sulfur content) or from continuous emission monitoring system (CEMS) output. Units equipped with FGD equipment or other methods of  $SO_2$  control are required to estimate emissions either from coal data or from the output of a CEMS positioned ahead of the scrubber. As described below, it may be necessary to correct  $SO_2$  CEMS data for non-ideal stack flow conditions.

The following relationship is used to estimate the sulfuric acid manufactured from combustion in utility sources:

$$EM_{Comb} = K \bullet F1 \bullet E2 \quad \text{Eq. 4-1}$$

where,

$EM_{Comb}$	=	total $H_2SO_4$ manufactured from combustion, lbs/yr
K	=	Molecular weight and units conversion constant
	=	$98.07 / 64.04 \bullet 2000 = 3,063$
		$98.07$ = Molecular weight of $H_2SO_4$
		$64.04$ = Molecular weight of $SO_2$
		2000 = Conversion from tons per year to pounds per year.
F1	=	Fuel Impact Factor
E2	=	Sulfur dioxide ( $SO_2$ ) emissions, either: (1) recorded by a continuous emissions monitor, tons/yr, or (2) calculated from coal burn data, tons/yr.

The Fuel Impact Factor (F1) is a numerical value or a mathematical relationship reflecting the conversion of  $SO_2$  to  $SO_3$  in the boiler for a specific coal type and boiler type. In the derivation of Equation 4-1, the following assumptions are made:

- SO<sub>3</sub> concentrations are proportional to SO<sub>2</sub> concentrations.
- The grade of coal being burned impacts the rate of conversion from SO<sub>2</sub> to SO<sub>3</sub>.
- All SO<sub>3</sub> that forms is converted to H<sub>2</sub>SO<sub>4</sub>.
- The rate of SO<sub>3</sub> formation is independent of the boiler firing rate (unit load).

The estimates of sulfur dioxide emissions (E2) and F1 factors are further described in the following sections.

### Sulfur dioxide (SO<sub>2</sub>) Emissions from Combustion (E2)

Estimating the sulfuric acid production from Equation 4-1 requires knowledge of the mass rate of SO<sub>2</sub> generated. This rate is designated as E2 in Equation 4-1. As noted previously, the value of E2 can be estimated from either (a) the EPA CEMS data, or (b) calculated from the coal burn data (EPA, 1995a).

If the CEMs data are used to directly quantify the annual SO<sub>2</sub> production rate in tons/year of SO<sub>2</sub>, it may be necessary to correct for stack geometry, depending on the measurement method used. The user should check with their CEMs operator to obtain the bias correction factors, or the bias corrections may already be taken care of in the instrument software.

If a facility used EPA Methods 1 and 2 for CEM flow monitor setup and validation under the guidelines described in 40 CFR Part 60, Appendix A, flow bias and wall effects corrections should be made to the CEMs SO<sub>2</sub> measurements to accurately estimate sulfuric acid releases. This correction can be made using one of the following two equations:

$$E2 = E \left[ 1 - \frac{(C1 \cdot R^2 + C2 \cdot R + C3)}{100} \right] \quad \text{Eq. 4-2}$$

where,

E2 = Corrected SO<sub>2</sub> mass rate, tons per year

E = CEMS-derived SO<sub>2</sub> mass rate, tons per year

C1 = 0.0264 (non-axial flow bias factor)

C2 = 0.183 (non-axial flow bias factor)

C3 = 1.5 (wall effects bias factor) – default value for cylindrical stacks

R = Stack/duct average resultant angle (or swirl angle) from site verification tests, degrees

The average resultant angle, R, is determined using Method 1. The wall effects bias factor, C3, is the percent difference between flow rates calculated using standard Method 1 sampling and flow rates calculated using measured near-wall velocity data. Many utilities do not have bias data

available, and as such, an average default value of 1.5, derived from actual data, can be used. Measured bias factors were within the range of 0.9 to 2.2% (Noble, 1998).

If a facility used EPA Method 2H (EPA, 1999) for round stacks, or CTM-041 (EPA, 2003) for rectangular stacks to determine a Wall Adjustment Factor (WAF), then this value can be used instead and the correction equation can be simplified to the following:

$$E2 = E \bullet WAF \quad \text{Eq. 4-3}$$

where,

E2 = Corrected SO<sub>2</sub> mass rate, tons per year

E = CEMS-derived SO<sub>2</sub> mass rate, tons per year

WAF= Wall Adjustment Factor, determined from Method 2H

The WAF correction factor determined by Method 2H is applicable to stack flow rates determined by Methods 2, 2F and 2G. A default value of 0.995 can be used, although actual data should be used if available.

As an alternative to using CEMS data, the following relationship based on coal burn data can be used to estimate the rate of SO<sub>2</sub> emissions:

$$E2 = K1 \bullet K2 \bullet C1 \bullet S1 \quad \text{Eq. 4-4}$$

where,

E2 = SO<sub>2</sub> mass rate, tons/yr

C1 = Dry coal burn, tons/yr. The dry coal can be calculated from wet coal through the following relationship:

Dry coal (tons/yr) = wet coal (tons/yr) • (1-moisture(%)/100%)

S1 = Coal sulfur weighted average, %, dry

K1 = Molecular weight and units conversion constant

= (64.04)/(100 • 32.06) = 0.02

64.04 = molecular weight of SO<sub>2</sub>

32.06 = molecular weight of S

100 = conversion of % S to a fraction

K2 = Sulfur conversion to SO<sub>2</sub>, implicit from EPA AP-42 (EPA, 1995b)

= 0.95 for bituminous coals

= 0.875 for subbituminous coals

= 0.55 to 0.85 for lignite, based on the Na content

= 1.0 for oil

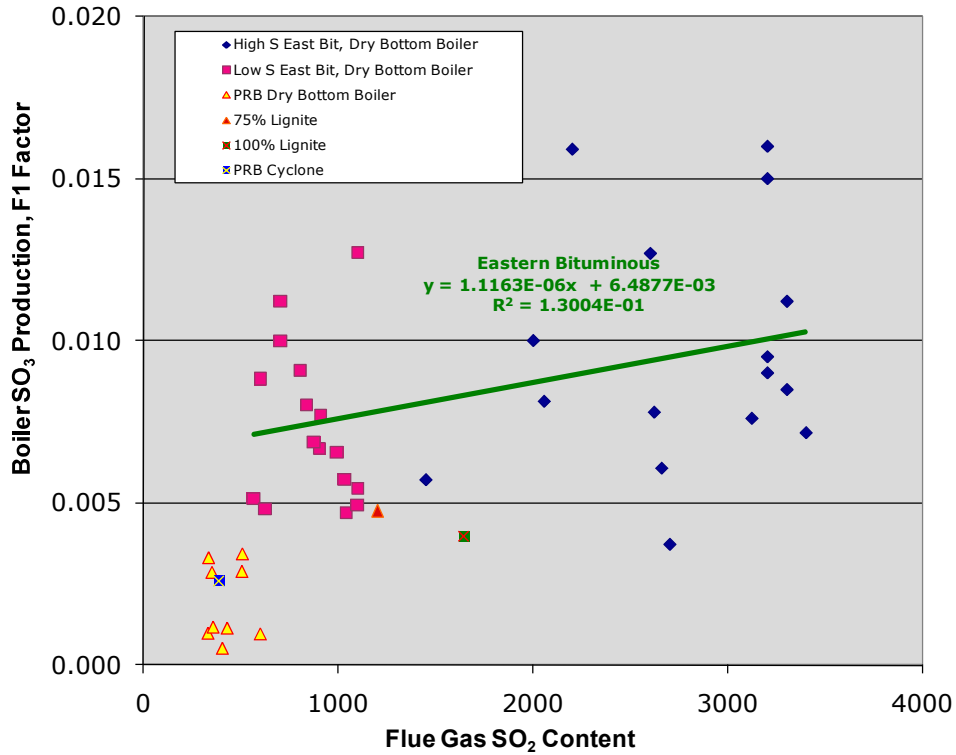


When any source uses FGD equipment or another technology to control SO<sub>2</sub> emissions, either the fuel basis must be used for the manufacturing and release calculations, or CEMS data can be used, but only when the CEMS precedes the FGD or SO<sub>2</sub> control equipment. Data from a CEMS located after a flue gas desulfurization system cannot be used, because the measured SO<sub>2</sub> has already been decreased by the control equipment, and therefore is not an accurate predictor of the SO<sub>3</sub> emissions rate.

**Fuel Impact Factor (F1).** Figure 4-1 depicts the fraction of H<sub>2</sub>SO<sub>4</sub> produced as a function of flue gas SO<sub>2</sub> content for several coal sources and boiler types. The coal ranks and boiler types consist of (a) high sulfur (>2.5%) eastern bituminous coal, fired in a dry bottom boiler (wall-fired or cell-fired), (b) low sulfur eastern bituminous coal, fired in a dry bottom boiler, (c) PRB coal, fired in both a cyclone and dry bottom boilers. Data are also shown for one unit that fires 75% lignite with the balance PRB and one unit that fires 100% lignite.

Figure 4-1 shows that a wide range in SO<sub>3</sub> production is observed for all coals and boiler types. This range exceeds the theoretical predictions by Senior (2000), suggesting that the role of ash in either catalyzing SO<sub>3</sub> production or absorbing/neutralizing SO<sub>3</sub> is not fully accounted for. The only consistent results in Figure 4-1 are for SO<sub>3</sub> from PRB-fired units, regardless of boiler type, in that less than 1 ppm was observed.

The current model uses a linear relationship to estimate SO<sub>3</sub> production for all eastern bituminous, dry bottom boiler data, as shown in Figure 4-1. The equation expressing this relationship is shown in Equation 4-5. This relationship is significant at the 95% confidence level, although the correlation coefficient (R<sup>2</sup>) is low (0.13) due to scatter in the data. The current model retains F1 factors based on average fraction of SO<sub>2</sub> converted to SO<sub>3</sub> for all other coal types.



**Figure 4-1**  
**Relationship between Boiler SO<sub>3</sub> Production and Flue Gas SO<sub>2</sub> (corrected to 3% O<sub>2</sub>)**

$$F1_{\text{ebit}} = 1.12\text{E-}6 \bullet \text{SO}_2 + 0.0065 \quad \text{Eq. 4-5}$$

where,

$F1_{\text{ebit}}$  = Fuel Impact Factor for all Eastern Bituminous coals burned in a dry-bottom boiler

$\text{SO}_2$  = Boiler SO<sub>2</sub> concentration (ppm), derived from fuel sulfur content (%)

In order to use this approach, it is necessary to relate coal sulfur (%) to the SO<sub>2</sub> concentration in the boiler. Equation 4-6 is used to calculate that relationship:

$$\text{SO}_2 = S1 \bullet \frac{K_{F1}}{HV} \quad \text{Eq. 4-6}$$

where,

$\text{SO}_2$  = Boiler SO<sub>2</sub> concentration (ppmvd, 3% O<sub>2</sub>, dry) derived from fuel sulfur content (%)

$S1$  = Coal sulfur weighted average, %, dry

$K_{F1}$  = Conversion factor = 10,003,602

$HV$  = Coal heating value, Btu/lb, dry

The conversion factor  $K_{F1}$  considers all relevant constants to yield the result in ppm of  $SO_2$ . The derivation of this constant is presented in Text Box A.

*Text Box A: Derivation of Conversion Factor,  $K_{F1}$ .* The U.S. Code of Federal Regulations 40, Part 60, Table 19-1 “F Factors for Various Fuels” states that 1 million Btu of heat input for bituminous or subbituminous coal will produce 10,640 wet standard cubic feet of flue gas, defined at 0% oxygen and on a wet basis at 20°C and 760 mm Hg. Correcting this volume to 3%  $O_2$  on a dry basis (typical of the  $SO_2$  measurement data used in the Fuel Impact Factors correlation) yields a volume of 11,419 scf. The standard volume of one pound mole of any gas is 359 scf, defined at 0°C and 760 mm Hg. Converting this to the English units standard of 20C (68°F), one pound mole occupies 385.5 standard cubic feet. The value 0.95 is the AP-42 (EPA, 1995b) K2 factor for sulfur conversion to  $SO_2$  for a bituminous coal.

Equation 4-4 above can then be expanded as follows:

S1%	0.95	385.5 scf S	1 lb mol S	1 MBtu	1 lb fuel	$10^6$ Btu	$10^6$ ppm
	100%	1 lb mol S	32.06 lbs S	11,419 scf	HV Btu	1 MBtu	

Grouping terms,

$$SO_2 = S1 \bullet 10,003,602 / HV$$

Therefore, the value of  $K_{F1}$  is equal to  $10,003,602$  [ppmvd  $SO_2$  (3%  $O_2$ , dry) • Btu/lb]/%S.

Table 4-1 summarizes the F1 factors. There are no changes to these factors from the previous version of the model (EPRI, 2012).

**Table 4-1**  
**Summary of Fuel Impact (F1) Factors for Steam Generating Units**

Fuel	Equipment	F1	Comment
E. Bituminous (all) <sup>1</sup>	Dry Bottom Boiler	Slope: 1.1163E-6 Intercept: 0.0064877	F1 = slope SO <sub>2</sub> + intercept 32 data points
Med-High S Eastern Bituminous (>2.5%)	Cyclone	0.016	One data point.
W. Bituminous	Dry Bottom Boiler	0.00111	One data point.
W. Bituminous	Cyclone	0.0022	One data point.
Subbituminous/PRB	All Boilers	0.0019	Average of 8 units
Lignite	Dry Bottom Boiler	0.0044	Two data points.
Lignite	Cyclone	0.00112	One data point.
Petroleum coke	Boiler	0.04	One data point.
Natural gas	Boiler	0.01	
#2 Fuel oil	Boiler	0.01	
#6 Fuel oil	Boiler	0.025	
Used oil	Boiler	0.0175	
Natural gas	CT	See Table 6-1	
#2 Fuel oil	CT	See Table 6-1	
Natural gas	CC	0.0555	
#2 Fuel oil	CC	0.0555	
Other Alternative Fuels	Any	0.04	
Other Alternative Fuels, co-fired w/coal, >75% heat throughput	NA		Use Coal F1, in absence of any applicable data.

<sup>1</sup>For eastern bituminous coal, a linear relationship between SO<sub>2</sub> and SO<sub>3</sub> is used instead of an average F1 factor.

### ***Sulfuric Acid Manufactured from SCR ( $EM_{SCR}$ )***

This section describes a method to estimate impacts of SCR on sulfuric acid emissions. As discussed in Section 3, SCR produces  $SO_3$  (and ultimately sulfuric acid), while SNCR removes or reduces it due to the reaction with residual ammonia. As such, only the SCR process will be addressed in this section. The removal equations will be discussed in subsequent sections, and will address both SCR and SCNR, as residual ammonia from either process contributes to sulfuric acid removal.

The following relationship estimates the total  $H_2SO_4$  manufactured from an SCR equipped utility boiler or steam generator:

$$EM_{SCR} = K \bullet S2 \bullet f_{sops} \bullet E2 \bullet F3_{SCR} \quad \text{Eq. 4-7}$$

where,

$EM_{SCR}$  = Total  $H_2SO_4$  manufactured from SCR, lbs per year

$K$  = Molecular weight and units conversion constant  
=  $98.07 / 64.04 \bullet 2000 = 3,063$

98.07 = Molecular weight of  $H_2SO_4$

64.04 = Molecular weight of  $SO_2$

2000 = Conversion from tons per year to pounds per year.

$S2$  = SCR catalyst  $SO_2$  oxidation rate (specified as a fraction, typically from 0.001- 0.03)

$f_{sops}$  = Operating factor of SCR system, or the fraction of coal burn when the flue gas is directed through the SCR, whether  $NH_3$  reagent is injected to derive  $NO_x$  reduction or not. This value should reflect the hours the SCR reactor processed flue gas, which will be site-specific but can be approximated by generally 0.8 for year-round peaking operation, 0.98 for year-round base-loaded operation, or 0.43 for seasonal operation

$E2$  =  $SO_2$  produced, tons per year

$F3_{SCR}$  = Technology Impact Factor, for SCR

The Technology Impact Factor for SCR ( $F3_{SCR}$ ) is required to adjust  $SO_3$  content for the presence of alkaline fly ash, as described in Section 3, unless direct measurements exist for the subject unit documenting  $SO_3$  increase across the SCR reactor.

It is important to select the correct  $SO_2$  oxidation rate,  $S2$ , for use in Equation 4-7. Typically, the  $SO_2$  oxidation rate from SCR catalysts can range from as low as 0.3% of flue gas  $SO_2$  content, up to 3% for low sulfur, highly alkaline coals (e.g., PRB). There are two means by which  $SO_2$  oxidation is specified and measured for SCR process equipment, and each has significantly different implications for  $SO_3$  produced. One method – based on actual field tests in commercial units – does not require adjustment and can be used as reported to predict sulfuric acid. The other method is based on laboratory tests of catalyst samples in the absence of ash and alkaline

materials, and must be adjusted to account for these latter factors. The consequences of each of these methods on estimates of sulfuric acid emissions are described as follows:

Full-Scale Catalyst Performance Tests. Ideally, SO<sub>2</sub> conversion data will be determined with commercial testing of full-scale equipment. These data – measured on commercial plants under actual operating conditions – are the most authentic in reflecting actual SO<sub>3</sub> content, as the impact of ash alkalinity is taken into account. This approach reflects commercial process operation, and the resulting fractional oxidation rate can be used as the S2 value in Equation 4-7 without adjustment by the F3<sub>SCR</sub> Technology Impact Factor.

Laboratory Bench-Scale Tests. Some owners and process suppliers prefer to specify and conduct guarantee measurements for SO<sub>2</sub> oxidation on laboratory-scale equipment using synthetic flue gases without fly ash. There are good reasons to select this methodology; evidence suggests SO<sub>3</sub> measurements in the environment of the test laboratory are more accurate and reproducible than field tests. However, this method does not expose the catalyst being tested to ash, so there is no alkaline component to mitigate or absorb any SO<sub>3</sub> generated. Accordingly, SO<sub>2</sub> oxidation reported by this method exceeds that measured in commercial practice, particularly for PRB coals. SO<sub>2</sub> oxidation data from bench-scale tests can be used, but must be adjusted for the role of ash alkalinity. This adjustment is provided by the Technology Impact factor F3<sub>SCR</sub>.

Table 4-2 shows the F3<sub>SCR</sub> factors. It should be noted that the 0.17 factor for PRB coals when using laboratory-scale SO<sub>2</sub> conversion (S2) data without fly ash is based on measurements at two PRB-fired units. SO<sub>3</sub> emitted from these units was lower than specified in the catalyst guarantee, which was based on laboratory test data. At present, there are no data to support F3<sub>SCR</sub> factors for other coals, so a factor of 1 (full penetration) is recommended. Additionally, if full-scale catalyst performance SO<sub>2</sub> conversion data is used, the F3<sub>SCR</sub> factor is 1 for all coal types.

**Table 4-2**  
**F3<sub>SCR</sub> Technology Impact Factors for SCR**

Coal Type	F3 <sub>SCR</sub>
Using Laboratory-Scale SO <sub>2</sub> Conversion Data (S2), Without Fly Ash	
PRB	0.17 (n = 2)
Other Coals	1 (no data available)
Using Full-Scale Catalyst Performance SO <sub>2</sub> Conversion Data (S2)	
All Coals	1

SNCR does not result in the manufacture of sulfuric acid; thus, EM<sub>SNCR</sub> for SNCR is by definition zero.

### ***Sulfuric Acid Manufactured from FGC (EM<sub>FGC</sub>)***

In order to moderate ash resistivity, most SO<sub>3</sub>-based FGC systems attempt to maintain a fixed concentration of SO<sub>3</sub> in the flue gas, typically between 5 and 7 ppm by volume (ppmv). Calculations to estimate the sulfuric acid manufactured during FGC use the setpoint of the FGC system as the key input. The FGC system is assumed to operate during most of the plant's duty, except for perhaps startup and low load operation. The sulfuric acid manufactured by SO<sub>3</sub>-based FGC equipment (EM<sub>FGC</sub>) is calculated as follows:

$$EM_{FGC} = K_e \bullet B \bullet f_e \bullet I_s \bullet F3_{FGC}$$

Eq. 4-8

where,

- $EM_{FGC}$  = Total  $H_2SO_4$  manufactured from FGC, lbs per year, either upstream of APH ( $EM_{FGC\_beforeAPH}$ ) and/or downstream of APH ( $EM_{FGC\_afterAPH}$ )
- $K_e$  = Conversion factor = 3,799, see Text Box B.
- $B$  = Coal burn in TBtu/yr
- $f_e$  = Operating factor of FGC system: the fraction of coal burn when the FGC system operates. This value is site-specific, must be determined for each unit, but generally will be about 0.8.
- $I_s$  =  $SO_3$  injection rate in ppmv at 6%  $O_2$ , wet; generally,
  - = 7 ppmv if before the APH
  - = 5 ppmv if after the APH
- $F3_{FGC}$  = Technology Impact Factor for FGC
  - = 0.17 for PRB coal
  - = 1 for all other coals

A Technology Impact Factor for FGC ( $F3_{FGC}$ ) is used to adjust the flue gas  $SO_3$  manufacture from FGC injection to account for the presence of alkaline fly ash. The principle is the same as for the  $F3_{SCR}$  factor that is used to adjust the flue gas  $SO_3$  produced by  $SO_2$  oxidation rate on the SCR catalyst.

The method first reduces the  $SO_3$  that is injected into a PRB-fired boiler using the  $F3_{FGC}$  factor to account for sorption by the alkaline fly ash. Subsequently,  $SO_3$  from FGC is treated the same as all other sources of sulfuric acid with respect to ABS formation or reduction through control devices. The  $F3_{FGC}$  factor (0.17) is assumed to be equal to the  $F3_{SCR}$  factor. A  $F3_{SCR}$  of 1.0 is used for eastern bituminous coals (zero reduction), as those coals produce an acidic ash that does not adsorb appreciable amounts of  $SO_3$ .

The conversion factor  $K_e$ , equal to 3,799, considers all relevant constants to yield the result in pounds per year of sulfuric acid. The derivation of this constant, for the case where residual  $\text{SO}_3$  is reported in terms of 6% oxygen and “wet” flue gas at 8.1%  $\text{H}_2\text{O}$ , is presented in Text Box B.

**Text Box B: Derivation of Conversion Factor,  $K_e$ .** The U.S. Code of Federal Regulations 40, Part 60, Table 19-1 “F Factors for Various Fuels” lists that 1 million Btu of heat input for bituminous or subbituminous coal will produce 10,640 wet standard cubic feet of flue gas, defined at 0% oxygen and on a wet basis at 20°C and 760 mm Hg. Correcting this volume to 6%  $\text{O}_2$  (typical at ESP conditions) yields a volume of 14,925 scf. The standard volume of one pound mole of any gas is 359 scf, defined at 0°C and 760 mm Hg. Converting this to the English units standard of 20°C (68°F), one pound mole occupies 385 standard cubic feet. Using these in the equation above,

$$(K_e \bullet B \bullet f_e \bullet I_s) = \text{lbs H}_2\text{SO}_4 \text{ per yr} =$$

$B$ TBtu	$I_s(S_{\text{NH}_3})$ scf $\text{NH}_3$	1 lb mol $\text{SO}_3$	1 lb mol $\text{H}_2\text{SO}_4$	98 lbs $\text{H}_2\text{SO}_4$	14925 scf fg	$10^6$ MBtu
year	$10^6$ scf flue gas	385 scf $\text{SO}_3$	1 lb mol $\text{NH}_3$	1 lb mol $\text{H}_2\text{SO}_4$	1 MBtu	TBtu

Grouping terms,

$$= B \bullet f_e \bullet I_s \bullet 3,799$$

Therefore, the value of  $K_e$  is equal to 3,799 lbs  $\text{H}_2\text{SO}_4$ /(TBtu • ppmv  $\text{SO}_3$  @ 6%  $\text{O}_2$  and wet).

Equation 4-8 specifies the concentration of  $\text{SO}_3$  in flue gas ( $I_s$ ) in terms of ppmv at 6%  $\text{O}_2$ , wet flue gas basis. If the concentration of  $\text{SO}_3$  is reported at different conditions, the value of the constant  $K_e$  will change. The following formula is used to adjust the value of the constant  $K_e$ :

$$K_e (\text{O}_2, \text{H}_2\text{O}) = 3,799 (6\% \text{O}_2, 8.1\% \text{H}_2\text{O}) \bullet [(100-8.1)/(100-\text{new H}_2\text{O})] \bullet [(20.9 - 6.0)/(20.9 - \text{new O}_2)] \quad \text{Eq. 4-9}$$

For example, if the  $\text{SO}_3$  concentration is quantified at a value (in ppm) that is defined at 0% oxygen and a dry basis, the value of  $K_e$  that should be used is:

$$K_e (\text{O}_2, \text{H}_2\text{O}) = 3,799 (6\% \text{O}_2, 8.1\% \text{H}_2\text{O}) \bullet [(100-8.1)/(100-0)] \square [(20.9 - 6.0)/(20.9 - 0)]$$

$$K_e = 2,489$$

The sulfuric acid manufacture from FGC should be noted as either upstream of the APH,  $\text{EM}_{\text{FGC\_beforeAPH}}$ , or downstream of the APH,  $\text{EM}_{\text{FGC\_afterAPH}}$ . These values must be kept separate for the release equations.

FGC equipment that employs  $\text{NH}_3$  injection alone does not manufacture sulfuric acid and therefore this amount,  $\text{EM}_{\text{FGC}}$ , would be zero. However, the injected  $\text{NH}_3$  will reduce the total



release of sulfuric acid by reacting with SO<sub>3</sub> or the resultant H<sub>2</sub>SO<sub>4</sub>, and therefore should be used in the release equation, as discussed in subsequent sections.

### **Total Manufacture from All Sources**

The total manufacture of sulfuric acid is the sum of the individual manufacture estimates, prior to any adjustments or modifications due to fuel conditioning or particulate devices. Therefore, if a site burns coal and uses both SCR and FGC, the amount of sulfuric acid manufactured – by combustion, SCR, and/or FGC – is summed to determine the total amount.

Accordingly, total sulfuric acid manufacture (TSAM) is estimated for a generating unit equipped with SCR and flue gas conditioning by the following equation:

Total Sulfuric Acid Manufacture (TSAM) is described by the following equation:

$$\text{TSAM} = \text{EM}_{\text{Comb}} + \text{EM}_{\text{SCR}} + (\text{EM}_{\text{FGC\_beforeAPH}} + \text{EM}_{\text{FGC\_afterAPH}}) \quad \text{Eq. 4-10}$$

### **Sulfuric Acid Release**

Both SCR and/or ammonia-based FGC may have a negative effect on sulfuric acid release, as the ammonia slip can combine with some or all of the sulfuric acid generated from combustion to form a non-reportable ammonia salt (ABS or AS). Under these conditions, ammonia-based FGC can serve to only reduce the release of sulfuric acid. Therefore, sources of ammonia are calculated in terms that are equivalent on a 1:1 molar basis as sulfuric acid, summed in relation to the APH, and used to adjust the sulfuric acid manufactured. Once adjusted by the equivalent ammonia, the remaining sulfuric acid is then adjusted by the removals in applicable downstream equipment such as the APH, ESP or other particulate control device and FGD equipment by applying Technology Impact Factors (F<sub>2</sub>) which describe the fraction of sulfuric acid that penetrates each component.

Total Sulfuric Acid Release (TSAR) is described by the following equation:

$$\text{TSAR} = \{ [ ((\text{EM}_{\text{Comb}} * F2_{\text{HotSide\_ESP}} * F2_{\text{Mag-ox}}) + \text{EM}_{\text{SCR}} + \text{EM}_{\text{FGC\_beforeAPH}}) - (\text{NH3}_{\text{SCR}} + \text{NH3}_{\text{FGC\_beforeAPH}}) ] * F2_{\text{APH}} + (\text{EM}_{\text{FGC\_afterAPH}} - \text{NH3}_{\text{FGC\_afterAPH}}) * F2_{\text{x}} \} \quad \text{Eq. 4-11}$$

where,

TSAR = Total Sulfuric Acid Release, lbs per year

EM<sub>Comb</sub> = Total sulfuric acid manufactured from combustion, lbs per year

F<sub>2HotSide\_ESP</sub> = Technology Impact Factor for hot-side ESP

= 0.63 if hot-side ESP is present

= 1.0 if hot-side ESP is not present (optional)

F<sub>2Mag-Ox</sub> = Technology Impact Factor for magnesium oxide addition in fuel or furnace

= 0.25 (or custom) if Mag-Ox is sprayed into furnace

	= 0.50 (or custom) if Mag-Ox is mixed with fuel	
	= 1.0 if Mag-Ox is <u>not</u> applied (optional)	EM <sub>SCR</sub> = Total sulfuric acid manufactured from SCR, lbs per year
EM <sub>FGC_beforeAPH</sub>	= Total sulfuric acid manufactured from FGC upstream of the APH	
EM <sub>FGC_afterAPH</sub>	= Total sulfuric acid manufactured from FGC downstream of the APH	
NH <sub>3SCR</sub>	= Total equivalent ammonia slip produced from SCR/SNCR, lbs per year	
NH <sub>3FGC_beforeAPH</sub>	= Total equivalent ammonia produced from FGC upstream of the APH, lbs per year	
NH <sub>3FGC_afterAPH</sub>	= Total equivalent ammonia produced from FGC downstream of the APH, lbs per year	
F <sub>2APH</sub>	= Technology Impact Factor for APH, applied only if subtotal for releases upstream of the APH is non-negative	
F <sub>2x</sub>	= Technology Impact Factors for processes downstream of the APH, all that apply	

Examples in Appendix A detail the use of these calculations. Ammonia produced from SCR/SNCR and FGC are calculated using equations from the sections below.

The application of the hot-side ESP and Mag-Ox F2 factors to the sulfuric acid manufactured from combustion are a change from all previous versions of the report where these factors were applied to the total sulfuric acid release, which also included sulfuric acid from flue gas conditioning and SCR/SNCR. However, as a hot-side ESP removes sulfuric acid upstream of the APH, and therefore prior to any subsequent manufacture of sulfuric acid via SCR or FGC, the hot-side ESP F2 factor should only be applied to EM<sub>Comb</sub>. Furthermore, application of magnesium oxide compounds into the furnace or fuel has been shown to only affect sulfuric acid produced from combustion, and does not affect any downstream formation due to SCR oxidation (Blythe, 2004). These two factors are discussed in more detail in subsequent sections, but it should be noted that as with other devices, these F2 factors only need to be included if the technology or device is present, and are optional (i.e. equal to 1.0) if the technology is not present.

The F2 factor for the APH (F<sub>2APH</sub>) should only be applied if the subtotal of the sum of the sulfuric acid manufactured minus the ammonia slip upstream of the APH  $[(EM_{Comb} * F_{2HotSide\_ESP} * F_{2Mag-ox}) + EM_{SCR} + EM_{FGC\_beforeAPH}] - (NH_{3SCR} + NH_{3FGC\_beforeAPH})$  is a positive value. If this subtotal is negative, this would indicate that excess ammonia slip is still present after all the sulfuric acid from combustion, SCR and FGC has been consumed to form ABS. In this instance, the resulting ammonia slip should not be reduced by the F<sub>2APH</sub> factor, as all the ammonia is expected to penetrate the APH. This negative ammonia slip value can then be added to any downstream FGC injection, as summarized in Equation 4-12:

$$TSAR_{ExcessNH3} = \{ [ (EM_{Comb} * F_{2HotSide\_ESP} * F_{2Mag-ox}) + EM_{SCR} + EM_{FGC\_beforeAPH} ] - (NH_{3SCR} + NH_{3FGC\_beforeAPH}) \} + (EM_{FGC\_afterAPH} - NH_{3FGC\_afterAPH}) * F_{2x} \quad \text{Eq. 4-12}$$

Text Box C summarizes calculations for a unit equipped with a FGD process that employs partial flue gas bypass, to account for the fact that the entire flue gas flow is not subject to sulfuric acid removal by the FGD process. This bypass factor is pertinent only to units that employ flue gas bypass.

*Text Box C: Flue Gas Desulfurization Bypass Calculation.* Those units equipped with scrubbers where some of the flue gas bypasses the scrubber should take this into account in their total release calculations. No credit for sulfuric acid removal should be taken for the fraction of the flue gas that bypasses the scrubber. Therefore, this amount of the flue gas should not be multiplied by the F2 factor for the scrubber. However, the flue gas volume should still be multiplied by the F2 factors for the other control devices.

Modified equations considering partial scrubber bypass are given below and should be used where appropriate.

$$TSAR_{bypass} = \{[(EM_{Comb} + EM_{SCR/SNCR} + EM_{FGC\_beforeAPH}) - (NH3_{SCR} + NH3_{FGC\_beforeAPH})] \bullet$$

$$F2_{APH} + (EM_{FGC\_afterAPH} - NH3_{FGC\_afterAPH})\} \bullet F2_x$$

$$TSAR = [SB_f + (1 - SB_f) \bullet F2_s] \bullet TSAR_{bypass}$$

where,  $SB_f$  = fraction of scrubber bypass, as a decimal

$F2_s$  = F2 for scrubber

$F2_x$  = All other applicable F2 factors except for scrubber.

### **Ammonia Slip from SCR and SNCR ( $NH3_{SCR}$ )**

A key assumption in the calculation methodology is that residual ammonia from either a SCR or SNCR captures all available sulfuric acid in the (ammonium) bisulfate form. The bisulfate form is not reportable under the Toxics Release Inventory rules and thus is not part of the manufacture calculation. If any additional ammonia reacts with bisulfate to form ammonium sulfate, that reaction is of no consequence to the sulfuric acid calculation – although it needs to be taken into account when estimating ammonia releases.

The total sulfuric acid released from combustion, SCR, and FGC is determined by subtracting from the sulfuric acid manufactured the amount removed by the residual ammonia, or equivalent ammonia slip, as calculated on a 1:1 molar basis with sulfuric acid. For SCR/SNCR, the ammonia slip is calculated using the following:

$$NH3_{SCR} = K_s \bullet B \bullet f_{sreagent} \bullet S_{NH3} \quad \text{Eq. 4-13}$$

where,

$NH3_{SCR}$  = Total equivalent ammonia slip produced from SCR/SNCR, lbs per year

$K_s$  = Conversion factor = 3799, which is equivalent to  $K_e$  (See Text Box B)

$B$  = Coal burn in TBtu/yr

$f_{sreagent}$  = fraction of SCR operation with reagent injection, when residual  $NH_3$  is produced that will remove  $SO_3$ . The value of  $f_{sreagent}$  will be similar to, but slightly less than, the value of  $f_{sops}$ , defined for Equation 4-6.

$S_{NH3}$  =  $NH_3$  slip from SCR/SNCR, ppmv at 6%  $O_2$ , wet:

- SCR averages 0.75 ppmv over catalyst guarantee period
- SNCR averages 5 ppmv
- Note: actual NH<sub>3</sub> slip data should be used if available

The conversion factor K<sub>s</sub>, equal to 3,799, is equivalent to the factor K<sub>e</sub> used for SO<sub>3</sub> injected from FGC, and considers all relevant constants to yield the result in pounds per year of equivalent ammonia. The derivation of this constant, in the form of K<sub>e</sub>, was presented previously in Text Box B.

Equation 4-13 specifies the concentration of NH<sub>3</sub> in flue gas (S<sub>NH3</sub>) in terms of ppmv at 6% O<sub>2</sub>, wet flue gas basis. If the concentration of NH<sub>3</sub> is reported at different conditions, the value of the constant K<sub>s</sub> will change. As with K<sub>e</sub>, Equation 4-9, described previously and repeated again below for reference, is used to adjust the value of the constant K<sub>s</sub>:

$$K_s (O_2, H_2O) = 3799 (6\% O_2, 8.1\% H_2O) \bullet [(100-8.1)/(100-\text{new } H_2O)] \bullet [(20.9 - 6.0)/(20.9 - \text{new } O_2)] \quad \text{Eq. 4-9}$$

The operating factor of the SCR describes the portion of the coal burn that reflects the period of SCR operation, based on whether the unit operates seasonally (0.43), annually in a base-load duty (0.98), or annually in peaking duty (0.80).

The coal burn rate in TBtu/yr can be obtained from coal use records, such as those reported to EIA in Form 767, or can be calculated from the annual coal burn (tons/yr) and the heating value of the coal, as described in the equation below:

$$B = C1 \bullet HV \bullet K_B \quad \text{Eq. 4-14}$$

where,

- B = Coal burn in TBtu/yr
- C1 = Dry coal burn, tons/yr. The dry coal can be calculated from wet coal through the following relationship:  
 Dry coal (tons/yr) = wet coal (tons/yr) • (1-moisture(%)/100%)
- HV = Coal heating value, Btu/lb, dry
- K<sub>B</sub> = Conversion factor = 2E-9. The factor is calculated from the conversion of tons per year to pounds per year and Btu to TBtu (2000/10<sup>12</sup> = 2E-9)

### ***Ammonia Injection from FGC (NH<sub>3</sub><sub>FGC</sub>)***

Similar to reactions with ammonia slip from SCR or SNCR, any ammonia injected from FGC will react with sulfuric acid manufactured to form ABS. The following equation is used to calculate equivalent ammonia from FGC. Care must be taken to note the location of the ammonia injection, upstream or downstream of the APH, such that the ammonia can be utilized correctly in the release equation.

$$NH_{3FGC} = K_e \bullet B \bullet f_e \bullet I_{NH3} \quad \text{Eq. 4-15}$$

where,

- $NH_{3FGC}$  = Total equivalent ammonia produced from FGC, lbs per year, either upstream of APH,  $NH_{3FGD\_beforeAPH}$ , or downstream of APH,  $NH_{3FGC\_afterAPH}$
- $K_e$  = Conversion factor = 3,799, as described in Text Box B
- $B$  = Coal burn in TBtu/yr
- $f_e$  = Operating factor of FGC system, or the fraction of fuel burn when the FGC system operates. This value will be the same as  $f_e$  described previously and in many cases can be approximated by 0.8.
- $INH_3$  =  $NH_3$  injection for dual flue gas conditioning, ppmv at 6%  $O_2$ , wet; generally 3 ppmv  $NH_3$  if operating, or zero (0) if no ammonia is used.

### **Total Release Calculation for Sources Employing Alkali Injection**

As described in Section 3, sources that employ alkali injection to mitigate stack opacity or a visible plume will typically have access to field measurements describing  $SO_3$  concentration in flue gas, most likely at the stack. The concentration of  $SO_3$  measured at the stack can be converted to a mass emission rate using Equation 4-16.

$$ER_{ALKINJ} = K_{alkali} \bullet B \bullet S_{SO_3} \bullet F_{2x} \bullet F_{alkali} \quad \text{Eq. 4-16}$$

where,

- $ER_{ALKINJ}$  = Total  $H_2SO_4$  released from unit equipped with alkali injection, lbs per year
- $K_{alkali}$  = Constant, equal to 3,799, which is equivalent to  $K_e$ , as described in Text Box B.
- $B$  = Coal burn in TBtu/yr
- $S_{SO_3}$  =  $SO_3$  content, as measured in the stack or particulate collector exit, ppmv at 6%  $O_2$ , wet
- $F_{alkali}$  = Operating factor for the alkali injection system, fraction of coal burn when unit is operated with alkali addition to remove  $SO_3$
- $F_{2x}$  = Technology Impact Factors, to be applied only if  $SO_3$  measurements are conducted at a location preceding the stack. The value of  $F_{2x}$  is 1 if measurements are conducted at the stack, and there are no control components downstream of the measurement location. If the control device is an  $SO_2$  scrubber,  $F_{2x}$  is denoted as  $F_{2s}$ , but is handled the same way.

If the  $SO_3$  content ( $S_{SO_3}$ ) is known at conditions other than 6%  $O_2$  and wet, Equation 4-8 can be used to calculate a new value  $K_{alkali}$  at the new conditions.

The Technology Impact Factors selected should represent the control equipment between the point of  $SO_3$  measurement and the stack. For example, if a unit is equipped with only an ESP,

and the SO<sub>3</sub> measurement is conducted at the ESP inlet, then the F<sub>2</sub> factor for an ESP (Table 4-5, below) should be selected.

If the utility employing alkali injection does not have access to measured data, the total sulfuric acid releases may be calculated as described by Equation 4-11 (i.e., by estimating and summing the manufacture and applying the technology Impact Factors), and an alkali injection factor, F<sub>3ALKINJ</sub>, is then applied to the total release. This F<sub>3ALKINJ</sub> is either the expected fractional reduction in SO<sub>3</sub> (generally as guaranteed by the vendor), a default value of 0.2, as available data indicates 80% removal is easily achievable (EPRI, 2010b).

$$ER_{ALKINJ} = (TSAR_{Comb+SCR+FGC}) \bullet F_{alkali} F_{3ALKINJ} \quad \text{Eq. 4-17}$$

where,

$ER_{ALKINJ}$	=	Total H <sub>2</sub> SO <sub>4</sub> released from unit equipped with alkali injection, lbs per year
$TSAR_{Comb+SCR+FGC}$	=	Total H <sub>2</sub> SO <sub>4</sub> released from combustion, SCR and FGC, as calculated using Equation 4-10.
$F_{alkali}$	=	Operating factor for the alkali injection system, fraction of coal burn when unit is operated with alkali addition to remove SO <sub>3</sub>
$F_{3ALKINJ}$	=	Technology Impact Factor for alkali injection; the expected fractional reduction in SO <sub>3</sub> (generally as guaranteed by the vendor). If no vendor information is available, use a default value of 0.2.

### Partial Year Injection

If alkali injection is not utilized for the entire operating year ( $F_{alkali}$  does not equal 1), then Equation 4-16 (or Equation 4-17) must be added to the fraction of the total sulfuric acid release (TSAR) calculated from combustion, SCR/SNCR and/or FGC for the remainder of the operating time (Equation 4-11). Furthermore, in the calculation of TSAR for partial-year alkali injection, if SO<sub>3</sub> measurements also exist for operation without alkali injection, these data should be used with Equation 4-16 instead of the standard estimation equations, as shown below:

$$ER_{NOINJ} = K_{alkali} \bullet B \bullet S_{SO3} \bullet F_{2x} \bullet (1 - F_{alkali}) \quad \text{Eq. 4-18}$$

where,

$ER_{NOINJ}$	=	Total H <sub>2</sub> SO <sub>4</sub> released from unit without alkali injection, lbs per year
$K_{alkali}$	=	Constant, equal to 3,799, which is equivalent to $K_e$ , as described in Text Box B.
$B$	=	Coal burn in TBtu/yr
$S_{SO3}$	=	SO <sub>3</sub> content without alkali injection, as measured in the stack or particulate collector exit, ppmv at 6% O <sub>2</sub> , wet

- $F_{\text{alkali}}$  = Operating factor for the alkali injection system, fraction of coal burn when unit is operated with alkali addition to remove  $\text{SO}_3$
- $F_{2x}$  = Technology Impact Factors, to be applied only if  $\text{SO}_3$  measurements are conducted at a location preceding the stack. The value of  $F_{2x}$  is 1 if measurements are conducted at the stack, and there are no control components downstream of the measurement location. If the control device is an  $\text{SO}_2$  scrubber,  $F_{2x}$  is denoted as  $F_{2s}$ , but is handled the same way.

Accordingly, total sulfuric acid release (TSAR) for a unit employing partial-year alkali injection is estimated by one of the following equations:

$$\text{TSAR} = \text{ER}_{\text{ALKINJ}} + (\text{TSAR}_{\text{Comb+SCR+FGC}}) \bullet (1 - F_{\text{alkali}}) \quad \text{Eq. 4-19}$$

$$\text{TSAR} = \text{ER}_{\text{ALKINJ}} + \text{ER}_{\text{NOINJ}} \quad \text{Eq. 4-20}$$

## Technology Impact Factors (F2)

The sulfuric acid estimating methodology employs empirically-derived Technology Impact Factors (F2). These F2 factors describe sulfate removal observed over the air heater, the ESP or other particulate control device, and FGD process equipment. Background information on these processes and the derivation of these F2 factors are addressed in this section.

### *Air Heater*

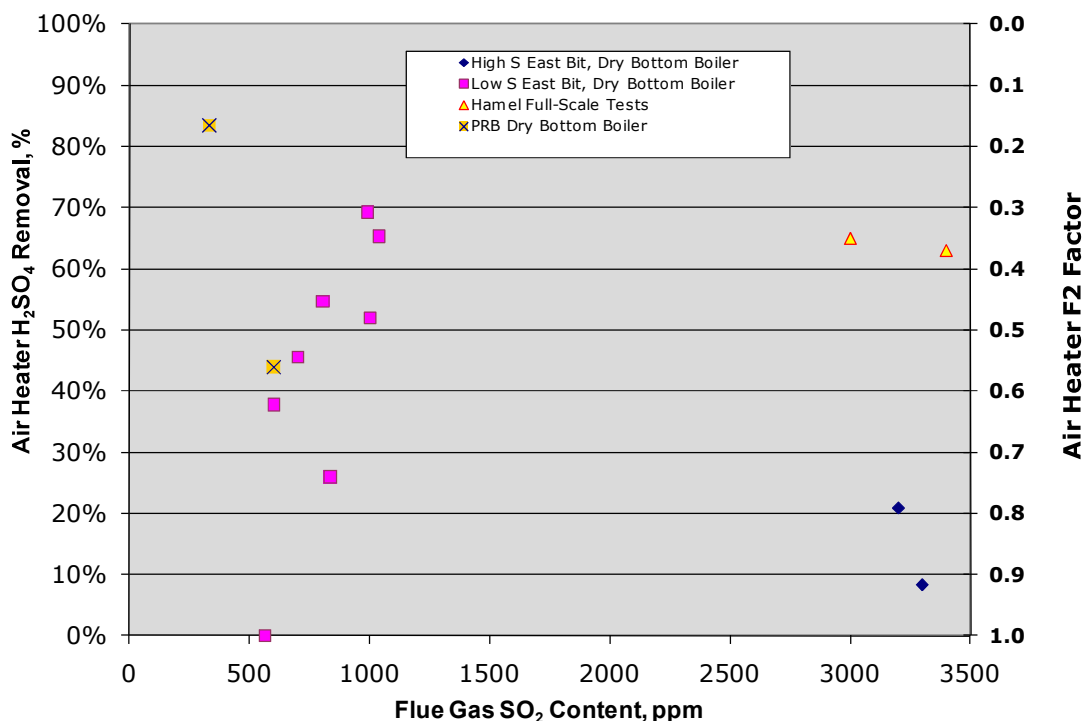
The removal of  $\text{SO}_3$  and/or  $\text{H}_2\text{SO}_4$  within the air heater is due to the condensation of sulfuric acid and its removal as discrete individual particles (along with the fly ash) on the surface of this heat exchanger. The conventional Ljungstrom-type air heater has been documented to provide a removal sink for sulfuric acid (Saranuc, 1999). In fact, the largest supplier of Ljungstrom air heaters has evaluated the feasibility of employing the air heater process environment in conjunction with limestone injection as a proactive sulfuric acid control strategy (Hamel, 2003, and Bowes, 2006).

Air heater surfaces follow a pattern of alternately heating and cooling as the heat exchange elements move from the relatively hot flue gas to the cooler combustion air. As reported during field tests of commercial equipment (Saranuc, 1999), this temperature profile introduces a strong gradient in sulfuric acid concentration across the exit plane of the air heater. The cyclic thermal conditions as described by Hamel (2003) reveal that a significant portion of the air heater basket surface metal is exposed to flue gas temperature below the sulfuric acid dewpoint. This phenomenon may promote sulfuric acid deposition on the heat exchanger metal surface, compared to a tube-type heat exchanger in which the metal temperature is always above the sulfuric acid dewpoint.

Figure 4-2 presents data obtained from a survey of power plant operators and general literature sources describing  $\text{SO}_3/\text{H}_2\text{SO}_4$  removal (and the corresponding F2 factors) across commercial, Ljungstrom-type air heaters. These data are presented as a function of  $\text{SO}_2$  content of the flue gas for the host unit. Most data shown are for low sulfur eastern bituminous coal, for which air heater  $\text{H}_2\text{SO}_4$  removal varies significantly between 0% and 69%, averaging 50% as indicated by the horizontal line. Two high sulfur (>2.5%) eastern cases are shown, along with limited data for PRB coal.

The data point showing 0% removal at approximately 600 ppm SO<sub>2</sub> is believed suspect, as an identical companion unit firing the same coal exhibited sulfuric acid capture of 38%. This measurement was not included in the F2 calculation.

Figure 4-2 presents two points reported by Hamel (2003) based on a low sulfur eastern bituminous-fired unit where SO<sub>3</sub> was “spiked” into the flue gas to elevate the concentration entering the air heater to 80 and 122 ppm. These two points are plotted separately on Figure 4-2 versus an estimated flue gas SO<sub>2</sub> content that could generate such values (using the average SO<sub>2</sub> oxidation rate for high sulfur, eastern bituminous coal in Figure 4-1. It should be noted these values measured for the “spiked” flue gas significantly exceed those measured for the two high sulfur eastern coal cases.



**Figure 4-2**  
**Removal of Sulfuric Acid by Ljungstrom-Type Air Heaters**

The F2 factor for the air heater, calculated as  $[1 - \text{Percent Removal}]$ , is estimated excluding the “spiked” SO<sub>3</sub> and suspect 0% removal measurement. The F2 factors for the air heater for low sulfur eastern bituminous, medium-high sulfur eastern bituminous, and PRB coals are shown in Table 4-4. Data are not currently available for other coal types. For those coals, as well as fuel oils, the model user could consider adopting the F2 factor for PRB if the ash is strongly alkaline and the low sulfur, eastern bituminous value if the ash is acidic.



**Table 4-3**  
**Summary of F2 Factors for Air Heater Removal of Sulfuric Acid**

Boiler Type	Fuel	F2	Standard Deviation	Comment
All Boilers	Low S Eastern Bit	0.50	0.15	Average of measurements at 7 units.
All Boilers	Med-High S Eastern Bit (S >2.5%)	0.85	n/a	Based on two data points.
All Boilers	PRB	0.36	n/a	Based on two data points.

The standard deviation of the reported measurements for low sulfur eastern bituminous coal is about one third of the average measurement. Inadequate data prevent calculating a standard deviation for F2 factors for the other fuels.

### ***Particulate and SO<sub>3</sub> Control Processes***

This section discusses the available data on removal of SO<sub>3</sub> by ESPs, FGDs, and alkali injection.

#### **ESPs and Baghouses**

An ESP provides extended residence time at relatively low temperatures, allowing contact between sulfuric acid and fly ash particles, as well as having collecting plates that can retain sulfuric acid particles. These features contribute to the removal of sulfuric acid. The ESP is the flue gas contacting device with perhaps the longest residence time; for large units, usually 10 seconds and in some cases, up to 15 seconds. Given the low flue gas velocities of 2 to 4 actual feet per second (0.6 – 1.2 meters per second), and the opportunity for heat loss at or near the walls, sulfuric acid condensation can be significant.

Figure 4-3 plots sulfuric acid removal by the ESP and the corresponding F2 factors as a function of the SO<sub>2</sub> content of the flue gas for the host unit, from a survey of plant operators. Most data shown are for a cold-side ESP and low sulfur eastern bituminous coal; three data points are shown for high sulfur coal (>2.5%). Also shown is a single data point for a hot-side ESP and four data points for low sulfur eastern bituminous coal. Similar to the case for the air heater, the 0% sulfuric acid removal at approximately 800 ppm SO<sub>2</sub> is suspect, as a companion unit at the same site firing the identical coal had 50% sulfuric acid removal. Accordingly, this “zero” removal datum, although shown in Figure 4-3, is not used in the analysis.

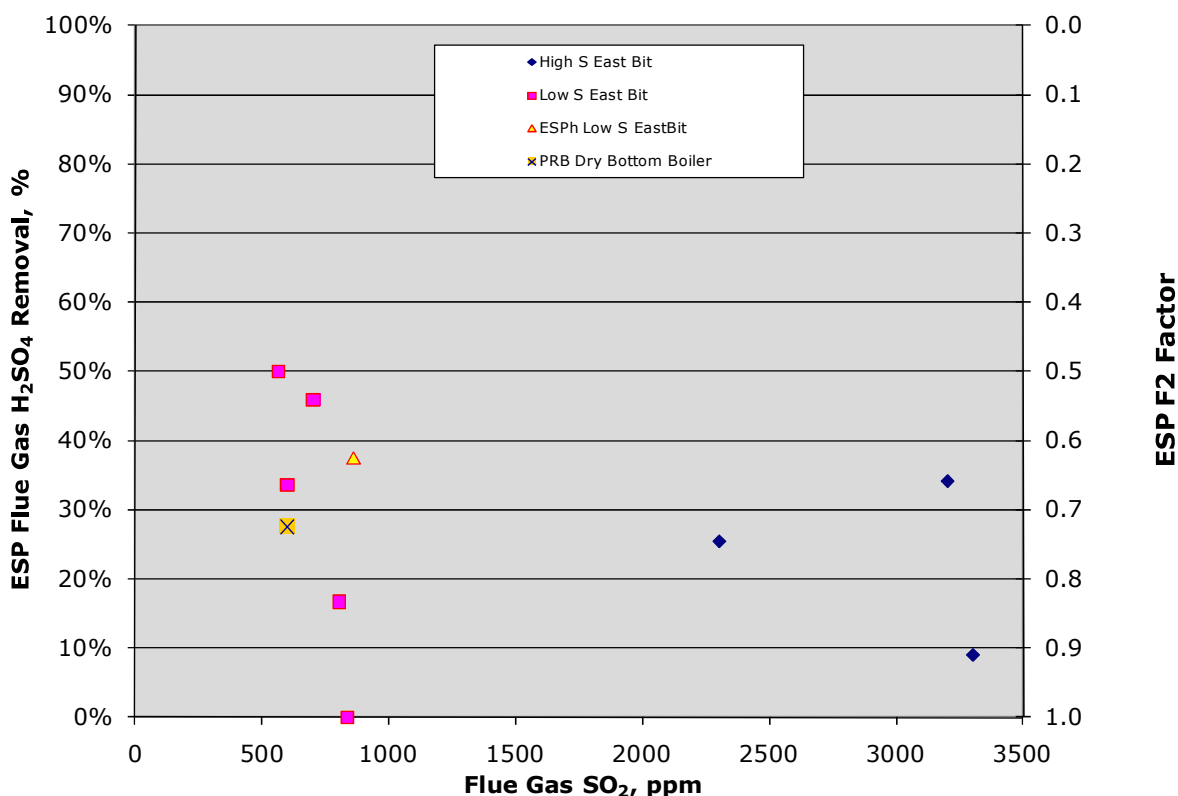
The F2 factor for the cold-side ESP, calculated as [1- Percent Removal], is estimated using all data except the 0% removal point. The F2 factors for ESP capture for low sulfur eastern bituminous, medium-high sulfur eastern bituminous, and PRB coals are listed in Table 4-5. Data are not currently available for other coal types. Western subbituminous coals (e.g., non-PRB) could consider adopting the F2 factor for PRB if the ash is strongly alkaline; western coals with acidic ash (e.g., bituminous) may consider adopting the low sulfur, eastern bituminous value. This guidance also applies to for fuel oils or any other coal that is not listed in the table.

Data describing the reduced H<sub>2</sub>SO<sub>4</sub> penetration for one hot-side ESP (ESPh) is based on only a single test series. It should be noted that although this F2 factor is used for all coals, the measurement is from a power plant burning a low-sulfur, eastern bituminous coal. Comparison of F2 factors for a cold-side ESP burning low and high sulfur eastern bituminous coals show a

significant difference between the two coal types. As a result, total  $H_2SO_4$  releases for hot-side ESP configurations may have a low bias; however, there is insufficient data to recommend alternate values.

Wet ESP's operate in much the same manner as a traditional ESP; however, due to the lower operating temperature and saturated environment, higher power levels are achievable, resulting in higher collection efficiency for sulfuric acid mists. Data describing sulfuric acid removal for a Wet ESP is based on two sets of paired measurements, both of which demonstrated 88% removal. One data point was from a high sulfur, eastern bituminous, coal-fired boiler and the other from a petroleum-coke fired boiler. Flue gas  $SO_2$  was not reported for these tests; therefore, the data points are not included in Figure 4-3. Until further data are available, EPRI recommends using a wet ESP F2 factor of 0.12 for all fuels.

Baghouses show high  $H_2SO_4$  removal based on very limited data. The average of two data points is 90% removal.



**Figure 4-3**  
Removal of Sulfuric Acid by Cold-Side ESPs and One Hot-Side ESP

**Table 4-4**  
**Summary of F2 Factors for Particulate Control Devices (ESP, Baghouse)**

Equipment Type	Coal Type	F2 Factor	Standard Deviation	Comment or Observation
Cold-side ESP	Low S Eastern Bit	0.63	0.15	Average of measurements at 4 units.
Cold-side ESP	High S Eastern Bit (>2.5%)	0.77	0.13	Average of measurements at 3 units.
Cold-side ESP	Subbituminous (PRB)	0.72	n/a	Based on one measurement at one unit.
Hot-side ESP	All	0.63	n/a	Based on one measurement at one unit.
Wet ESP	All	0.12	n/a	Average of measurements at two units
Baghouse	Subbituminous coal	0.10	n/a	Two data points.

n/a – not applicable – too few points to calculate.

The standard deviation of the reported measurements for low sulfur eastern bituminous coal is about one fourth of the average measurement, while the standard deviation of the measurements for the high sulfur eastern bituminous coal is about one sixth of the average. Inadequate data prevent calculating a standard deviation for F2 factors for the other fuels.

### **FGD**

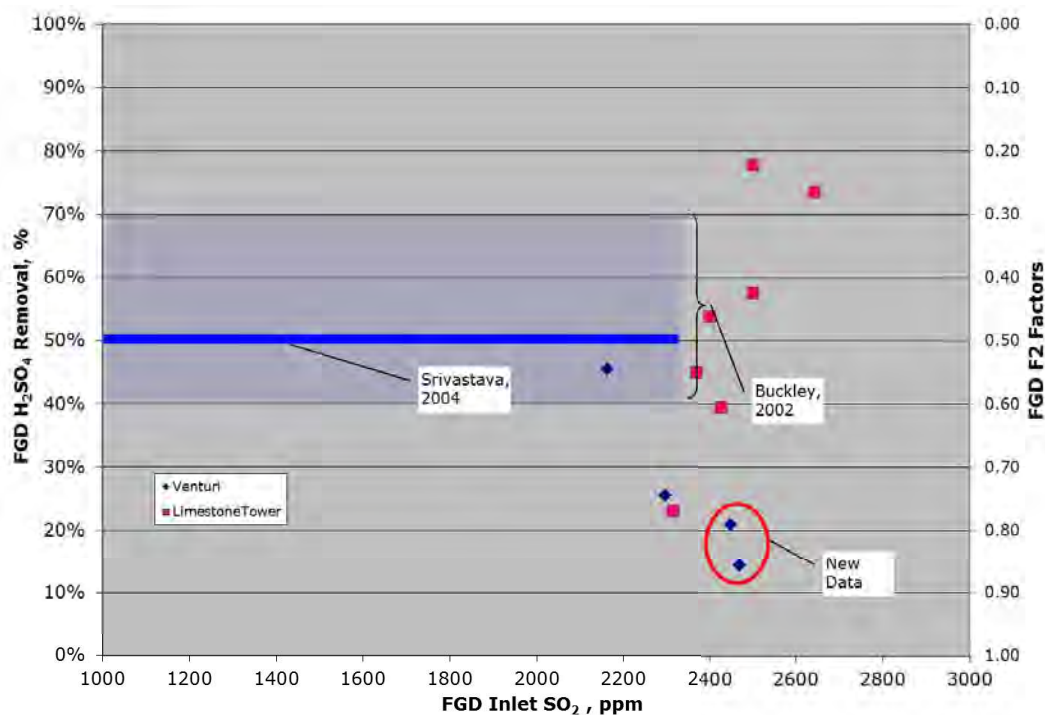
FGD process equipment rapidly cools or quenches flue gas, condensing a significant portion of the sulfuric acid into submicron droplets that can escape the process environment, confounding capture. Buckley (2002) notes that for condensation to occur, sulfuric acid generally must be supersaturated. However, fly ash particles can provide a nucleus for condensation of sulfuric acid, even at conditions that are not thermodynamically supersaturated. Buckley also projects sulfuric acid condensation on surfaces where equipment walls are lower in temperature than the flue gas (common in commercial equipment). However, the thin laminar boundary layer at the wall limits mass transfer, and for FGD equipment this mechanism provides no appreciable removal. Ironically, it is the high saturation conditions in this laminar layer near surfaces that are key to producing fine sulfuric acid mist.

Srivastava (2004) suggests that the condensed submicron droplets, once formed, are sufficiently small so that they follow the flow streamlines and avoid contact with the remaining wetted walls, liquid sheets, and droplets in the flow path. Although some degree of sulfuric acid removal is observed in FGD equipment, the amount is highly variable and depends on the design of the system. Buckley (2002) estimates FGD equipment removes 40-70% of the sulfuric acid, and Srivastava an average of 50%.

Figure 4-4 summarizes data reported in the public domain and from utility-specific tests describing FGD removal (and corresponding F2 factors) of sulfuric acid. The percent of sulfuric acid removal is depicted as a function of FGD inlet SO<sub>2</sub> concentration. Removals range from 14% to 78%, with an average of about 50%. The shaded portion of Figure 4-4 represents the upper and lower bounds of the data reported by Buckley (2002), while the solid horizontal line reflects the average reported by Srivastava (2004).

Table 4-6 summarizes the F2 factors for FGD process equipment, including results for a wet spray tower burning bituminous coal, and also one burning a blend of PRB/lignite. Given the limited data, the latter is assumed to serve as the basis of an F2-factor for 100% firing of PRB or lignite. Data for a wet venturi -type combined particulate/FGD process is also available, but only for a bituminous coal. Similar to the case for a wet spray tower, the lack of data merits assuming sulfuric acid removal for all coals is described by that measured for bituminous coal.

F2 factors for the use of magnesium-based additives in oil-fired boilers are also included in Table 4-6. These additives are used to control furnace slagging caused by the vanadium in the oil or to control sulfuric acid emissions or both. The fuel oil vanadium can also catalyze  $\text{SO}_2$  to  $\text{SO}_3$  oxidation, but the additive, when added to the oil, tends to effectively bind up the vanadium, partially reducing its catalytic effect. Addition of magnesium-based additives in the fuel oil tend to be less effective in controlling the emissions of sulfuric acid than the same additive sprayed into the furnace downstream of the flame zone. The factors for Mag-Ox addition are derived from a single data point; as such, it is recommended to use measured facility data if available



**Figure 4-4**  
Removal of Sulfuric Acid by Flue Gas Desulfurization Equipment: Various FGD Designs, Coals

**Table 4-5**  
**Summary of F2 Factors for Wet and Dry FGD Equipment and Additives**

<b>FGD Type</b>	<b>Coal Type</b>	<b>F2 Factor</b>	<b>Standard Deviation</b>	<b>Comment or Observation</b>
Wet: Spray Tower	E. Bituminous	0.47	0.17	Seven data points.
Wet: Spray Tower	PRB or Lignite	0.40	n/a	Two data points.
Wet: Venturi Tower	All coals	0.73	0.13	Four data points from three units, bituminous coal only; limited data merit assigning same factor for other coals.
Dry FGD and baghouse	All coals	0.01	n/a	Two data points.
Mg-Ox mixed w/fuel oil	All fuel	0.50	n/a	One data point.
Mg-Ox into furnace	All fuel	0.25	n/a	One data point.

# 5

## ESTIMATING GUIDELINE: MULTIPLE FUEL OR BLENDED FUEL BOILERS

Estimating sulfuric acid production of steam boilers firing multiple or blended fuels – such as natural gas, fuel oil, and perhaps coal – uses the same approach as for single fuels. This will consist of determining the contribution of each source (combustion, SCR or SNCR NO<sub>x</sub> control, and FGC) for each different fuel, and adjusting for loss or removal. It is assumed for multiple fuel boilers that the contribution of each fuel can be separated and treated individually. The same approach is to be used for boilers that fire a blended coal. This assumption is particularly important when considering blends of PRB with low or high sulfur eastern bituminous coal, as this approach accounts for the role of alkalinity in PRB ash in mitigating SO<sub>3</sub>.

This approach of treating blends of coal as separate fuels in proportion to the mass burn rate is believed to be conservative with regard to SO<sub>3</sub> emissions when considering PRB coal, in that it will likely project H<sub>2</sub>SO<sub>4</sub> emissions higher than actual. The ability of PRB coal to neutralize SO<sub>3</sub> by an amount that is greater than a direct proportion of the coal blend is due to the extremely high content of alkaline material, particularly CaO. However, data to quantify this impact with any reasonable degree of confidence are not available at present. Accordingly, the conservative approach is to presume an impact in direct proportion to the coal blend until a database can be developed.

The sequence of calculations is performed for the first component of the blend, including calculations for SCR and FGC, if applicable. The sequence is repeated for each component. When complete, the total manufacture of sulfuric acid is calculated by adding all of the manufacture totals for all fuels from all processes. Likewise, the release is summed over all processes and fuels.

As an example, if a unit with an SCR and FGC burns mostly coal, but uses natural gas in a NO<sub>x</sub> reburn process and also disposes of used oil by combustion in the furnace, then the following sequence of calculations would be required:

1. Coal fuel
  - a. Combustion manufacture
  - b. Combustion release
  - c. SCR manufacture
  - d. SCR release
  - e. FGC manufacture
  - f. FGC release
2. Natural gas
  - a. Combustion manufacture
  - b. Combustion release
  - c. SCR manufacture

- d. SCR release
  - e. FGC manufacture
  - f. FGC release
- 3. Used oil
  - a. Combustion manufacture
  - b. Combustion release
  - c. SCR manufacture
  - d. SCR release
  - e. FGC manufacture
  - f. FGC release
- 4. Sum manufacture and releases
  - a. Manufacture
 
$$= 1a + 1c + 1e + 2a + 2c + 2e + 3a + 3c + 3e$$
  - b. Release
 
$$= 1b + 1d + 1f + 2b + 2d + 2f + 3b + 3d + 3f$$

All of the manufactured results would be summed together and the releases summed also to give the final result. Example 8 in Appendix A details this calculation procedure.

# 6

## ESTIMATING GUIDELINE: COMBUSTION TURBINES

Natural gas-fired sources typically have negligible content of sulfur in the fuel, thus sulfuric acid production is negligible. Facilities that burn only natural gas are not required to participate in the TRI reporting program. However, sources that are co-located with coal units will need to be included in the estimates for total sulfuric acid release for the site. The calculation described in this section can also be used to estimate sulfuric acid emissions for Prevention of Significant Deterioration (PSD) review of new natural gas-fired generation sites.

The calculations for gas-fired units are structured very much the same as for coal- and oil-fired sources. For simple cycle combustion turbines, the only source of sulfuric acid is the sulfur in the fuel. The EPA AP-42 emissions factor suggests a value of 2000 grains of sulfur per million cubic feet of natural gas as a default sulfur content value. This value is equivalent to approximately 3.5 ppm of sulfur in the raw natural gas.

A methodology to estimate manufacture and release of sulfuric acid for simple cycle and combined cycle units is provided below.

### Manufacture and Release for Simple Cycle Units

Given the current configuration of simple cycle units, any sulfuric acid *manufactured* is *released*; thus, the estimates of sulfuric acid are the same. This is because there is no equipment located following the simple cycle arrangement that removes sulfuric acid. Even though simple cycle units can be equipped with SCR, and the use of SCR with sulfur-containing fuels will manufacture SO<sub>3</sub>, the exit gas temperature is too high to allow condensation of SO<sub>3</sub> or reaction with ammonia slip. Selective non-catalytic reduction is not applied to simple cycle or combined cycle combustion turbines; therefore, no estimation procedure is provided for that configuration.

Accordingly, the equations for formation of sulfuric acid from natural gas (NG) combustion are:

$$EM_{SC} = K \bullet F1 \bullet E2_{NG} \quad \text{Eq. 6-1}$$

where,

$EM_{SC}$  = total H<sub>2</sub>SO<sub>4</sub> *manufactured* from combustion, lbs/yr

K = Molecular weight and units conversion constant

$$= 98.07 / 64.04 \bullet 2000 = 3,063$$

98.07 = Molecular weight of H<sub>2</sub>SO<sub>4</sub>

64.04 = Molecular weight of SO<sub>2</sub>

2,000 = Conversion from tons per year to pounds per year.

F1 = Fuel Impact Factor for NG



$E_{2NG}$  = Sulfur dioxide (SO<sub>2</sub>) emissions either: (1) recorded by a continuous emissions monitor, tons/yr, or (2) calculated from fuel burn data, tons/yr.

SO<sub>2</sub> emissions can be obtained through a calculation using the heat input of natural gas.

$$E_{2NG} = K_b \bullet B_{NG} \bullet S \quad \text{Eq. 6-2}$$

where,

$E_{2NG}$  = Total SO<sub>2</sub> production from NG combustion, tons/yr

$K_b$  = Molecular weight and units conversion constant = 0.0001359

$B_{NG}$  = Burn of NG in Tbtu/yr

$S$  = Sulfur content of natural gas, in grains per million standard cubic feet (Mscf), typically 2000 gr/10<sup>6</sup> scf per EPA AP-42.

The derivation of constant  $K_b$  is presented in Text Box D.

Text Box D: Derivation of Molecular Weight and Units Conversion Constant,  $K_b$

$K_b$  is determined from the following equation.

$(K_b \bullet B_{NG} \bullet S) = \text{tons SO}_2 \text{ per yr} =$

$B_{NG}$ Tbtu	$S$ gr S	1 scf nat gas	10 <sup>12</sup> Btu	lb S	1 ton S	1 ton mol S	1 ton mole SO <sub>2</sub>	64 tons SO <sub>2</sub>
Year	10 <sup>6</sup> scf nat gas	1050 Btu	Tbtu	7000 gr S	2000 lbs S	32 tons S	1 ton mol S	1 ton mole SO <sub>2</sub>

Grouping terms,

$= (B_{NG} \bullet S) \bullet 64 / (1050 \bullet 32 \bullet 14) = (B_{NG} \bullet S) \bullet 0.0001359$

Therefore, the value of  $K_b$  is equal to 0.0001359 tons SO<sub>2</sub>/(Tbtu • grains S/million SCF NG).

The SO<sub>2</sub> emissions can also be calculated from the volume of natural gas burned:

$$E_{2NG} = K_{NG} \bullet N1 \bullet S \quad \text{Eq. 6-3}$$

where,

$E_{2NG}$  = total SO<sub>2</sub> production from NG combustion, tons/yr

$K_{NG}$  = Molecular weight and units conversion constant =  $1.427 \bullet 10^{-7}$

$N1$  = NG burn in million standard cubic feet (Mscf) per year

$S$  = NG sulfur content in grains per million standard cubic feet; use EPA's value of 2000 gr/10<sup>6</sup> scf as default

The derivation of constant  $K_{NG}$  is presented in Text Box E.

Text Box E: Derivation of Molecular Weight and Units Conversion Constant,  $K_{NG}$

$(K_{NG} \bullet N1 \bullet S) = \text{tons SO}_2 \text{ per yr} =$

$N1 \ 10^6 \text{ scf}$	$S \text{ gr S}$	$\text{lb S}$	$1 \text{ ton S}$	$1 \text{ ton mol S}$	$1 \text{ ton mole SO}_2$	$64 \text{ tons SO}_2$
Year	$10^6 \text{ scf nat gas}$	$7000 \text{ gr S}$	$2000 \text{ lbs S}$	$32 \text{ tons S}$	$1 \text{ ton mol S}$	$1 \text{ ton mole SO}_2$

Grouping terms,

$$(N1 \bullet S) \bullet 64 / (7000 \bullet 2000 \bullet 32) = (N1 \bullet S) \bullet 1.427 \bullet 10^{-7}$$

Therefore, the value of  $K_{NG}$  is equal to  $1.427 \bullet 10^{-7} \text{ tons SO}_2/(\text{grains S})$

Table 6-1 presents the F1 factors for simple cycle units as a function of stack temperature, as sulfuric acid vapor is related to the temperature of the exhaust. As simple cycle combustion turbines (CT) exhaust is usually around 1000°F, and TRI rules require the reporting of sulfuric acid (not of SO<sub>3</sub>), the amount manufactured and released depends on stack temperature. Table 6-1 combines the temperature-based SO<sub>3</sub> to H<sub>2</sub>SO<sub>4</sub> conversion with the SO<sub>2</sub> to SO<sub>3</sub> conversion to give the Fuel Impact Factor, F1.

**Table 6-1**  
**Fuel Impact (F1) Factors for a Simple CT**

Stack T, °F	F1
300	0.055
400	0.055
500	0.047
600	0.022
700	0.0055
750	0.0027
800	0.0013
850	0.00071
900	0.00039
950	0.00022
1000	0.00013
1050	0.00008
1100	0.00005
1150	0.00003
1200	0.00002

## Combined Cycle Units

### Sulfuric Acid Manufactured

For combined cycle units, sources of *manufacture* of sulfuric acid are combustion, oxidation of SO<sub>2</sub> across catalyst used for NO<sub>x</sub> control and recently, oxidation of SO<sub>2</sub> across catalyst used for CO control.

For combustion, the manufacture of sulfuric acid for combined-cycle units is described by Equation 6-4.

$$EM_{CCcom} = K \bullet F1 \bullet E2_{NG} \quad \text{Eq. 6-4}$$

where,

$EM_{CCcom}$  = Total H<sub>2</sub>SO<sub>4</sub> *manufactured* from combustion, lbs/yr

K = Molecular weight and units conversion constant

$$= 98.07/64.04 \bullet 2000 = 3,063$$

98.07 = Molecular weight of H<sub>2</sub>SO<sub>4</sub>;

64.04 = Molecular weight of SO<sub>2</sub>;

2,000 = Conversion from tons per year to pounds per year.

F1 = Fuel Impact Factor for NG (See Table 4-1)

$E2_{NG}$  = Sulfur dioxide (SO<sub>2</sub>) emissions either: (1) recorded by a continuous emissions monitor, tons/yr, or (2) calculated from fuel burn data, tons/yr.

Recently, it has been shown that CO catalysts in combined cycle units can oxidize SO<sub>2</sub> to SO<sub>3</sub> in a manner similar to SCR<sub>s</sub>. Equation 6-5 describes the manufacture of sulfuric acid across the CO catalyst. For the case of combined cycle combustion turbines, the CO catalyst SO<sub>2</sub> oxidation rate (S3) will be approximately 0.1. This value is an estimate based on data from a prominent catalyst vendor. A more accurate value can be obtained from field measurements of SO<sub>2</sub> oxidation, or from the vendor's specification of the CO catalyst.

$$EM_{cc\_co} = K \bullet S3 \bullet f_{COops} \bullet E2 \quad \text{Eq. 6-5}$$

where,

$EM_{cc\_co}$  = Total H<sub>2</sub>SO<sub>4</sub> manufactured from the CO catalyst, lbs per year

K = Molecular weight and units conversion constant

$$= 98.07/64.04 \bullet 2000 = 3,063$$

98.07 = Molecular weight of H<sub>2</sub>SO<sub>4</sub>

64.04 = Molecular weight of SO<sub>2</sub>

2000 = Conversion from tons per year to pounds per year

- S3 = CO catalyst SO<sub>2</sub> oxidation rate (specified as a decimal, typically from 0.1-0.6)
- f<sub>COops</sub> = Operating factor of CO catalyst system, or the fraction of fuel burn when the flue gas is directed through the CO catalyst. This value should reflect the fraction of hours that the CO catalyst processed flue gas. This value will be site-specific but can be approximated as 0.8 for year-round peaking operation, 0.98 for year-round base-loaded operation, or 0.43 for seasonal operation.
- E2 = SO<sub>2</sub> produced, tons per year

Equation 6-6 describes the manufacture of sulfuric acid in an SCR. The amount of sulfuric acid manufactured due to SO<sub>2</sub> oxidation across the CO catalyst (EM<sub>CC\_CO</sub>) must be subtracted from the total amount of SO<sub>2</sub> produced (E2), because the CO catalyst will reduce the amount available for conversion by the SCR catalyst. For the case of combined cycle combustion turbines, the SCR catalyst SO<sub>2</sub> oxidation rate (S2) will be approximately 0.03. A more precise value can be obtained from either field test reports of SO<sub>2</sub> oxidation, or from the vendor's specification of the SCR catalyst or process. The Technology Impact Factor for SCR, F<sub>3SCR</sub>, will be 1.0.

$$EM_{CCSCR} = [(K \bullet E2) - EM_{CC\_CO}] \bullet f_{sops} \bullet S2 \bullet F_{3SCR} \quad \text{Eq. 6-6}$$

where,

- EM<sub>CCSCR</sub> = Total H<sub>2</sub>SO<sub>4</sub> manufactured from SCR, lbs per year
- K = Molecular weight and units conversion constant  
 = 98.07/64.04 • 2000 = 3,063  
 98.07 = Molecular weight of H<sub>2</sub>SO<sub>4</sub>;  
 64.04 = Molecular weight of SO<sub>2</sub>;  
 2,000 = Conversion from tons per year to pounds per year
- E2 = SO<sub>2</sub> produced, tons per year
- EM<sub>CC\_CO</sub> = Total H<sub>2</sub>SO<sub>4</sub> manufactured from the CO catalyst, lbs per year
- S2 = SCR catalyst SO<sub>2</sub> oxidation rate (specified as a decimal, typically from 0.001- 0.03)
- f<sub>sops</sub> = Operating factor of SCR system, or the fraction of coal burn when the flue gas is directed through the SCR, whether NH<sub>3</sub> reagent is injected to derive NO<sub>x</sub> reduction or not. This value should reflect the hours the SCR reactor processed flue gas, which will be site-specific but can be approximated by generally 0.8 for year-round peaking operation, 0.98 for year-round base-loaded operation, or 0.43 for seasonal operation
- F<sub>3SCR</sub> = Technology Impact Factor, for SCR (equal to 1.0, refer to Table 4-2)

The total sulfuric acid *manufacture* (TSAM) for a combined cycle unit is estimated using the equation below:

$$\text{TSAM}_{\text{CC}} = \text{EM}_{\text{CCcom}} + \text{EM}_{\text{CC\_CO}} + \text{EM}_{\text{CCSCR}} \quad \text{Eq. 6-7}$$

#### Sulfuric Acid Released

The sulfuric acid released by all sources in combined cycle units is estimated as shown in Equation 6-8. This equation takes into account the reducing effect of ammonia slip from the SCR equipment in a similar method as described in Section 4:

$$\text{TSAR}_{\text{CC}} = [\text{TSAM}_{\text{CC}} - (\text{K}_s \bullet \text{B} \bullet \text{f}_{\text{sreagent}} \bullet \text{S}_{\text{NH3}})] \bullet \text{F2}_{\text{cc}} \quad \text{Eq. 6-8}$$

where,

- TSAR<sub>CC</sub> = Total H<sub>2</sub>SO<sub>4</sub> released, lbs per year
- TSAM<sub>CC</sub> = Total H<sub>2</sub>SO<sub>4</sub> manufactured from all sources, lbs per year
- K<sub>s</sub> = Conversion factor = 3,799 (see Text Box B)
- B = Fuel burn in Tbtu/yr
- f<sub>sreagent</sub> = Fraction of SCR operation with reagent injection, when residual NH<sub>3</sub> is produced that will remove SO<sub>3</sub>.
- S<sub>NH3</sub> = NH<sub>3</sub> slip from SCR, ppmv at 6% O<sub>2</sub>, wet (averages 0.75 ppmv over catalyst guarantee period. Actual NH<sub>3</sub> slip data should be used if available)
- F2<sub>CC</sub> = Technology Impact Factor for the combined cycle heat exchanger, equal to a value of 0.5.

Examples 9 and 10 of Appendix A illustrates a gas-fired combined cycle plant calculation.

# 7

## REFERENCES

- Benson, 2006a Benson, L. et al., “Uses of Lime for Controlling SO<sub>3</sub> Emissions,” Presentation to the 2006 DOE NETL Environmental Controls Conference, May, 2006, Pittsburgh, PA.
- Benson, 2006b Benson, L., “Use of Magnesium Hydroxide for Reduction of SO<sub>3</sub> Emissions from Coal-Fired Power Plants,” Presentation to the 2006 DOE NETL Environmental Controls Conference, May, 2006, Pittsburgh, PA.
- Blythe, 2004 Blythe, G., “Furnace Injection of Alkaline Sorbents for Sulfuric Acid Removal,” Final report prepared for the U.S. Department of Energy, Cooperative Agreement No: DE-FC26-99FT40718, January 2004
- Bowes, 2006 Bowes, E., et al., “Sulfur Trioxide Reduction Strategy Demonstrated At Dominion Energy’s Chesterfield Station,” Proceedings of the 2006 Mega-Symposium, August, 2006, Baltimore, MD.
- Buckley, 2002 Buckley, W., et al., “Acid Mist Causes Problems for FGD Systems,” Power Engineering, November, 2002.
- Dahlin, 1991 Dahlin, R., et al., “Control of Acid Mist Emissions From FGD Systems,” paper presented to the EPRI-EPA-DOE 1991 SO<sub>2</sub> Control Symposium, Washington, DC, December, 1991.
- Dombrowski, 2004 Dombrowski, K. et al., “SO<sub>3</sub> Mitigation Guide and Cost-Estimating Workbook,” Proceedings of the Combined Power Plant Air Pollution Control Mega-Symposium, August 30-September 2, 2004, Washington, DC.
- EPA, 1991 EPA Code of Federal Regulations 40, Part 60, Appendix A, Method 1, Section 2.5, 1991 Edition.
- EPA, 1995a EPA, “Sulfuric Acid: Toxic Chemical Release Reporting: Community Right-To-Know.” Final Rule. 60 FR 34182. June 30, 1995.
- EPA, 1995b EPA, “Compilation of Air Pollutant Emission Factors AP-42, Fifth Edition, Volume I: Stationary Point and Area Sources.” <http://www.epa.gov/ttnchie1/ap42pdf/c01s01.pdf>.
- EPA, 1997 EPA, Emergency Planning and Community Right-to-Know Act – Section 313. Guidance for Reporting Sulfuric Acid (acid aerosols including mists vapors, gas, fog, and other airborne forms of any particle size). EPA-745-R-97-007, November 1997.

EPA, 1999	40 CFR Part 60, Appendix A, Method 2H- Determination of Stack Gas Velocity Taking into Account Velocity Decay Near the Stack Wall.
EPA, 2003	Conditional Test Method (CTM-041) – Determination of Volumetric Gas Flow in Rectangular Ducts or Stacks Taking into Account Velocity Decay Near the Stack or Duct Walls.
EPA, 2009	Federal Register, Vol. 74, No. 163, Tuesday, August 25, 2009, 40 CFR Part 60 - Revisions to Test Method for Determining Stack Gas Velocity Taking Into Account Velocity Decay Near the Stack Walls.
EPRI, 2001	EPRI Report 1004027, “Flue Gas Sulfuric Acid Measurement Improvements,” August, 2001.
EPRI, 2008	<i>Estimating Total Sulfuric Acid Emissions from Stationary Power Plants</i> , EPRI, Palo Alto, CA: 2008. 1016384. (revised April, 2009)
EPRI, 2010a	<i>Estimating Total Sulfuric Acid Emissions from Stationary Power Plants</i> , EPRI, Palo Alto, CA: 2010. 1020636.
EPRI, 2010b	<i>Operation and Maintenance Guidelines for Selective Catalytic Reduction: 2010 Update</i> . EPRI, Palo Alto, CA: 2010. 1019707.
Gale, 2006	Gale. T., et al., “Hydrated Lime for SO <sub>3</sub> Removal,” Proceedings of the Power Plant Air Pollutant Control “Mega Symposium”, Baltimore, MD, August, 2006.
Hamel, 2003	Hamel, B., “The Role of the Combustion Air Preheater in an Effective Multipollutant Control Strategy,” Proceedings of the Combined Power Plant Air Pollutant Control Mega Symposium, Washington, DC, May, 2003.
Hardman, 1998	Hardman, R., Stacy R., Dismukes, E., <i>Estimating Total Sulfuric Acid Emissions from Coal-Fired Power Plants</i> . Internal Report of Research & Environmental Affairs Department, Southern Company Services, March 1998.
Hardman, 1999	Hardman, R., Stacy, R., Dismukes, E., Harrison, K., Monroe, L., <i>Estimating Total Sulfuric Acid Emissions from Coal-Fired Power Plants</i> . Revised Internal Report of Research & Environmental Affairs Department, Southern Company Services, February 1999.
Harrison, 2004	Harrison, K., et al., “Estimating Total Sulfuric Acid Emissions from Stationary Power Plants: Revision 3 (2004).” Revised Internal Report of Research & Environmental Affairs Department, Southern Company Services, December, 2004.
Harrison, 2005	Harrison, K., et al., “Estimating Total Sulfuric Acid Emissions from Stationary Power Plants: Revision 4 (2005).” Revised Internal Report of

- Research & Environmental Affairs Department, Southern Company Services, October, 2005.
- Lindenhoff, 2004      Lindenhoff, Peter, "SCR Catalyst Developments: SO<sub>2</sub> Oxidation," presentation to the EPRI 2004 Workshop on Selective Catalytic Reduction, November, 2004, Pittsburgh, PA.
- Monroe, 2001          Monroe, L. and K. Harrison, "An Updated Method for Estimating Total Sulfuric Acid Emissions from Stationary Power Plants: Revision 1," White Paper Issued by Southern Company Services, March, 2001.
- Monroe, 2006          Monroe, L., et al., "A Review of Sulfuric Acid Formation and Behavior in Coal-Fired Power Plants," Proceedings of the 2006 Mega-Symposium, August, 2006, Baltimore, MD.
- Moser, 2007           Moser, R., "SO<sub>3</sub>'s Impact on Plant O&M: Part III," Power Magazine, April, 2007.
- Noble, 1998           Noble, R; Martz, T, "A Measurement Bias Correction factor for CEM Derived SO<sub>2</sub> Emission Data" White Paper Issued by Southern Company Services, July, 1998
- Ritzenthaler, 2006    Ritzenthaler, D. et al., "A System Approach to SO<sub>3</sub> Mitigation With Trona," Proceedings of the Power Plant Air Pollutant Control "Mega Symposium", Baltimore, MD, August, 2006.
- Saranuc, 1999          Saranuc, N., et al., "Factors Affecting Sulfuric Acid Emissions From Boilers," Proceedings of the Combined Power Plant Air Pollutant Control Mega Symposium, Atlanta, GA, August, 1999.
- Senior, 2000           Senior, C.L., et al., "Simulation of SO<sub>3</sub> Production," Fuel Processing Technology, April 2000, Vol. 63, 197-213.
- Srivastava, 2004      Srivastava, R., et al., "Emissions of Sulfur Trioxide from Coal-Fired Power Plants," Journal of the Air & Waste Management Association, Volume 54, June 2004.
- Weilert, 2004          C. Weilert, "Wet ESPs vs. Sorbent Injection for SO<sub>3</sub> Control," Proceedings of the Combined Power Plant Air Pollution Control Mega-Symposium, August 30-September 2, 2004, Washington, DC.



# A

## EXAMPLE CALCULATIONS

### Example 1: Conventional Coal-Fired Boiler with an ESP

A 500 MW pulverized coal-fired (PC) boiler, equipped with a cold-side electrostatic precipitator, burns an Eastern bituminous coal. The coal used in the reporting year is 1,126,938 tons with a weighted average sulfur concentration of 2.0% and a heating value of 12,000 Btu/lb.

#### **Solution**

Manufactured

$$E2 = K1 \bullet K2 \bullet C1 \bullet S1$$

$$E2 = 0.02 \bullet 0.95 \bullet 1,126,938 \bullet 2.0 = 42,824 \text{ tons SO}_2/\text{yr}$$

$$EM_{\text{Comb}} = K \bullet F1 \bullet E2$$

$$F1_{\text{eastbit}} = 1.1163\text{E-}6 \bullet \text{SO}_2 + 0.0064876$$

$$\text{SO}_2 = S1 \bullet \frac{K_{F1}}{HV} = 2.0 \bullet \frac{10,003,602}{12,000} = 1667 \text{ ppm}$$

$$F1_{\text{eastbit}} = 1.1163\text{E-}6 \bullet + 0.0064876 = 0.0083$$

$$EM_{\text{Comb}} = 3063 \bullet 0.0083 \bullet 42,824 = 1,088,710 \text{ lbs H}_2\text{SO}_4/\text{yr}$$

The 25,000 lbs/yr threshold has been exceeded; therefore, a release estimate must be made and the result reported on Form R.

Released

$$\text{TSAR} = EM_{\text{Comb}} \bullet F2_{\text{APH}} \bullet F2_{\text{ESP}}$$

$$\text{TSAR} = 1,088,710 \bullet 0.50 \bullet 0.63 = 342,944 \text{ lbs H}_2\text{SO}_4/\text{yr}$$

## Example 2: SCR Added to Example 1

A 500 MW PC boiler, equipped with a cold-side electrostatic precipitator, burns an Eastern bituminous coal. The plant is equipped with an SCR process that operates during the ozone season only, so that 0.43 of the coal burn occurred with the SCR operating. The remaining time that the SCR is not in service the flue gas is bypassed around the SCR. The SCR catalyst SO<sub>2</sub> oxidation rate specified in the design is 0.75%, and the ammonia slip is estimated to be 0.75 ppmv. The coal used in the reporting year is 1,126,938 tons with a weighted average sulfur concentration of 2.0% and a heating value of 12,000 Btu/lb.

### Solution

Manufactured

$$E2 = K1 \bullet K2 \bullet C1 \bullet S1$$

$$E2 = 0.02 \bullet 0.95 \bullet 1,126,938 \bullet 2.0 = 42,824 \text{ tons SO}_2/\text{yr}$$

Combustion

$$EM_{\text{comb}} = K \bullet F1 \bullet E2$$

$$F1_{\text{eastbit}} = 1.1163\text{E-}6 \bullet \text{SO}_2 + 0.0064877$$

$$\text{SO}_2 = S1 \bullet \frac{K_{F1}}{HV} = 2.0 \bullet \frac{10,003,602}{12,000} = 1667 \text{ ppm}$$

$$F1_{\text{eastbit}} = 1.1163\text{E-}6 \bullet + 0.0064877 = 0.0083$$

$$EM_{\text{Comb}} = 3063 \bullet 0.0083 \bullet 42,824 = 1,088,710 \text{ lbs H}_2\text{SO}_4/\text{yr}$$

SCR

$$EM_{\text{SCR}} = K \bullet S2 \bullet f_s \bullet E2$$

$$EM_{\text{SCR}} = 3063 \bullet 0.0075 \bullet 0.43 \bullet 42,824 = 423,023 \text{ lbs H}_2\text{SO}_4/\text{yr}$$

Total

$$\text{TSAM} = EM_{\text{comb}} + EM_{\text{SCR}}$$

$$\text{TSAM} = 1,088,710 + 423,023 \text{ lbs H}_2\text{SO}_4/\text{yr}$$

$$\text{TSAM} = 1,511,733 \text{ lbs H}_2\text{SO}_4/\text{yr}$$

The 25,000 lbs/yr threshold has been exceeded; therefore, a release estimate must be made and the result reported on Form R.

Released

Coal Burn

$$B = C1 \bullet HV \bullet K_B$$

$$B = 1,126,938 \text{ tons/yr} \bullet 2000 \text{ lbs/ton} \bullet 12,000 \text{ Btu/lb} \bullet 1 \text{ Tbtu}/10^{12} \text{ Btu}$$

$$B = 27.05 \text{ Tbtu/yr}$$

*Ammonia Slip*

$$\text{NH3}_{\text{SCR}} = K_s \bullet B \bullet f_{\text{sreagent}} \bullet S_{\text{NH3}}$$

$$\text{NH3}_{\text{SCR}} = 3799 \bullet 27.05 \bullet 0.43 \bullet 0.75 = 33,141 \text{ lbs NH}_3/\text{yr}$$

*Total Releases*

$$\text{TSAR} = [(\text{EM}_{\text{Comb}} + \text{EM}_{\text{SCR/SNCR}}) - (\text{NH3}_{\text{SCR}})] \bullet F2_{\text{APH}} \bullet F2_{\text{ESP}}$$

$$\text{TSAR} = [(1,088,710 + 423,023) - (33,141)] \bullet 0.50 \bullet 0.63$$

$$\text{TSAR} = 465,756 \text{ lbs H}_2\text{SO}_4/\text{yr}$$

### Example 3: Alkali Injection Added to Example 2

A 500 MW PC boiler, equipped with a cold-side electrostatic precipitator, burns an Eastern bituminous coal. The plant is equipped with an SCR process that operates during the ozone season only, so that 0.43 of the coal burn occurred with the SCR operating. The remaining time that the SCR is not in service the flue gas is bypassed around the SCR. The SCR catalyst SO<sub>2</sub> oxidation rate specified in the design is 0.75%, and the ammonia slip is estimated to be 0.75 ppmv.

The plant employs injection of alkali material (e.g., lime, sodium bicarbonate, sodium bisulfate, etc.) to control SO<sub>3</sub> emissions at the stack. The plant operator has conducted a series of field tests to determine the amount of alkali material that must be injected to limit flue gas SO<sub>3</sub> concentration at the stack. The test contractor has issued a report defining the amount of alkali that should be added to limit the stack SO<sub>3</sub> to 5 ppm, as measured in the flue gas at 6.6% O<sub>2</sub> and 8.8% moisture. The alkali injection system will be operated throughout the entire year, so that no more than 5 ppm of SO<sub>3</sub> at the stated conditions of excess O<sub>2</sub> and moisture exist in the stack.

The coal burn rate in the reporting year is 1,126,938 tons, with a weighted average sulfur concentration of 2.0%, and a heating value of 12,000 Btu/lb.

The calculation of manufactured sulfuric acid is the same as Example 1, and is repeated here:

#### **Solution**

Manufactured

$$E2 = K1 \bullet K2 \bullet C1 \bullet S1$$

$$E2 = 0.02 \bullet 0.95 \bullet 1,126,938 \bullet 2.0 = 42,824 \text{ tons SO}_2/\text{yr}$$

Combustion

$$EM_{\text{comb}} = K \bullet F1 \bullet E2$$

$$F1_{\text{eastbit}} = 1.1163\text{E-}6 \bullet \text{SO}_2 + 0.0064877$$

$$\text{SO}_2 = S1 \bullet \frac{K_{F1}}{HV} = 2.0 \bullet \frac{10,003,602}{12,000} = 1667 \text{ ppm}$$

$$F1_{\text{eastbit}} = 1.1163\text{E-}6 \bullet + 0.0064877 = 0.0083$$

$$EM_{\text{Comb}} = 3063 \bullet 0.0083 \bullet 42,824 = 1,088,710 \text{ lbs H}_2\text{SO}_4/\text{yr}$$

SCR

$$EM_{\text{SCR}} = K \bullet S2 \bullet f_s \bullet E2$$

$$EM_{\text{SCR}} = 3063 \bullet 0.0075 \bullet 0.43 \bullet 42,824 = 423,023 \text{ lbs H}_2\text{SO}_4/\text{yr}$$

Total

$$\text{TSAM} = EM_{\text{comb}} + EM_{\text{SCR}}$$

$$\text{TSAM} = 1,088,710 + 423,023 \text{ lbs H}_2\text{SO}_4/\text{yr}$$

$$\text{TSAM} = 1,511,733 \text{ lbs H}_2\text{SO}_4/\text{yr}$$

The 25,000 lbs/yr threshold has been exceeded; therefore, a release estimate must be made and the result reported on Form R.

#### Released

The total sulfuric acid released is based on the maximum value allowed by alkali injection, as measured in the stack, and the volume flow rate of combustion products processed.

The concentration of SO<sub>3</sub> measured at the stack can be converted to a mass emission rate, as described by Equation 4-15

$$\text{ER}_{\text{ALKINJ}} = K_{\text{alkali}} \bullet B \bullet S_{\text{SO}_3} \bullet F_{\text{alkali}} \bullet F_{2x}$$

where,

$\text{ER}_{\text{ALKINJ}}$  = Total H<sub>2</sub>SO<sub>4</sub> released from unit equipped with alkali injection, lbs per year

$K_{\text{alkali}}$  = Constant, equal to 3,799, with units of lbs H<sub>2</sub>SO<sub>4</sub>/(Tbtu ppmv SO<sub>3</sub>) (SO<sub>3</sub> measured at @ 6% O<sub>2</sub> and 8.1% H<sub>2</sub>O)

$B$  = 27.05 Tbtu/yr, for the specific case of Example 1

$S_{\text{SO}_3}$  = SO<sub>3</sub> content as measured in the stack or particulate collector exit, corrected to a concentration basis of ppmv at 6% O<sub>2</sub>, 8.1% moisture

$F_{\text{alkali}}$  = fraction of operation with alkali addition to remove SO<sub>3</sub>.

$F_{2x}$  = 1 (as the SO<sub>3</sub> measurement is in the stack, there are no control technology components downstream of the measurement)

The conversion factor  $K_{\text{alkali}}$  is equal to 3,799 (see Text Box B). This constant is derived for the case where flue gas SO<sub>3</sub> is reported in terms of 6% oxygen and wet flue gas at 8.1% H<sub>2</sub>O. However, the SO<sub>3</sub> concentration of 5 ppm in the stack is measured at slightly different conditions of excess O<sub>2</sub> and moisture (6.6% oxygen and 8.8% moisture and therefore, a new value of  $K_{\text{alkali}}$  must be calculated:

$$K_{\text{alkali}} (\text{O}_2, \text{H}_2\text{O}) = 3799 (6\% \text{ O}_2, 8.1\% \text{ H}_2\text{O}) \bullet [(100-8.1)/(100-\text{new H}_2\text{O})] \bullet [(20.9 - 6.0)/(20.9 - \text{new O}_2)]$$

$$K_{\text{alkali}} (\text{O}_2, \text{H}_2\text{O}) = 3799 (6\% \text{ O}_2, 8.1\% \text{ H}_2\text{O}) \bullet [(100-8.1)/(100-8.8)] \bullet [(20.9 - 6.0)/(20.9 - 6.6)]$$

$$K_{\text{alkali}} (6.6\%, 8.8\%) = 3799 \bullet [1.0077] \bullet [1.034]$$

$$K_{\text{alkali}} (6.6\%, 8.8\%) = 3958$$

Total sulfuric acid release is then calculated as follows:

$$\text{ER}_{\text{ALKINJ}} = [3,958] \bullet [27.05] \bullet [5.0] \bullet [1] \bullet [1]$$

$$ER_{ALKINJ} = 535,320 \text{ lbs/yr}$$

$$TSAR = ER_{ALKINJ}$$

$$TSAR = 535,320 \text{ lbs/yr}$$

#### Example 4: 500 MW PRB-fired Boiler with ESP, SCR

A 500 MW PC boiler, equipped with a cold-side electrostatic precipitator, burns a PRB coal. The plant is equipped with an SCR process that operates during the ozone season only, so that 0.43 of the coal burn occurred with the SCR operating. The SCR is bypassed when not in use. The SCR catalyst SO<sub>2</sub> oxidation rate specified in the design is 2%, and the ammonia slip is estimated to be 0.75 ppmv. The coal used in the reporting year is 1,384,552 tons with a weighted average sulfur concentration of 0.40% and a heating value of 8,500 Btu/lb.

#### **Solution**

Manufactured

$$E2 = K1 \bullet K2 \bullet C1 \bullet S1$$

$$E2 = 0.02 \bullet 0.875 \bullet 1,384,552 \bullet 0.40 = 9,692 \text{ tons SO}_2/\text{yr}$$

Combustion

$$EM_{\text{comb}} = K \bullet F1 \bullet E2$$

$$EM_{\text{comb}} = 3063 \bullet 0.0019 \bullet 9,692 = 56,405 \text{ lbs H}_2\text{SO}_4/\text{yr}$$

SCR

$$EM_{\text{SCR}} = K \bullet S2 \bullet f_s \bullet f_{\text{SCR}} \bullet E2$$

$$EM_{\text{SCR}} = 3063 \bullet 0.020 \bullet 0.43 \bullet 0.17 \bullet 9,692 = 43,402 \text{ lbs H}_2\text{SO}_4/\text{yr}$$

Total

$$\text{TSAM} = EM_{\text{comb}} + EM_{\text{SCR}}$$

$$\text{TSAM} = 56,404 + 43,402 \text{ lbs H}_2\text{SO}_4/\text{yr}$$

$$\text{TSAM} = 99,806 \text{ lbs H}_2\text{SO}_4/\text{yr}$$

The 25,000 lbs/yr threshold has been exceeded; therefore, a release estimate must be made and the result reported on Form R.

Released

Coal Burn

$$B = C1 \bullet HV \bullet K_B$$

$$B = 1,384,552 \text{ tons/yr} \bullet 2000 \text{ lbs/ton} \bullet 8,500 \text{ Btu/lb} \bullet 1 \text{ Tbtu}/10^{12} \text{ Btu}$$

$$B = 23.54 \text{ Tbtu/yr}$$

Ammonia Slip

$$\text{NH}_{3\text{SCR}} = K_s \bullet B \bullet f_{\text{sreagent}} \bullet S_{\text{NH}_3}$$

$$\text{NH}_{3\text{SCR}} = 3799 \bullet 23.54 \bullet 0.43 \bullet 0.75 = 28,841 \text{ lbs NH}_3/\text{yr}$$

*Total Releases*

$$\text{TSAR} = [(\text{EM}_{\text{Comb}} + \text{EM}_{\text{SCR/SNCR}}) - (\text{NH}_{3\text{SCR}})] \bullet \text{F}_{2\text{APH}} \bullet \text{F}_{2\text{ESP}}$$

$$\text{TSAR} = [(56,404 + 43,402) - (28,841)] \bullet 0.36 \bullet 0.72$$

$$\text{TSAR} = 18,394 \text{ lbs H}_2\text{SO}_4/\text{yr}$$



### Example 5: FGC Added to Example 1

A 500 MW PC boiler, equipped with a cold-side electrostatic precipitator, burns an Eastern bituminous coal. The plant is equipped with a FGC process that injects both SO<sub>3</sub> and NH<sub>3</sub> upstream of the air preheater. The SO<sub>3</sub> is injected at 7 ppmv at 6% O<sub>2</sub> wet, and the ammonia at 3 ppmv also at 6% O<sub>2</sub> wet. The FGC system operates whenever the plant is on, except during startup and shutdown, with an operating factor estimated at 0.9. The coal used in the reporting year is 1,126,938 tons with a weighted average sulfur concentration of 2.0% and a heating value of 12,000 Btu/lb.

#### Solution

Manufactured

$$E2 = K1 \bullet K2 \bullet C1 \bullet S1$$

$$E2 = 0.02 \bullet 0.95 \bullet 1,126,938 \bullet 2.0 = 42,824 \text{ tons SO}_2/\text{yr}$$

Combustion

$$EM_{\text{Comb}} = K \bullet F1 \bullet E2$$

$$F1_{\text{eastbit}} = 1.1163\text{E-}6 \bullet \text{SO}_2 + 0.0064877$$

$$\text{SO}_2 = S1 \bullet \frac{K_{F1}}{HV} = 2.0 \bullet \frac{10,003,602}{12,000} = 1667 \text{ ppm}$$

$$F1_{\text{eastbit}} = 1.1163\text{E-}6 \bullet + 0.0064877 = 0.0083$$

$$EM_{\text{Comb}} = 3063 \bullet 0.0083 \bullet 42,824 = 1,088,710 \text{ lbs H}_2\text{SO}_4/\text{yr}$$

FGC

$$B = 1,126,938 \text{ tons/yr} \bullet 2000 \text{ lbs/ton} \bullet 12000 \text{ Btu/lb} \bullet 1 \text{ Tbtu}/10^{12} \text{ Btu}$$

$$B = 27.05 \text{ Tbtu/yr}$$

$$EM_{\text{FGC}} = K_e \bullet B \bullet f_e \bullet I_s \bullet F3_{\text{FGC}}$$

$$EM_{\text{FGC}} = 3799 \bullet 27.05 \bullet 0.9 \bullet 7 \bullet 1 = 647,407 \text{ lbs H}_2\text{SO}_4/\text{yr}$$

Total

$$\text{TSAM} = EM_{\text{Comb}} + EM_{\text{FGC}}$$

$$\text{TSAM} = 1,088,710 + 647,407 \text{ lbs H}_2\text{SO}_4/\text{yr}$$

$$\text{TSAM} = 1,736,117 \text{ lbs H}_2\text{SO}_4/\text{yr}$$

The 25,000 lbs/yr threshold has been exceeded; therefore, a release estimate must be made and the result reported on Form R.

Released

*Coal Burn*

$$B = C1 \bullet HV \bullet K_B$$

$$B = 1,126,938 \text{ tons/yr} \bullet 2000 \text{ lbs/ton} \bullet 12000 \text{ Btu/lb} \bullet 1 \text{ Tbtu}/10^{12} \text{ Btu}$$

$$B = 27.05 \text{ Tbtu/yr}$$

*FGC Ammonia Injection*

$$NH3_{FGC} = K_e \bullet B \bullet f_e \bullet I_{NH3}$$

$$NH3_{FGC} = 3799 \bullet 27.05 \bullet 0.9 \bullet 3.0 = 277,460 \text{ lbs } NH_3/\text{yr}$$

*Total Releases*

$$TSAR = [(EM_{Comb} + EM_{FGC}) - (NH3_{FGC})] \bullet F2_{APH} \bullet F2_{ESP}$$

$$TSAR = [(1,088,710 + 647,407) - (277,460)] \bullet 0.50 \bullet 0.63$$

$$TSAR = 459,477 \text{ lbs } H_2SO_4/\text{yr}$$

### Example 6: SCR and FGC Added to Example 1

A 500 MW PC boiler, equipped with a cold-side electrostatic precipitator, burns an Eastern bituminous coal. The plant is equipped with an SCR process that operates during the ozone season only, so that 0.43 of the coal burn occurred with the SCR operating. The SCR is bypassed when not in operation. The SCR catalyst SO<sub>2</sub> oxidation rate specified in the design is 0.75%, and the ammonia slip is estimated to be 0.75 ppmv. The plant is also equipped with a FGC process that injects both SO<sub>3</sub> and NH<sub>3</sub> upstream of the air preheater. The SO<sub>3</sub> is injected at 7 ppmv at 6% O<sub>2</sub> wet, and the ammonia at 3 ppmv also at 6% O<sub>2</sub> wet. The FGC system operates whenever the plant is on, except during startup and shutdown, with an operating factor estimated at 0.9. The coal used in the reporting year is 1,126,938 tons with a weighted average sulfur concentration of 2.0% and a heating value of 12,000 Btu/lb.

### Solution

Manufactured

*Total (from previous examples)*

$$TSAM = EM_{Comb} + EM_{SCR} + EM_{FGC}$$

$$TSAM = 1,088,710 + 423,023 + 647,407 \text{ lbs H}_2\text{SO}_4/\text{yr}$$

$$TSAM = 2,159,140 \text{ lbs H}_2\text{SO}_4/\text{yr}$$

The 25,000 lbs/yr threshold has been exceeded; therefore, a release estimate must be made and the result reported on Form R.

Released

*Total Releases (from previous examples)*

$$TSAR = [(EM_{Comb} + EM_{SCR} + EM_{FGC}) - (NH_{3SCR} + NH_{3FGC})] \bullet F_{2APH} \bullet F_{2ESP}$$

$$TSAR = [(1,088,710 + 423,023 + 647,407) - (33,141 + 277,460)] \bullet 0.50 \bullet 0.63$$

$$TSAR = 582,290 \text{ lbs H}_2\text{SO}_4/\text{yr}$$

### Example 7: SCR and Downstream FGC Added to Example 1

A 500 MW PC boiler, equipped with a cold-side electrostatic precipitator, burns an Eastern bituminous coal. The plant is equipped with an SCR process that operates during the ozone season only, so that 0.43 of the coal burn occurred with the SCR operating. The SCR is bypassed when not operating. The SCR catalyst SO<sub>2</sub> oxidation rate specified in the design is 0.75%, and the ammonia slip is estimated to be 0.75 ppmv. The plant is also equipped with a FGC process that injects both SO<sub>3</sub> and NH<sub>3</sub> downstream of the air preheater. The SO<sub>3</sub> is injected at 7 ppmv at 6% O<sub>2</sub> wet, and the ammonia at 3 ppmv also at 6% O<sub>2</sub> wet. The FGC system operates whenever the plant is on, except during startup and shutdown, with an operating factor estimated at 0.9. The coal used in the reporting year is 1,126,938 tons with a weighted average sulfur concentration of 2.0% and a heating value of 12,000 Btu/lb.

### Solution

Manufactured

*Total (from previous examples)*

$$TSAM = EM_{Comb} + EM_{SCR} + EM_{FGC}$$

$$TSAM = 1,088,710 + 423,023 + 647,407 \text{ lbs H}_2\text{SO}_4/\text{yr}$$

$$TSAM = 2,159,140 \text{ lbs H}_2\text{SO}_4/\text{yr}$$

The 25,000 lbs/yr threshold has been exceeded; therefore, a release estimate must be made and the result reported on Form R.

Released

*Total Releases (from previous examples)*

$$TSAR = \{[(EM_{Comb} + EM_{SCR}) - NH3_{SCR}] \bullet F2_{APH} + (EM_{FGC\_afterAPH} - NH3_{FGC\_afterAPH})\} \bullet F2_{ESP}$$

Check that subtotal from upstream sources is positive:

$$TSAR_{upstream} = [(1,088,710 + 423,023) - 33,141] = 1,478,592 > 0$$

$$TSAR = [(1,088,710 + 423,023) - 33,141] \bullet 0.50 + (647,407 - 277,460) \bullet 0.63$$

$$TSAR = 698,823 \text{ lbs H}_2\text{SO}_4/\text{yr}$$

### Example 8: Coal-Fired Boiler with FGC, NG Startup Fuel, and Used Oil Co-Firing

A 500 MW PC boiler, equipped with a cold-side electrostatic precipitator, burns an Eastern bituminous coal as the main fuel. The plant is equipped with an SCR process that operates during the ozone season only, so that 0.43 of the coal burn occurred with the SCR operating. The SCR is bypassed when not in operation. The SCR catalyst SO<sub>2</sub> oxidation rate specified in the design is 0.75%, and the ammonia slip is estimated to be 0.75 ppmv. The plant is also equipped with a FGC process that injects both SO<sub>3</sub> and NH<sub>3</sub> upstream of the air preheater. The SO<sub>3</sub> is injected at 7 ppmv at 6% O<sub>2</sub> wet, and the ammonia at 3 ppmv also at 6% O<sub>2</sub> wet. The FGC system operates whenever the plant is on, except during startup and shutdown, with an operating factor estimated at 0.9.

The coal used in the reporting year is 1,126,938 tons with a weighted average sulfur concentration of 2.0% and a heating value of 12,000 Btu/lb.

Natural gas is used as a startup fuel, with 0.5 Tbtu per year. During startup, neither the SCR nor the FGC system is used. Used oil is also burned, with 483.2 tons burned (0.0185 Tbtu/yr) in the year. Since the used oil is burned when the unit is at full load, it is burned while the SCR and FGC are both operating. The used oil has a sulfur content of 0.1% from analysis.

### Solution

#### Coal fuel calculations

*Manufactured from coal*

*Total (from previous examples)*

$$TSAM = EM_{Comb} + EM_{SCR} + EM_{FGC}$$

$$TSAM = 1,088,710 + 423,023 + 647,407 \text{ lbs H}_2\text{SO}_4/\text{yr}$$

$$TSAM = 2,159,140 \text{ lbs H}_2\text{SO}_4/\text{yr}$$

*Released from coal*

*Total Releases (from previous examples)*

$$TSAR_{coal} = 582,290 \text{ lbs H}_2\text{SO}_4/\text{yr}$$

#### Natural gas fuel calculations

*Manufactured from natural gas*

*Combustion*

$$E_{2NG} = K_b \bullet B_{NG} \bullet S$$

$$E_{2NG} = 0.0001359 \bullet 0.5 \text{ Tbtu/yr} \bullet 2000 \text{ gr}/10^6 \text{ scf}$$

$$E_{2NG} = 0.136 \text{ tons SO}_2/\text{year}$$

$$EM_{Comb} = K \bullet F1 \bullet E_{2NG}$$

$$EM_{\text{Comb}} = 3063 \bullet 0.01 \bullet 0.136$$

$$EM_{\text{Comb}} = 4.17 \text{ lbs H}_2\text{SO}_4 \text{ manufactured}$$

No sulfuric acid is manufactured in either the SCR or FGC.

*Released from natural gas*

*Total Releases*

$$TSAR_{\text{NG}} = EM_{\text{Comb}} \bullet F2_{\text{APH}} \bullet F2_{\text{ESP}}$$

$$TSAR_{\text{NG}} = 4.17 \bullet 0.50 \bullet 0.63$$

$$TSAR_{\text{NG}} = 1.31 \text{ lbs H}_2\text{SO}_4/\text{yr}$$

F2 is taken to be equal to 0.50 for the air heater and 0.63 for the ESP.

***Used oil fuel calculations***

*Manufactured from used oil*

*Combustion*

$$E2 = K1 \bullet K2 \bullet C1 \bullet S1$$

$$E2 = 0.02 \bullet 1.0 \bullet 483.2 \bullet 0.1$$

$$E2 = 0.966 \text{ tons SO}_2/\text{year}$$

$$EM_{\text{Comb}} = K \bullet F1 \bullet E2$$

$$EM_{\text{Comb}} = 3063 \bullet 0.0175 \bullet 0.966$$

$$EM_{\text{Comb}} = 51.8 \text{ lbs H}_2\text{SO}_4 \text{ manufactured}$$

***SCR***

$$EM_{\text{SCR}} = K \bullet S2 \bullet f_s \bullet E2$$

$$EM_{\text{SCR}} = 3063 \bullet 0.0075 \bullet 1.0 \bullet 0.966$$

$$EM_{\text{SCR}} = 22.2 \text{ lbs H}_2\text{SO}_4 \text{ manufactured}$$

***FGC***

$$EM_{\text{FGC}} = K_e \bullet B \bullet f_e \bullet I_s \bullet F3_{\text{FGC}}$$

$$EM_{\text{FGC}} = 3799 \bullet 0.0185 \bullet 1.0 \bullet 7.0 \bullet 1$$

$$EM_{\text{FGC}} = 492 \text{ lbs H}_2\text{SO}_4 \text{ manufactured}$$

***Total Manufactured***

$$TSAM = EM_{\text{Comb}} + EM_{\text{SCR}} + EM_{\text{FGC}}$$

$$TSAM = 51.8 + 22.2 + 492 \text{ lbs H}_2\text{SO}_4/\text{yr}$$

$$\text{TSAM} = 566 \text{ lbs H}_2\text{SO}_4/\text{yr}$$

*Released from used oil*

***Ammonia Slip***

$$\text{NH}_{3\text{SCR}} = K_s \bullet B \bullet f_{\text{sreagent}} \bullet S_{\text{NH}_3}$$

$$\text{NH}_{3\text{SCR}} = 3799 \bullet 0.0185 \bullet 1.0 \bullet 0.75 = 52.7 \text{ lbs NH}_3/\text{yr}$$

***FGC Ammonia Injection***

$$\text{NH}_{3\text{FGC}} = K_e \bullet B \bullet f_e \bullet I_{\text{NH}_3}$$

$$\text{NH}_{3\text{FGC}} = 3799 \bullet 0.0185 \bullet 1.0 \bullet 3.0 = 211 \text{ lbs NH}_3/\text{yr}$$

***Total Releases***

$$\text{TSAR}_{\text{oil}} = [(\text{EM}_{\text{Comb}} + \text{EM}_{\text{SCR}} + \text{EM}_{\text{FGC}}) - (\text{NH}_{3\text{SCR}} + \text{NH}_{3\text{FGC}})] \bullet F_{2\text{APH}} \bullet F_{2\text{ESP}}$$

$$\text{TSAR}_{\text{oil}} = [(51.8 + 22.2 + 492) - (52.7 + 211)] \bullet 0.5 \bullet 0.63$$

$$\text{TSAR}_{\text{oil}} = 95 \text{ lbs H}_2\text{SO}_4/\text{yr}$$

F2 is taken to be equal to 0.50 for the air heater and 0.63 for the ESP

Grand totals for all fuels

***Manufactured***

$$\text{TSAM} = \text{TSAM}_{\text{coal}} + \text{TSAM}_{\text{NG}} + \text{TSAM}_{\text{oil}}$$

$$\text{TSAM} = 2,159,140 + 4.17 + 566 \text{ lbs H}_2\text{SO}_4/\text{yr}$$

$$\text{TSAM} = 2,159,710 \text{ lbs H}_2\text{SO}_4/\text{yr}$$

***Released***

$$\text{TSAR} = \text{TSAR}_{\text{coal}} + \text{TSAR}_{\text{NG}} + \text{TSAR}_{\text{oil}}$$

$$\text{TSAR} = 582,290 + 1.31 + 95 \text{ lbs H}_2\text{SO}_4/\text{yr}$$

$$\text{TSAR} = 582,386 \text{ lbs H}_2\text{SO}_4/\text{yr}$$

### Example 9: Natural Gas Combined Cycle Plant

A natural gas-fired combined-cycle unit uses 12.3 Tbtu/yr. of natural gas, with the standard sulfur content.

#### ***Solution***

Manufactured

$$E_{2NG} = K_b \bullet B_{NG} \bullet S$$

$$E_{2NG} = 0.0001359 \bullet 12.3 \bullet 2000$$

$$E_{2NG} = 3.343 \text{ tons SO}_2/\text{yr} \square$$

*Combustion*

$$EM_{CC} = K \bullet F1 \bullet E_{2NG}$$

$$EM_{CC} = 3063 \bullet 0.0555 \bullet 3.343$$

$$EM_{CC} = 568 \text{ lbs H}_2\text{SO}_4/\text{yr}$$

Released

$$TSAR_{NG} = EM_{Comb} \bullet F2_{CC}$$

$$TSAR_{NG} = 568 \bullet 0.5$$

$$TSAR_{NG} = 284 \text{ lbs H}_2\text{SO}_4/\text{yr}$$

$F2_{CC} = 0.5$  because the low temperature of the back-end tubes of the HRSG act like an air heater.



### Example 10: SCR and CO catalyst added to Example 9

A natural gas-fired combined-cycle unit uses 12.3 Tbtu/yr. of natural gas, with the standard sulfur content. The plant is equipped with an SCR process that operates continually (operating factor of 1.0). The SCR catalyst SO<sub>2</sub> oxidation rate specified in the design is 2.0%, and the ammonia slip is estimated to be 0.75 ppmv. The plant is also equipped with a CO catalyst, which also is in continuous operation, and has an estimated SO<sub>2</sub> oxidation rate of 10%.

#### **Solution**

Manufactured

$$E_{2NG} = K_b \cdot B_{NG} \cdot S$$

$$E_{2NG} = 0.0001359 \cdot 12.3 \cdot 2000$$

$$E_{2NG} = 3.343 \text{ tons SO}_2/\text{yr}$$

Combustion

$$EM_{CC} = K \cdot F_1 \cdot E_{2NG}$$

$$EM_{CC} = 3063 \cdot 0.0555 \cdot 3.343$$

$$EM_{CC} = 568 \text{ lbs H}_2\text{SO}_4/\text{yr}$$

CO Catalyst

$$EM_{CC\_CO} = K \cdot S_3 \cdot f_{COops} \cdot E_2$$

$$EM_{CC\_CO} = 3063 \cdot 0.1 \cdot 1.0 \cdot 3.343$$

$$EM_{CC\_CO} = 1024 \text{ lbs H}_2\text{SO}_4/\text{yr}$$

SCR

$$EM_{CCSCR} = [(K \cdot E_2) - EM_{CC\_CO}] \cdot f_{sops} \cdot S_2 \cdot F_{3SCR}$$

$$EM_{CCSCR} = [(3063 \cdot 3.343) - 1024] \cdot 1.0 \cdot 0.02 \cdot 1.0$$

$$EM_{CCSCR} = 184 \text{ lbs H}_2\text{SO}_4/\text{yr}$$

Total

$$TSAM_{CC} = EM_{Comb} + EM_{CC\_CO} + EM_{SCR}$$

$$TSAM_{CC} = 568 + 1024 + 184$$

$$TSAM_{CC} = 1776 \text{ lbs H}_2\text{SO}_4/\text{yr}$$

Released

$$TSAR_{CC} = [TSAM - (K_s \cdot B \cdot f_{sreagent} \cdot S_{NH3})] \cdot F_{2cc}$$

$$TSAR_{CC} = [1776 - (3799 \cdot 12.3 \cdot 1.0 \cdot 0.75)] \cdot 0.5$$

$$TSAR_{CC} = -16,635 = 0 \text{ lbs H}_2\text{SO}_4/\text{yr}$$

The total releases are zero because the actual result is a negative value, indicating that the ammonia slip is greater than the sulfuric acid, thereby forming ABS, which is not reportable.

$F_{2CC} = 0.5$  because the low temperature of the back-end tubes of the HRSG act like an air heater.

# B

## CHRONOLOGY OF CHANGES TO THE EPRI SULFURIC ACID ESTIMATION MODEL

### EPRI, 2018 (EPRI Report 3002012398)

Modification	Description
Stack correction for CEMs SO <sub>2</sub> measurements	Added equation using wall affects factor (WAF) for CEMs measurements in conjunction with Method 2H.
Total Sulfuric Acid Release Methodology (TSAR)	Changed application location of F <sub>2Hotside_ESP</sub> and F <sub>2Mag-Ox</sub> such that they apply only to EM <sub>COMB</sub> .
Partial-Year SCR/SNCR	Added methodology to calculate the Total Sulfuric Acid Release if injection for SCR/SNCR is partial-year.

### EPRI, 2012 (EPRI Report 1023790)

Modification	Description
SCR Factor (F <sub>3SCR</sub> )	Changes made to Table 4-2 to clarify proper use of the F <sub>3SCR</sub> factor.
Alkali Injection	<p>Changed description of F<sub>alkali</sub> such that it is fraction of coal burn instead of fraction of operating year, to be consistent with other operating factors</p> <p>Added alternate approach for calculating releases with alkali injection to be used if the utility does not have measured data. F<sub>3ALKINJ</sub> factor is introduced.</p>
Total Sulfuric Acid Release Methodology (TSAR)	Reorganized release equations such that sources are summed upstream of the APH and ammonia from SCR/SNCR is applied to reduce releases based on ABS formation, then the F <sub>2</sub> factor for the APH is applied. Then, any downstream source of SO <sub>3</sub> or ammonia from downstream FGC is added, followed by application of all remaining F <sub>2</sub> factors.
FGC Factor (F <sub>3FGC</sub> )	Corrected the F <sub>3FGC</sub> factor. The F <sub>3FGC</sub> factor was introduced in the 2001 version of the report, but as actual data has become available to update the F <sub>2</sub> factors, the F <sub>3FGC</sub> factor has become outdated. F <sub>3FGC</sub> will now account only for alkalinity in PRB coal, and be applied directly to the manufacture equation.

**EPRI, 2012 (EPRI Report 1023790), continued**

Combined Cycle	Introduced a potential third source of sulfuric acid manufacture and release from oxidation across CO catalysts.
Technology Factors (F2)	<p>Added Wet ESP, all fuels: 0.1.</p> <p>Changed FGD, venturi, all coals from 0.65 to 0.73 (2 new data points).</p> <p>Updated and corrected Figure 4-4 to reflect two new data points, change the shaded area to reflect the proper data range, and deleted an inaccurate PRB/lignite data point</p> <p>Changed the F2 factor in Table 4-6 for Mg-Ox into furnace from 0.5 to 0.25 to rectify an error introduced in the 2004 version of the report.</p>
Examples	Updated examples to account for new release equation methodology.

**EPRI, 2010a (EPRI Report 1020636)**

Modification	Description
Fuel Impact Factor (F1)	<p>Combined low and high-sulfur eastern bituminous coals into a single category with a linear curve fit. F1 factor based on fuel SO<sub>2</sub> content calculated from fuel sulfur content:</p> $F1_{\text{ebit}} = 1.1163\text{E-}6 \bullet \text{SO}_2 + 0.0065$ <p>Changed the following F1 factors based on additional data:</p> <p>Subbit/PRB – changed from 0.0018 to 0.0019</p> <p>Lignite – changed from 0.0048 to 0.0044</p>
Technology Factors (F2)	<p>Changed factors for APH and ESP due to addition and re-evaluation of data:</p> <p>APH, low-sulfur east. bit. – changed from 0.49 to 0.50</p> <p>APH, PRB – changed from 0.56 to 0.36</p> <p>ESP, low-sulfur east. bit – changed from 0.49 to 0.63</p> <p>ESP, PRB – changed from 0.73 to 0.72</p>

**EPRI, 2010a (EPRI Report 1020636) (continued)**

Alkali Injection	Added a procedure to determine total releases from partial year injection.  Incorporated correction to alkali injection conversion factor, $K_{\text{alkali}}$ .
Report Organization	Moved F2 Factors from Section 3 to Section 4.
Examples	Updated examples to account for new F1 and F2 factors.

**EPRI, 2008 (EPRI Report 1016384)**

Modification	Description
Alkali Injection	Added a procedure to estimate a stack release using a measured or specified stack gas $\text{SO}_3$ concentration, to support estimates on units with alkali injection.  Errata page published to correct error in alkali injection conversion factor, $K_{\text{alkali}}$ .
Combustion Turbines	Clarified procedures for estimating emissions from simple and combined cycle CTs.
Blended Coals	New method calculates $\text{SO}_3$ manufacture by calculating the $\text{SO}_3$ emission rate separately for each of the component coals, and proportioning the contribution of $\text{SO}_3$ from each. The prior method assumed the $\text{SO}_3$ production was the same as that of the major coal component.
Examples	Provided new example calculations for alkali injection and blended coal.

**EPRI, 2007 (Report 1014773) changes from Harrison, 2005**

Modification	Description
Formatting	Adapted Southern Company paper (Harrison, 2005) to EPRI format.
Fuel (F1) Factors	Changed the following F1 factors based on additional data:  Low S E. Bit, Dry Boiler – from 0.0080 to 0.0082  Subbit. (including PRB), Dry Boiler – from 0.0014 to 0.0018  Subbit. (including PRB), Cyclone – from 0.003 to 0.0018

**EPRI, 2007 (Report 1014773) changes from Harrison, 2005 (continued)**

Technology (F2) Factors	Added new F2 Factors:  Air Preheater, PRB fuel - 0.56  Cold-side ESP, PRB fuel – 0.73
SCR	Added a Technology Impact Factor for SCR, $F3_{SCR}$ .

**The Electric Power Research Institute, Inc.** (EPRI, [www.epri.com](http://www.epri.com)) conducts research and development relating to the generation, delivery and use of electricity for the benefit of the public. An independent, nonprofit organization, EPRI brings together its scientists and engineers as well as experts from academia and industry to help address challenges in electricity, including reliability, efficiency, affordability, health, safety and the environment. EPRI members represent 90% of the electric utility revenue in the United States with international participation in 35 countries. EPRI's principal offices and laboratories are located in Palo Alto, Calif.; Charlotte, N.C.; Knoxville, Tenn.; and Lenox, Mass.

Together...Shaping the Future of Electricity

© 2018 Electric Power Research Institute (EPRI), Inc. All rights reserved.  
Electric Power Research Institute, EPRI, and TOGETHER...SHAPING THE  
FUTURE OF ELECTRICITY are registered service marks of the Electric  
Power Research Institute, Inc.

3002012398

## Attachment H-2

### Sulfuric Acid Mist Emissions Calculations at Coal Creek Station Due to Selective Catalytic Reduction using EPRI Guidance



## GRE Coal Creek Station 2019 BART Review

### Sulfuric Acid Mist Generation from SCR Operation

Basis EPRI publication 300201298: "Estimating Total Sulfuric Acid Emissions from Stationary Power Plants, 2018 Update"

The EPRI document describes an emissions estimation procedure for the manufacture and release of sulfuric acid from formation within the boiler and the SCR, and the effects of flue gas conditioning (FGC), alkali injection, and removal by downstream equipment such as air preheaters (APH), electrostatic precipitators (ESPs) and flue gas desulfurization (FGD) equipment.

This analysis only includes formation of sulfuric acid from the SCR, the effects of ammonia slip produced by the SCR, and removal by downstream pollution control equipment. Sulfuric acid manufactured by the boiler is not included in the calculations.

Sulfuric acid manufactured from SCR is estimated using the following equation.

$$\text{Eq. 4-7: } \text{EMSCR} = K \cdot S2 \cdot \text{fsops} \cdot E2 \cdot F3\text{SCR}$$

where,

**EMSCR** = Total  $\text{H}_2\text{SO}_4$  manufactured from SCR, lbs per year

**K** = Molecular weight and units conversion constant =  $98.07 / 64.04 \cdot 2000 = 3,063$

98.07 = Molecular weight of  $\text{H}_2\text{SO}_4$

64.04 = Molecular weight of  $\text{SO}_2$

2000 = Conversion from tons per year to pounds per year.

**S2** = SCR catalyst  $\text{SO}_2$  oxidation rate (specified as a fraction, typically from 0.001- 0.03),

Catalyst Manufacturer's suggested oxidation rate for the proposed catalyst is 0.05.

**fsops** = Operating factor of SCR system, or the fraction of coal burn when the flue gas is directed through the SCR, whether  $\text{NH}_3$  reagent is injected to derive  $\text{NO}_x$  reduction or not. This value should reflect the hours the SCR reactor processed flue gas, which will be site-specific but can be approximated by generally 0.8 for year-round peaking operation, 0.98 for year-round base- loaded operation, or 0.43 for seasonal operation.

**E2** =  $\text{SO}_2$  produced, tons per year

**F3SCR** = Technology Impact Factor, for SCR. Table 4-2 recommends a factor of 1 for all coals except PRB.

K	S2	fsops	E2	F3SCR	EMSCR			
			tons/year		lb/hour	lb/year	ton/year	lb $\text{H}_2\text{SO}_4$ / ton $\text{SO}_2$
3,063	0.05	0.98	40,500	1	796	6,078,524	3,039	150

The Total Sulfuric Acid Release accounts for sulfuric acid manufactured from the SCR, the amount removed by ammonia slip, and the amount captured by downstream emission control equipment. Ammonia slip from the SCR can combine with some or all of the sulfuric acid generated to reduce the amount released.

Total Sulfuric Acid Release (TSAR) is described by the following equation:

$$\text{Eq. 4-11 TSAR} = (((\text{EMComb} \cdot \text{F2Hotside\_ESP} \cdot \text{F2Mag\_ox}) + \text{EMSCR} + \text{EMFGC\_beforeAPH}) - (\text{NH3SCR} + \text{NH3FGC\_beforeAPH})) \cdot \text{F2APH} + (\text{EMFGC\_afterAPH} - \text{NH3FGC\_afterAPH}) \cdot \text{F2x}$$

where,

<b>TSAR</b> =	Total Sulfuric Acid Release, lbs per year
<b>EMComb</b> =	Total sulfuric acid manufactured from combustion, lbs per year. Only H <sub>2</sub> SO <sub>4</sub> manufactured by the SCR is addressed in this analysis.
<b>F2Hotside_ESP</b> =	Technology Impact Factor for hot-side ESP. Only H <sub>2</sub> SO <sub>4</sub> manufactured by the SCR is addressed in this analysis so this factor is not applicable.
<b>F2Mag-Ox</b> =	Technology Impact Factor for magnesium oxide addition in fuel or furnace. Only H <sub>2</sub> SO <sub>4</sub> manufactured by the SCR is addressed in this analysis so this factor is not applicable.
<b>EMSCR</b> =	Total sulfuric acid manufactured from SCR, lbs per year. See equation 4-7 above.
<b>EMFGC_beforeAPH</b> =	Total sulfuric acid manufactured from FGC upstream of the air preheater (APH). Not Applicable.
<b>NH3SCR</b> =	Total equivalent ammonia slip produced from SCR/SNCR, lbs per year. See equation 4-13 below.
<b>NH3FGC_beforeAPH</b> =	Total equivalent ammonia produced from FGC upstream of the APH, lbs per year.
<b>F2APH</b> =	Technology Impact Factor for APH, applied only if subtotal for releases upstream of the APH is non-negative = 0.5, average measurement for air preheater, Table 4-3.
<b>EMFGC_afterAPH</b> =	Total sulfuric acid manufactured from FGC downstream of the APH. Not Applicable.
<b>NH3FGC_afterAPH</b> =	Total equivalent ammonia produced from FGC downstream of the APH, lbs per year
<b>F2x</b> =	Technology Impact Factors for processes downstream of the APH, all that apply Cold Side ESP F2 Factor 0.65 equivalent to 35% eff Spray Tower FGD F2 Factor 0.45 equivalent to 55% eff Control Equip F2 Factor F2 <sub>x</sub> 0.29 equivalent to 71% eff

The following equation calculates the amount of ammonia slip from SCR.

$$\text{Eq. 4-13 NH3SCR} = K_s \cdot B \cdot \text{fsreagent} \cdot \text{SNH3}$$

where,

<b>NH3SCR</b> =	Total equivalent ammonia slip produced from SCR/SNCR, lbs per year
<b>Ks</b> =	Conversion factor = 3,799 lb H <sub>2</sub> SO <sub>4</sub> /(TBtu * ppmv SO <sub>3</sub> @ 6% O <sub>2</sub> and wet)
<b>B</b> =	Coal burn in TBtu/yr See calculations below.
<b>fsreagent</b> =	Fraction of SCR operation with reagent injection, when residual NH <sub>3</sub> is produced that will remove SO <sub>3</sub> . The value of fsreagent will be similar to, but slightly less than, the value of fsops, defined for Equation 4-6. 0.98 is used in the analysis.
<b>SNH3</b> =	NH <sub>3</sub> slip from SCR/SNCR, ppmv at 6% O <sub>2</sub> , wet. Performance guarantee = 2 PPM.

Ks	B	fsreagent	SNH3	NH3SCR		
	TBTU/yr			lb/hour	lb/year	ton/year
3,799	44.8	0.98	2	44	333,506	167

Coal data based on Black & Veatch BART report, Appendix A.

Coal Input	Operating hours	Coal Energy	Coal Burn
ton/hour	hour/year	Btu/lb	TBtu/year
443.79	7,632	6,612	44.8

EMSCR	NH3SCR	F2APH	F2x	TSAR		
lb/year	lb/year			lb/hour	lb/year	ton/year
6,078,524	333,506	0.5	0.29	109	833,027	417



12300 Elm Creek Boulevard  
Maple Grove, Minnesota 55369-4718  
763-445-5000  
greatriverenergy.com

December 23, 2019

**VIA ELECTRONIC MAIL**

Jim Semerad  
Director, Division of Air Quality  
North Dakota Department of Environmental Quality  
918 E. Divide Ave., 2nd Floor  
Bismarck, ND 58501-1947

RE: Regional Haze Four-factor Analysis for SO<sub>2</sub> and NO<sub>x</sub> Emissions at Coal Creek Station Units 1 and 2

Dear Mr. Semerad:

This letter and attachment serve to respond to the North Dakota Department of Environmental Quality's (NDDEQ) May 2, 2018 request for Great River Energy (GRE) to prepare a "four factors" analysis (herein termed a four-factor analysis) of SO<sub>2</sub> and NO<sub>x</sub> emissions control measures for Coal Creek Station Units 1 and 2.<sup>1</sup> The NDDEQ had requested that this analysis be submitted by January 31, 2019. In follow-up conversations with NDDEQ staff during 2018 and 2019, GRE agreed to focus first on completing an updated best available retrofit technology (BART) analysis of NO<sub>x</sub> emissions for the phase 1 State Implementation Plan (SIP). The updated NO<sub>x</sub> BART analysis was submitted to the NDDEQ on September 12, 2019. We understand that submission of this SO<sub>2</sub> four-factor analysis before the end of 2019 is timely for the NDDEQ's preparations on the phase 2 SIP (RHR2), due to the U.S. Environmental Protection Agency (EPA) by July 31, 2021.

Under RHR2, the NDDEQ four-factor analysis request is specific to SO<sub>2</sub> and NO<sub>x</sub> emissions because "sulfate and nitrates continue to be the largest contributors to visibility impairment" at North Dakota's Class I areas. For informational purposes, actual annual SO<sub>2</sub> emissions in the last decade from GRE's electric generating units in North Dakota – Coal Creek Station, Stanton Station, and Spiritwood Station – have decreased from nearly 31,000 tons in 2009 to less than 6,900 tons in 2018, representing a 78 percent reduction. In this same time frame, actual annual NO<sub>x</sub> emissions have decreased 44 percent from nearly 13,000 tons in 2009 to 7,300 tons in 2018.

---

<sup>1</sup> May 2, 2018 letter from Terry O'Clair of the North Dakota Department of Health (now the North Dakota Department of Environmental Quality) to Mary Jo Roth of Great River Energy. Pursuant to a June 1, 2018 teleconference between GRE and NDDEQ staff, the NDDEQ confirmed that the four-factor analysis is to be completed only for the two electricity generating units, Unit 1 and Unit 2, which together constitute the vast majority of the actual SO<sub>2</sub> and NO<sub>x</sub> emissions at Coal Creek Station. Other emissions units at Coal Creek Station are not subject to the four-factor analysis.

## **SO<sub>2</sub> Four-factor Analysis**

The enclosed technical report (SO<sub>2</sub> four-factor report) provides a detailed analysis of SO<sub>2</sub> emissions control measures at Units 1 and 2. This report is based on and references EPA's final regional haze SIP guidance<sup>2</sup> issued on August 20, 2019 (2019 RH SIP Guidance), per verbal communication with NDDEQ staff, instead of earlier draft guidance issued in 2016 that was referenced in the May 2, 2018 NDDEQ letter.

The SO<sub>2</sub> four-factor report describes existing operations and SO<sub>2</sub> emissions performance at Units 1 and 2. As a result of GRE's work in recent years to better understand the opportunities and implications of reducing SO<sub>2</sub> emissions with its existing infrastructure (i.e., wet scrubber system, flue gas reheat technology, and dry stack design), GRE determined its baseline annualized SO<sub>2</sub> emissions performance level to be 626 lb/hr at each unit, which is equivalent to 0.104 lb/MMBtu at full load conditions.<sup>3</sup> Setting this emissions rate for the baseline control scenario is consistent with the 2019 RH SIP Guidance. It is also notably less than the current 0.15 lb/MMBtu BART limit on a 30-day rolling average. The SO<sub>2</sub> performance level is consistent with operation of multiple emissions control measures in place, namely the wet scrubber system, DryFining<sup>TM</sup> technology, and flue gas reheat applications.

An assessment of additional SO<sub>2</sub> emissions control measures was conducted relative to this baseline control scenario. Upon review of potentially available control technologies, the two technically feasible measures that were further evaluated in the four-factor analysis are both intended to increase the amount of flue gas to the existing wet scrubbers by either: 1) replacing the current stack with a wet stack design, or 2) installing a natural gas-fired flue gas reheat system to maintain dry stack operating temperature. GRE estimates that the annual SO<sub>2</sub> emissions performance level from either of these measures is 0.080 lb/MMBtu compared to the baseline control scenario of 0.104 lb/MMBtu.

The costs of compliance for these two control measures have been determined with a screening-level engineering cost estimate. The cost effectiveness analysis of either control measure is summarized in the following table and is compared to the cost effectiveness threshold of \$4,630/ton represented in today's dollars. The cost of either control measure is significantly greater than this threshold. GRE believes the screening-level costs provided in Appendix A of this report are conservatively low and that a more detailed cost estimate is likely to increase the costs for installing and implementing either of the projects.

---

<sup>2</sup> US EPA, "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period," August 20, 2019, EPA-457/B-19-003.

<sup>3</sup> 626 lb/hr = 0.104 lb/MMBtu x 6,015 or 6,022 MMBtu/hr rated capacities for Unit 1 and 2 listed in the Title V operating permit.

SO <sub>2</sub> Emissions Control Measure	Installed Capital Cost (\$)	Annualized Capital Cost (\$/yr)	Annual Operating Costs (\$/yr)	Total Annualized Costs (\$/yr)	Annual SO <sub>2</sub> Emissions Reduction (tpy)	Pollution Control Cost Effectiveness (\$/ton)
New Wet Stack	\$38.8 million	\$3.2 million	\$0.8 million	\$4.0 million	550	7,200
Natural Gas Reheat System	\$14.5 million	\$1.2 million	\$2.2 million	\$3.4 million	550	6,200

Additionally, the observations of energy and environmental burden from installation of these measures (i.e., demolition and disposal of the existing stacks, natural gas combustion NO<sub>x</sub> emissions from the flue gas reheat system) leads to the conclusion that these additional emissions control measures are not reasonably supported at Units 1 or 2.

In consultation with the NDDEQ, GRE proposes a federally enforceable SO<sub>2</sub> emissions rate limit of 626 lb/hr as an annualized average (365-boiler-operating-day rolling average) limit for each unit, with plant averaging between the two units. GRE proposes to implement operational practices summarized in Section 2.5 of the report in order to comply with the proposed SO<sub>2</sub> emissions rate limit, effective upon approval of a federally enforceable permit to construct (PTC) issued by the NDDEQ. This new performance level further reduces annual SO<sub>2</sub> emissions at each unit by an estimated 1,050 tpy in comparison to the BART limit.<sup>4</sup>

#### NO<sub>x</sub> Four-factor Analysis

GRE submitted to the NDDEQ an updated NO<sub>x</sub> BART report for Units 1 and 2 on September 12, 2019. This updated report follows the same evaluation steps as the SO<sub>2</sub> four-factor report summarized above with respect to the following two key elements:

- The annual NO<sub>x</sub> emissions performance level is updated to reflect current and expected conditions, as was done for the SO<sub>2</sub> four-factor analysis, in order to appropriately evaluate the effectiveness of additional future control measures.
- The analysis of additional available NO<sub>x</sub> emissions control measures follows the same four statutory factors (costs of compliance, energy and non-air environmental impacts, pollution control equipment in use at the source, and remaining useful life of the source) that are used in the SO<sub>2</sub> four-factor analysis, in addition to the visibility impacts analysis.

With respect to the first bullet, Unit 2 is currently operating at an annual NO<sub>x</sub> emissions performance level of 0.13 lb/MMBtu. Unit 1 is scheduled to install the same LNC3+ NO<sub>x</sub> control technology in the first half of 2020 and will therefore have equivalent NO<sub>x</sub> performance. Using the same methodology as in the

---

<sup>4</sup> Comparing the two SO<sub>2</sub> performance levels and applying the 87% annual capacity factor equals an emissions reduction of 1,054 tpy at each unit. (0.15 lb/MMBtu BART limit 30-day rolling average - 0.104 lb/MMBtu expected level 365-day rolling average) x (6,015 or 6,022 MMBtu/hr rated capacities for Unit 1 and 2) x (87% annual capacity factor), converted to tpy basis.

SO<sub>2</sub> four-factor report for full-load operation, the corresponding annualized baseline NO<sub>x</sub> emissions level is 782 lb/hr for each unit.<sup>5</sup>

A thorough evaluation of potentially available control measures was completed in the updated BART analysis that resulted in two technologies, selective non-catalytic reduction (SNCR) and selective catalytic reduction (SCR), that were examined against the same four statutory factors as in the SO<sub>2</sub> report. Significant technical feasibility concerns were noted in the BART report of implementing either of these controls at Coal Creek Station, but both controls were conservatively carried forward into the more detailed, cost of compliance evaluation.

The costs of compliance for these two measures were determined in the BART report by third-party engineering firms. The cost effectiveness of either measure is summarized in the following table excerpted from the updated BART report and is compared to the same cost effectiveness threshold of \$4,630/ton as in the SO<sub>2</sub> four-factor report. The cost of either NO<sub>x</sub> control measure is significantly greater than this threshold.

NO <sub>x</sub> Emissions Control	Installed Capital Cost (\$)	Annualized Capital Cost (\$/yr)	Annual Operating Costs (\$/yr)	Total Annualized Costs (\$/yr)	Annual NO <sub>x</sub> Emissions Reduction (tpy)	Pollution Control Cost Effectiveness (\$/ton)
SNCR	\$12.8 million	\$1.1 million	\$4.4 million	\$5.4 million	692	7,818
SCR	\$180 million	\$12.1 million	\$3.4 million	\$15.4 million	1,153	13,391

Additionally, the BART report describes other environmental impacts and implementation issues if SCR or SNCR were to be applied at Coal Creek Station, leading to the conclusion that these SNCR or SCR emissions control measures are not reasonably supported at Units 1 or 2.

In consultation with the NDDEQ for RHR2, GRE proposes a federally enforceable NO<sub>x</sub> emissions rate limit of 782 lb/hr as an annualized average (365-boiler-operating-day rolling average) limit for each unit, with plant averaging between the two units. This is consistent with the updated NO<sub>x</sub> BART report that establishes 0.13 lb/MMBtu as the baseline. GRE proposes to implement operational practices summarized in Section 2.1 of the updated BART report, specifically DryFinishing™ and LNC3+ technologies, in order to comply with the proposed NO<sub>x</sub> mass emissions limit. The NO<sub>x</sub> limit shall be effective after both approval of a federally enforceable PTC issued by the NDDEQ and startup of LNC3+ technology at Unit 1.

---

<sup>5</sup> 782 lb/hr = 0.13 lb/MMBtu x 6015 or 6022 MMBtu/hr rated capacities for Unit 1 and 2 listed in the Title V operating permit.

Jim Semerad  
December 23, 2019  
Page 5

Please contact me at 763-445-5212 if you have any questions regarding the SO<sub>2</sub> four-factor analysis or wish to discuss any of the above.

Sincerely,

**GREAT RIVER ENERGY**

A handwritten signature in black ink, appearing to read "Mary Jo Roth". The signature is fluid and cursive, with the first name "Mary" and last name "Roth" clearly distinguishable.

Mary Jo Roth  
Manager, Environmental Services

c: David Stroh, NDDEQ  
John Bauer, Great River Energy

Attachment

## **Coal Creek Station Units 1 and 2**

### ***Regional Haze Four-Factor Analysis for SO<sub>2</sub> Emissions Control***

Prepared for  
Great River Energy



**GREAT  
RIVER  
ENERGY®**

December 2019



## **Coal Creek Station Units 1 and 2**

### ***Regional Haze Four-Factor Analysis for SO<sub>2</sub> Emissions Control***

Prepared for  
Great River Energy



**GREAT  
RIVER  
ENERGY®**

December 2019

# Coal Creek Station Units 1 and 2 Regional Haze Four-Factor Analysis for SO<sub>2</sub> Emissions Control

December 2019

## Contents

1	Introduction .....	1
2	Existing Operations and SO <sub>2</sub> Emissions Performance .....	4
2.1	DryFining™ Technology .....	5
2.2	Wet Stack Conversion Efforts .....	6
2.3	Flue Gas Reheat Technology .....	8
2.4	Recent Reheat Optimization Assessments .....	12
2.4.1	2017 Winter Test Case .....	12
2.4.2	2019 Winter Test Case .....	14
2.4.3	Low Load Reheat Augmentation System .....	16
2.5	Updated Baseline SO <sub>2</sub> Emissions Performance Level .....	16
3	Sulfur Dioxide (SO <sub>2</sub> ) Four-Factor Analysis .....	18
3.1	Four-Factor Analysis Approach .....	18
3.1.1	Identify all Emission Control Options .....	18
3.1.2	Factor #1 – Cost of Compliance .....	19
3.1.3	Factor #2 – Time Necessary for Compliance .....	22
3.1.4	Factor #3 – Energy and Non-air Environmental Impacts: .....	22
3.1.5	Factor #4 – Remaining Useful Life of the Source .....	22
3.2	Identification of Pre-Combustion Controls .....	22
3.3	Identification of Post-Combustion Controls .....	23
3.3.1	Dry Sorbent Injection (DSI) .....	24
3.3.2	Spray Dry Absorption .....	24
3.3.3	Wet Lime/Limestone Scrubbing .....	24
3.3.4	Increase Amount of Flue Gas to Existing Wet Scrubbers .....	25
3.3.4.1	Replace Current Stack with Wet Stack .....	26
3.3.4.2	Natural Gas Reheat System .....	26
3.4	Factor 1 Evaluation – Costs of Compliance .....	27
3.5	Factor 2 Evaluation – Time Necessary for Compliance .....	28
3.6	Factor 3 Evaluation – Energy and Non-Air Quality Environmental Impacts .....	29

3.7	Factor 4 Evaluation – Remaining Useful Life.....	29
3.8	Proposed SO <sub>2</sub> Controls and Emissions Rates .....	29

### List of Tables

Table 3-1: Additional SO <sub>2</sub> Control Measures with Potential Application at CCS Units 1 and 2 .....	19
Table 3-2: Annual Average Capacity Factors at CCS Unit 1 and Unit 2 .....	21
Table 3-3: SO <sub>2</sub> Control Cost Summary, per Unit Basis.....	28

### List of Figures

Figure 1-1: Annual SO <sub>2</sub> Emissions from GRE Electric Generating Units in North Dakota .....	3
Figure 2-1: Unit 1 Annual SO <sub>2</sub> Emissions Prior to and After DryFinishing™ .....	6
Figure 2-2: Illustration of CCS Flue Gas Reheat System.....	9
Figure 2-3: Unit 1 SO <sub>2</sub> Emissions Reductions After Implementation of the Flue Gas Reheat System.....	10
Figure 2-4: Cutaway Illustration of Interface between Scrubber Bypass Dampers and Flue Gas Reheat Ducts at the Absorber Module Outlets .....	12
Figure 2-5: Winter 2017 Test Case Results of Unit 2 SO <sub>2</sub> Emissions vs Load .....	13
Figure 2-6: Winter 2017 Test Case Results of Unit 2 Load vs Stack Temperature.....	14
Figure 2-7: Winter 2019 Test Case Results of Daily Unit 2 SO <sub>2</sub> Emissions vs Stack Temperature.....	15

### List of Appendices

Appendix A: Unit Specific Screening Level Cost Summary for SO <sub>2</sub> Control Measures
---

# 1 Introduction

The Regional Haze Rule (RHR),<sup>1</sup> published on July 15, 2005 by the U.S. Environmental Protection Agency (EPA), defines regional haze as “visibility impairment that is caused by the emission of air pollutants from numerous sources located over a wide geographic area. Such sources include, but are not limited to, major and minor stationary sources, mobile sources, and area sources.” The RHR requires state regulatory agencies to submit a series of state implementation plans (SIPs) in ten-year increments to protect visibility in certain national parks and wilderness areas, known as mandatory federal Class I areas. The original state SIPs were due on December 17, 2007 and included milestones for establishing reasonable progress towards the visibility improvement goals, with the ultimate goal to achieve natural background visibility by 2064. The original SIP was informed by best available retrofit technology (BART) analyses that were completed on all subject-to-BART sources. The second RHR planning period requires development and submittal of updated state SIPs by July 31, 2021.

On May 2, 2018, the North Dakota Department of Environmental Quality (NDDEQ), formerly known as the North Dakota Department of Health, requested that Great River Energy (GRE) complete a “four factors” analysis (herein termed a four-factor analysis), for Coal Creek Station (CCS) Units 1 and 2 as part of the state’s regional haze reasonable progress.<sup>2</sup> The analysis considers the following four statutory factors:

1. The cost of compliance;
2. The time necessary to achieve compliance;
3. The energy and non-air quality environmental impact of compliance; and
4. The remaining useful life of any existing source subject to such requirements.

The NDDEQ’s May 2018 letter to GRE specified that the “... analysis should be prepared using the draft EPA guidance,” referring to a draft EPA regional haze SIP guidance document issued in July 2016.<sup>3</sup> Since

---

<sup>1</sup> The EPA also refers to this regulation as the Clean Air Visibility Rule. The regional haze program requirements are promulgated at 40 CFR 51.308. The SIP requirements for this implementation period are specified in §51.308(f).

<sup>2</sup> May 2, 2018 letter from Terry O’Clair of NDDEQ to Mary Jo Roth of GRE. Pursuant to a June 1, 2018 teleconference between GRE and NDDEQ staff, the NDDEQ confirmed that the four-factor analysis is to be completed only for the two electricity generating units, Unit 1 and Unit 2, which together constitute the vast majority of the actual SO<sub>2</sub> and NO<sub>x</sub> emissions at Coal Creek Station. Other emissions units at Coal Creek Station are not subject to the four-factor analysis.

<sup>3</sup> US EPA, “Draft Guidance on Progress Tracking Metrics, Long-term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period,” July 2016, EPA-457/P-16-001.

then, EPA has issued final regional haze SIP guidance<sup>4</sup> on August 20, 2019 (2019 RH SIP Guidance) that replaces the 2016 draft guidance. Pursuant to verbal communications with NDDEQ, the four-factor analysis is conducted in accordance with the four statutory factors described in the 2019 RH SIP Guidance.

This report describes the background and analysis for conducting a four-factor analysis for sulfur dioxide (SO<sub>2</sub>) as applied to the review of emissions controls at GRE CCS.<sup>5</sup> Coal Creek Station consists of two coal-fired electric generating units. Both boilers are tangentially-fired boilers manufactured by Combustion Engineering (CE, now a part of General Electric, or GE), and each unit produces about 605 megawatts (MW) of power on a gross basis. Coal Creek Station is a mine-mouth facility located near Underwood, North Dakota and burns lignite coal from the co-located Falkirk Mine.

For informational purposes, actual SO<sub>2</sub> emissions in the last decade from GRE's electric generating units (EGUs) located in North Dakota – Coal Creek Station, Stanton Station, and Spiritwood Station – have decreased from nearly 31,000 tons in 2009 to less than 6,900 tons in 2018, representing a 78 percent reduction in SO<sub>2</sub> emissions. The aggregated actual annual SO<sub>2</sub> emissions for the last 10 calendar years from GRE's North Dakota EGUs are illustrated in Figure 1-1. During this period:

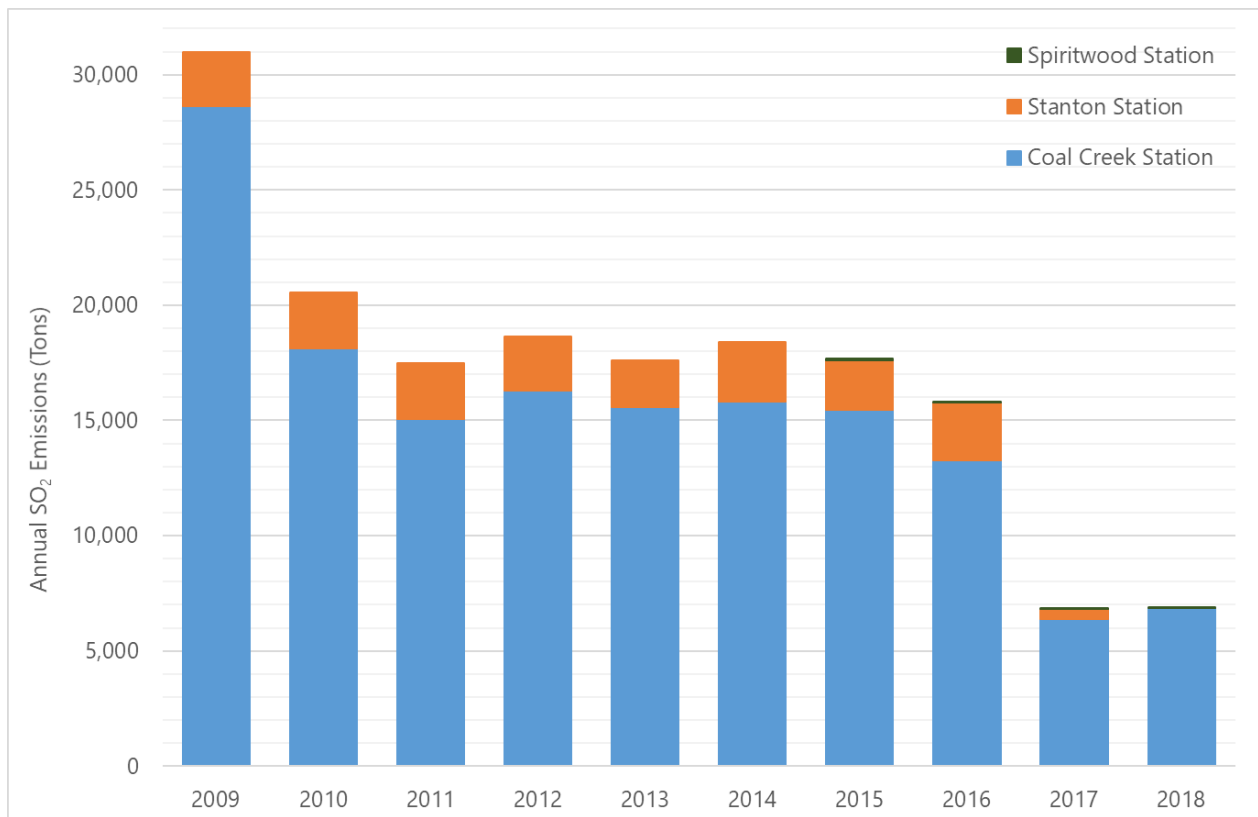
- GRE commenced operation of its combined heat and power plant, Spiritwood Station, located on the east side of North Dakota. Given its best available emission controls (BACT), Spiritwood Station does not cause or contribute to regional haze at Class 1 areas based on a screening "Q/D" determination made by the North Dakota Department of Environmental Quality (NDDEQ).<sup>6</sup>
- GRE has permanently ceased operations of its 180 MW coal-fired power plant located just outside of Stanton (Stanton Station). Stanton Station's retirement results in an SO<sub>2</sub> actual emissions reduction of approximately 2,500 tons annually.
- GRE implemented DryFining™ and flue gas reheat technology at CCS, as described in more detail below, which are novel multi-pollutant emission controls that do not exist anywhere else in the world.

---

<sup>4</sup> US EPA, "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period," August 20, 2019, EPA-457/B-19-003.

<sup>5</sup> As described in the cover letter, the regional haze four-factor analysis for NO<sub>x</sub> emissions was provided in separate correspondence and is effectively the updated BART report dated September 12, 2019.

<sup>6</sup> Information on Spiritwood Station's screening analysis provided by NDDEQ staff during teleconference between GRE and NDDEQ staff on June 1, 2018.



**Figure 1-1: Annual SO<sub>2</sub> Emissions from GRE Electric Generating Units in North Dakota**

## 2 Existing Operations and SO<sub>2</sub> Emissions Performance

In 2007, GRE submitted its BART analysis that evaluated SO<sub>2</sub> control strategies, in addition to particulate matter (PM), and oxides of nitrogen (NO<sub>x</sub>).<sup>7</sup> For SO<sub>2</sub>, this BART analysis determined that EPA's presumptive emissions level of 0.15 pounds per million British thermal units (lb/MMBtu), as a 30-day rolling average, appropriately met BART requirements. GRE proceeded with installation and operation of DryFinishing™ in conjunction with additional work on scrubber modifications and conversion to a "wet stack" design in order to meet the presumptive emissions level.<sup>8,9</sup>

DryFinishing™ technology was installed and became operational on January 1, 2010 as further described in Section 2.1. However, as GRE was making preparations to convert its existing stacks to a wet stack design pursuant to Electric Power Research Institute (EPRI) guidance currently available at that time (1996 EPRI Guide),<sup>10</sup> EPRI issued new guidance (2012 EPRI Guide) based on additional day-to-day operational observations and information gathered from wet stacks.<sup>11</sup> Specifically, EPRI lowered the allowable exit velocity for a wet stack, which caused the GRE design stack velocity to be higher than the new specifications. Thus, GRE's wet stack conversion project was discontinued. See Section 2.2 for additional details.

Subsequently, in 2017, GRE designed and implemented a novel stack flue gas reheat system, which increases the exhaust temperature in order to allow each unit to operate with a dry stack and with improved capture of the flue gas to the existing wet gas scrubber (i.e., reduced use of the scrubber bypass). See Section 2.3 for a description of this system.

GRE currently operates the DryFinishing™ system, the existing four-module wet flue gas desulfurization (FGD) scrubbers, and the newly installed novel reheat system in order to comply with the SO<sub>2</sub> presumptive BART limit, which became effective May 2017. Together, the DryFinishing™ technology and the novel reheat system are a unique emissions control design, requiring a site-specific evaluation for consideration of

---

<sup>7</sup> GRE, "Coal Creek Station Units 1 and 2 Best Available Retrofit Technology Analysis," revised December 12, 2007.

<sup>8</sup> DryFinishing™ is referred to in Section 5.2.1 of the GRE December 2007 BART Analysis Report as "coal drying." This pre-combustion emissions control project was later implemented and trademarked as DryFinishing™.

<sup>9</sup> A "wet stack" is designed to exhaust saturated (i.e., 100% relative humidity) flue gas downstream from a wet flue gas desulfurization system without causing problems such as stack liquid discharge, plume downwash and icing, and corrosion/chemical attack. The Unit 1 and 2 stacks were originally designed as "dry stacks," meaning that the inner metallurgy and other physical characteristics of the stacks are not meant to carry a saturated exhaust stream.

<sup>10</sup> EPRI, "Wet Stacks Design Guide," November 1996, EPRI Technical Report No. TR-107099.

<sup>11</sup> EPRI, "Revised Wet Stack Design Guide," December 2012, EPRI Technical Report No. TR-1026742.

---

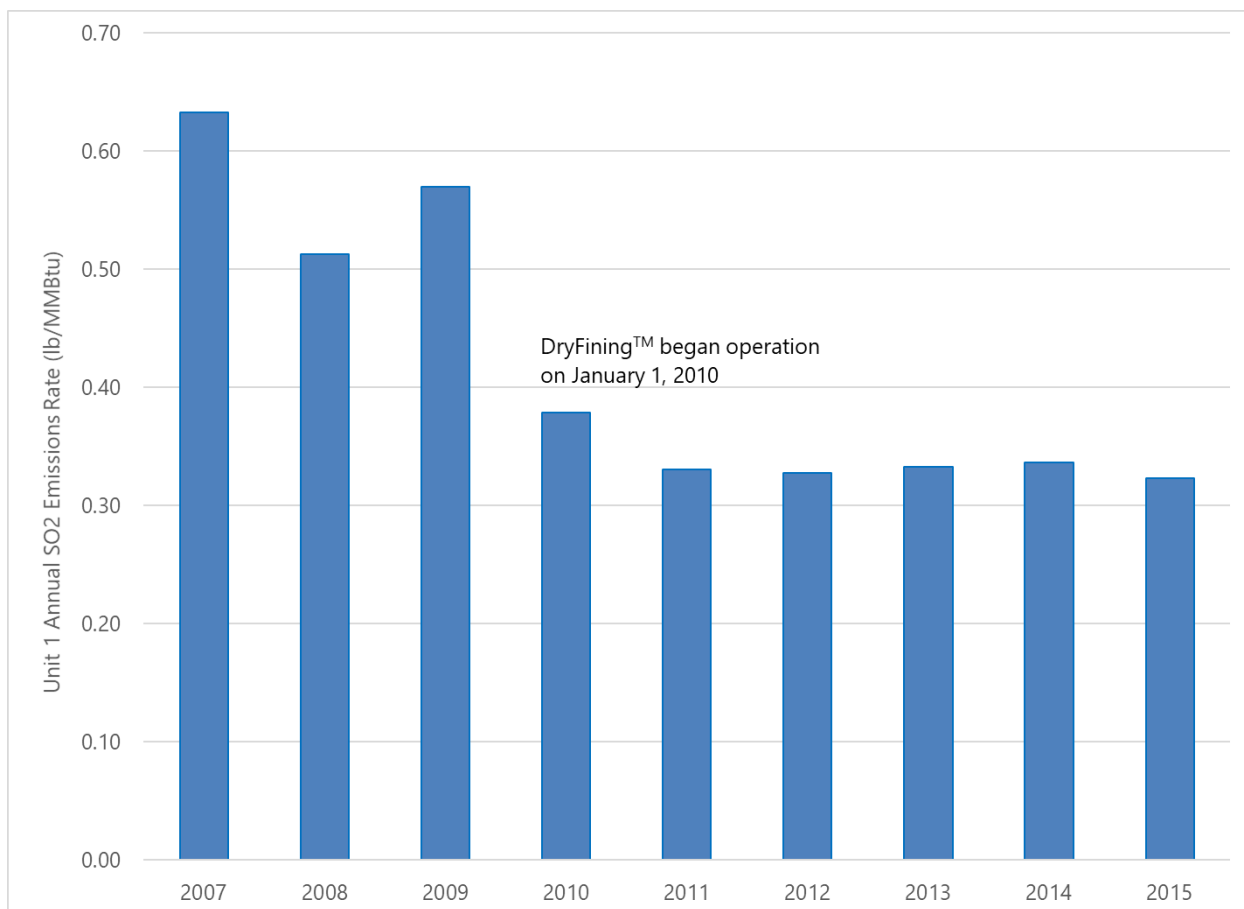
further SO<sub>2</sub> emission reductions. In Section 3.3.4, GRE evaluates opportunities to optimize scrubber performance for all operating modes.

## 2.1 DryFining™ Technology

In collaboration with many project participants, including the Department of Energy (DOE), the Lignite Research Council (LRC), Lehigh University, and EPRI, among others, GRE developed, tested, and commercialized the DryFining™ technology. DryFining™ is a multi-pollutant control technology, and Coal Creek Station represents the first full-scale, commercial installation of this technology. In short, this technology reduces coal moisture to increase the heat content of Fort Union lignite, which has the highest moisture content of any coal in the US. The DryFining™ process is also designed to segregate dense material (pyritic sulfur) from the coal prior to combustion to support SO<sub>2</sub> reductions.

DryFining™ was fully operational on January 1, 2010 and has since demonstrated a heat input reduction of approximately 2 to 3 percent for the same level of output. This heat input reduction correspondingly decreased the amount of flue gas created by the combustion process, which in turn has allowed for an additional proportion of gas to be routed to the wet scrubber instead of bypassing the scrubber. The corresponding SO<sub>2</sub> emissions rate on a lb/MMBtu decreased upon operation of DryFining™. For illustrative purposes, Figure 2-1 summarizes the calendar-year SO<sub>2</sub> emissions on a lb/MMBtu basis prior to, and after implementation of, DryFining™ at Unit 1. Unit 2 has a similar SO<sub>2</sub> emissions reduction trend.





**Figure 2-1: Unit 1 Annual SO<sub>2</sub> Emissions Prior to and After DryFining™**

## 2.2 Wet Stack Conversion Efforts

Consistent with its 2007 SO<sub>2</sub> BART assessment and report, GRE also began implementation of its wet stack conversion project which, in conjunction with DryFining™, was intended to improve the amount of exhaust gas to the wet scrubber. The wet stack conversion project at both stacks was planned to occur over 3-year outage increments and would have been completed by 2017. However, during conversion to wet stack as mentioned, EPRI revised its wet stack guide, which caused the planned design velocities for Units 1 and 2 stacks to be higher than the new specification, potentially resulting in stack liquid discharge, also known as stack rainout. This section describes the history of GRE's wet stack conversion efforts as related to EPRI's design guide.

In 1996, EPRI issued a design guide for wet stacks.<sup>12</sup> The 1996 EPRI Guide was prepared in order to address problems that were being caused by the presence of liquid water in electric utility chimneys

<sup>12</sup> EPRI, "Wet Stacks Design Guide," November 1996, EPRI Technical Report No. TR-107099.

downstream of wet flue gas desulfurization systems. The liquid water originates from water droplets passing through wet scrubber mist eliminator systems and from water condensation in the chimney. Most of the liquid water accumulates on the chimney walls and can be captured by water collection systems in a properly designed "wet stack." In order for the wet stacks to function properly, the chimney design must limit flue gas velocities to less than the recommended values as identified by EPRI's wet stack design guidelines. If stack velocities are higher than the guidelines, water droplets have the potential to form in the gas/liquid interface at the stack wall. These droplets will then become entrained in the exhaust gas and carried out of the stack, which causes liquid discharge conditions. Additionally, the water droplets carried out the chimneys create an acidic precipitation and deposition of liquid droplets from the stack plume onto the surrounding area. This condition is generally called "stack rainout." Winter operations at CCS further complicate the issue due to downwash at the chimney exit and the potential for ice buildup.

Based on the 1996 EPRI Guide, GRE commissioned three technical studies to evaluate the potential for mitigating these adverse impacts:

1. In 2004, the CCS wet stack design included a dual liner with brick liner in the lower portion of the stack and alloy liner in the top portion of the stack. The velocities in the brick liner were expected to exceed the EPRI recommendation of 55 feet per second (fps) for approximately 70 lineal feet of the stack. The alloy velocities were limited to the EPRI recommendation of 70 fps.
2. In 2005, URS Corporation performed computational flow dynamic modeling of the CCS stacks to address flue gas downwash and icing potentials at the stack exit.
3. In 2006, Alden Research Laboratory, Inc. constructed a scale model of the CCS chimneys to evaluate wet stack operation and concluded that the velocities in the brick liner would be consistent with the 1996 EPRI Guide with modifications made to the liner.

Based on these three studies, GRE began to implement the wet stack conversion changes.

During the course of making these stack improvements, industry began to report that stack rainout events were occurring while operating in accordance with the 1996 EPRI Guide. In response to these industry observations, EPRI revised its wet stack design guide (2012 EPRI Guide).<sup>13</sup> The new maximum gas velocity in the 2012 EPRI Guide was lowered to be approximately 45 fps for brick liners and approximately 55 fps for alloy liners.

At full load, CCS stack velocities average 65 to 70 fps in both units based on 40 CFR Part 75 stack monitoring, which has been verified by independent stack testing firms. Although conforming with the 1996 EPRI Guide, both CCS Unit 1 and 2 greatly exceeded the 2012 EPRI recommended maximum gas flow velocities for both the lower brick portion and upper alloy portion of the stacks. Calculated inner diameters needed to avoid stack rainout is 32 feet for the brick portion and 30 feet for the alloy portion of

---

<sup>13</sup> EPRI, "Revised Wet Stack Design Guide," December 2012, EPRI Technical Report No. TR-1026742. EPRI notes that, "A limited number of units, although designed within the recommendation of the original Wet Stack Design Guide, experienced "stack liquid discharge" (SLD), or rainout, from the start. It was found that most of these units had been designed for the higher end of the recommended liner-gas velocity range..."

the stacks. The concrete shell of both Unit 1 and 2 stacks has exit inner diameters of 29 feet, making it impossible to expand liners inside the shell to a diameter large enough to achieve velocities consistent with the 2012 EPRI Guide. In summary, the current design of the stacks prevents their conversion to wet stacks, so a complete replacement of the two stacks would be necessary if the stack gas temperature were to be at saturated conditions.<sup>14</sup>

To confirm the 2012 EPRI values for maximum gas velocities, GRE conducted a test in 2013 to evaluate the impacts of closing the bypass damper as much as physically possible in order to route the boiler flue gas through the wet scrubbing systems. Only a portion of the stack liner upgrade had been completed at the time of the test. During the tests GRE observed the following conditions:

- Stack liquid discharge and rainout, confirming that 1996 EPRI Guide values were not protective.
- Scrubbing water break-through onto the mist eliminators at a lower flue gas velocity than predicted due to improper design.
- Actual stack velocity data that are higher than the predicted design.

In 2014, an additional test was completed in order to reflect a state of maximizing the flue gas to the wet scrubber. This test did not experience stack liquid discharge and rainout. However, it was determined that the scrubber bypass leakage was approximately 6 percent during the test. The plant was unable to completely close/blind the bypass, so some bypass flue gas leaked through to the scrubbed gas, effectively reheating it to maintain a dry stack condition.

Following these tests, GRE replaced the wet scrubber mist eliminators in order to minimize water carryover from the wet scrubbers. Nevertheless, water accumulation on chimney walls due to condensation could not be eliminated when GRE maximized the proportion of flue gas to the wet scrubber. Therefore, a different solution was needed.

The technical conclusions and subsequent testing results described above were driving factors to cease work on the wet stack conversion project, resulting in abandoned costs of approximately \$20 million. Instead, GRE designed and implemented a novel flue gas reheat system as described in Section 2.3 so that the stacks could operate in a dry (non-saturated) state to comply with the SO<sub>2</sub> BART limit of 0.15 lb/MMBtu.

## 2.3 Flue Gas Reheat Technology

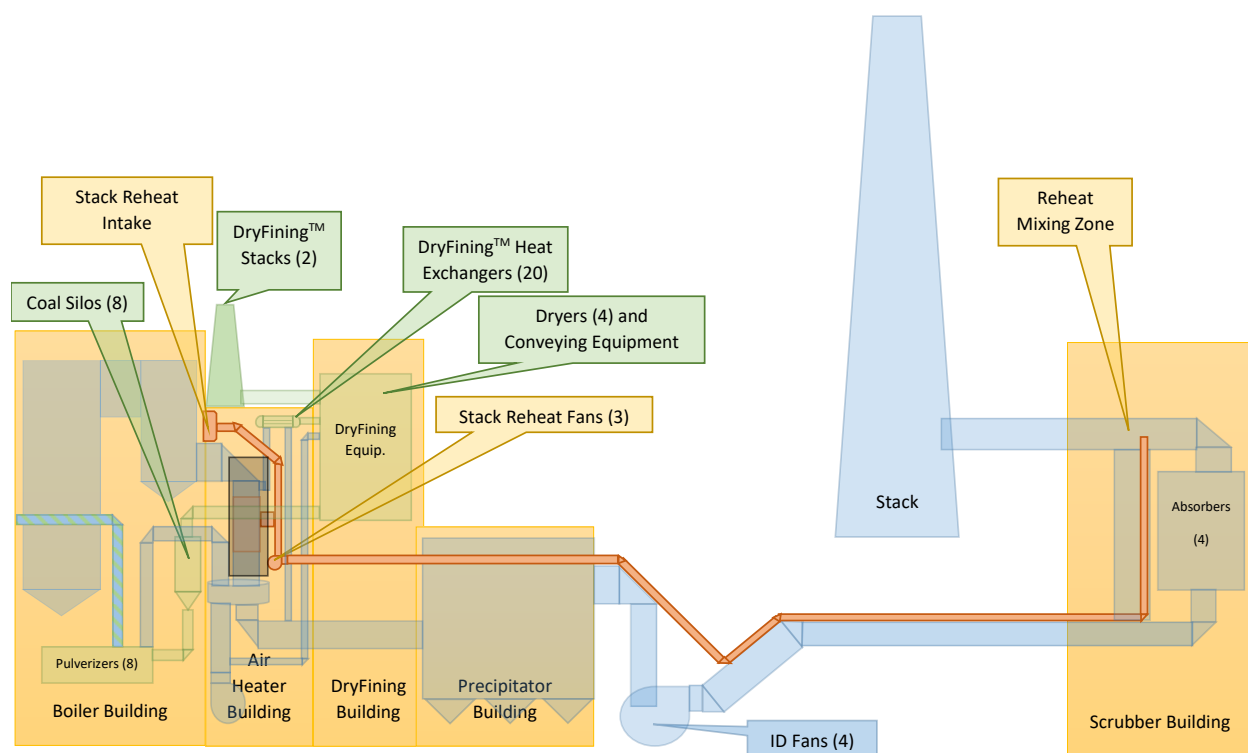
To maintain dry stack conditions while increasing the proportion of flue gas to the wet scrubber, GRE designed and installed a novel flue gas reheat system in late spring and early summer of 2017. The design

---

<sup>14</sup> Saturation conditions or saturation temperature refers to the stack temperature at which a wet stack occurs, thus creating potential for stack liquid discharge, rainout, and icing, as described in this report. Generally, the minimum saturation temperature value used at the plant is 132°F. However, due to variability in conditions that create a saturated environment (i.e., relative humidity) as well as the significant consequences of a wet stack operation at CCS, GRE attempts to apply an operating safety margin above the minimum saturated temperature target at the stack (referred to as dry stack operating temperature) such that the gas temperature at the absorber outlets is sufficiently warm.

of the reheat system is to pull ambient air from within the boiler house building, which contains residual heat from all plant processes. The reheat inlet temperature typically runs a steady state of about 80 degrees Fahrenheit (°F) throughout the year. This reheat air is ducted across the outer surface of the economizer ductwork by new fans. The economizer area increases the reheat air temperature. From the reheat fan discharge, the ductwork then passes between the two precipitators gaining more heat before being routed to the scrubber building. Once in the scrubber building, this reheat air is injected into the flue stream immediately downstream of the absorber outlet. (See Figure 2-4.)

For illustrative purposes, Figure 2-2 provides a basic profile view of the flue gas reheat ductwork and corresponding tie-ins in the boiler house building and the scrubber building.

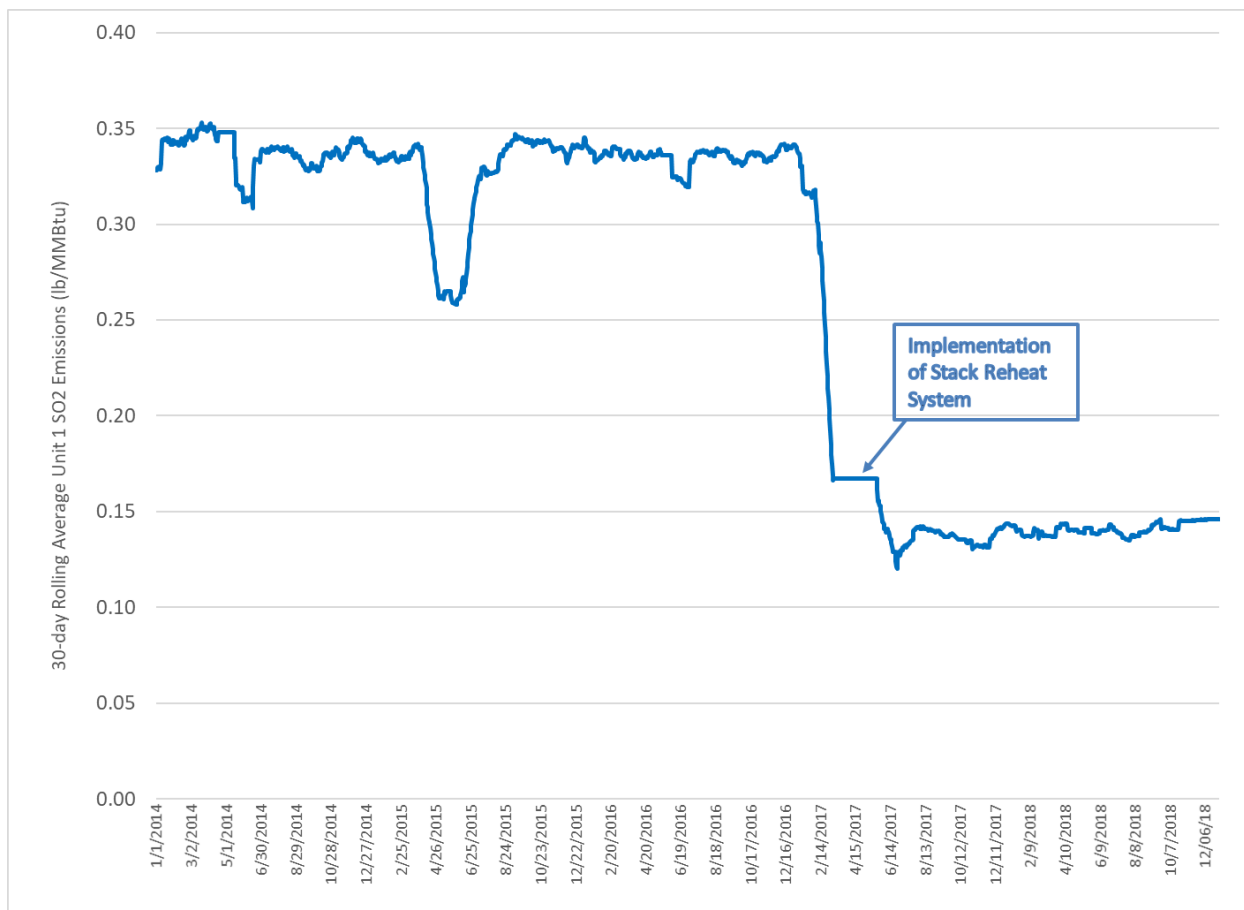


**Figure 2-2: Illustration of CCS Flue Gas Reheat System**

In 2014, the NDDEQ approved installation of the flue gas reheat systems for Units 1 and 2.<sup>15</sup> In 2017, the flue gas reheat systems began operation. Use of this reheat system in concert with DryFining™ has allowed GRE to maintain compliance with the SO<sub>2</sub> BART limit of 0.15 lb/MMBtu on a 30-day rolling average basis. Figure 2-3 provides an illustration of Unit 1 SO<sub>2</sub> emissions on a lb/MMBtu basis before and

<sup>15</sup> December 1, 2014 letter from Terry O'Clair of the NDDEQ to Deb Nelson of GRE.

after installation of the flue gas reheat design. Unit 2's SO<sub>2</sub> emissions reduction trend is consistent with Unit 1.



**Figure 2-3: Unit 1 SO<sub>2</sub> Emissions Reductions After Implementation of the Flue Gas Reheat System**

However, upon completion of the flue gas reheat installation, GRE observed that the reheat system did not meet design criteria. Specifically, the reheated air provided only ~200°F to the reheat mixing zone, rather than the 300°F design. This was due to an error in the modeling in which the surface of the economizer duct was assumed to have minimal temperature losses and would remain at approximately 780°F. The actual temperature loss of the economizer ductwork with the reheat system was found to decrease the economizer side walls to roughly 320°F, significantly less than the 780°F design value. The net effect was lower-temperature reheat mixing air. The resulting stack temperature could not be maintained at 10°F to 12°F above saturation temperature<sup>16</sup> at full unit load, which was the minimum

<sup>16</sup> See footnote 15, which describes saturation temperature.

design specification. This target flue gas temperature range is generally referred to herein as dry stack operation.

The installed flue gas reheat system only increases stack temperature by approximately 2°F above the saturation temperature at full load. GRE also observed that the volume of dry reheat mixing air decreases the adiabatic saturation temperature by roughly 3°F, thus resulting in a total reheat system benefit of approximately 5°F above saturation at full load. This is a very narrow margin for dry stack operation given the inherent variability and dynamic nature of functional and meteorological parameters for all operating conditions.

During non-cold weather and at full unit load with all coal dryers in operation, the stack reheat system is capable of maintaining dry stack operation such that the proportion of boiler flue gas to the wet scrubber may be maximized. However, by increasing flue gas volume to the scrubber, less of un-scrubbed hotter gas is bypassed, thus consuming the margin in the system needed to maintain a dry stack. As a result, in the following circumstances, the scrubber bypass may need to be opened to a certain degree to maintain dry stack conditions:

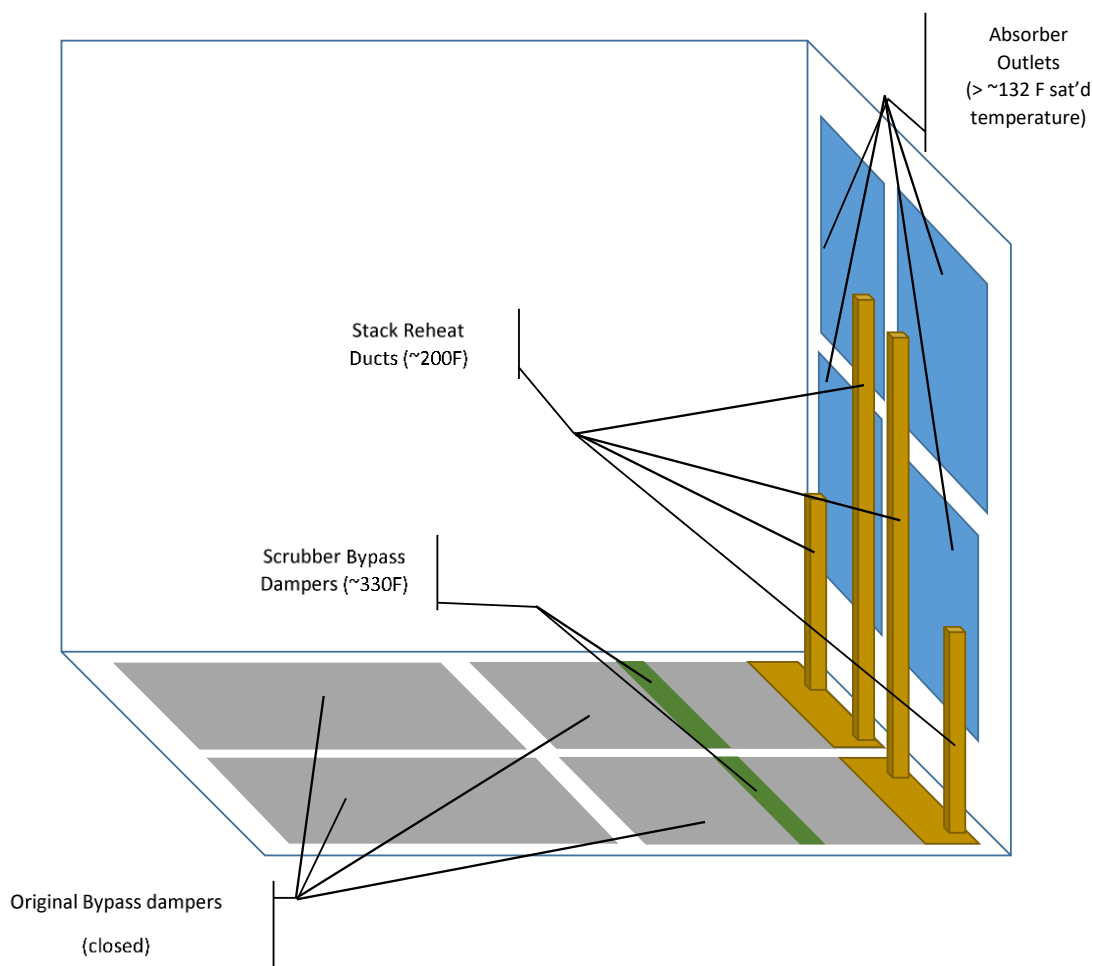
1. At reduced unit load, flue gas temperature cannot be sustained above the saturation point, since the plant is producing less thermal energy for the reheat system. As the available level of heat degrades, the temperature of the reheat air is reduced, increasing the risk that the stack will become wet.
2. During extended cold weather periods, the stack temperature cannot be sustained above the saturation point due to both heat losses throughout the reheat ductwork and denser ambient air to the boilers.<sup>17</sup>

For example, during a recent winter test case, GRE staff confirmed that at mid-load (~350 MW) operation, the heat absorbed by the equipment and duct work dissipated, which significantly degraded the effectiveness of the reheat system. Had the test continued for a prolonged period, plant staff anticipated a wet stack condition. The test ended prior to observing a wet stack condition, but this example demonstrates the need to have the scrubber bypass available to increase stack temperature safely above the saturation level.

In these aforementioned circumstances, the scrubber bypass must be opened slightly to allow hotter, drier gases to increase the gas temperature at the absorber outlets to the stack. Figure 2-4 provides a basic cutaway illustration of the interface between the scrubber bypass dampers and flue gas reheat ductwork at the outlet of the four scrubber (absorber) modules.

---

<sup>17</sup> "Cold" is used to describe weather conditions that create the need for additional reheat, requiring more flue gas to bypass the scrubber to maintain dry stack operation. Cold weather is a function of temperature, wind speed, and other weather factors that cause significant cooling of the power plant equipment and flue gases.



**Figure 2-4: Cutaway Illustration of Interface between Scrubber Bypass Dampers and Flue Gas Reheat Ducts at the Absorber Module Outlets**

## 2.4 Recent Reheat Optimization Assessments

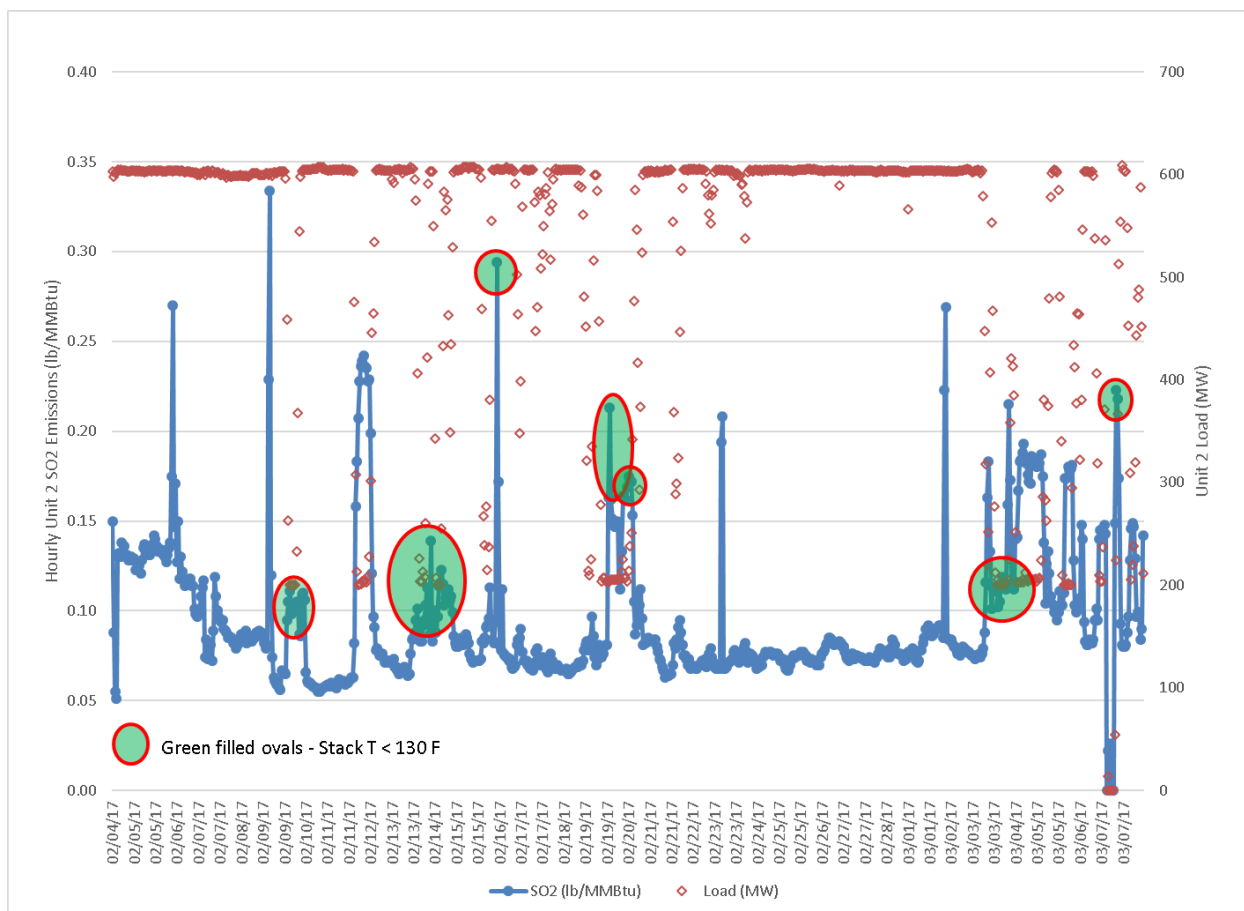
Given that the novel flue gas reheat system was commissioned in 2017, GRE has had relatively limited operational experience with it over the full range of operation. Since the commissioning of this system, GRE has conducted two optimization assessments to better understand and identify the limits of its operation, specifically to test the level of SO<sub>2</sub> control performance at high load and non-cold weather conditions and during variable load and colder weather operation. These optimization assessments are detailed in this section as the 2017 and 2019 winter test cases.

### 2.4.1 2017 Winter Test Case

The 2017 winter test case was performed in February and March 2017 at Unit 2 to better understand the optimal level of SO<sub>2</sub> control performance (i.e., maximum proportion of flue gas routed to the wet

scrubber) below 0.15 lb/MMBtu that could be achieved for short periods and at varying loads and weather conditions.

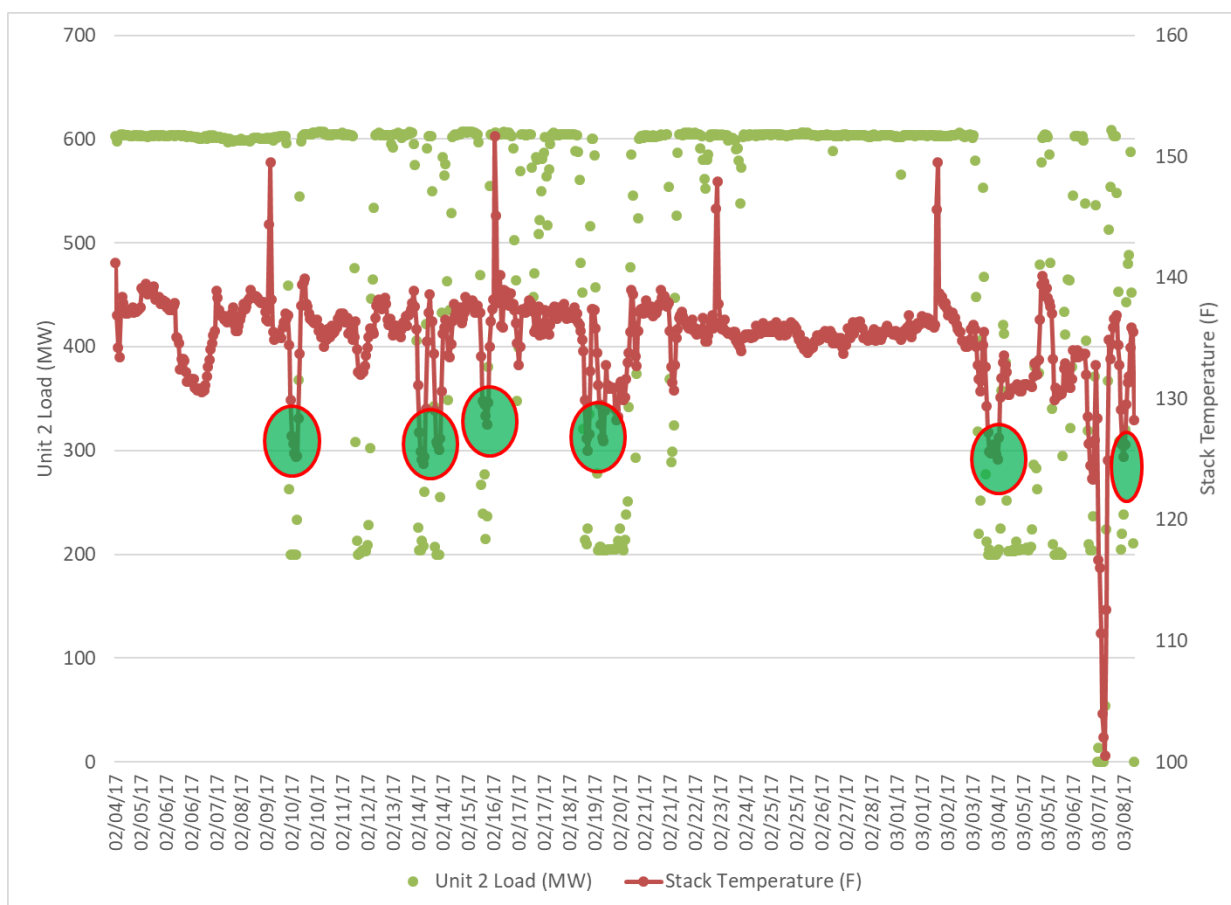
Throughout the duration of this first test, GRE observed several periods when the stack temperature dropped to lower than the saturation point, indicating high potential for wet stack conditions. Figure 2-5 provides the hourly Unit 2 SO<sub>2</sub> emissions data on a lb/MMBtu basis for the period February 4 through March 8 at Unit 2. The hourly Unit 2 load (MW) during this period is shown on the secondary axis. The green-filled areas demonstrate periods when the stack temperature was less than 130°F. At other times, SO<sub>2</sub> emissions increased for short periods due to low unit load or absorber cleaning.



**Figure 2-5: Winter 2017 Test Case Results of Unit 2 SO<sub>2</sub> Emissions v. Load**

GRE observed a correlation between low load and decreased stack temperature, unless the scrubber bypass damper is opened to allow hot, unsaturated flue gas to mix with the scrubbed gas. Figure 2-6 compares the Unit 2 load with stack temperature. In every instance that the unit load was reduced by at least half of its maximum capacity, the stack temperature rapidly decreased to levels that approached or reached saturation levels. As in the previous figure, the green shaded areas demarcate generally when the stack temperature was less than 130°F.





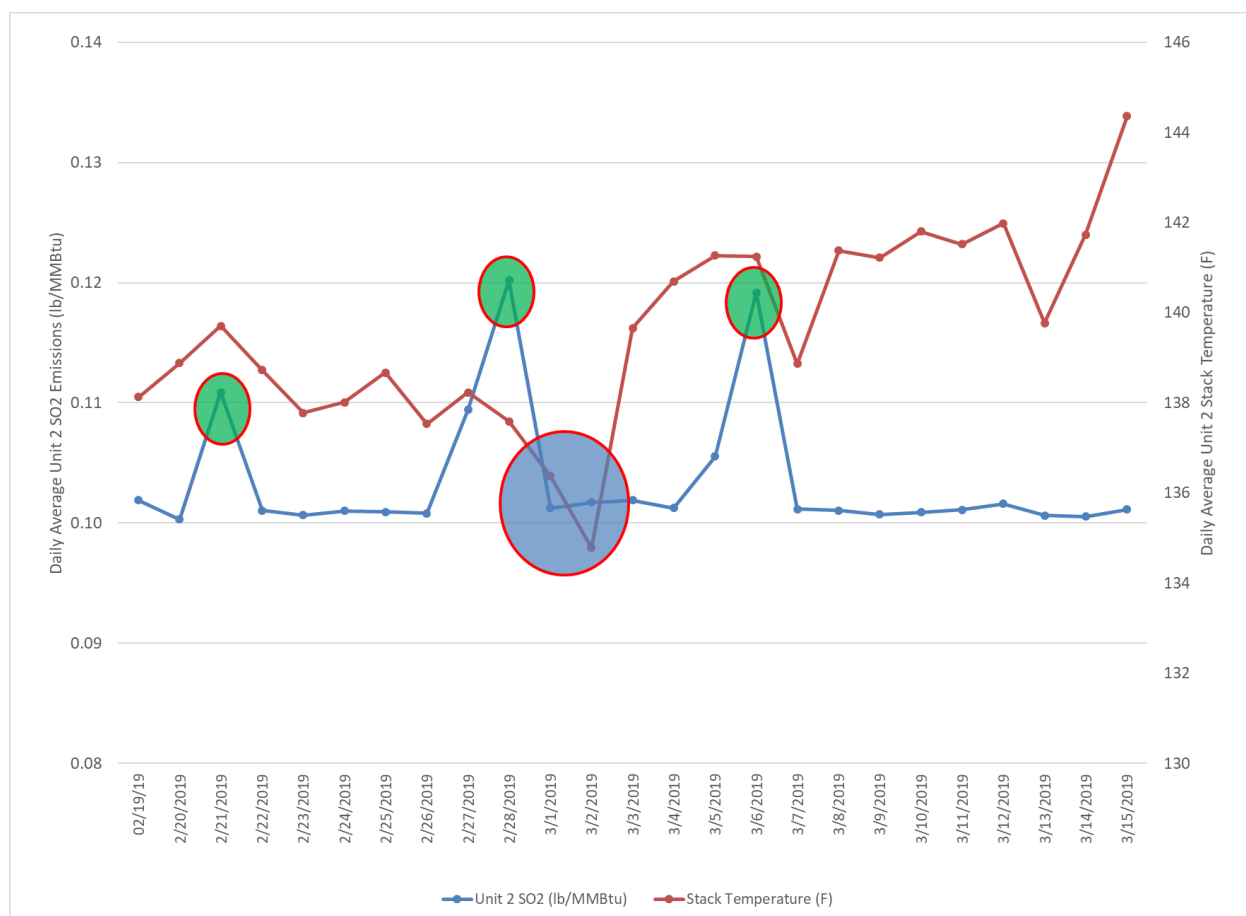
**Figure 2-6: Winter 2017 Test Case Results of Unit 2 Load v. Stack Temperature**

## 2.4.2 2019 Winter Test Case

GRE conducted a second assessment during winter to both optimize scrubber performance and to gather additional data on flue gas reheat at high unit load averaging 595 MW while maintaining dry stack. Over approximately a four-week period, GRE attempted to operate Unit 2 at an SO<sub>2</sub> emissions performance level of approximately 0.10 lb/MMBtu while monitoring for wet stack conditions and any other operational issues. The test concluded with a unit outage to inspect the physical characteristics of the emissions control system. Figure 2-7 illustrates the daily average SO<sub>2</sub> emissions performance and the corresponding stack temperature measured during the test with certain days shaded for emphasis as follows:

- The days with green-shaded areas indicate that an absorber cleaning event occurred, so one of the four scrubber modules was out of service for a few hours on those days.
- The two days (March 1 and 2) encircled in the blue shaded area demarcate a significant reduction in daily ambient temperature that occurred during the test. The daily average temperature dropped 22°F between February 28 and March 2, with the single-day decline of 17°F (from 9°F

to -8°F) between March 1 and 2 being the most significant single-day ambient temperature decrease.



**Figure 2-7: Winter 2019 Test Case Results of Daily Unit 2 SO<sub>2</sub> Emissions v. Stack Temperature**

GRE made the following key observations during this second test:

1. The lowest stack temperature recorded of 133.8°F on March 2 corresponded to the most significant day-to-day decline in ambient temperature and one of the lowest daily ambient temperature readings during the test of -9°F. However, ambient temperatures observed during the test did not reach the level of extreme cold that CCS experiences each winter, with the lowest hourly temperature of -15°F occurring on March 3. The lowest recorded stack temperature during the test was within 2°F of what is generally considered the saturation temperature of 132°F and is less than the targeted dry stack operating temperature.
2. Broken and cracked duct stiffeners were observed during the outage. An inspection of the broken stiffeners revealed heavy corrosion. Upon more detailed cleaning and inspection, corrosion was present on all stiffeners with the worst conditions on the downstream airflow side. It is suspected

that moisture collected on the front of the stiffeners was blown to the back where it resided, which may explain more corrosion on the back of the stiffeners. Although this area historically has required some patch repairs, the extent of corrosion and damage was unexpected in this outage. Without a detailed history of inspections and corrosion rates, it is difficult to causally relate the increased scrubbing during the four-week test to the evidence of accelerated damage in this area.

3. The stack drains did not have any liquid and there were no stack opacity spikes. An opacity spike can be an indication of excessive moisture in the stack. However, evidence of moisture was observed on new stack view ports in the mid-level area of the stack. Additionally, the entire breeching area was moist, and two of the four stack drains were plugged with solid material or precipitate, indicating moisture was potentially present.

In summary, Unit 2 SO<sub>2</sub> emissions performance averaged ~0.10 lb/MMBtu (0.104 lb/MMBtu) for this short duration test, understanding that longer term effects are difficult to assess from this test, especially given the unfavorable observations made with respect to the integrity of the equipment internals observed during the outage.

### **2.4.3 Low Load Reheat Augmentation System**

These two optimization assessments in 2017 and 2019 indicate that the emissions control systems are capable of improved SO<sub>2</sub> emissions performance levels for short periods of time, while fully understanding that there are potential long-term operational risks. As a measure to potentially mitigate or better manage the risk of a wet stack, especially at low load conditions, GRE is in the process of installing an emergency heat source, termed Low Load Reheat Augmentation System, that is expected to be ready for use as needed in 2020. The design of this system is to temporarily reroute some air from an existing forced draft fan to the existing reheat system. The additional air flow and thermal energy is intended to maintain a stack temperature safely above the saturation temperature.

The system is designed as a contingency to be used during low load operating conditions and when there is potential for wet stack (i.e., increased opacity levels, measured stack temperature approaching possible saturation conditions, presence of liquid in stack drains) in order to maintain a dry stack operating temperature. Accordingly, use of this system only in these infrequent situations to support an incremental level of additional flue gas to the wet scrubber is expected to not appreciably affect annualized SO<sub>2</sub> emissions on a mass basis.

## **2.5 Updated Baseline SO<sub>2</sub> Emissions Performance Level**

As a result of GRE's test efforts in the last two years to better understand the opportunities and implications of improved SO<sub>2</sub> emissions performance, GRE proposes to adjust its annual SO<sub>2</sub> emissions to be reflective of a performance level less than the current BART limit of 0.15 lb/MMBtu. Specifically, through a permitting action to be completed via the NDDEQ's permit to construct regulatory program at NDAC 33.1-15-14, GRE seeks an annual-average mass emissions limit of 626 lb/hr that is equivalent to

0.104 lb/MMBtu at full load, as described in Section 3.8.<sup>18</sup> This performance level is consistent with operation of multiple emissions control measures, namely the wet scrubber system, DryFining™ technology, and flue gas reheat applications at Units 1 and 2.

This baseline emissions update is in alignment with the 2019 RH SIP Guidance with respect to evaluating a projected scenario for baseline emissions. At page 29 in the section entitled “Baseline control scenario for the analysis,” excerpted below, EPA considers the projected 2028 emissions scenario as a “reasonable and convenient choice” for the baseline control scenario:

“Typically, a state will not consider the total air pollution control costs being incurred by a source or the overall visibility conditions that would result after applying a control measure to a source but would rather consider the incremental cost and the change in visibility associated with the measure relative to a baseline control scenario. The projected 2028 (or the current) scenario can be a reasonable and convenient choice for use as the baseline control scenario for measuring the incremental effects of potential reasonable progress control measures on emissions, costs, visibility, and other factors. A state may choose a different emission control scenario as the analytical baseline scenario. Generally, the estimate of a source’s 2028 emissions is based at least in part on information on the source’s operation and emissions during a representative historical period. However, there may be circumstances under which it is reasonable to project that 2028 operations will differ significantly from historical emissions. Enforceable requirements are one reasonable basis for projecting a change in operating parameters and thus emissions; energy efficiency, renewable energy, or other such programs where there is a documented commitment to participate and a verifiable basis for quantifying any change in future emissions due to operational changes may be another. A state considering using assumptions about future operating parameters that are significantly different than historical operating parameters should consult with its EPA Regional office.”

Section 3.8 provides additional detail on the proposed mass emissions rate limit for SO<sub>2</sub> at Units 1 and 2 following the four-factor analysis of additional emissions control measures.

---

<sup>18</sup> 626 lb/hr = 0.104 lb/MMBtu x 6,015 or 6,022 MMBtu/hr rated capacities for Unit 1 and 2 listed in the Title V operating permit.

---

## 3 Sulfur Dioxide (SO<sub>2</sub>) Four-Factor Analysis

GRE has completed a four-factor analysis of additional SO<sub>2</sub> emissions control technologies and optimizations at CCS Units 1 and 2 above and beyond those described in Section 2.

Section 3.1 summarizes the four-factor analysis approach with respect to the regional haze program detailed in the 2019 RH SIP Guidance. Sections 3.2 and 3.3 identify and describe various SO<sub>2</sub> control measures. Sections 3.4 through 3.7 evaluate the four statutory factors to CCS Units 1 and 2. Section 3.8 proposes an SO<sub>2</sub> emissions limit and control measures.

### 3.1 Four-Factor Analysis Approach

Consistent with EPA's guidance and NDDEQ direction, GRE has completed a four-factor analysis as summarized in Sections 3.1.1 to 3.1.5.

#### 3.1.1 Identify all Emission Control Options

Prior to completing a four-factor analysis of each emissions control technology, all commercially available and technically feasible emission control options for CCS Units 1 and 2 must first be identified. Potentially available emission control options include both add-on control equipment and process improvement applications. All control options identified as available and technically feasible are then evaluated against the "four factors."

In order to be considered available and technically feasible, an emissions control must have been previously installed and operated successfully on a similar source under similar physical and operating conditions. Novel controls that have not been demonstrated on full-scale, coal-fired utilities are not considered as part of this analysis. Instead, this evaluation focuses on commercially demonstrated control options.

The control effectiveness of currently available retrofit technologies ranges from 40% to 98+%. For purposes of this analysis, GRE evaluated only those technologies that have the potential to achieve an overall SO<sub>2</sub> reduction greater than the performance of the existing systems, including optimizations.

Sulfur emissions from coal combustion consist primarily of SO<sub>2</sub>, with a much lower quantity of SO<sub>3</sub> and gaseous sulfates. These compounds form in the coal as organic and pyritic sulfur. Either form is oxidized during the combustion process. For permitting and design purposes, it is assumed that 100% of the fuel sulfur will convert to SO<sub>2</sub> during the combustion process, and that 1% of the uncontrolled SO<sub>2</sub> will oxidize to SO<sub>3</sub>. Theoretically, several techniques can be used to reduce SO<sub>2</sub> emissions from coal combustion sources and they are grouped into pre-combustion controls and post combustion controls, which further subdivide into wet and dry technologies, as summarized in Table 3-1.

**Table 3-1: Additional SO<sub>2</sub> Control Measures with Potential Application at CCS Units 1 and 2**

Control Technology
<u>Pre-Combustion Controls (operational improvements)</u> <ul style="list-style-type: none"><li>• DryFining™ Optimization</li></ul>
<u>Post-Combustion SO<sub>2</sub> Control Technologies</u>
<ul style="list-style-type: none"><li>• Dry Flue Gas Desulfurization<ul style="list-style-type: none"><li>- Add Dry Sorbent Injection</li><li>- Add Spray Dry Absorption</li></ul></li><li>• Wet Flue Gas Desulfurization<ul style="list-style-type: none"><li>- Replace Wet Lime/Limestone Scrubber</li><li>- Increase Proportion of Flue Gas to Existing Wet Scrubber<ul style="list-style-type: none"><li>○ Install Replacement Wet Stacks</li><li>○ Install Natural Gas Fired Reheat System</li></ul></li></ul></li></ul>

An evaluation of additional pre-combustion and post-combustion SO<sub>2</sub> emissions control measures to CCS Units 1 and 2 are described in Sections 3.2 and 3.3, respectively.

### 3.1.2 Factor #1 – Cost of Compliance

Factor #1 considers and estimates, as needed, the capital and annual operating and maintenance (O&M) costs of the control measure. As directed by the 2019 RH SIP Guidance at page 21, costs of emissions controls follow the accounting principles and generic factors from the EPA Air Pollution Control Cost Manual (EPA Control Cost Manual)<sup>19</sup> unless more refined site-specific estimates are available. Under this step, the annualized cost of installation and operation on a dollars per ton of pollutant removed (\$/ton) of the control measure, referred to as “average cost effectiveness,” is compared to a cost effectiveness threshold that is estimated by the NDDEQ.

Generally, if the average cost effectiveness is greater than the threshold, the cost is considered to not be reasonable, pending an evaluation of other factors. Conversely, if the average cost effectiveness is less than the threshold, then the cost is considered reasonable for purposes of Factor #1, pending an evaluation of whether the absolute cost of control (i.e., costs in absolute dollars, not normalized to \$/ton) is unreasonable. This situation is particularly applicable to a source with existing emissions controls with

---

<sup>19</sup> US EPA, “EPA Air Pollution Control Cost Manual, Sixth Edition,” January 2002, EPA/452/B-02-001. The EPA has updated certain sections and chapters of the manual since January 2002. These individual sections and chapters may be accessed at <https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution> as of the date of this report.

an intermediate or high degree of effectiveness, as is the case at CCS Units 1 and 2 due to its existing SO<sub>2</sub> emissions controls.

The cost of an emissions control measure is derived using capital and annual operation and maintenance (O&M) costs. Capital costs generally refer to the money required to design and build the system. This includes direct costs, such as equipment purchases, and installation costs. Indirect costs, such as engineering and construction field expenses and lost revenue due to additional unit downtime in order to install the additional control measure(s), are considered as part of the capital calculation. Annual O&M costs include labor, supplies, utilities, etc., as used to determine the annualized cost in the numerator of the cost effectiveness value. The denominator of the cost effectiveness value (tons of pollutant removed) is derived as the difference in: 1) projected emissions using the current emissions control measures (baseline emissions), as described in Section 2.5, in tons per year (tpy), and 2) expected annual emissions performance through installation of the additional control measure (controlled emissions), also in tpy.

For purposes of calculating cost effectiveness, GRE uses the updated baseline emissions value of 626 lb/hr, as described in Section 2.5, in conjunction with projected utilization (also called annual capacity factor or ACF) of the unit to determine an annual tpy value.<sup>20</sup> Over the past 10 years, CCS averages 87% plant utilization, as shown in Table 3-2. GRE considers this value representative of projected operations for purposes of determining annualized emissions. The product of the 626 lb/hr value and 87 percent ACF converted to a tpy basis is 2,385 tpy SO<sub>2</sub> for each unit as the baseline annual emissions rate to be used for purposes of determining annual emissions reductions for a given additional control measure.

---

<sup>20</sup> Annual capacity factor is defined by EPA (40 CFR 60 Subpart Dc) as "... the ratio between the actual heat input to a steam generating unit from an individual fuel or combination of fuels during a period of 12 consecutive calendar months and the potential heat input to the steam generating unit from all fuels had the steam generating unit been operated for 8,760 hours during that 12-month period at the maximum design heat input capacity..." Because the proposed mass SO<sub>2</sub> emissions limit is based on the maximum rated heat input capacity to the boiler, the annual capacity factor is a reasonable representation to determine projected annual heat input duty for purposes of this analysis. Unit outages are considered in the annual capacity factor calculation.

**Table 3-2: Annual Average Capacity Factors at CCS Unit 1 and Unit 2**

Year	Annual Capacity Factor	
	Unit 1	Unit 2
2009	94.2%	92.7%
2010	93.8%	79.6%
2011	81.6%	89.0%
2012	92.4%	90.9%
2013	92.4%	83.3%
2014	87.8%	88.2%
2015	89.3%	87.3%
2016	86.3%	72.9%
2017	70.8%	85.0%
2018	91.6%	90.5%
<b>10 yr Average</b>	<b>88%</b>	<b>86%</b>
<b>Plant Average</b>	<b>87%</b>	

The calculated cost effectiveness value for each control measure is compared to a cost effectiveness threshold established by the NDDEQ. The NDDEQ's original BART cost thresholds were based on the "high cost" value of \$3,000 per ton listed in the June 1999 WRAP Annex to Grand Canyon Visibility Transport Commission (GCVTC) Report.<sup>21</sup> This 1999 value is scaled to today's dollars using the Chemical Engineering Plant Cost Index (CEPCI).<sup>22</sup> The CEPCI is an industrial plant index that is considered more representative for purposes of this analysis than general cost indices such as the Consumer Price Index (CPI). The average cost effectiveness threshold in current dollars is calculated to be \$4,630 per ton.<sup>23</sup>

---

<sup>21</sup> Cited by EPA in the "Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations" proposed rule; 69 FR 25198; May 5, 2004.

<sup>22</sup> More information on CEPCI may be found at this link: <https://www.chemengonline.com/pci-home>. The CEPCI is accessible by subscription through "Chemical Engineering" magazine. The CEPCI scaling factors for this analysis compare 1999 values to December 2018 values.

<sup>23</sup> The NDDEQ also calculated an incremental cost effectiveness (cost effectiveness between two control measures) threshold in addition to the average cost effectiveness threshold for the BART evaluations. Pursuant to a June 1, 2018 teleconference between GRE and NDDEQ staff, the NDDEQ stated that the average cost effectiveness and absolute costs of an additional control measure will be considered, but incremental cost effectiveness will not be evaluated for purposes of the screening level analysis.



---

### 3.1.3 Factor #2 – Time Necessary for Compliance

Factor #2 is considered by NDDEQ in setting reasonable deadlines for the selected control. This includes the planning, installation and commissioning of the selected control.

For purposes of this analysis and if a given SO<sub>2</sub> control measure requires a unit outage as part of its installation, GRE considers the forecasted outage schedule for Units 1 and 2 in conjunction with the expected timeframe for engineering and equipment procurement following NDDEQ and EPA approval of the given control measure.

### 3.1.4 Factor #3 – Energy and Non-air Environmental Impacts:

Factor #3 involves consideration of the energy and non-air environmental impacts of each control measure. Non-air quality impacts may include solid or hazardous waste generation, wastewater discharges from a control device, increased water consumption, and land use. The environmental impact analysis is conducted based on consideration of site-specific circumstances.

The energy impact analysis considers whether use of an emissions control technology results in any significant or unusual energy penalties or benefits. Energy use may be evaluated on an energy used per unit of production basis, energy used per ton of pollutant controlled, or total annual energy use.

### 3.1.5 Factor #4 – Remaining Useful Life of the Source

Factor #4 is the remaining useful life of the source, which is the difference between the date that additional emissions controls will be put in place and the date that the facility permanently ceases operation. Generally, the remaining useful life of the source is assumed to be longer than the useful life of the emissions control measure unless there is an enforceable cease-operation requirement. In the presence of an enforceable end date, the cost calculation can use a shorter period to amortize the capital cost.

For the purpose of this evaluation, the remaining useful life of both Unit 1 and Unit 2 is assumed to be longer than the useful life of the additional emission controls measures. Therefore, the expected useful life of the control measure is used to calculate the emissions reductions, amortized costs, and the resulting cost per ton (\$/ton).

## 3.2 Identification of Pre-Combustion Controls

As introduced in Section 2.1, GRE developed and commercialized a novel multipollutant control technology, described as DryFining™. At issue is the question of whether there is any opportunity to further optimize this pre-combustion technology. In theory, either more high-density segregation could be achieved to remove pyritic sulfur, or more moisture could be removed in order to increase the proportion of flue gas that may be routed to the wet scrubber instead of the scrubber bypass.

For purposes of SO<sub>2</sub> emissions control, DryFining™ is a two-stage process, beginning with an air jig that separates higher density coal, containing some pyritic sulfur, before routing the coal to the next stage.

GRE's plant engineering staff have reviewed alternative techniques for improving pyritic segregation but have not found anything to impact SO<sub>2</sub> at the stack.

With respect to stage 2 after the air jig, the coal is moved through fluid bed dryers using plant waste heat to reduce its moisture content. This dried coal provides many benefits, including that it improves plant heat rate, which reduces plant energy use and, with respect to SO<sub>2</sub>, reduces flue gas volume thus allowing more of the flue gas to be scrubbed.

There is a limit to the effectiveness of the coal drying stage without causing negative environmental consequences.<sup>24</sup> Each CCS unit was designed with four dryers, so eight total dryers are installed. The plant can produce enough dried coal to operate at full load with seven dryers in service. Therefore, one dryer can be out of service for maintenance while still maintaining emission rates. In theory, this extra dryer could be used to process (i.e., dry) coal to a lower moisture content; however, in practice, this would be environmentally detrimental.

When the dryers are operating properly, the plant can decrease coal moisture by 10% to 12%. As removal approaches 12%, the plant begins to experience significant operational issues such as auto-ignition of coal in bunkers in addition to difficulties maintaining steam temperature. Specifically, DryFining™ increases the heat content of coal from ~6,300 to ~6,700 Btu/lb. When the coal reaches very high Btu values for the design of Units 1 and 2, the fireball becomes too hot at a lower location in the boiler. The water walls absorb most of the heat and it thus does not reach the upper area of the boiler necessary to maintain steam temperature. To combat this, the burner tilts are changed to raise the fireball higher to get better heat transfer in the upper part of the boiler and to maintain steam temperature to the turbine. Changing the burner tilts in this way will, in and of itself, negatively impact NO<sub>x</sub> emissions performance.

In summary, after almost a decade of operating DryFining™ technology at Units 1 and 2, GRE has fully optimized its ability to reduce SO<sub>2</sub> as a pre-combustion control measure.

### 3.3 Identification of Post-Combustion Controls

The flue gas desulfurization (FGD) systems commonly used to control SO<sub>2</sub> emissions can be classified as either dry or wet systems. As implied by the name, dry scrubbers require less water than wet systems but also require higher temperatures to ensure that all moisture has been evaporated before leaving the scrubber. Wet systems are generally capable of achieving higher removal efficiencies than dry systems because it is easier to mix a gas with a liquid than a solid.

FGD systems require the use of an alkali powder or slurry. Lime (or limestone) is the most widely used compound for acid gas absorption. Wet FGD systems may discard all the waste by-product streams or

---

<sup>24</sup> DryFining™ is a multipollutant technology that, in part, reduces mercury, SO<sub>2</sub> and NO<sub>x</sub> emissions. While this evaluation is focused on SO<sub>2</sub>, drier coal beyond that currently targeted will negatively impact NO<sub>x</sub> emissions.

regenerate and reuse them. Wet systems generally require more extensive networks of pumps and piping than dry systems to recirculate, collect and treat the scrubbing liquid.

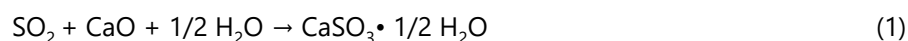
There are three main FGD systems including wet scrubbing, spray dryer absorption, and dry sorbent injection. CCS Units 1 and 2 currently operate with a wet scrubber.

### 3.3.1 Dry Sorbent Injection

Dry sorbent injection involves the injection of a lime, limestone or even sodium powder into the exhaust gas stream. The flue gas is then routed through a baghouse or electrostatic precipitators to remove the sorbent and entrained SO<sub>2</sub>. The process was developed as a lower cost FGD option because the mixing occurs directly in the exhaust gas stream instead of in a separate tower. Depending on the residence time and gas stream temperature, sorbent injection control efficiency is typically between 50% and 70%. While dry sorbent injection is a technically feasible retrofit option, given that the maximum expected removal efficiency of this technology is approximately 70%, it will not provide improvement over CCS's existing SO<sub>2</sub> emissions control system and is therefore not evaluated further for this analysis.

### 3.3.2 Spray Dry Absorption

Spray dry absorption is a dry scrubbing system that sprays a fine mist of lime slurry into an absorption tower where the SO<sub>2</sub> is absorbed by the droplets. The absorption of the SO<sub>2</sub> leads to the formation of calcium sulfite (CaSO<sub>3</sub>•2H<sub>2</sub>O) and calcium sulfate (CaSO<sub>4</sub>) within the droplets as illustrated by equations 1 and 2 below.



The liquid-to-gas ratio is such that the heat from the exhaust gas causes the water to evaporate before the droplets reach the bottom of the tower. This leads to the formation of a dry powder that is collected with a fabric filter. Spray dryer absorption control efficiency is typically in the 70% to 90% range. A spray dry scrubber is a technically feasible control option, but it will not provide improvement over the existing removal efficiency and is therefore not evaluated further as part of this analysis.

### 3.3.3 Wet Lime/Limestone Scrubbing

Wet lime/limestone scrubbing involves scrubbing the exhaust gas stream with a slurry comprised of lime (CaO) or limestone (CaCO<sub>3</sub>) in suspension. The process takes place in a wet scrubbing tower located downstream of a particulate matter control device. Similar to the chemistry illustrated above for spray dry absorption, the SO<sub>2</sub> in the flue gas reacts with the lime or limestone slurry to form calcium sulfite (CaSO<sub>3</sub>•2H<sub>2</sub>O) and calcium sulfate (CaSO<sub>4</sub>).

There are two basic types of wet scrubber technologies: natural oxidation and forced oxidation. For new installations, forced oxidized scrubbers are capable of achieving 98+% control. Both Coal Creek units have

natural oxidation scrubbers. GRE estimates that the existing wet scrubbers control SO<sub>2</sub> to approximately 94% to 95%, based on the proposed permitted mass emissions limit that is calculated from a 0.104 lb SO<sub>2</sub>/MMBtu performance level as well as some bypass leakage as provided in the analysis from a third-party engineering firm.<sup>25,26</sup> Theoretically, with a completely closed and sealed flue gas system and a new “wet” stack, the existing scrubber performance would improve only to approximately 96%. This estimate is specific to the scrubber/absorber proper and does not include upstream SO<sub>2</sub> emissions control that results from DryFining™ air jig operations.

As described in GRE’s CCS BART report,<sup>27</sup> several wet scrubber modifications were assessed. These included the addition of a fifth scrubber module and expansion of the existing absorber towers to scrub all the flue gas. With the implementation of DryFining™, the flue gas volume was reduced such that the existing scrubber modules could handle 100% of the flue gas, notwithstanding that the current stacks are designed as dry stacks, as detailed in Sections 2.2 through 2.4. Therefore, the fifth absorber module and/or expanded absorber towers are no longer needed. Further, conducting a four-factor evaluation to replace the existing wet scrubber system with a new design for a possible incremental level of improved SO<sub>2</sub> performance (and which would also require one of the two projects described in Section 3.3.4) will inherently result in unreasonable costs on absolute cost and average cost effectiveness bases.

### **3.3.4 Increase Amount of Flue Gas to Existing Wet Scrubbers**

As a potential method to reduce SO<sub>2</sub>, a greater proportion of the unit’s flue gas could be routed to the existing wet scrubbers if additional control measures are taken. As detailed in Sections 2.2 through 2.4, a relatively minor bypass is currently needed in limited situations to maintain dry stack conditions. If new wet stacks are installed or if a natural gas-fired reheat system is implemented, as considered in Sections 3.3.4.1 and 3.3.4.2, then theoretically there would no longer be a need to bypass the scrubbers. In this scenario, some un-scrubbed flue gas would still leak through the scrubber bypass dampers, which are not designed to be completely sealed and are estimated to add approximately 0.007 lb SO<sub>2</sub>/MMBtu to the total SO<sub>2</sub> emissions rate.

In total, based on testing with scrubber bypass closed and accounting for future variability in operations, GRE estimates that the annual emissions from either technology will improve SO<sub>2</sub> performance to a level of 0.08 lb/MMBtu, representing an approximately 20% improvement from the proposed permit level that

---

<sup>25</sup> The SO<sub>2</sub> emissions rate is not directly measured in the flue gas to the wet scrubbers. Because DryFining™ serves as a pre-combustion SO<sub>2</sub> control and due to the minor proportion of flue gas that is required to bypass the scrubber to maintain a dry stack, it is incorrect to conclude that the difference in SO<sub>2</sub> at the stack versus the sulfur in the incoming coal is solely a function of wet scrubber performance.

<sup>26</sup> URS Corporation, “GRE Coal Creek Units 1 & 2 Review of Options to Reduce SO<sub>2</sub> Emissions,” October 26, 2004. This slide deck was included in the December 2007 GRE CCS BART Report.

<sup>27</sup> GRE, “Coal Creek Station Units 1 and 2 Best Available Retrofit Technology Analysis,” revised December 12, 2007.

is based on 0.10 lb/MMBtu. The resulting average annual expected emissions reduction for each unit is 550 tpy, calculated as the difference in the baseline emissions of 2,385 tpy calculated in Section 3.1.2 and the controlled emissions rate of 1,835 tpy, calculated as the product of 6,019 MMBtu/hr (average of the two rated heat input capacities for Units 1 and 2), 0.080 lb SO<sub>2</sub>/MMBtu performance, and 87% ACF.

#### **3.3.4.1 Replace Current Stack with Wet Stack**

As detailed in Section 2.2, Coal Creek has a unique emission control configuration, coupling a wet scrubber with a dry stack and novel flue gas reheat system. It is not possible to convert the existing stack to a wet stack design. Instead, a new wet stack would need be installed and the current stack would be abandoned for each unit.

A screening-level four-factor analysis is provided for the project to replace the Unit 1 and 2 stacks in their entirety with wet stacks. For this evaluation, Hamon Custodis, Inc. (Custodis) was engaged to provide a budgetary quote for a new wet stack, excluding foundation and tie-ins. Custodis provided an initial high-level concept to effectively replace the two existing stacks with a “rough budget price.”<sup>28</sup> GRE has added to this price a high-level and conservatively low set of cost estimates to convert the Custodis cost to an appropriate diameter and to include foundations, duct work, and continuous emissions monitoring systems (CEMS).

#### **3.3.4.2 Natural Gas Reheat System**

As detailed in Section 2.3, the novel flue gas reheat system is capable of maintaining a dry stack under most, but not all, operational situations, while maximizing the proportion of flue gas to the wet scrubber. During low load and cold weather operation, the existing reheat system does not provide enough thermal energy to reheat the stack gas to a dry state. There is no significant additional heat in the buildings or equipment that can be scavenged to be used for the current flue gas reheat system; therefore, GRE has considered the additional control measure of a natural gas-fired reheat system. A screening-level four-factor analysis is provided for the project to replace the existing flue gas reheat system with a natural gas-fired reheat system.

In order to maintain dry stack operation, GRE estimates approximately 31.5 MMBtu/hr of additional heat would be required. For reference, the existing reheat system adds approximately 11 MMBtu/hr, which would be abandoned at an estimated \$12 million/unit loss. Therefore, the new natural gas reheat system is sized at 31.5 MMBtu/hr per unit. The most logical location for a natural gas fired duct burner is adjacent to the current reheat mixing zone. See Figure 2-2 and Figure 2-4 for illustrations of the current flue gas reheat system.

---

<sup>28</sup> April 5, 2019 email from David Durham of Custodis to Loren Loritz of GRE.

Two companies were engaged to provide estimates to support this evaluation. Given that Coal Creek does not currently have a gas supply, WBI Energy (WBI) provided a cost estimate for a new gas line with firm (non-interruptible) gas supply up to Coal Creek's fence line.<sup>29</sup> The cost for installation of the natural gas pipeline is split between Unit 1 and Unit 2, because the same pipeline could be used for both sources. GRE plant staff estimated a connecting gas line from the WBI fence line point to the duct burner locations. Barr Engineering (Barr) was engaged to provide an estimate for the natural gas-fired duct burner system. Its high-level (Class 5) estimate of the system was provided with additional consideration for site-specific installation factors.<sup>30</sup>

### 3.4 Factor 1 Evaluation – Costs of Compliance

GRE has completed a high-level screening-level cost estimate for the replacement wet stack and natural gas-fired reheat system projects. The capital cost estimates are considered by GRE's plant engineering staff, based on their considerable experience with projects at CCS and their informal conversations with other companies that have completed similar types of projects at power plants, to be conservatively low. A more detailed cost estimate is likely to increase the costs for installing and implementing either of the projects. Importantly, this initial set of cost estimates does not include additional outage time that will very likely be necessary, especially for the replacement wet stack. Cost summary spreadsheets for these two are provided in Appendix A.

The cost effectiveness analysis compares the annualized cost of the technology per ton of pollutant removed and is evaluated on dollar per ton basis using the annual cost (annualized capital cost plus annual operating costs) divided by the annual emissions reduction (tons) achieved by the control device. For purposes of this screening evaluation, a 20-year life (before new and extensive capital is needed to maintain and repair the equipment) at 5.25% interest is assumed in annualizing capital costs.

The resulting cost effectiveness calculations are summarized in Table 3-3.

---

<sup>29</sup> March 20, 2019 email from David Dahms of WBI to Richard Garman of GRE.

<sup>30</sup> March 21, 2019 email from Joel Trinkle of Barr to several staff at GRE, forwarding a March 20, 2019 email quote prepared by William Mullinix of Barr.

**Table 3-3: SO<sub>2</sub> Control Cost Summary, per Unit Basis**

Additional Emissions Control Measure	Installed Capital Cost (\$)	Annualized Capital Cost (\$/yr)	Annual Operating Costs (\$/yr)	Total Annualized Costs (\$/yr)	Annual Emissions Reduction (tpy)	Pollution Control Cost Effectiveness (\$/ton)
New Wet Stack	\$38.8 million	\$3.2 million	\$0.8 million	\$4.0 million	550	7,200
Natural Gas Reheat System	\$14.5 million	\$1.2 million	\$2.2 million	\$3.4 million	550	6,200

The cost effectiveness values of both projects are substantially greater than the cost effectiveness threshold of \$4,630 derived in Section 3.1.2. Therefore, the costs for either retrofit option to replace the current stack with a wet stack or to implement a natural gas-fired reheat system are not reasonable.

Sections 3.5 through 3.7 provide a screening-level summary of the remaining three factors evaluated for the replacement wet stack and natural gas-fired reheat system, understanding that these projects represent substantial capital investments that are not justified on a cost per ton or absolute cost basis.

### 3.5 Factor 2 Evaluation – Time Necessary for Compliance

Factor #2 estimates the amount of time needed for full implementation of different control measures, which in this case is the replacement wet stack or the natural gas-fired reheat system. Typically, time for compliance includes the time needed to develop and approve the new emissions limit into the state implementation plan (SIP) by state and federal action, then to implement the project necessary to meet the SIP limit via installation and tie-in of equipment for the emissions control measure.

Either projects would require significant resources and time of at least two to three years to engineer, permit, and install the equipment, whether it be a 675-foot-high, 30-foot-inner-diameter chimney or a 10-mile-long, 6-inch-diameter natural gas pipeline with an integrated duct burner system. Subsequently, the new stacks would need to be tied-in to the existing scrubber building, which will likely require several additional days beyond the standard extended outage duration of approximately seven weeks. Similarly, the duct burner systems would need to be tied-in during a subsequent outage after the equipment is built before it can begin operation.

Assuming that a SIP is approved in 2022, then the next set of extended outages for the two units are scheduled to occur in 2025 and 2026 for potentially installing the required technology.

### 3.6 Factor 3 Evaluation – Energy and Non-Air Quality Environmental Impacts

The energy and non-air environmental impacts associated with implementation of the two technologies are summarized herein.

For the replacement wet stack, the current stacks would be abandoned, resulting in demolition and disposal of a significant amount of materials with associated use of demolition equipment and portable engines to accommodate these activities. Additionally, it is not clear where the new stacks would be located because the property surrounding this area is already being used. Significant planning and logistical issues will need to be addressed in order to locate and tie in these stacks.

The natural gas-fired reheat system creates additional non-SO<sub>2</sub> pollutant emissions associated with combustion of natural gas onsite. Based on an estimated range of emission factors (0.1 to 0.2 lb/MMBtu) and assuming year-round operation of the burner, potential NO<sub>x</sub> emissions from each unit range from between 14 and 27 tpy. Combustion emissions from the duct burners will require a permit to construct from NDDEQ.

### 3.7 Factor 4 Evaluation – Remaining Useful Life

Because CCS will operate for the foreseeable future, a 20-year life is used for each control measure, as described in Section 3.4, to calculate emission reductions, amortized costs and cost effectiveness on a dollar per ton basis.

### 3.8 Proposed SO<sub>2</sub> Controls and Emissions Rates

This analysis does not support the installation of additional SO<sub>2</sub> control technologies at CCS Unit 1 or Unit 2 beyond those described in Section 2. The two identified control strategies of a replacement wet stack or a natural gas-fired reheat system are not cost effective and have significant implementation concerns.

In consultation with NDDEQ, GRE proposes a federally enforceable SO<sub>2</sub> emissions rate limit of 626 lb/hr as an annualized average (365-boiler-operating-day rolling average) limit for each unit, with plant averaging between the two units.<sup>31</sup> GRE proposes to implement operational practices consistent with those summarized in Section 2.5 in order to comply with the proposed SO<sub>2</sub> emissions rate limit, effective upon approval of a federally enforceable permit to construct issued by NDDEQ. This new performance level

---

<sup>31</sup> 626 lb/hr = 0.104 lb/MMBtu x 6,015 or 6,022 MMBtu/hr rated capacities for Unit 1 and 2 listed in the Title V operating permit.



further reduces annual SO<sub>2</sub> emissions at each unit by an estimated 1,050 tpy in comparison to the BART limit.<sup>32</sup>

In the 2019 RH SIP Guidance (p. 44), there is the section entitled “Averaging period and units,” which prescribes the options for the form of a limit being taken pursuant to this regional haze implementation period. EPA states that the “... Regional Haze Rule also allows SIPs to contain limits on mass emissions during a particular time period (e.g., a cap on 30-operating day mass emissions).” The proposed SO<sub>2</sub> limit is on a mass rate basis instead of a lb/MMBtu basis for the following reasons:

1. It is consistent with a mass emissions rate used in the dispersion modeling analysis to determine the visibility benefits at Class I areas due to application of control measures.
2. It is consistent with a mass emissions rate needed for control cost evaluation purposes, such as when considering other emissions control options and improvements with respect to conducting a regional haze four-factor analysis.
3. As described above, low load conditions may cause higher lb/MMBtu levels due to the lack of available heat to maintain the stack temperature safely above saturation. The lb/hr emission rate is inclusive of these higher lb/MMBtu levels during low load operation.
4. The proposed 626 lb/hr SO<sub>2</sub> limit on a 365-day rolling average in the permit to construct shall be inclusive of all expected operations throughout the year, including low load, planned startups and shutdowns, and maintenance activities such as routine absorber cleanings. An annual average limit that is inclusive of startups and shutdowns aligns EPA’s current startup, shutdown, and malfunction (SSM) state implementation plan (SIP) policy.<sup>33</sup>

For purposes of clarifying compliance demonstration with this limit, GRE uses the same framework as in 40 CFR 60 Subpart Da for which Units 1 and 2 are already subject. The definition of “boiler operating day” in Subpart Da for a newer boiler is a “24-hour period between 12 midnight and the following midnight during which any fuel is combusted at any time in the steam generating unit.” Compliance with the proposed SO<sub>2</sub> limit will be demonstrated using the existing continuous emissions monitoring system (CEMS) by averaging all hourly SO<sub>2</sub> emissions data over each 365-boiler-operating-day rolling average with the first compliance date occurring after 365 boiler operating days of the limit becoming effective when the permit to construct is issued.

---

<sup>32</sup> Comparing the two SO<sub>2</sub> performance levels and applying the 87% annual capacity factor equals an emissions reduction of 1,054 tpy at each unit. (0.15 lb/MMBtu BART limit - 0.104 lb/MMBtu expected level) x (6,015 or 6,022 MMBtu/hr rated capacities for Unit 1 and Unit 2) x (87% annual capacity factor), converted to tpy basis.

<sup>33</sup> EPA’s current SSM policy for SIPs is found at 80 FR 33840, June 12, 2015, “State Implementation Plans: Response to Petition for Rulemaking; Restatement and Update of EPA’s SSM Policy Applicable to SIPs; Findings of Substantial Inadequacy; and SIP Calls To Amend Provisions Applying to Excess Emissions During Periods of Startup, Shutdown and Malfunction,” Final Rule.



---

## Appendix A

### Unit Specific Screening Level Cost Summary for SO<sub>2</sub> Control Measures

Great River Energy Coal Creek Station: Unit Specific Screening Level Cost Summary									
Appendix A									
New Wet Stack									
Cost Item					\$	Comments			
CAPITAL COST									
Direct Capital Costs									
Purchased Equipment Cost						Custodis, GRE, and Barr engineering estimates			
Concrete Chimney					\$20,663,265	Estimate for 30' diameter, 675' tall concrete chimney; includes exterior			
Foundation					\$8,000,000	Estimate based on recent area builds; costs are considered minimum			
Elevated Ductwork					\$8,352,000	estimates; actual costs would increase based on height and geotechnical data			
Electrical Equipment					\$1,000,000				
Misc. Equipment									
CEMS shelter					\$250,000				
CEMS equipment					\$500,000				
Total Capital Investment					\$38,765,265				
ANNUAL COSTS									
Utilities, Supplies, Replacements & Waste Management									
Electricity					\$533,000	Cost for increased fan power to support additional flue gas scrubbing plus			
Load Reduction/Absorber Washer					\$150,000	\$ 30.0	\$/MWH; 100 MW (total plant) load reduction for 100 hours annually due to increased absorber cleaning requirements		
Lime					\$104,608	\$ 217.5	\$/ton; 481 tons annual incremental lime usage to support additional scrubbing		
Solid Waste Disposal					\$10,826	\$ 10.5	\$/ton; 1,031 tons waste generated annually as a result of additional scrubbing		
Total Indirect Annual Costs					\$798,433				
Indirect Annual Operating Costs									
Capital Recovery					\$3,176,902	0.0820	for a 20-year equipment life and a 5.25% interest rate		
Total Indirect Annual Costs					\$3,176,902				
Total Annual Cost					\$3,975,335	Screening-level cost estimate is considered to be conservatively low and does not include all items that would typically be included as part of a more detailed cost evaluation			
					\$7,228	\$/ton SO2 removed at 550 tpy SO2 reduced due to the new control measure			

# Great River Energy Coal Creek Station: Unit Specific Screening Level Cost Summary

## Appendix A

### Natural Gas Fired Reheat System

Cost Item		\$	Comments
<b>CAPITAL COST</b>			
<b>Direct Capital Costs</b>			
Purchased Equipment Cost			GRE and Barr engineering estimates
Natural Gas Fired 2-duct Burner		\$10,267,500	
Natural Gas Pipeline			Estimated costs for natural gas pipeline inside CCS fenceline
6" high pressure pipe		\$1,312,000	
2" high pressure pipe		\$80,000	
buried length		\$2,050,000	
boring length		\$480,000	
flow meters (2x)		\$30,000	
gas heaters (2x)		\$300,000	
<b>Total Capital Investment</b>		<b>\$14,519,500</b>	
<b>ANNUAL COSTS</b>			
<b>Direct Annual Costs</b>			
<i>Utilities, Supplies, Replacements &amp; Waste Management</i>			
Natural Gas		\$840,237	\$ 3.5 \$/MMBtu; 31.5 MMBtu/hr gas required to achieve design stack temp
Electricity		\$200,000	Cost for increased fan power to support additional flue gas scrubbing
Load Reduction/Absorber Washer		\$150,000	\$ 30.0 \$/MWH; 100 MW (total plant) load reduction for 100 hours annually due to increased absorber cleaning requirements
Lime		\$104,608	\$ 217.5 \$/ton; 481 tons annual incremental lime usage to support additional scrubbing
Solid Waste Disposal		\$10,826	\$ 10.5 \$/ton; 1,031 tons waste generated annually as a result of additional scrubbing
Firm Natural Gas Pipeline Fee		\$930,000	Pipeline fee for new pipeline from existing WBI line to CCS fenceline and reservation for firm gas supply
<b>Total Indirect Annual Costs</b>		<b>\$2,235,671</b>	
<b>Indirect Annual Operating Costs</b>			
Capital Recovery		\$1,189,906	0.0820 for a 20-year equipment life and a 5.25% interest rate
<b>Total Indirect Annual Costs</b>		<b>\$1,189,906</b>	
<b>Total Annual Cost</b>		<b>\$3,425,577</b>	Screening-level cost estimate is considered to be conservatively low and does not include all items that would typically be included as part of a more detailed cost evaluation
		<b>\$6,228</b>	<b><u>\$/ton SO2 removed at 550 tpy SO2 reduced due to the new control measure</u></b>

#### B.4.c – Communications

**Stroh, David E.**

---

**From:** Roth, Mary Jo GRE-MG <mjroth@GREnergy.com>  
**Sent:** Tuesday, December 18, 2018 3:08 PM  
**To:** Stroh, David E.  
**Cc:** O'Clair, Terry L.; Bachman, Tom A.  
**Subject:** RE: RH2 4 Factor Letter - GRE CCS

**CAUTION:** This email originated from an outside source. Do not click links or open attachments unless you know they are safe.

David,

I concur that it makes sense to focus on the BART analysis since it is a precursor to round 2. Following our updated round 1 submittal, we will work diligently on the round 2 analysis. Thanks.

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](http://www.GreatRiverEnergy.com)

---

**From:** Stroh, David E. <deStroh@nd.gov>  
**Sent:** Tuesday, December 18, 2018 2:46 PM  
**To:** Roth, Mary Jo GRE-MG <mjroth@GREnergy.com>  
**Cc:** O'Clair, Terry L. <toclair@nd.gov>; Bachman, Tom A. <tbachman@nd.gov>  
**Subject:** RH2 4 Factor Letter - GRE CCS

Mary Jo,

Based on the tentatively established timeline for Great River Energy's Regional Haze Round 1 report submittal (March 2019), the Department would like GRE to focus their efforts on completing the updated BART analysis associated with Round 1.

This means GRE may delay efforts to complete the analysis required by the May 2, 2018 Regional Haze Second Planning Period letter (due 1/31/19) until further notified by the Department.

Should you have any questions, please let me know. Thanks.

**David Stroh**

Environmental Engineer

North Dakota Department of Health

Division of Air Quality

918 E. Divide Ave. 2nd Floor

Bismarck, ND 58501-1947

701.328.5188

[destroh@nd.gov](mailto:destroh@nd.gov)

Division Website:

[www.deq.nd.gov/aq/](http://www.deq.nd.gov/aq/)

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.



# Major power supply changes to reduce costs to member-owner cooperatives (<https://greatriverenergy.com/major-power-supply-changes-to-reduce-costs-to-member-owner-cooperatives/>)

May 7, 2020

## Great River Energy plans to replace coal with low cost renewables and market energy purchases

Great River Energy announced plans today to transform its portfolio of power supply resources in the coming years, significantly reducing member-owner wholesale power costs. The electric cooperative plans to phase out remaining coal resources, add significant renewable energy and explore critical grid-scale battery technology.

Great River Energy plans to take the following actions:



**Keeping power reliable  
and affordable**



**Continuing to reduce  
carbon dioxide emissions**



**Adding cleaner  
electricity sources**

- Retire the 1,151-megawatt (MW) Coal Creek Station in the second half of 2022
- Add 1,100 MW of wind energy purchases by the end of 2023
- Modify the 99-MW, coal and natural gas-based Spiritwood Station power plant to be fueled by natural gas
- Install a 1-MW, long-duration battery demonstration system
- Support the repowering of the Blue Flint biorefinery with natural gas

"We are building a power supply portfolio that will serve our member-owner cooperatives for decades," Great River Energy President and Chief Executive Officer David Saggau said. "We are taking advantage of cost-competitive renewables and reliable access to market energy while fostering innovation as the technology of our industry evolves."

Today's announcement follows several changes Great River Energy has made in recent years to seek economic efficiencies in its power supply portfolio. Past analysis has led to decisions to exit a contract for half the output of a Wisconsin coal plant in 2015, retire the coal-based Stanton Station power plant in 2017, close the waste-to-energy Elk River Resource Recovery Project in 2019 and purchase the output of several wind energy projects.

The portfolio changes announced today will significantly reduce Great River Energy's member-owner power supply costs. In addition, the cooperative's power supply resources will be more than 95% carbon dioxide-free, virtually eliminating carbon risk.

"Our power supply plans deliver on our member-owners' three highest priorities: affordability, reliability and environmental stewardship," Saggau said. "Electric cooperatives have a bright future in Minnesota."

Great River Energy plans to purchase more than 1,100 MW from new wind energy projects. This amounts to a more than \$1.2 billion investment in the Midwest's abundant clean energy resources. Great River Energy's renewable capacity is projected to grow from approximately 660 MW in 2020 to more than 1,760 MW by the end of 2023. The Great River Energy board of directors today approved 600 MW of wind energy projects, most of which will be located in Minnesota.

Great River Energy plans to add energy and capacity as needed through upgrades at its fleet of modern, natural gas peaking plants and purchases from the MISO energy market.

Coal Creek Station has been a critical part of Great River Energy's power supply portfolio for decades, but it has lost value compared to other alternatives in recent years. Great River Energy plans to shut down both units of Coal Creek Station during the second half of 2022, although the cooperative is willing to consider opportunities to sell the plant. Coal Creek Station began operations in 1979 in Underwood, North Dakota, and employs 260 people.

"Like all of Great River Energy's decisions, these changes are made in the best interests of our member-owner cooperatives," Saggau said. "Coal Creek Station is operated efficiently, safely and with pride by a dedicated and talented staff. We will make every effort to minimize impacts on our employees and the communities through this transition."

To assist local communities during the upcoming transition, Great River Energy plans to make voluntary annual payments of the local government share of the plant's taxes for five years after the plant's closure.

Great River Energy plans to negotiate an agreement to terminate its steam and water supply contract with Blue Flint, an ethanol biorefinery fueled by process steam from Coal Creek Station. Blue Flint's owner, Midwest AgEnergy, is considering using the contract termination payment from Great River Energy to

reinvest in an economical alternate source for its process heat, thereby benefitting area farmers by continuing to support the local market for corn.

Located near Jamestown, North Dakota, Spiritwood Station is a combined heat and power plant fueled by a combination of DryFine™ lignite coal and natural gas. Great River Energy plans to modify the plant to be fueled with natural gas. The plant generates electricity for the regional electric grid and supplies steam to a nearby ethanol biorefinery.

Great River Energy is working with Form Energy, a battery storage technology developer based in Somerville, Massachusetts, on a first-of-its-kind demonstration of Form's unique long-duration storage technology. The battery project will be a 1-MW, grid-connected storage system capable of delivering its rated power continuously for 150 hours, far longer than the four-hour usage period common among lithium ion batteries. Long-duration storage will help maintain grid reliability in the future during extreme conditions, such as a heat wave or polar vortex. The battery system will be located in Cambridge, Minnesota, and completed in late 2023.

The projects announced today will create hundreds of high-quality construction jobs. "We look forward to partnering with local labor and industry on our projects," Saggau said.

Categories: Company news (<https://greatriverenergy.com/category/company-news/>), Power generation resources (<https://greatriverenergy.com/category/power-generation-resources/>), Power plants (<https://greatriverenergy.com/category/power-generation-resources/power-plants/>), Renewable energy (<https://greatriverenergy.com/category/power-generation-resources/renewable-energy/>)  
← Great River Energy to be conservative in returning to normal work arrangements (<https://greatriverenergy.com/great-river-energy-to-be-conservative-in-returning-to-normal-work-arrangements/>)

B.5 – Minnkota MRY

B.5.a – Department Request



May 2, 2018

**FILE**

Mr. Craig Bleth  
Minnkota Power Cooperative  
5301 – 32<sup>nd</sup> Avenue S  
Grand Forks, ND 58203

Re: Regional Haze  
Second Planning Period

Dear Mr. Bleth:

The Department of Health (Department) has begun work on the second planning period (Round 2) State Implementation Plan (SIP) for regional haze. In Round 1 of the regional planning process, the emphasis was on Best Available Retrofit Technology (BART) and making reasonable progress towards the national visibility goal. In Round 2, there are no BART requirements; therefore, we will focus on making reasonable progress. The reasonable progress analysis will be made using the four factors in Section 169A(g)(1) of the Clean Air Act:

The four factors are:

1. The cost of compliance
2. The time necessary to achieve compliance
3. The energy and non-air quality environmental impact of compliance; and
4. The remaining useful life of any existing source subject to such requirements

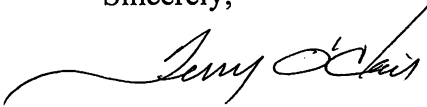
Guidance provided by the U.S. Environmental Protection Agency (Draft Guidance on Progress Tracking Metrics, Long Term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period at [https://www.epa.gov/sites/production/files/2016-07/documents/draft\\_regional\\_haze\\_guidance\\_july\\_2016.pdf](https://www.epa.gov/sites/production/files/2016-07/documents/draft_regional_haze_guidance_july_2016.pdf)) indicates the Department must address 80% of the visibility impairment caused by in-state sources. Data from the IMPROVE monitoring sites at Theodore Roosevelt National Park (TRNP) and Lostwood Wilderness Area (LWA) indicate that sulfates and nitrates continue to be the largest contributors to visibility impairment in these areas. The primary precursors of sulfates and nitrates are emissions of sulfur dioxide (SO<sub>2</sub>) and nitrogen oxides (NO<sub>x</sub>).

Coal-fired electrical generating units have been identified as one of the largest source of sulfur dioxide and nitrogen oxides in North Dakota. Therefore, the Department requests that you prepare a "four factors" analysis for your coal-fired electrical generating units. The analysis should be prepared using the draft EPA guidance noted above. The Department will identify other sources in North Dakota that will be required to submit a four factors analysis.

The Department will be working with the Western Regional Air Partnership (WRAP) to prepare the Round 2 SIP. WRAP will be conducting air quality modeling of regional emissions reductions in early 2019. The Department asks that your "four factors" analysis be submitted by January 31, 2019.

If you have any questions, please contact David Stroh of my staff at (701)328-5188.

Sincerely,




Terry L. O'Clair  
Director  
Division of Air Quality

TLO/TB:saj

xc: Kevin Thomas, Minnkota Power Cooperative

## B.5.b – Facility Response



A Touchstone Energy® Cooperative 

5301 32<sup>nd</sup> Avenue South  
Grand Forks, ND 58201

Phone 701.795.4000  
[www.minnkota.com](http://www.minnkota.com)

January 31, 2019

Mr. Terry L. O'Clair, Director  
Division of Air Quality  
North Dakota Department of Health  
918 East Divide Avenue  
Bismarck, ND 58501-1947



RE: Milton R. Young Station Regional Haze Control Study  
Second Planning Period

Dear Mr. O'Clair:

As requested in your May 2, 2018 correspondence, I am enclosing three copies of the Regional Haze Control Study (Four Factor Analysis) for Unit 1 and Unit 2 at the Milton R. Young Station.

If you have any questions regarding this study, please contact me at 701-794-8711.

Sincerely,

MINNKOTA POWER COOPERATIVE, INC.

A handwritten signature in blue ink that reads "Craig J. Bleth". The signature is written in a cursive, flowing style.

Craig J. Bleth  
Senior Manager of Power Production

Cc: Gerad Paul  
Dan Laudal  
Kevin Thomas  
Jon Madison  
Station File






# Regional Haze Control Study



**Minnkota Power**  
**COOPERATIVE**

A Touchstone Energy® Cooperative 

**Minnkota Power Cooperative, Inc.**

**Milton R. Young Station Unit 1 and Unit 2**  
**Project No. 107926**

**Revision 0**  
**1/29/2019**

# **Regional Haze Control Study**

**prepared for**

**Minnkota Power Cooperative, Inc.  
Milton R. Young Station Unit 1 and Unit 2  
Center, North Dakota**

**Project No. 107926**

**Revision 0  
1/29/2019**

**prepared by**

**Burns & McDonnell Engineering Company, Inc.  
Kansas City, Missouri**

## INDEX AND CERTIFICATION

### Minnkota Power Cooperative, Inc. Regional Haze Control Study

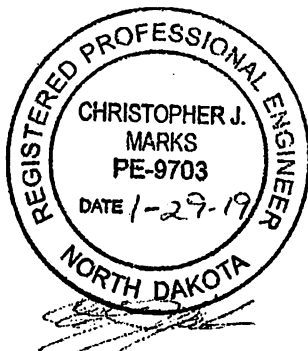
Project No. 107926

#### Report Index

<u>Chapter Number</u>	<u>Chapter Title</u>	<u>Number of Pages</u>
	Executive Summary	3
1.0	Introduction	6
2.0	NO <sub>x</sub> RHCT Evaluation	13
3.0	SO <sub>2</sub> RHCT Evaluation	14
4.0	Regional Haze Control Technology Results	3

#### Certification

I hereby certify, as a Professional Engineer in the state of North Dakota, that the information in this document was assembled under my direct personal charge. This report is not intended or represented to be suitable for reuse by the Minnkota Power Cooperative, Inc. or others without specific verification or adaptation by the Engineer.



\_\_\_\_\_  
Insert Engineer's Name, P.E., state, & license

\_\_\_\_\_  
Date: Insert Date

Jan 29 2019 6:38 PM

**TABLE OF CONTENTS****Page No.**

<b>EXECUTIVE SUMMARY .....</b>	<b>III</b>
<b>1.0 INTRODUCTION .....</b>	<b>1-1</b>
1.1 RCHT Analysis Process.....	1-2
1.1.1 Identification of Retrofit Control Technologies .....	1-2
1.1.2 Feasibility Analysis.....	1-3
1.1.3 Evaluate Technically Feasible Control Option by Effectiveness .....	1-3
1.1.4 Impact Analysis .....	1-3
1.1.5 Baseline Emissions .....	1-4
1.1.6 Methodology for Estimated Costs .....	1-4
1.2 RHCT Analysis Approach .....	1-6
1.2.1 Background.....	1-6
<b>2.0 NO<sub>x</sub> RHCT EVALUATION .....</b>	<b>2-1</b>
2.1 NO <sub>x</sub> Evaluation Basis.....	2-1
2.2 Identification of Retrofit NO <sub>x</sub> Control Technologies.....	2-2
2.3 Technical Description and Feasibility Analysis .....	2-2
2.3.1 Selective Catalytic Reduction.....	2-2
2.3.2 Rich Reagent Injection & Selective Non-Catalytic Reduction.....	2-3
2.3.3 Optimized Selective Non-Catalytic Reduction.....	2-3
2.3.4 Results of Feasibility Analysis .....	2-3
2.4 Evaluate the Technically Feasible NO <sub>x</sub> Control Options by Effectiveness .....	2-4
2.5 Evaluation of Impacts for Feasible NO <sub>x</sub> Controls.....	2-5
2.5.1 Cost Estimates.....	2-5
2.5.2 Energy Impacts .....	2-11
2.5.3 Non-Air Quality Environmental Impacts.....	2-12
<b>3.0 SO<sub>2</sub> RHCT EVALUATION.....</b>	<b>3-1</b>
3.1 Identification of Retrofit SO <sub>2</sub> Control Technologies .....	3-1
3.2 Technical Description and Feasibility Analysis .....	3-2
3.2.1 Wet Flue Gas Desulfurization.....	3-2
3.2.2 Semi-Dry Flue Gas Desulfurization.....	3-3
3.2.3 ReACT Dry Scrubbing Process .....	3-4
3.2.4 Results of Feasibility Analysis .....	3-4
3.3 Evaluate Technically Feasible SO <sub>2</sub> Control Options by Effectiveness .....	3-5
3.4 Evaluation of Impacts for Feasible SO <sub>2</sub> Controls .....	3-5
3.4.1 Cost Evaluation.....	3-6
3.4.2 Energy Impacts .....	3-12
3.4.3 Non-Air Quality Environmental Impacts.....	3-13
3.4.4 SO <sub>2</sub> Control Technology Evaluation Conclusion .....	3-13
<b>4.0 REGIONAL HAZE CONTROL TECHNOLOGY RESULTS .....</b>	<b>4-1</b>



**LIST OF TABLES**

	<b><u>Page No.</u></b>
Table 1-1: Economic Factors .....	1-5
Table 2-1: NOx Control Technologies Identified for RHCT Analysis .....	2-2
Table 2-2: MRYS RHCT NOx Control Feasibility Analysis Results .....	2-4
Table 2-3: Feasible NOx Control Technologies Identified for RHCT Analysis .....	2-4
Table 2-4: Capital Cost Estimate for MRYS Unit 1 & 2 RRI + SNCR System.....	2-6
Table 2-5: Capital Cost Estimate for MRYS Unit 1 & 2 Optimized SNCR System.....	2-7
Table 2-6: O&M Cost Estimate for MRYS Unit 1 & 2 RRI + SNCR System.....	2-8
Table 2-7: O&M Cost Estimate for MRYS Unit 1 & 2 Optimized SNCR System.....	2-9
Table 2-8: Levelized Total Annual Cost of MRYS Unit 1 NOx Control Technologies .....	2-10
Table 2-9: Levelized Total Annual Cost of MRYS Unit 2 NOx Control Technologies .....	2-10
Table 2-10: Energy Requirement of MRYS Unit 1 NOx Control Technologies .....	2-11
Table 2-11: Energy Requirement of MRYS Unit 2 NOx Control Technologies .....	2-11
Table 3-1: SO <sub>2</sub> Control Technologies Identified for RHCT Analysis.....	3-1
Table 3-2: MRYS RHCT SO <sub>2</sub> Control Feasibility Analysis Results.....	3-5
Table 3-3: Feasible SO <sub>2</sub> Control Technologies Identified for RHCT Analysis .....	3-5
Table 3-4: Capital Cost Estimate for MRYS Unit 2 Wet Lime FGD System.....	3-7
Table 3-5: Capital Cost Estimate for MRYS Unit 1 Wet FGD System Modification.....	3-9
Table 3-6: O&M Cost Estimate for a New MRYS Unit 2 Wet Lime FGD System.....	3-10
Table 3-7: O&M Cost Estimate for MRYS Unit 1 and 2 Wet Lime FGD System Modification .....	3-11
Table 3-8: MRYS Unit 1 SO <sub>2</sub> Control System Levelized Total Annual Cost.....	3-11
Table 3-9: MRYS Unit 2 SO <sub>2</sub> Control System Levelized Total Annual Cost.....	3-12
Table 3-10: Energy Requirement of MRYS Unit 1 FGD Upgrades.....	3-13
Table 3-11: Energy Requirement of MRYS Unit 2 New FGD .....	3-13
Table 4-1: RHCT 30-Day Rolling Average Emission Rate, MRYS Unit 1 .....	4-2
Table 4-2: RHCT 30-Day Rolling Average Emission Rate, MRYS Unit 2 .....	4-2

**LIST OF ABBREVIATIONS**

<b><u>Abbreviation</u></b>	<b><u>Term/Phrase/Name</u></b>
ASOFA	Advanced separated over fire air
B&W	Babcock & Wilcox
BACT	Best Available Control Technology
BART	Best Available Retrofit Technology
BOP	Balance of plant
Burns & McDonnell	Burns & McDonnell Engineering Company, Inc.
CD	Consent decree
CDS	Circulating dry scrubber
CFD	Computational fluid dynamics
CO	Carbon monoxide
CO <sub>2</sub>	Carbon dioxide
CRF	Capital recovery factor
EPA	United States Environmental Protection Agency
ESP	Electrostatic precipitator
FDA	Flash dryer absorber
FGD	Flue gas desulfurization
LACC	Levelized annual capital cost
LAOMC	Levelized annual O&M cost
LTAC	Levelized total annual cost
Minnkota	Minnkota Power Cooperative, Inc.
MRYS	Milton R. Young Station

<b><u>Abbreviation</u></b>	<b><u>Term/Phrase/Name</u></b>
NDDH	North Dakota Department of Health
NOx	Nitrogen oxides
NPV	Net present value
O&M	Operation & maintenance
OEM	Original equipment manufacturer
OMLF	O&M levelization factor
RBLC	RACT/BACT/LAER Clearinghouse
RHCT	Regional Haze Control Technology
RHR	Regional Haze Regulations
RRI	Rich reagent injection
RO	Reverse Osmosis
SCR	Selective catalytic reduction
SDA	Spray dryer absorber
SNCR	Selective non-catalytic reduction
SO <sub>2</sub>	Sulfur dioxide
Square Butte	Square Butte Electric Cooperative
TPI	Total plant investment
URGE	Ultimate short-term maximum gross output
VOCs	Volatile organic compounds
WRAP	Western Regional Air Partnership



## EXECUTIVE SUMMARY

This report presents the Regional Haze Control Technology (RHCT) analysis for nitrogen oxides (NO<sub>x</sub>), and sulfur dioxide (SO<sub>2</sub>) for Minnkota Power Cooperative, Inc.'s (Minnkota's) Unit 1 and Square Butte Electric Cooperative's (Square Butte's) Unit 2 at the Milton R. Young Station (MRYS) located near Center, North Dakota. On July 6, 2005, the United States Environmental Protection Agency (U.S. EPA or EPA) finalized the Regional Haze Regulations (RHR) and Guidelines for BART Determinations. In July of 2016, the EPA issued draft guidance for the second implementation period of the regional haze regulations. The guidance document requires a "four factor analysis" to be conducted for sources that have the potential to impair visibility in Class 1 areas. The four statutory factors are:

- The cost of compliance
- The time necessary for compliance
- The energy and non-air quality environmental impacts of compliance, and
- The remaining useful life of the source

This report presents the required "four factor analysis" for MRYS. Note that for MRYS, Minnkota has determined that the "remaining useful life of the source" is not a relevant factor in the analysis. The term "RHCT analysis" is used throughout this report to refer to the analysis that has been conducted in compliance with the requirements of EPA's July 2016 draft guidance.

The guidance document, in general, indicates that the goal of the second implementation period is to look at all sources for incremental visibility improvement including all sources that were previously determined to be Best Available Retrofit Technologies (BART) eligible. Milton R. Young Station Unit 1 and Unit 2 were previously determined to be BART-eligible by the North Dakota Department of Health (NDDH). This evaluation is intended to inform NDDH of the future potential to reduce emissions at Milton R. Young Station and the cost associated with these reductions. This evaluation is based on a top down evaluation of control technologies and will provide NDDH an emission rate for visibility impairment modeling.

There are five predefined steps for conducting a RHCT analysis. Steps 1 through 3 include identifying control technologies, evaluating feasibility, and ranking feasible options by control effectiveness. Step 4 involves a technical evaluation of various impacts related to each feasible control technology. The evaluation reviews include economics, energy, and non-air environmental impacts. This evaluation addresses these first four steps, resulting in an emission rate for the Step 5 Class 1 area visibility impairment impact analysis.

Unlike the previous BART analysis, this analysis reviews technologies on a ‘Top Down’ basis. The best (lowest emitting) feasible technology that is acceptable (considering economic, energy and non-air impacts) will be evaluated by NDDH for visibility impact reduction. The results of conducting the first four step analysis will provide a recommendation to NDDH of a potential RHCT and the associated emission rate.

This analysis used several reference works, including the RACT/BACT/LAER Clearinghouse (RBLC), to identify which control technologies to evaluate. The technologies were reviewed for feasibility and those deemed infeasible were eliminated from further study. The feasible control technologies were ranked by control efficiency and estimates of costs to implement, operate, and maintain such technologies were developed for the top ranked technologies. Evaluating the top ranked technology based upon the average cost (dollars per ton removed) and other impacts determined if the top ranked technology was acceptable. The final RHCT results are summarized in the tables below. The RHCT emission rates are presented as a 30-day rolling average to account for variations in boiler operation and variations in fuel quality (including sulfur content).

#### **MRYS Unit 1 RHCT 30-Day Rolling Average**

<b>Pollutant</b>	<b>Control Technology</b>	<b>Emission Rate (lb/million Btu)</b>
NO <sub>x</sub>	Existing Selective Non-Catalytic Reduction (SNCR) and Advanced Separated Over Fire Air (ASOFA) <sup>1</sup>	0.36
SO <sub>2</sub>	Modify the existing Wet Flue Gas Desulfurization (FGD) system <sup>2</sup>	0.10

1: Excludes startups. See referenced BACT analysis for a detailed discussion.

#### **MRYS Unit 2 RHCT 30-Day Rolling Average**

<b>Pollutant</b>	<b>Control Technology</b>	<b>Emission Rate (lb/million Btu)</b>
NO <sub>x</sub>	Existing Selective Non-Catalytic Reduction (SNCR) and Advanced Separated Over Fire Air (ASOFA) <sup>1</sup>	0.35
SO <sub>2</sub>	Modify the existing Wet Flue Gas Desulfurization (FGD) system <sup>2</sup>	0.10

1: Excludes startups. See referenced BACT analysis for a detailed discussion.

The four factor analysis was completed based on a request by the North Dakota Department of Health (NDDH) while utilizing the EPA 2016 Guidance document. The NDDH has requested this information for the purpose of WRAP modeling. As EPA has indicated, the Regional Haze Roadmap may be updated, and the results of the WRAP modeling will provide new information to be considered, Minnkota reserves the right to modify the 4 Factor analysis once the Regional Haze Roadmap, any additional

guidance and the results of the WRAP modeling are available. In addition, Minnkota reserves the right to conduct a 5<sup>th</sup> Factor based on visibility modeling once the results of the WRAP modeling are available. This analysis is provided to assist the NDDH in the WRAP modeling and is not intended to serve as an agreement by Minnkota to any changes in permitted emission limits or permit conditions.

## 1.0 INTRODUCTION

The United States Environmental Protection Agency (U.S. EPA or EPA) finalized the Regional Haze Regulations (RHR) and Guidelines for Best Available Retrofit Technology (BART) Determinations<sup>1</sup> in the Federal Register on July 6, 2005 (70 FR 39104). In July, 2016, the EPA issued draft guidance for the second implementation period of the regional haze regulations<sup>2</sup>. The draft guidance for the second implementation period retains many aspects of the BART guidelines.

The guidance documents, in general, indicate the goal of the second implementation period is to look at all sources for incremental visibility improvement including all sources that were previously Best Available Retrofit Technologies (BART) eligible. Milton R. Young Station Unit 1 and Unit 2 were previously determined to be BART-eligible by the NDDH. BART is defined as “an emission limitation based on the degree of reduction achievable through the application of the best system of continuous emission reduction for each pollutant which is emitted by a BART-eligible source. The emission limitation must be established on a case-by-case basis, taking into consideration the technology available, the costs of compliance, the energy and non-air quality environmental impacts of compliance, any pollution control equipment in use at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology” (70 FR 39163). Note that for MRYS, Minnkota has determined that the “remaining useful life of the source” is not a relevant factor in the analysis.

The second implementation guidance indicates a similar review to BART should be performed but in the second round the technology evaluation should be based on a ‘top down’ approach. The evaluation criteria are the same as the previous BART analysis; case-by-case basis considering availability, cost, energy and non-air quality impacts. However, in a ‘top down’ analysis the highest ranked technology that meets the acceptable criteria in the first four steps is the selected technology. The final determination of what top ranked technologies across the utility fleet will be accepted, if any, as RHCT is dependent on Step 5 (visibility modeling) and will be based on the modeling performed by the Western Regional Air Partnership (WRAP). This RHCT evaluation will be used by the NDDH as a tool to evaluate the potential to reduce emissions at Minnkota Power Cooperative, Inc.’s (Minnkota’s) Unit 1 and Square

---

<sup>1</sup> “Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations”; Environmental Protection Agency; Federal Register, Volume 70, No. 128; July 6, 2005.

<sup>2</sup> “Draft Guidance on Progress Tracking Metrics, Long-Term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period”, Environmental Protection Agency; Federal Register, Volume 81, No. 131; July 8, 2016.

Butte Electric Cooperative's (Square Butte's) Unit 2 at the Milton R. Young Station (MRYS) located near Center, North Dakota and the cost associated with these reductions.

## **1.1 RCHT Analysis Process**

The general steps for determining RHCT for each pollutant are virtually the same as the previous BART steps (70 FR 39164) and are as follows:

STEP 1 - Identify all available retrofit control technologies.

STEP 2 - Eliminate technically infeasible options.

STEP 3 - Evaluate control effectiveness of remaining control technologies.

STEP 4 - Evaluate the following impacts for each feasible control technology and document results:

The cost of compliance.

The time required for compliance.

The energy and non-air quality environmental impacts of compliance.

The remaining useful life of the source.

STEP 5 – Evaluate the visibility impacts.

Unlike the previous BART analysis where all five steps were performed at once, NDDH's approach for the second implementation of the regional haze program is breaking the first four steps apart from the fifth step. The first four steps are performed on a 'top down' basis to determine the top ranked control technology that is applicable to each source. The fifth step is then taken by NDDH to determine which of the sources top down technologies are selected as RHCT.

Minnkota Power Cooperative, Inc. retained Burns & McDonnell to assist in the completion of the first four steps of the RHCT analysis for Milton R. Young Station. Burns & McDonnell is a full service engineering, architectural, construction and environmental firm. The company plans, designs and constructs electric generating facilities and has been providing environmental services to the power industry since the 1970s. As a result of their long history providing these services, Burns & McDonnell has extensive experience in permitting, Best Available Control Technology (BACT) studies, BART studies and control technology analysis similar to a RHCT analysis.

### **1.1.1 Identification of Retrofit Control Technologies**

The initial step in the RHCT determination is the identification of retrofit control technologies. In order to identify the applicable control technologies, several reference works are consulted. A preliminary list of control technologies and their estimated capabilities is developed.

### **1.1.2 Feasibility Analysis**

The second step of the RHCT process is to evaluate the control processes that have been identified and determine if any of the processes are technically infeasible. The BART guidelines are also applicable for the RHCT analysis and discuss consideration of two key concepts during this step in the analysis. The two concepts to consider are the “availability” and “applicability” of each control technology.

A control technology is considered available, “if the source owner may obtain it through commercial channels, or it is otherwise available in the common sense meaning of the term” or “if it has reached the stage of licensing and commercial availability.” On the contrary, a control technology is not considered available, “in the pilot scale testing stages of development.” (70 FR 39165) When considering a source’s applicability, technical judgment must be exercised to determine “if it can reasonably be installed and operated on the source type.” The EPA also does not “expect a source owner to conduct extended trials to learn how to apply a technology on a totally new and dissimilar source type.” (70 FR 39165) “A technology that is available and applicable is technically feasible.” (70 FR 39165)

### **1.1.3 Evaluate Technically Feasible Control Option by Effectiveness**

The third step in the RHCT analysis is to evaluate the control effectiveness of the technically feasible alternatives. During the feasibility determination in step 2 of the analysis, the control efficiency is reviewed and presented with the description of each technology. The evaluation of the technically feasible alternatives concludes with the alternatives ranked in descending order of control effectiveness.

### **1.1.4 Impact Analysis**

Step four in the analysis procedure is the impact analysis. The BART Determination Guidelines (70 FR 39166) and the draft guidelines for the second implementation period (81 FR 44608) each list four factors to be considered in the impact analysis. The RHCT evaluation will consider the following four factors in the impact analysis:

- The costs of compliance
- The time required for compliance
- The energy and non-air quality environmental impacts of compliance
- The remaining useful life of the source.

The first three of the four factors considered in the impact analysis are discussed in the associated pollutant section. The remaining useful life of the source is included as part of the cost of compliance.

In the second implementation period the impact analysis is performed on a 'top down' basis. The highest ranked (lowest emitting) technology is evaluated on the above factors for acceptability. If the top-ranked control technology is unacceptable, then the next highest ranked control technology is evaluated. This process continues until the highest ranked acceptable technology is identified.

### 1.1.5 Baseline Emissions

The cost of compliance evaluation is typically performed on a levelized dollars per tons of pollutant removed basis. In determining the tons removed, a baseline emission rate must be determined. The MRYS units both have existing SO<sub>2</sub> and NO<sub>x</sub> pollution control systems that are part of the baseline. The baseline emission rate was developed by evaluating the 2014-2018 daily emissions data. A 30-day rolling average emission rate for all boiler operating days was developed and the highest 30-day value was determined. The highest 30-day emission rate for Unit 1 was 0.35 lbs/MMBtu NO<sub>x</sub> and 0.14 lbs/MMBtu SO<sub>2</sub>. The highest 30-day emission rate for Unit 2 was 0.35 lbs/MMBtu NO<sub>x</sub> and 0.15 lbs/MMBtu SO<sub>2</sub>. The highest 30-day rate is selected to reflect an emission rate the existing system would have maintained on a continuous basis during 2014-2018. Potential reductions from higher removal options will be evaluated from this baseline rate to evaluate the average/actual and incremental cost of control.

### 1.1.6 Methodology for Estimated Costs

The cost summary of each alternative is presented in the section for each pollutant. Installed capital and annual O&M cost estimates for each alternative are presented individually. The Levelized Total Annual Cost (LTAC) represents the levelized annual cost of procurement, construction and operation over a 20 year design life, in 2021 dollars. The LTAC represents an annual payment in current day dollars sufficient to finance the project over its entire life.

In determining the LTAC, a Capital Recovery Factor was calculated from the project economic conditions and then applied separately to the estimated capital costs. The equation used is shown below.

$$LACC / NPV = \left( \frac{i_d (1 + i_d)^n}{(1 + i_d)^n - 1} \right) = CRF$$

Where,

LACC = Levelized Annual Capital Cost

NPV = Net Present Value of the capital investments required.

i<sub>d</sub> = discount rate

n = design life in years

CRF = Capital Recovery Factor

Therefore:

$$LACC = CRF \times NPV$$

For the economic conditions described in Table 1-1, the Capital Recovery Factor was calculated to be 0.08368.

The O&M cost used is the first year costs, in 2021 dollars. The O&M cost was not further inflated or otherwise leveled.

The Levelized Total Annual Cost, or LTAC is the sum of the levelized capital cost and the first year O&M cost. Therefore:

$$LTAC = LACC + 1^{\text{st}} \text{ Year O\&M} = (CRF \times NPV) + 1^{\text{st}} \text{ Year O\&M} = 0.08368 \times NPV + 1^{\text{st}} \text{ Year O\&M}$$

The economic analyses presented in this report not only include the estimated capital and annual O&M costs for each top ranked control technology, but also the LTAC for economic comparison.

**Table 1-1: Economic Factors**

<b>Factor</b>	<b>Value</b>
Total Possible Operating Hours per Year	8,760
Plant Capacity Factor	85%
Amortization Life, Years	20
Allowance for Funds Used During Construction	Not Included
Property Taxes, Insurance, %	NA
Amortization Rate for APC Capital Costs	0%
Discount Rate	5.5%
Construction Cost Escalation	3%
Maintenance Material and Labor Cost, % of Direct Capital	3%
Non-Fuel O&M Escalation	1.5%
Fuel (coal and natural gas) Escalation	1.5%
Auxiliary Electric Power Cost, \$/MW-hr	\$52.28
Reverse Osmosis Water, \$/kgal	\$9.44
Condensate water, \$/kgal	\$10.30
Urea 70% Solution, \$/ton	\$438.14
Lime, \$/ton	\$200.77
FGD Byproduct Disposal, \$/ton	\$6.27

(1) All costs are in 2021 dollars unless noted otherwise.



## 1.2 RHCT Analysis Approach

The purpose of the Regional Haze Rule (RHR) is to address visibility impairment in mandatory Class 1 areas. Before the actual RHCT analysis can begin the approach used to conduct the analysis should be addressed. The following sections present specific subjects related to MRYS's background, which warrant mention due to their effects on the contents of the report.

### 1.2.1 Background

Minnkota Power Cooperative, Inc. operates the Milton R. Young Station near Center, North Dakota. MRYS is a steam electric generating plant with two units. Unit No. 1 is a Babcock & Wilcox (B&W) cyclone-type coal-fired boiler burning lignite coal, serving a turbine generator with a nameplate rating of 257 MW.<sup>3</sup> Unit 1 employs advanced separated over fire air (ASOFA) and selective non-catalytic reduction (SNCR) for NO<sub>x</sub> control achieving 59% NO<sub>x</sub> reduction. Particulate control is provided by a Research-Cottrell Electrostatic Precipitator rated at approximately 99% control. Unit 1 has a wet scrubber provided by Marsulex Environmental Technologies achieving compliance with a 30-day rolling average 95% SO<sub>2</sub> removal efficiency and exhausts to a 544 foot tall stack.

Unit No. 2 is a B&W cyclone-fired unit burning lignite coal, with a turbine-generator nameplate rating of 477 MW.<sup>4</sup> Unit 2 employs ASOFA and SNCR for NO<sub>x</sub> control achieving 60% NO<sub>x</sub> reduction. Particulate control for Unit 2 is provided by a Wheelabrator-Lurgi precipitator rated at approximately 99% control. Unit 2 has a Combustion Equipment Associates wet flue gas desulfurization (FGD) system (modified by Combustion Engineering) achieving compliance with a 30-day rolling average 90% SO<sub>2</sub> removal efficiency and a 30-day rolling average 0.15 lb/MMBtu emission rate, and exhausts to a 550 foot tall stack.

Unit 1 began commercial operation on November 20, 1970 and Unit 2 on May 11, 1977.

---

<sup>3</sup> "Generator Nameplate Data"; Emissions & Generation Resource Integrated Database (eGRID); U.S. Environmental Protection Agency; April, 2003.

<sup>4</sup> Ibid footnote 3 reference.

## 2.0 NO<sub>x</sub> RHCT EVALUATION

The RHCT analyses for NO<sub>x</sub> emissions from MRYS Unit 1 and Unit 2 are described in this section. Technical descriptions of MRYS Unit 1 and Unit 2 boilers and existing air pollution control equipment are provided. Minnkota previously entered into a Consent Decree (CD) that required MRYS to install BACT for NO<sub>x</sub>, which was determined to be Selective Non-Catalytic Reduction (SNCR) systems with Advanced Separated Overfire Air (ASOFA) on both units. These technologies are the current baseline condition for the two units.

### 2.1 NO<sub>x</sub> Evaluation Basis

Milton R. Young Station Unit 1 includes a B&W steam generator installed in 1970. The steam generator is a lignite-fired boiler with multiple cyclone-furnaces installed in parallel using balanced-draft and natural circulation. Original unit design steam generating capacity is 1.714 million lbs/hr at 1,920 psi with a fuel heat input of 2,510 MMBtu/hr. The boiler is fired by seven ten-foot diameter cyclone burners, arranged “three over four” across the front wall of the lower furnace. The unit has a tubular air heater installed between the boiler and the flue gas ductwork leading to the electrostatic precipitator (ESP). Unit 1’s boiler serves a turbine generator with a nameplate rating of 257 MW<sup>5</sup>. The Unit 1 boiler at MRYS includes a unique coal conditioning system (drying, crushing, and feeding) for each cyclone furnace specifically designed to aid in proper combustion of the lignite fuel. Lignite fuel is the sole solid fuel for the plant and is supplied from a mine located adjacent to the site.

Milton R. Young Unit 2 is a B&W steam generator installed in 1977. The steam generator is a lignite-fired boiler with multiple cyclone-furnaces installed in parallel using balanced-draft and natural circulation assisted with circulation pumps. Original unit design steam generating capacity is 3.20 million lbs/hr at 2,620 psi with a fuel heat input of 4,696 MMBtu/hr. The boiler is fired by twelve ten-foot diameter cyclone burners, arranged “three over three” across the front and rear walls of the lower furnace. The unit has a tubular air heater installed between the boiler and the flue gas ductwork leading to the ESP. Unit 2’s boiler serves a turbine-generator with a nameplate rating of 477 MW<sup>6</sup>. The Unit 2 boiler at MRYS includes a unique coal conditioning system (drying, crushing, and feeding) for each cyclone furnace specifically designed to aid in proper combustion of the lignite fuel. Lignite fuel is the sole solid fuel for the plant and is supplied from a mine located adjacent to the site.

---

<sup>5</sup> Ibid EPA’s eGRID database; April, 2003.

<sup>6</sup> Ibid EPA’s eGRID database; April, 2003.

## 2.2 Identification of Retrofit NOx Control Technologies

The initial step in the RHCT determination is the identification of retrofit NOx control technologies. In order to identify the applicable NOx control technologies, several reference works were consulted, including the RACT/BACT/LAER Clearinghouse (RLBC). From this and other literature sources, a preliminary list of control technologies and their estimated capabilities for potential application to MRYS was developed. However, as discussed in the introduction, Minnkota already has ASOFA and SNCR systems installed on both units to achieve 30-day rolling average removal rates of approximately 60% on Unit 1 and Unit 2. Thus, the control technologies included in the RHCT analysis either meet this minimum level of control or have more stringent removal efficiency. Table 2-1 contains the results of this effort.

**Table 2-1: NOx Control Technologies Identified for RHCT Analysis**

<b>Control Technology</b>	<b>Approximate Control Efficiency*</b>
Selective Catalytic Reduction and Advanced Separated Over Fire Air (ASOFA)	90%
Rich Reagent Injection and Selective Non-Catalytic Reduction and Advanced Separated Over Fire Air (ASOFA)	66-67%
Optimized Selective Non-Catalytic Reduction and Advanced Separated Over Fire Air (ASOFA)	61-62%
Existing Selective Non-Catalytic Reduction* and Advanced Separated Over Fire Air (ASOFA)	Baseline 59-60%

\*Based on pre SNCR/ASOFA baseline of 0.884/0.874 lb NOx/MMBtu for Units 1 and 2, respectively.

## 2.3 Technical Description and Feasibility Analysis

The second step in the RHCT analysis procedure is a technical feasibility analysis of the options identified in Step 1. The RHCT guidelines discuss consideration of two key concepts during this step in the analysis. The two concepts to consider are the “availability” and “applicability” of each control technology. A control technology is considered available, “if it has reached the stage of licensing and commercial availability.” (70 FR 39165) On the contrary, a control technology is not considered available, “if it is in the pilot scale testing stages of development.” (70 FR 39165) When considering a source’s applicability, technical judgment must be exercised to determine “if it can reasonably be installed and operated on the source type.” (70 FR 39165) The technical and feasibility analysis is presented below for each identified option.

### 2.3.1 Selective Catalytic Reduction

The lowest NOx emission levels from coal-fired utility boilers are typically achieved by installing and operating selective catalytic reduction (SCR) technology. In the SCR process, the gas stream is passed through a catalyst bed in the presence of ammonia to reduce NOx to molecular nitrogen and water. The

process is termed “selective” because the ammonia preferentially reacts with the NO<sub>x</sub> rather than with the oxygen in the flue gas. A large reactor containing catalyst is used to enhance NO<sub>x</sub> reduction and ammonia utilization at lower flue gas temperatures than required by a SNCR system. SCR is usually applied to flue gas in the 600°F to 750°F temperature range. There are variations in the SCR process for coal-fired boilers that mostly involve locations in the flue gas path where the catalyst is placed in order to promote the desired NO<sub>x</sub> emission reduction effect. This technology was reviewed in the previous BART and BACT analysis (2008-2010) and it was concluded by NDDH that SCR systems (of all types) are not technically feasible at the Milton R Young facility. No new information or experience has occurred since 2010 to change the result of this analysis and this technology remains not technically feasible.

### **2.3.2 Rich Reagent Injection & Selective Non-Catalytic Reduction**

Rich Reagent Injection (RRI) has been demonstrated and placed in continuous operation on multiple cyclone-fired boilers. RRI is specifically intended for NO<sub>x</sub> emissions control on cyclone boilers. RRI adds dilute urea reagent to the hot furnace gases near the cyclones, which must be devoid of free oxygen in order to avoid oxidation of the urea. This system is combined with a SNCR system to further reduce NO<sub>x</sub> emissions within the boiler. However, the RRI injection location is limited to the lower portion of the furnace and requires an oxygen deprived environment. RRI is considered technically feasible for application on the Unit 1 and Unit 2 cyclone boilers at the Milton R. Young Station.

### **2.3.3 Optimized Selective Non-Catalytic Reduction**

Taking into consideration the past operating experience of the existing system and vendor experience since the original installation, there is potential to reduce the emission rate further with enhancements to the existing design. These enhancements could include changing the nozzles on existing lances, replacing the existing lances, and adding lances in new locations. Additionally, allowing for higher ammonia slip rates than originally designed will allow for higher levels of urea injection which has the potential to further reduce NO<sub>x</sub> emission rates. Optimized SNCR is considered technically feasible for application on the Unit 1 and Unit 2 cyclone boilers at the Milton R. Young Station.

### **2.3.4 Results of Feasibility Analysis**

The evaluations of the identified RHCT alternatives following the feasibility analysis are summarized in Table 2-2.

**Table 2-2: MRYS RHCT NOx Control Feasibility Analysis Results**

<b>Control Technology</b>	<b>In full-scale service on Existing Utility Boilers</b>	<b>In Service on Other Combustion Sources</b>	<b>Commercially Available</b>	<b>Technically Applicable To Milton R. Young Station</b>
SCR	Yes	Yes	No*	No
RRI + SNCR	Yes	Yes	Yes	Yes
Optimized SNCR	Yes	Yes	Yes	Yes
Existing SNCR	Yes	Yes	Yes	Yes

\*Not available on cyclone fired units firing North Dakota lignite.

## 2.4 Evaluate the Technically Feasible NOx Control Options by Effectiveness

The third step in the RHCT analysis procedure is to evaluate the control effectiveness of the technically feasible alternatives. During the feasibility determination in step 2 of the RHCT analysis, the NOx control efficiency was reviewed and presented as part of the technical description for each technology. The evaluations of the remaining RHCT alternatives following the feasibility analysis are summarized in Table 2-3. The alternatives are ranked in 'top down' descending order according to their effectiveness in NOx control.

**Table 2-3: Feasible NOx Control Technologies Identified for RHCT Analysis**

<b>Control Technology</b>	<b>Unit 1 lb/MMBtu</b>	<b>Unit 2 lb/MMBtu</b>
RRI + SNCR	0.30	0.29
Optimized SNCR	0.345	0.335
Existing SNCR	0.36	0.35

The emission rates identified above were developed as continuously achievable 30-day emission rates taking into account vendor supplied information, variations in load, experience in the long-term variation of boiler NOx control technologies, and the variable quality associated with the supply of mine mouth lignite. The vendor information is based on MRYS unit-specific boiler mapping data and CFD modeling results to determine the equipment, approximate injection locations, and subsequent emission rate. The emission rates take into account that the rates must be continuously achievable on a 30-day period including the impacts of changing unit loads, control equipment limitations, and variability in coal quality.

Load variations must be considered because at lower loads the ability to control NOx is reduced. The RRI and SNCR systems are designed to inject dilute ammonia/urea into the correct temperature zones in the boiler for NOx control. The maximum NOx reductions from both RRI and SNCR systems occur when the boiler is at or near full load. At other conditions the ability to control NOx can be significantly impacted. RRI operation depends on oxygen-deprived conditions, and without this (such as with a single

cyclone out of service and/or at lower loads), using the RRI system could increase NOx emissions. Multiple levels of injection are included to introduce reagent into the correct temperature zone at multiple loads. However, even with multiple injection levels, emission reductions are reduced at lower loads.

The Milton R. Young facility is a mine-mouth plant that utilizes run-of-mine fuel, resulting in significant coal quality variability. Within a 30-day period, the plant can, and has, experienced multiple days of lower quality coal that in turn, creates conditions that make NOx harder to control (such as burning fuel oil to control cyclone fouling), increasing emissions and reagent usage rates.

These factors, along with unit-specific vendor information, were considered in developing the continuously achievable 30-day emission rates. The emission rates guaranteed by vendors are based on stable, steady state operating conditions, and do not reflect the varying conditions that occur over the life of the equipment or even in a 30-day operating period. A 30-day emission rate must account for operating during periods such as the transition period between two planned stable load conditions, and other unplanned operating variations such as changing coal quality.

## **2.5 Evaluation of Impacts for Feasible NOx Controls**

Step four in the RHCT analysis procedure is the impact analysis. The draft Guidelines (81 FR 44608) lists four factors to be considered in the impact analysis.

- The costs of compliance
- The time required for compliance
- The energy and non-air quality environmental impacts of compliance
- The remaining useful life of the source

Three of the four impacts required by the RHCT Guidelines are discussed in the following sections. The remaining useful life of the source was determined to be greater than the project life definition in the EPA's OAQPS Control Cost Manual (EPA/453/B-96-001) and thus had no impact on the RHCT determination for MRYS.

### **2.5.1 Cost Estimates**

Cost estimates for the RRI + SNCR control technology were developed based on vendor budgetary quotes, and installation estimates were based upon Burns & McDonnell's in-house experience. The vendor has utilized MRYS unit-specific boiler mapping data and CFD modeling results to determine the

equipment and approximate injection locations. Economic information utilized as inputs to the model are provided in Table 1-1.

### 2.5.1.1 RRI + SNCR Capital Cost Estimate

The vendor equipment cost estimate for the RRI and SNCR system includes new RRI injectors for the lowest level of the boiler, a new RRI distribution module, and modifications to the existing SNCR system to provide load-following flexibility. The remaining capital cost estimate includes installation of the vendor equipment, supply and installation of necessary equipment access, and balance of plant (BOP) costs. The NOx control system cost is representative of a typical furnish and erect contract.

**Table 2-4: Capital Cost Estimate for MRYS Unit 1 & 2 RRI + SNCR System**

<b>DIRECT COSTS</b>	<b>Unit 1 Estimated Cost (\$)</b>	<b>Unit 2 Estimated Cost (\$)</b>
<b>RRI and SNCR System</b>		
Equipment Cost	\$4,283,000	\$5,507,000
<b>BOP Costs</b>		
Mechanical Contract	\$1,611,000	\$4,709,000
Foundations and Steel	\$559,000	\$900,000
Electrical and Controls	\$131,000	\$179,000
<b>BOP Total Direct Cost =</b>	<b>\$2,301,000</b>	<b>\$5,788,000</b>
<b>Total Direct Cost =</b>	<b>\$6,584,000</b>	<b>\$11,295,000</b>
<b>INDIRECT COSTS</b>		
Engineering 10% of DC	\$647,000	\$1,129,000
Escalation to 2021	\$611,000	\$1,048,000
Indirect Cost Subtotal	\$1,258,000	\$2,177,000
Contingency (20% of DC)	\$784,000	\$1,348,000
Prime Contractor's Fee (3% of DC)	\$604,000	\$1,038,000
<b>Total Capital Requirement</b>	<b>\$9,230,000</b>	<b>\$15,858,000</b>

The total estimated capital cost estimate to upgrade the existing Unit 1 SNCR system to a RRI + SNCR system is \$9,230,000, or \$35.9/kW. The total estimated capital cost estimate to upgrade the existing Unit 2 SNCR system to a RRI + SNCR system is \$15,858,000, or \$33.2/kW.

### 2.5.1.2 Optimized SNCR Capital Cost Estimate

The vendor equipment cost estimate for optimizing the SNCR system is based on vendor estimates and may include changing the nozzles on the existing lances, replacing the existing lances, adding lances in new locations, and/or boiler modifications for the additional lances. The NOx control system cost is representative of a typical furnish and erect contract.

**Table 2-5: Capital Cost Estimate for MRYS Unit 1 & 2 Optimized SNCR System**

<b>DIRECT COSTS</b>	<b>Unit 1 Estimated Cost (\$)</b>	<b>Unit 2 Estimated Cost (\$)</b>
<b>Optimized SNCR System</b>		
SNCR Equipment Cost	\$628,000	\$748,000
<b>BOP Costs</b>		
Mechanical Contract	\$311,000	\$932,000
Foundations and Steel	\$100,000	\$250,000
Electrical and Controls	\$15,000	\$25,000
<b>BOP Total Direct Cost =</b>	<b>\$425,000</b>	<b>\$1,207,000</b>
<b>Total Direct Cost =</b>	<b>\$1,054,000</b>	<b>\$1,955,000</b>
<b>INDIRECT COSTS</b>		
Engineering 10% of DC	\$105,000	\$195,000
Escalation to 2021	\$98,000	\$181,000
Indirect Cost Subtotal	\$203,000	\$376,000
Contingency (20% of DC)	\$126,000	\$233,000
Prime Contractor's Fee (3% of DC)	\$97,000	\$180,000
<b>Total Capital Requirement</b>	<b>\$1,479,000</b>	<b>\$2,744,000</b>

The total estimated capital cost estimate to optimize the Unit 1 SNCR system is \$1,479,000 or \$5.8/kW.

The total estimated capital cost estimate to optimize the Unit 2 SNCR system is \$2,744,000, or \$5.8/kW.

### 2.5.1.3 RRI + SNCR O&M Cost Estimate

The annual operating and maintenance costs (O&M) costs are comprised of fixed costs (maintenance and labor) and variable cost (consumables). The fixed costs include operating labor, administrative and support labor and the maintenance material and labor costs. No change in administrative, support and operating labor cost was assumed. The maintenance material and labor cost was estimated at



approximately 3% of the system direct capital cost in Table 2-4. Table 2-6 summarizes the O&M cost estimates for the RRI + SNCR system.

Variable costs include reagent, cooling water, auxiliary power costs and increased coal consumption. The estimated annual costs for these consumables are the estimated change from the baseline conditions based on vendor provided consumption rates, unit operating assumptions and the unit cost information provided in Table 1-1. The coal consumption cost increases because of the significant quantity of water that is introduced to the boiler with increased dilute urea injection. This additional water is evaporated and negatively impacts the unit efficiency.

**Table 2-6: O&M Cost Estimate for MRYS Unit 1 & 2 RRI + SNCR System**

<b>Fixed Costs</b>	<b>Unit 1</b>	<b>Unit 2</b>
Operating Labor	\$0	\$0
Admin and Support labor	\$0	\$0
Maintenance Material and Labor	\$47,000	\$54,000
<b>Total Fixed O&amp;M Costs =</b>	<b>\$47,000</b>	<b>\$54,000</b>
<b>Variable Costs</b>		
Dilute Urea Reagent	\$4,977,000	\$4,348,000
Water	\$296,000	\$696,000
Auxiliary Power	\$52,000	\$52,000
Increased Coal Usage	\$289,000	\$687,000
<b>Total Variable O&amp;M Costs =</b>	<b>\$5,614,000</b>	<b>\$5,783,000</b>
<b>Total Annual O&amp;M Costs</b>	<b>\$5,661,000</b>	<b>\$5,837,000</b>
<b>Net Annual O&amp;M Cost (\$/MWh)</b>	<b>2.96</b>	<b>1.64</b>

O&M Cost represent costs above the baseline (existing system)

#### 2.5.1.4 Optimized SNCR O&M Cost Estimate

The annual operating and maintenance costs (O&M) costs are comprised of fixed costs (maintenance and labor) and variable cost (consumables). The fixed costs include operating labor, administrative and support labor and the maintenance material and labor costs. The maintenance material and labor cost was estimated at approximately 3% of the new direct capital cost in Table 2-5. No change in administrative, support and operating labor cost was assumed. Table 2-7 summarizes the O&M cost estimates for the RRI + SNCR system.

Variable costs include reagent, cooling water, auxiliary power costs and increased coal consumption. The estimated annual costs for these consumables are the estimated change from the baseline conditions based on vendor provided consumption rates, unit operating assumptions and the unit cost information provided in Table 1-1 Economic Design Criteria. The coal consumption cost increases because of the significant

quantity of water that is introduced to the boiler with increased dilute urea injection. This additional water is evaporated and impacts the unit efficiency.

**Table 2-7: O&M Cost Estimate for MRYS Unit 1 & 2 Optimized SNCR System**

<b>Fixed Costs</b>	<b>Unit 1</b>	<b>Unit 2</b>
Operating Labor	\$0	\$0
Admin and Support labor	\$0	\$0
Maintenance Material and Labor	\$19,000	\$22,000
<b>Total Fixed O&amp;M Costs =</b>	<b>\$19,000</b>	<b>\$22,000</b>
<b>Variable Costs</b>		
Dilute Urea Reagent	\$1,820,000	\$717,000
Water	\$85,000	\$296,000
Auxiliary Power	\$26,000	\$26,000
Increased Coal Usage	\$57,000	\$253,000
<b>Total Variable O&amp;M Costs =</b>	<b>\$1,988,000</b>	<b>\$1,292,000</b>
<b>Total Annual O&amp;M Costs</b>	<b>\$2,007,000</b>	<b>\$1,314,000</b>
<b>Net Annual O&amp;M Cost (\$/MWh)</b>	<b>1.05</b>	<b>0.37</b>

O&M Cost represent costs above the baseline (existing system)

### 2.5.1.5 Levelized Total Annual Cost

In order to effectively compare the cost of installing, operating and maintaining the NOx control systems, capital and O&M costs can be evaluated on a levelized basis.

The Levelized Total Annual Cost (LTAC) for NOx control systems was calculated based on a 20-year project life and are presented in Table 2-8 and Table 2-9 along with the emissions reduction, resultant emissions rate and the Unit Control Cost. No salvage value was assumed at the end of the service life. The Unit Control Cost is the LTAC divided by the annual tons of NOx emissions that would be controlled by implementation of the respective alternative. The Levelized Total Annual Cost and Unit Control Cost are used to evaluate the technology alternatives on a cost effectiveness basis.

**Table 2-8: Levelized Total Annual Cost of MRYS Unit 1 NO<sub>x</sub> Control Technologies**

NO <sub>x</sub> Control Alternative	Emission Rate lb/10 <sup>6</sup> Btu	Annual Emissions (tpy) <sup>1</sup>	Annual Emission Reduction (tpy) <sup>1</sup>	Installed Capital Cost (\$2021) <sup>2</sup>	Annual O&M Cost (\$2021)	Levelized Total Annual Cost (\$2021) <sup>3</sup>	Actual Unit Control Cost (\$/ton) <sup>4</sup>	Incremental Unit Control Cost (\$/ton)
RRI+SNCR/ASOFA	0.30	2,803	467	9,230,000	5,661,000	6,433,360	13,769	10,232
Optimized SNCR/ASOFA	0.345	3,224	47	1,479,000	2,007,000	2,130,762	45,603	
Existing SNCR/ASOFA <sup>5</sup>	0.35	3,271	Baseline					

1. Based on 2,510 MMBtu/hr and 85% capacity factor.
2. All Costs in 2021 dollars.
3. For LTAC calculation, Capital Recovery Factor = 0.08368 and first year O&M Cost.
4. Overall control cost is LTAC divided by actual annual emissions reduction of each alternative.
5. Baseline emission rate based on maximum 30-day emission rate between 2014-2018.

**Table 2-9: Levelized Total Annual Cost of MRYS Unit 2 NO<sub>x</sub> Control Technologies**

NO <sub>x</sub> Control Alternative	Emission Rate lb/10 <sup>6</sup> Btu	Annual Emissions (tpy) <sup>1</sup>	Annual Emission Reduction (tpy) <sup>1</sup>	Installed Capital Cost (\$2021) <sup>2</sup>	Annual O&M Cost (\$2021)	Levelized Total Annual Cost (\$2021) <sup>3</sup>	Actual Unit Control Cost (\$/ton) <sup>4</sup>	Incremental Unit Control Cost (\$/ton)
RRI+SNCR/ASOFA	0.29	5,070	1049	15,858,000	5,837,000	7,163,987	6,829	7,144
Optimized SNCR/ASOFA	0.335	5,857	262	2,744,000	1,314,000	1,543,644	5,886	
Existing SNCR/ASOFA <sup>5</sup>	0.35	6,119	Baseline					

1. Based on 4,696 MMBtu/hr and 85% capacity factor.
2. All Costs in 2021 dollars.
3. For LTAC calculation, Capital Recovery Factor = 0.08368 and first year O&M Cost.
4. Overall control cost is LTAC divided by actual annual emissions reduction of each alternative.
5. Baseline emission rate based on maximum 30-day emission rate between 2014-2018.

### 2.5.1.6 Cost Estimate Conclusion

In the RHCT guidelines, EPA does not provide definition, or even discussion of what Unit Control Costs are considered reasonable or unreasonable. NDDH has indicated that costs below \$5,000 per ton may be considered to be reasonable.

The cost analysis portion of the RHCT determination for MRYS Unit 1 and 2 indicates that Actual Unit Control Costs for the top ranked RRI + SNCR for Unit 1 is more than double \$5,000 per ton and the Unit 2 cost is well above \$5,000 per ton. The incremental rate (cost of removal between two options) of controlling NO<sub>x</sub> with RRI + SNCR is also over \$5,000 per ton on both Units. From an economic analysis

viewpoint, the RRI+SNCR system, although the top ranked technology, is not an economically effective NOx control alternative for either Unit 1 or Unit 2.

The Actual Unit Control Costs for the next top ranked control technology, optimized SNCR system, is above \$5,000 per ton on Unit 1 and Unit 2. From an economic analysis viewpoint, optimized SNCR system is not an economically effective NOx control alternative for Unit 1 or Unit 2.

### 2.5.2 Energy Impacts

The primary energy impact of the RRI + SNCR and Optimized SNCR systems is reduced boiler efficiency due to evaporation of large amounts of dilute urea. For Unit 1, the equivalent of an additional 39 tons of coal per day will be required to evaporate the expected amount of dilute urea to be injected into the boiler. For Unit 2, the equivalent of an additional 93 tons of coal per day will be required to evaporate the expected amount of dilute urea to be injected into the boiler. Increasing heat input to maintain present unit production capacity may have PSD implications that could add significant cost and significant permitting considerations.

Other energy impacts include an incremental increase in water consumption due to the need for additional cooling water, and an incremental increase in energy related to providing more compressed air for reagent atomization. The impact of these items is negligible.

**Table 2-10: Energy Requirement of MRYS Unit 1 NOx Control Technologies**

<b>RHCT Alternative</b>	<b>Energy Demand (kW)</b>	<b>Percent of Nominal Generation</b>
Existing SNCR	200	0.09%
Optimized SNCR	266	0.11%
RRI + SNCR	332	0.14%

**Table 2-11: Energy Requirement of MRYS Unit 2 NOx Control Technologies**

<b>RHCT Alternative</b>	<b>Energy Demand (kW)</b>	<b>Percent of Nominal Generation</b>
Existing SNCR	300	0.07%
Optimized SNCR	366	0.08%
RRI + SNCR	432	0.10%

### 2.5.3 Non-Air Quality Environmental Impacts

The addition of the RRI system to the SNCR system is not expected to significantly impact emissions of CO or volatile organic compounds (VOCs).

Operation of the existing SNCR-related system creates a small amount of unreacted ammonia to be emitted. In the future, the settings for the new RRI+SNCR or Optimized SNCR system may increase the amount of ammonia slip produced. Higher NO<sub>x</sub> reduction performance involves greater amounts of reagent usage and consequently, the increased ammonia slip. This is typically controlled to less than 10 ppmvd, especially when the possible formation of sulfates such as ammonium sulfate [(NH<sub>4</sub>)<sub>2</sub>SO<sub>4</sub>] and ammonium bisulfate [NH<sub>4</sub>HSO<sub>4</sub>] will be more problematic at higher slip levels. Sulfur trioxide (SO<sub>3</sub>) formed during combustion in the boiler can combine with ammonia during passage through the flue gas ductwork to form the sulfates.

Some of the unreacted ammonia (ammonia slip) will be collected with the flyash in the ESP. Any remaining ammonia slip that is not collected or condensed in the air pollution control system will be collected in the wet scrubber or emitted from the stack as an aerosol or condensable particulate. Increasing the ammonia slip has the potential to increase atmospheric visibility impairment downwind of the facility compared with a pristine condition. Although the predicted amount of such potential impact from ammonia slip emissions has not been determined, it is expected to be small in comparison with the significant anticipated reduction in far-field ozone and improvement in atmospheric visibility as a result of the overall NO<sub>x</sub> emission reduction.

One mole of carbon dioxide (CO<sub>2</sub>) will be created and emitted for every mole of urea injected for reaction with NO<sub>x</sub>. The consumption rate of urea will significantly increase with the use of RRI+SNCR or optimized SNCR and thus the CO<sub>2</sub> rate will also increase. However, this is a relatively small increase in the total amount of CO<sub>2</sub> produced as part of the combustion of carbon-based fossil fuel in the form of lignite.

Delivery of the urea reagent to the MRYS and storage of aqueous urea reagent on-site creates the potential for accidents, leaks, and subsequent releases to air, ground, and surface water immediately surrounding the facility. Urea is much less volatile than anhydrous or aqueous ammonia, and these risks are expected to be manageable. Emergency planning and community communications are already part of the management plan requirements for such reagent usage.

Increased dilution water and urea usage rates will require the production of greater volumes of Reverse Osmosis (RO)/condensate quality water for dilution of concentrated urea deliveries and injection into the boiler. The production of RO/condensate quality water results in a discharge of a concentrated brine solution, which is ultimately discharged under the requirements of the facility NDPDES permit. This waste stream typically represents 20% of the RO product volume produced. This would result in millions of gallons of additional water treatment wastewaters being discharged from the MRYS facility on an annual basis.

### 3.0 SO<sub>2</sub> RHCT EVALUATION

The RHCT determination process has five predefined steps as described in Section 1. In this section, steps 1 through 4 of the RHCT determination for Milton R. Young Station (MRYS) are described for SO<sub>2</sub> and a presentation is made of the results. Potentially applicable SO<sub>2</sub> control technologies are first identified. A brief description of the processes and their capabilities are reviewed for availability and feasibility. Subsequently, those available technologies deemed feasible for retrofit application are ranked according to nominal SO<sub>2</sub> control capability. The impacts analysis then reviews the estimated capital and O&M costs for each alternative. Following the cost determination, the energy impacts and non-air quality impacts are reviewed for each technology. The impact based on the remaining useful life of the source is reviewed as part of the cost analysis. The results of the impact analyses are tabulated and potential RHCT options are listed.

#### 3.1 Identification of Retrofit SO<sub>2</sub> Control Technologies

The initial step in the RHCT determination is the identification of retrofit SO<sub>2</sub> control technologies. In order to identify the applicable SO<sub>2</sub> control technologies, several reference works were consulted, including "Controlling SO<sub>2</sub> Emissions: A Review of Technologies (EPA-600/R-00-093, October 2000) and the RACT/BACT/LAER Clearinghouse (RLBC). From these and other literature sources, a preliminary list of control technologies and their estimated capabilities for potential application to MRYS was developed. However, Minnkota already has wet FGD systems installed on both units to achieve 30-day rolling average removal rates of 95% and 90% on Unit 1 and 2, respectively. Additionally, Unit 2 complies with a 0.15 lb/MMBtu 30-day rolling average emission rate. Thus, the control technologies included in the RHCT analysis either meet this minimum level of control or have more stringent removal efficiency. Table 3-1 contains the results of this effort.

**Table 3-1: SO<sub>2</sub> Control Technologies Identified for RHCT Analysis**

<b>Control Technology</b>	<b>Approximate Control Efficiency</b>
ReACT Scrubber	92-98%
New Wet Flue Gas Desulfurization (FGD)	98%
Modify Existing Wet FGD	96-97%
Circulating Semi-Dry FGD	90-97%
Semi-Dry FGD	90-95%

## **3.2 Technical Description and Feasibility Analysis**

The second step in the RHCT analysis procedure is a technical feasibility analysis of the options identified in Step 1. The RHCT guidelines, which reference the prior BART Guidelines, discuss consideration of two key concepts during this step in the analysis. The two concepts to consider are the “availability” and “applicability” of each control technology. A control technology is considered available “if it has reached the stage of licensing and commercial availability” (70 FR 39165). On the contrary, a control technology is not considered available “if it is in the pilot scale testing stages of development” (70 FR 39165). When considering a source’s applicability, technical judgment must be exercised to determine “if it can reasonably be installed and operated on the source type” (70 FR 39165). The technical and feasibility analysis is presented below for each identified option.

### **3.2.1 Wet Flue Gas Desulfurization**

Wet FGD technology utilizing lime or limestone as the reagent is commonly applied to coal-fired boilers. Wet FGD utilizes an absorber, such as an open spray tower or a spray tower with a perforated plate contactor, to expose flue gas to the neutralizing slurry. Absorbed SO<sub>2</sub> is converted to calcium sulfite and then may be oxidized to calcium sulfate dihydrate (gypsum) which is filtered from the scrubber solution and either disposed of in a permitted disposal facility, or possibly sold for either wallboard or cement production. Lime is utilized as the reagent in the wet FGD technology analysis, because the plant currently uses lime in the FGD processes and has existing lime reagent preparation equipment. Lime, rather than limestone, is used at the plant because it is the most cost-effective reagent to truck to the plant. The MRYS is not equipped with rail service.

An alternative reagent to lime or limestone is ammonia. The scrubbing technology is similar to other wet FGD systems; however, the byproduct handling is significantly different. The advantage of utilizing ammonia is the production of a high value fertilizer byproduct (ammonium sulfate). This byproduct is a commodity that can be sold worldwide all year. The disadvantage of utilizing ammonia reagent is the byproduct requires significant handling/treatment. This handling/treatment includes concentration, crystallization, drying, prilling and storage. Because ammonium sulfate is highly soluble in water, landfilling the byproduct is not feasible so the product must be stored and sold. As fertilizer is generally seasonal demand in a given part of the country, therefore access to the world market is necessary.

Historically, wet FGD systems have operated with SO<sub>2</sub> control efficiency anywhere from 70% to 98%. New coal-fired power plant SO<sub>2</sub> control projects have achieved coal to stack SO<sub>2</sub> control efficiency of ≥99 percent. However, considering a reasonable degree of margin is appropriate to allow for continuous



compliance including upsets, fuel variability, and operational variability, 98% removal on a 30-day rolling average basis is considered an appropriate removal rate for a new state of the art scrubber.

For the purposes of this analysis, a new wet FGD performance was evaluated at 98% SO<sub>2</sub> removal. Due to the relative ages of Unit 1 and Unit 2 scrubbers, a new wet scrubber was considered only for Unit 2, as the Unit 1 wet scrubber was placed in service relatively recently, in 2011. Based on the ability of a new wet FGD system to achieve 98% percent SO<sub>2</sub> removal efficiency and considering the commercial availability and applicability, a new wet FGD system was found to be an acceptable RHCT alternative for MRYS Unit 2 SO<sub>2</sub> emission control.

This report also evaluates the modification of the existing wet FGD process currently operating on Unit 1 and Unit 2 as a possible RHCT alternative. The original equipment manufacturer (OEM) of the Unit 1 scrubber was engaged to evaluate modifications required to increase the removal efficiency of the existing wet FGD processes. The same OEM has previously studied upgrading the Unit 2 scrubber to achieve higher removal efficiency, and was engaged to update and confirm the results of that study. Through this evaluation it was determined modifications can be made to achieve 95-98% removal in each of the two existing scrubbing systems. Upgrades include increasing the liquid-to-gas ratio, installation of new types of spray nozzles, running additional pumps, and adjusting the operating conditions of the scrubber.

The range of removal is dependent on both mechanical upgrades and a range of potential chemistry changes. The potential operating condition changes were evaluated with the Owner's experience with these different operating conditions and considering the impacts they have on reliability and BOP impacts (scaling, nozzle plugging, byproduct settling/removal). Considering these potential impacts/risks, this evaluation assumes 97% removal from the maximum future sulfur fuel (3.2 lb SO<sub>2</sub>/MMBtu) to set a not to exceed emission rate. Because the 10 year mining plan indicates the sulfur content of the coal will vary by 40% (generally increasing in the future) a minimum removal rate of 96% is also included.

### **3.2.2 Semi-Dry Flue Gas Desulfurization**

As an alternative to wet FGD technology, the control of SO<sub>2</sub> emissions can be accomplished using semi-dry FGD technology. The most common semi-dry FGD system is the lime Spray Dryer Absorber (SDA) using a fabric filter for downstream particulate collection. There are several variations of the semi-dry process in use today. Two other variations, the Flash Dryer Absorber (FDA) and Circulating Dry Scrubber (CDS) are similar in nature. They primarily differ by the type of reactor vessel used, the method in which water and lime are introduced into the reactor and the degree of solids recycling. This section addresses the SDA process and the CDS process.

No SDA process has clearly demonstrated the ability to achieve SO<sub>2</sub> removal levels similar to wet FGD systems in the U.S. The application of high SO<sub>2</sub> removal SDA system for high sulfur coal have been limited in the industry due to multiple factors. For purposes of completeness an SDA system is assumed to be able to achieve 93% removal in this application.

The CDS system can increase the lime injection rate independent of the water injection, higher removal rates can be achieved. The CDS system removal is assumed to be equivalent to the retrofit wet FGD system achieving 95-97% removal.

### **3.2.3 ReACT Dry Scrubbing Process**

ReACT (Regenerative Activated Coke Technology) is a multipollutant control system that utilizes activated coke to remove SO<sub>2</sub>, NO<sub>x</sub> and mercury. The process is divided into three main processes; 1) adsorption, 2) regeneration, 3) recovery. In the first step ammonia is injected into the flue gas and the flue gas is passed through an adsorber filled with a moving bed of activated coke pellets where the SO<sub>2</sub> and mercury are adsorbed and the NO<sub>x</sub> is reduced to N<sub>2</sub>. In the second step the activated coke pellets are transferred to a second vessel to be regenerated for recycle/reuse through thermal desorption. The captured mercury is concentrated in the lower portion of the regenerator vessel. The resulting gas from the regeneration step is a concentrated stream of SO<sub>2</sub> that must be further treated in a separate acid recovery plant to produce a sellable sulfuric acid byproduct. Sulfuric acid is a worldwide commodity that, with access, can be sold year-round. This ReACT process is installed and operating on multiple low sulfur coal fired units achieving ≥98% SO<sub>2</sub> removal. Burns & McDonnell contacted the supplier of the ReACT process and discussed the application of the technology to an application like MRYS. It was determined that MRYS is 'not a good application' for the technology, however, the technology could be applied and would work. Factors in this application at MRYS that would impact performance and cost of ReACT include that the inlet temperature is too high, higher oxidation of the activated coke can be expected, and the sulfuric acid production rates would be very high. This technology is still considered a viable alternative and previous ReACT pilot tests on high sulfur coals have shown ReACT can achieve 92-98% SO<sub>2</sub> removal rates.

### **3.2.4 Results of Feasibility Analysis**

The evaluations of the identified RHCT alternatives following the feasibility analysis are summarized in Table 3-2.

**Table 3-2: MRYS RHCT SO<sub>2</sub> Control Feasibility Analysis Results**

<b>Control Technology</b>	<b>In full-scale service on Existing Utility Boilers</b>	<b>In Service on Other Combustion Sources</b>	<b>Commercially Available</b>	<b>Technically Applicable To Milton R. Young Station</b>
ReACT Scrubber	Yes	Yes	Yes	Yes
Wet FGD	Yes	Yes	Yes	Yes
CDS Dry FGD	Yes	Yes	Yes	Yes
SDA Dry FGD	Yes	Yes	Yes	Yes

### 3.3 Evaluate Technically Feasible SO<sub>2</sub> Control Options by Effectiveness

The third step in the RHCT analysis procedure is to evaluate the control effectiveness of the technically feasible alternatives. During the feasibility determination in step 2 of the RHCT analysis, the SO<sub>2</sub> control efficiency was reviewed and presented as part of the technical description for each technology. The evaluations of the remaining RHCT alternatives following the feasibility analysis are summarized in Table 3-3. The alternatives are ranked in descending order according to their effectiveness in SO<sub>2</sub> control.

**Table 3-3: Feasible SO<sub>2</sub> Control Technologies Identified for RHCT Analysis**

<b>Control Technology</b>	<b>Unit 1</b>	<b>Unit 2</b>
New Wet FGD	Not Reviewed*	98% Control
ReACT	98% Control	98% Control
Retrofit Existing Wet FGD	97% Control	97% Control
CDS Semi-Dry FGD	NA**	NA**
SDA FGD	NA**	NA**

\*Existing system was installed in 2011, so replacement with a like-kind system was not reviewed.

\*\*SDA semi-dry FGD is not evaluated for Unit 1 or 2 because the existing wet FGD can be used to achieve equivalent removal efficiency while using existing equipment.

### 3.4 Evaluation of Impacts for Feasible SO<sub>2</sub> Controls

Step four in the RHCT analysis procedure is the impact analysis. The draft Guidelines (81 FR 44608) lists four factors to be considered in the impact analysis.

- The costs of compliance;
- The time required for compliance;
- Energy and non-air quality environmental impacts of compliance; and
- The remaining useful life of the source.

Three of the four impacts required by the RHCT Guidelines are discussed in the following sections. The remaining useful life of the source was determined to be greater than the project life definition in the

EPA's OAQPS Control Cost Manual (EPA/453/B-96-001) and thus had no impact on the RHCT determination for MRYS.

Unlike the Best Available Retrofit Technology (BART) evaluation performed in the last round for the RHCT evaluation, the technologies in the second implementation period are evaluated on a 'Top Down' down basis similar to a Best Available Control Technology (BACT) approach. Where multiple technologies achieve similar removal rates, a single technology is evaluated to represent that level of performance. The top rated SO<sub>2</sub> removal rate is 98% removal and can be achieved by replacing the existing wet FGD system with either a new wet FGD system or a ReACT system. As a wet FGD system is a well demonstrated technology for high sulfur fuel and ReACT has only been applied on low sulfur fuel this evaluation will focus on the new wet FGD option to evaluate the top rated option. As shown in Table 3-3, ReACT is not expected to have better performance than wet FGD in operating conditions encountered at MRYS.

### **3.4.1 Cost Evaluation**

The following sections evaluate the top two ranked control options for Unit 2, replacing the existing wet FGD system with a new wet FGD system, and upgrading the Unit 2 scrubber. A new wet FGD was not considered for Unit 1, as the existing wet FGD began operations in 2011 as part of the previous BART/BACT analysis and is within the previously evaluated useful life. The top ranked control option for Unit 1, modify the existing wet FGD, is evaluated.

#### **3.4.1.1 New Wet FGD Capital Cost Estimate**

Cost estimates for the new wet FGD SO<sub>2</sub> control technologies were completed utilizing the 'IPM Model – Updates to Cost and Performance for APC Technologies Wet FGD Cost Development Methodology' available from the U.S. Environmental Protection Agency and supplemented with engineering estimates based upon Burns & McDonnell's in-house experience. The IPM Model Update is a formula-based report that was specifically developed to estimate the cost of wet FGD technologies for utility power plants. The report was prepared for the EPA in January 2017. The report is available for download from the U.S. EPA website at [www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6](http://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6).

As a conservative (lowest cost) approach, this evaluation only considered the 'Absorber Island' portion of the new scrubber cost at a retrofit factor of 1.0 and supplemented this with engineering estimates for new duct work, connecting piping and space modifications required to fit the absorber. This approach assumes all of the existing balance of plant (BOP) systems are capable of supporting the new system with

no upgrades. Further, it is assumed there is no change in operating staff and only a proportional change in the variable operating cost. These conservative assumptions minimize the overall project cost resulting in a conservatively low dollars per ton control cost.

For the addition of a new wet FGD absorber, Unit 2 will require new ductwork to connect to the new wet FGD system, modifications to the coal pile to create space for the new system and electrical replacement/upgrades for the new scrubber or a significantly extended outage to allow for the existing wet FGD system to be shut down while the new system is tied in, commissioned and started up. The SO<sub>2</sub> control system cost is representative of a typical furnish and erect contract by a wet FGD system supplier. Economic information utilized as input into the model is given in Table 1-1. The results of the capital cost estimates are given in Table 3-4.

**Table 3-4: Capital Cost Estimate for MRYS Unit 2 Wet Lime FGD System**

<b>DIRECT COSTS</b>	<b>Unit 2 Estimated Cost (\$)</b>
<b>New FGD Absorber</b>	
FGD Island	\$51,586,000
<b>BOP Costs</b>	
Mechanical Contract	\$54,000,000
Foundations and Steel	\$4,461,000
<b>BOP Total Direct Cost =</b>	<b>\$58,461,000</b>
<b>Total Direct Cost =</b>	<b>\$110,047,000</b>
<b>INDIRECT COSTS</b>	
Engineering 10% of DC	\$11,005,000
Escalation to 2021	\$10,204,000
Indirect Cost Subtotal	\$21,209,000
Contingency (20% of DC)	\$13,126,000
Prime Contractor's Fee (3% of DC)	\$10,107,000
<b>Total Capital Requirement</b>	<b>\$154,489,000</b>

The total estimated capital cost estimate for a complete new wet FGD absorber is \$154,489,000 or \$324kW.

### **3.4.1.2 Wet FGD Modification Capital Cost Estimate**

Cost estimates for retrofitting the existing wet FGD systems were based on the equipment modification and associated pricing provided by the OEM and supplemented with engineering estimates for installation based upon Burns & McDonnell's in-house experience.

This evaluation assumes all of the existing balance of plant (BOP) systems are capable of supporting the new system with no further upgrades. Further, it is assumed there is no change in operating staff and only a proportional change in the variable operating cost. These conservative assumptions minimize the overall project cost resulting in a conservatively low dollars per ton control cost.

The capital cost estimate for the Unit 1 wet FGD system modification includes the OEM recommendation to replace three out of the four recirculation pump motors to increase the liquid to gas ratio in the scrubber. During this investigation the existing electrical system and foundation associated with the pump was reviewed and is believed to be sufficient to support this upgrade with no further modifications.

The capital cost estimate for the Unit 2 wet FGD system modification includes the OEM recommendation to replace all of the absorber spray nozzles with dual flow nozzles. The OEM did not recommend upgrading the pumps on Unit 2 due to velocity limitations in the riser pipe and headers and did not recommend upgrading the riser headers and spray headers to accommodate more flow as these upgrades could compromise or complicate the conditions of the existing towers. The results of the capital cost estimates for the FGD system modifications are given in Table 3-5.

**Table 3-5: Capital Cost Estimate for MRYS Unit 1 Wet FGD System Modification**

<b>DIRECT COSTS</b>	<b>Unit 1 Estimated Cost (\$)</b>	<b>Unit 2 Estimated Cost (\$)</b>
<b>Modified FGD System</b>		
FGD Modification Equipment Cost	\$569,000	\$1,011,000
<b>BOP Costs</b>		
Mechanical Contract	\$0	\$280,000
Electrical and Controls	\$16,000	\$0
<b>BOP Total Direct Cost =</b>	<b>\$16,000</b>	<b>\$280,000</b>
<b>Total Direct Cost =</b>	<b>\$585,000</b>	<b>\$1,291,000</b>
<b>INDIRECT COSTS</b>		
Engineering 10% of DC	\$58,000	\$129,000
Escalation to 2021	\$54,000	\$120,000
Indirect Cost Subtotal	\$112,000	\$249,000
Contingency (20% of DC)	\$70,000	\$154,000
Prime Contractor's Fee (3% of DC)	\$54,000	\$119,000
<b>Total Capital Requirement</b>	<b>\$821,000</b>	<b>\$1,813,000</b>

The total estimated capital cost for upgrades to the Unit 1 wet FGD system is \$821,000, or \$3.2/kW.

The total estimated capital cost for upgrades to the Unit 2 wet FGD system is \$1,813,000, or \$3.8/kW.

### 3.4.1.3 New Wet FGD O&M Cost Estimate

The annual operating and maintenance costs (O&M) costs are comprised of fixed costs (maintenance and labor) and variable cost (consumables). The operating and maintenance costs are evaluated as additional costs beyond the existing wet FGD system as the current costs are part of the baseline operating conditions. The operating labor cost of a new system is not expected to be significantly different than the existing system over the life of the equipment. No additional operating labor has been assumed.

Variable costs include reagent, makeup water, FGD byproduct disposal and auxiliary power costs. The estimated annual costs for these consumables are based on the incremental consumption rates change between the existing removal rate and the new removal rate and the unit cost information provided in Table 1-1 Economic Design Criteria.

**Table 3-6: O&M Cost Estimate for a New MRYS Unit 2 Wet Lime FGD System**

<b>Fixed Costs</b>	
Operating Labor	\$0
Admin and Support labor	\$0
Maintenance Material and Labor	\$3,301,000
<b>Total Fixed O&amp;M Costs =</b>	<b>\$3,301,000</b>
<b>Variable Costs</b>	
Lime Reagent	\$29,000
Byproduct Disposal	\$323,000
Auxiliary Power	\$854,000
<b>Total Variable O&amp;M Costs =</b>	<b>\$1,206,000</b>
<b>Total Annual O&amp;M Costs</b>	<b>\$4,507,000</b>
<b>Net Annual O&amp;M Cost (\$/MWh)</b>	<b>1.27</b>

#### **3.4.1.4 Wet FGD Modification O&M Cost Estimate**

The annual operating and maintenance costs (O&M) costs are comprised of fixed costs (maintenance and labor) and variable cost (consumables). The operating and maintenance costs are evaluated as additional costs beyond the existing wet FGD system as the current costs are part of the baseline operating conditions. The operating labor cost of a new system is not expected to be significantly different than the existing system over the life of the equipment. No additional operating labor has been assumed.

Variable costs include reagent, makeup water, FGD byproduct disposal and auxiliary power costs. The estimated annual costs for these consumables are based on the incremental consumption rates change between the existing removal rate and the new removal rate and the unit cost information provided in Table 1-1 Economic Design Criteria.



**Table 3-7: O&M Cost Estimate for MRYS Unit 1 and 2 Wet Lime FGD System Modification**

<b>Fixed Costs</b>	<b>Unit 1</b>	<b>Unit 2</b>
Operating Labor	\$0	\$0
Admin and Support labor	\$0	\$0
Maintenance Material and Labor	\$18,000	\$39,000
<b>Total Fixed O&amp;M Costs =</b>	<b>\$18,000</b>	<b>\$39,000</b>
<b>Variable Costs</b>		
Lime Reagent	\$86,000	\$162,000
Byproduct Disposal	\$8,000	\$15,000
Auxiliary Power	\$228,000	\$376,000
<b>Total Variable O&amp;M Costs =</b>	<b>\$322,000</b>	<b>\$553,000</b>
<b>Total Annual O&amp;M Costs</b>	<b>\$340,000</b>	<b>\$592,000</b>
<b>Net Annual O&amp;M Cost (\$/MWh)</b>	<b>0.18</b>	<b>0.17</b>

O&M Cost represent costs above the baseline (existing system)

### 3.4.1.5 Levelized Total Annual Cost

In order to effectively compare the cost of installing, operating, and maintaining the SO<sub>2</sub> control systems, capital and O&M costs should be evaluated on a levelized basis.

The Levelized Total Annual Cost (LTAC) for SO<sub>2</sub> control systems was calculated based on overnight construction period (2021), followed by a 20 year service life ending December 31, 2041. O&M costs were based on first year (2021) cost. No salvage value was assumed at the end of the service life for any of the alternatives. The results are presented in Table 3-8 and Table 3-9 along with the emissions reduction, resultant emissions rate and the Unit Control Cost. The Unit Control Cost is the LTAC divided by the annual tons of additional SO<sub>2</sub> emissions that would be controlled by implementation of the respective alternative.

**Table 3-8: MRYS Unit 1 SO<sub>2</sub> Control System Levelized Total Annual Cost**

<b>SO<sub>2</sub> Control Alternative</b>	<b>Emission Rate lb/10<sup>6</sup> Btu</b>	<b>Annual Emission (tpy)<sup>1</sup></b>	<b>Annual Emission Reduction (tpy)<sup>1</sup></b>	<b>Installed Capital Cost (\$2021)<sup>2</sup></b>	<b>Annual O&amp;M Cost (\$2021)</b>	<b>Levelized Total Annual Cost (\$2021)<sup>3</sup></b>	<b>Actual Unit Control Cost (\$/ton)<sup>4</sup></b>
Modified Wet FGD <sup>5</sup>	0.10	934	374	821,000	340,000	408,701	1,093
Baseline	0.14	1,308	Baseline				

1. Based on baseline heat input of 2,510 MMBtu/hr at 85% capacity factor

2. All Costs in 2021 dollars.

3. For LTAC calculation, Capital Recovery Factor = 0.08368 and first year O&M Cost.

4. Overall control cost is LTAC divided by actual annual emissions reduction of each alternative.

5. Emission rate based on future higher sulfur coal (96% removal).

**Table 3-9: MRYS Unit 2 SO<sub>2</sub> Control System Levelized Total Annual Cost**

SO <sub>2</sub> Control Alternative	Emission Rate lb/10 <sup>6</sup> Btu	Annual Emission (tpy) <sup>1</sup>	Annual Emission Reduction (tpy) <sup>1</sup>	Installed Capital Cost (\$2021) <sup>2</sup>	Annual O&M Cost (\$2021) <sup>2</sup>	Levelized Total Annual Cost (\$2021) <sup>3</sup>	Actual Unit Control Cost (\$/ton) <sup>4</sup>	Incremental Unit Control Cost (\$/ton)
New Wet FGD	0.065	1,136	1,486	154,489,000	6,133,196	19,060,732	12,826	29,934
Modified Wet FGD <sup>5</sup>	0.10	1,748	874	1,813,000	592,000	743,684	851	
Baseline	0.15	2,622	Baseline					

1. Based on baseline heat input of 4,696 MMBtu/hr at 85% capacity factor

2. All Costs in 2021 dollars.

3. For LTAC calculation, Capital Recovery Factor = 0.08368 and first year O&M Cost.

4. Overall control cost is LTAC divided by actual annual emissions reduction of each alternative.

5. Emission rate based on future higher sulfur coal (96% removal).

The annual tons of SO<sub>2</sub> reduction in this RHCT analysis are calculated as the difference between the baseline emission rate and the controlled emissions assumed to be at the same heat input and unit operating time.

### 3.4.1.6 Cost Estimate Conclusion

In the RHCT guidelines, EPA does not provide definition, or even discussion of what Unit Control Costs are considered reasonable or unreasonable. NDDH has indicated that costs below \$5,000 per ton may be considered to be reasonable.

The Actual Unit Control Cost are used to evaluate the technology alternatives on a cost effectiveness basis. As can be seen from a review of Table 3-9, the cost of the new Unit 2 wet FGD alternative is excessively high with an actual and incremental control cost far greater than \$5,000 dollars per ton.

As can be seen from a review of Table 3-8 and Table 3-9, the wet FGD modification alternatives for both units are not high, with a Actual Unit Control Cost of \$851-\$1,093 per ton.

### 3.4.2 Energy Impacts

The energy impacts of replacing the existing U2 wet FGD with a new wet FGD, or of upgrades to the existing wet FGD in the case of Unit 1, in terms of both estimated kW of energy usage and the percent of total generation, are given in Table 3-10 and Table 3-11. The primary energy impacts of the wet FGD alternative consists of the additional electrical load resulting from pumps and reagent preparation.

Building HVAC and interior and exterior lighting loads are considered minimal.

**Table 3-10: Energy Requirement of MRYS Unit 1 FGD Upgrades**

<b>RHCT Alternative</b>	<b>Energy Demand (kW)</b>	<b>Percent of Nominal Generation</b>
Existing Wet FGD	5,170	2.2%
Upgraded Wet FGD	5,756	2.5%

**Table 3-11: Energy Requirement of MRYS Unit 2 New FGD**

<b>RHCT Alternative</b>	<b>Energy Demand (kW)</b>	<b>Percent of Nominal Generation</b>
Existing Wet FGD	9,658	2.2%
Upgraded Wet FGD	10,623	2.4%
New Wet FGD	11,853	2.7%

### 3.4.3 Non-Air Quality Environmental Impacts

Non-air quality environmental impacts of replacing the existing wet FGD with a new wet FGD or retrofitting the existing FGD systems are expected to be very similar to the impacts of the existing system. These may include hazardous waste generation, solid and aqueous waste streams. The primary change anticipated due to the use of a new wet FGD or modifying the existing FGD systems will be an incremental increase in the solids disposal rate as additional removal of SO<sub>2</sub> will result in increased byproduct.

While the economic evaluation of a new wet FGD system assumes overnight installation, the actual process to bid, design, purchase, and install a retrofitted new wet FGD system can take five years to implement. The actual process to bid, design, purchase, and install a retrofits to an existing wet FGD system can take two to three years to implement.

### 3.4.4 SO<sub>2</sub> Control Technology Evaluation Conclusion

The energy impacts of a new wet FGD system are only incrementally higher than the existing system and are primarily driven by the increase in SO<sub>2</sub> removal. These incremental increases are acceptable.

The time period to install a new wet FGD system is significantly longer than the second ranked option (retrofitting the existing wet FGD) and would result in years of higher emission rates to achieve only a marginal increased removal rate. This would result in years of higher emissions before the RHCT would be installed.

Considering the existing systems are being replaced with like systems, there could be years of implementation delay with a new system for marginal removal improvement, and the high dollars per ton control cost includes low capital cost assumptions this evaluation rejects the top ranked control technology for Unit 2 (new wet FGD) as RHCT.

While this is not used as the reason for the rejection of this top ranked option, comparison to the second ranked option [an upgrade to the existing wet FGD] shows that the high levelized cost differential and low differential removal rate of the new FGD option result in an excessive incremental dollars per ton removed of almost \$30,000 per ton.

The time period to modify the existing wet FGD systems is significantly shorter than installing other new systems and would result in lower emission rates sooner than other options. The average control cost to modify the existing wet FGD systems is well below \$5,000 per ton. This evaluation results in modification of the wet FGD systems as RHCT.



## 4.0 REGIONAL HAZE CONTROL TECHNOLOGY RESULTS

This report presents the analysis of control technologies for nitrogen oxides (NO<sub>x</sub>), and sulfur dioxide (SO<sub>2</sub>) for Minnkota Power Cooperative Inc.'s (Minnkota's) Milton R. Young Station (MRYS) Units 1 and 2. The final result of this analysis is a Regional Haze Control Technology (RHCT) emission rate for each unit based upon "the costs of compliance, the energy and non-air quality environmental impacts of compliance, any pollution control equipment in use at the source, the remaining useful life of the source..." (70 FR 39163). The presented emission rates in this section are the RHCT results.

The first four steps of RHCT are usually used to identify technologies, determine feasibility and evaluate cost, energy, non-air quality and useful life impacts. This analysis reviewed technologies on these factors starting from the baseline of the existing units that include ASOFA/SNCR and wet scrubbers. The RHCT analysis does not review technologies that do not achieve at least the baseline level of performance.

As stated in previous sections of the report, the first four steps of the technology evaluation provided for in the Guidelines were completed for both Units. Each pollutant required a different approach in order to determine RHCT emission rate. This section provides a brief description of the approach used for each pollutant and summarizes the results.

For NO<sub>x</sub> emissions, the top ranked technically feasible control technology for both units is the use of Rich Reagent Injection (RRI) in combination with Selective Non-Catalytic Reduction (SNCR) and Advanced Separated Overfire Air (ASOFA). However, the RRI+SNCR system is not an economically effective NO<sub>x</sub> control alternative for either Unit 1 or Unit 2 with average control cost of \$6,829 – \$13,769.

The Unit Control Costs for the next top ranked control technology, Optimized SNCR system, is above \$5,000 per ton on Unit 1 (\$45,603 per ton) and Unit 2 (\$5,886). From an economic analysis viewpoint, optimized SNCR systems are not economically effective NO<sub>x</sub> control alternative for either unit.

This evaluation results show the existing SNCR system as the top ranked alternative.

For SO<sub>2</sub> emissions, the top ranked technology for Unit 2 was to replace the existing wet scrubber with a new wet scrubber. This technology was evaluated and rejected primarily because it was determined to be excessively costly on an actual dollars per ton removed basis (\$12,826 per ton). Furthermore this top

ranked control technology provided only limited additional removal for an order of magnitude additional costs compared to the second ranked control technology.

The next highest ranked control technology (and also top ranked for Unit 1) is to retrofit the existing wet scrubbers to increase removal. The OEM of the Unit 1 scrubber was engaged to evaluate how to increase the Unit 1 scrubber removal and re-evaluate a previous study they performed to increase removal in the Unit 2 scrubber. The mechanical upgrades the OEM included are replacing pump motors and changing nozzle designs. The various changes to operating conditions were evaluated based on the plant's previous operating history and experience to consider which conditions will improve removal, working with the existing system and not impact reliability. There are no sufficient economic or energy reasons to reject modifying the existing scrubbers. There are non-environmental reasons taking are into consideration associated with scrubber operational changes due to long term impact to the scrubber ponds. Based upon this analysis modifying the existing scrubbers is a RHCT option for SO<sub>2</sub> emissions.

Table 4-1 and Table 4-2 summarize the control technologies and associated emission rates for each pollutant and for each unit. The RHCT emission rates are presented as a 30-day rolling average to account for variations in boiler operation, and fuel sulfur content.

**Table 4-1: RHCT 30-Day Rolling Average Emission Rate, MRYS Unit 1**

<b>Pollutant</b>	<b>Control Technology</b>	<b>Emission Rate (lb/million Btu)</b>
NO <sub>x</sub>	Existing Selective Non-Catalytic Reduction (SNCR) and Advanced Separated Over Fire Air (ASOFA) <sup>1</sup>	0.36
SO <sub>2</sub>	Modify the existing Wet Flue Gas Desulfurization (FGD) system <sup>2</sup>	0.10

1: Excludes startups. See referenced BACT analysis for a detailed discussion.

**Table 4-2: RHCT 30-Day Rolling Average Emission Rate, MRYS Unit 2**

<b>Pollutant</b>	<b>Control Technology</b>	<b>Emission Rate (lb/million Btu)</b>
NO <sub>x</sub>	Existing Selective Non-Catalytic Reduction (SNCR) and Advanced Separated Over Fire Air (ASOFA) <sup>1</sup>	0.35
SO <sub>2</sub>	Modify the existing Wet Flue Gas Desulfurization (FGD) system <sup>2</sup>	0.10

1: Excludes startups. See referenced BACT analysis for a detailed discussion.

The four factor analysis was completed based on a request by the North Dakota Department of Health (NDDH) while utilizing the EPA 2016 Guidance document. The NDDH has requested this information for the purpose of WRAP modeling. As EPA has indicated the Regional Haze Roadmap may be updated, and the results of the WRAP modeling will provide new information to be considered, Minnkota reserves

the right to modify the 4 Factor analysis once the Regional Haze Roadmap, any additional guidance and the results of the WRAP modeling are available. In addition, Minnkota reserves the right to conduct a 5<sup>th</sup> Factor based on visibility modeling once the results of the WRAP modeling are available. This analysis is provided to assist the NDDH in the WRAP modeling and is not intended to serve as an agreement by Minnkota to any changes in permitted emission limits or permit conditions.



CREATE AMAZING.

Burns & McDonnell World Headquarters  
9400 Ward Parkway  
Kansas City, MO 64114  
O 816-333-9400  
F 816-333-3690  
[www.burnsmcd.com](http://www.burnsmcd.com)



May 29, 2019

Mr. Jim Semerad  
Director, Division of Air Quality  
North Dakota Department of Environmental Quality  
Gold Seal Center, 918 East Divide Ave  
Bismarck, ND 58501-1947

Dear Mr. Semerad:

Re: Four-Factor Analysis – Milton R. Young Station Unit 1 and Unit 2

Minnkota appreciates the North Dakota Department of Environmental Quality's (NDDEQ) review of the Milton R. Young Station (MRYS) four-factor analysis submitted for the second implementation period of the Regional Haze Rule. As a part of NDDEQ's review, six comments were provided to Minnkota (dated March 18, 2019) as the basis for revising our first report, which was submitted on January 31, 2019. The following provides Minnkota's responses to each of these six comments. Additionally, two hardcopies of Minnkota's revised four-factor analysis report are enclosed.

- 1) Summary of NDDEQ Comment: *"All estimates of costs should be based on current (2019) dollars not 2021 dollars...All estimates of capital costs must be consistent with [EPA's] Control Cost Manual."*

Minnkota Response: The revised report reflects 2019 dollars and all capital costs are now consistent with the Control Cost Manual. (Updates appear throughout report impacting cost values.)

- 2) Summary of NDDEQ Comment: *"...baseline emission rates were based on the maximum 30-day rolling average from 2014-2018. Baseline emissions should represent expected future annual emissions..."*

Minnkota Response: Per our discussion with NDDEQ, baseline emissions for both Unit 1 and Unit 2 have been revised and are now based on a 3-year annual average from 2016-2018. For each unit, this baseline period represents two non-major outage years and one major outage year. Emissions data submitted as required by 40 CFR Part 75 were used to determine the baseline emissions. (Discussed in section 1.1.5.)

- 3) Summary of NDDEQ Comment: *“The costs of Rich Reagent Injection (RRI) appears to be excessive...Please revise the estimates for both units or provide a detailed explanation for the high cost.”*

Minnkota Response: The cost estimates for RRI used in the first draft report were determined using: (1) computational fluid dynamics modeling, boiler mapping and RRI system design in conjunction with advanced separated overfire air (ASOFA) and selective non-catalytic reduction (SNCR) by technology vendor Fuel Tech, and (2) installation and balance of plant (BOP) costs determined by Burns & McDonnell (BMcD) with input from Minnkota. The enclosed revised report, as well as the separately submitted (through confidentiality) Fuel Tech vendor proposals, provide complete details. Minnkota firmly believes that the costs used in the first report are accurate and represent actual costs for installation of RRI with ASOFA and SNCR at MRYS. As such, these costs have not been changed in the revised report. (Discussed in Sections 2.5.1.1, 2.5.1.2 and the addition of Appendices A & B.)

- 4) Summary of NDDEQ Comment: *“Many cost estimates throughout the analysis are based on vendor budgetary quotes or engineering estimates. When cost estimates are not based on EPA’s Control Cost Manual, evidence for the estimate must be provided...”*

Minnkota Response: As requested, the revised report contains discussion and evidence of vendor budgetary quotes and engineering estimates where used. BMcD has prepared a more detailed breakdown of installation and BOP costs based on a combination of vendor quotations and engineering estimates; this is included as appendices to the revised report. Additionally, confidential vendor proposals from Fuel Tech (NO<sub>x</sub> control systems) and Marsulex Environmental Technologies (SO<sub>2</sub> control systems) have been submitted separately via confidential avenues. Minnkota is confident that the costs used accurately represent the actual costs for installing the emissions control systems at MRYS. (Discussed in Sections 2.5.1.1, 2.5.1.2, 3.5.1.2 and the addition of Appendices A & B.)

- 5) Summary of NDDEQ Comment: *“...“levelizing” of costs using the normal electric utility industry method is not acceptable...The costs must be revised to be consistent with the Control Cost Manual.”*

Minnkota Response: The actual cost estimating methods used in the first report were consistent with the Control Cost Manual. However, the nomenclature was not consistent. Therefore, in the revised report, the nomenclature has been updated to be consistent with the Control Cost Manual. The “annualized total cost” (ATC) represents the annual cost of procurement, construction and operation over a 20-year design life, in current day dollars. The ATC represents an annual payment in current day dollars sufficient to finance the project over its entire life. The ATC is the sum of the annualized capital cost and the first year operating & maintenance cost. (Revised Section 1.1.6.)

- 6) Summary of NDDEQ Comment: “...the projected emissions (tpy) for a “Modified Wet FGD” were based on future higher sulfur coal. It appears the baseline emission rates were also based on future higher sulfur coal. ...the high baseline emission rates should be explained.”

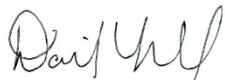
Minnkota Response: The projected emissions have been modified to reflect a common wet FGD inlet condition. The common/baseline wet FGD inlet condition is the average continuous emissions monitor readings for the 2016-2018 baseline years. (Discussed in section 1.1.5.)

In addition to Minnkota’s above responses to the NDDEQ comments and our enclosed revised four-factor analysis report, a separate submission containing confidential documents has also been provided.

Thank you for the attention given to the MRYs four-factor analysis report. If you have any further questions regarding this revised report, please contact me by email at [dlaudal@minnkota.com](mailto:dlaudal@minnkota.com) or by phone at (701) 795-4216.

Sincerely,

MINNKOTA POWER COOPERATIVE, INC.



Daniel A. Laudal, Ph.D.  
Environmental Manager

Enclosure

c: Gerad Paul  
Craig Bleth  
Tim Hagerott  
Kevin Thomas  
Jon Madison  
Young Station File

# Regional Haze Control Study



**Minnkota Power Cooperative, Inc.**

**Milton R. Young Station Unit 1 and Unit 2  
Project No. 107926**

**Revision 1  
5/28/2019**

# **Regional Haze Control Study**

prepared for

**Minnkota Power Cooperative, Inc.  
Milton R. Young Station Unit 1 and Unit 2  
Center, North Dakota**

**Project No. 107926**

**Revision 1  
5/28/2019**

prepared by

**Burns & McDonnell Engineering Company, Inc.  
Kansas City, Missouri**

## INDEX AND CERTIFICATION

### Minnkota Power Cooperative, Inc. Regional Haze Control Study

Project No. 107926

#### Report Index

<u>Chapter Number</u>	<u>Chapter Title</u>	<u>Number of Pages</u>
	Executive Summary	3
1.0	Introduction	6
2.0	NO <sub>x</sub> RHCT Evaluation	13
3.0	SO <sub>2</sub> RHCT Evaluation	14
4.0	Regional Haze Control Technology Results	3

#### Certification

I hereby certify, as a Professional Engineer in the state of North Dakota, that the information in this document was assembled under my direct personal charge. This report is not intended or represented to be suitable for reuse by the Minnkota Power Cooperative, Inc. or others without specific verification or adaptation by the Engineer.

Christopher J. Marks, PE; ND #PE-9703  
Insert Engineer's Name, P.E., state, & license

Date: \_\_\_\_\_ Insert Date

## TABLE OF CONTENTS

### Page No.

<b>EXECUTIVE SUMMARY .....</b>	<b>III</b>
<b>1.0 INTRODUCTION.....</b>	<b>1-1</b>
1.1 RHCT Analysis Process.....	1-2
1.1.1 Identification of Available Retrofit Control Technologies.....	1-3
1.1.2 Elimination of Technically Infeasible Options.....	1-3
1.1.3 Evaluate Technically Feasible Control Option by Effectiveness .....	1-4
1.1.4 Four Factor Impact Analysis.....	1-4
1.1.5 Baseline Emissions .....	1-4
1.1.6 Methodology for Estimated Costs .....	1-5
1.2 Background.....	1-7
<b>2.0 NO<sub>x</sub> RHCT EVALUATION .....</b>	<b>2-1</b>
2.1 NO <sub>x</sub> Evaluation Basis .....	2-1
2.2 Identification of Retrofit NO <sub>x</sub> Control Technologies .....	2-2
2.3 Technical Description and Feasibility Analysis .....	2-2
2.3.1 Selective Catalytic Reduction.....	2-2
2.3.2 Rich Reagent Injection & Selective Non-Catalytic Reduction.....	2-3
2.3.3 Optimized Selective Non-Catalytic Reduction.....	2-3
2.3.4 Results of Feasibility Analysis .....	2-3
2.4 Evaluate the Technically Feasible NO <sub>x</sub> Control Options by Effectiveness.....	2-4
2.5 Evaluation of Impacts for Feasible NO <sub>x</sub> Controls .....	2-6
2.5.1 Cost Estimates.....	2-6
2.5.2 Energy Impacts .....	2-13
2.5.3 Non-Air Quality Environmental Impacts.....	2-14
2.5.4 NO <sub>x</sub> Control Technology Evaluation Conclusion.....	2-15
<b>3.0 SO<sub>2</sub> RHCT EVALUATION .....</b>	<b>3-1</b>
3.1 SO <sub>2</sub> Evaluation Basis .....	3-1
3.2 Identification of Retrofit SO <sub>2</sub> Control Technologies.....	3-2
3.3 Technical Description and Feasibility Analysis .....	3-2
3.3.1 Wet Flue Gas Desulfurization.....	3-3
3.3.2 Semi-Dry Flue Gas Desulfurization.....	3-4
3.3.3 ReACT Dry Scrubbing Process .....	3-5
3.3.4 Results of Feasibility Analysis .....	3-5
3.4 Evaluate Technically Feasible SO <sub>2</sub> Control Options by Effectiveness .....	3-6
3.5 Evaluation of Impacts for Feasible SO <sub>2</sub> Controls .....	3-6
3.5.1 Cost Evaluation.....	3-7
3.5.2 Energy Impacts .....	3-13
3.5.3 Non-Air Quality Environmental Impacts.....	3-14
3.5.4 SO <sub>2</sub> Control Technology Evaluation Conclusion .....	3-14

<b>4.0</b>	<b>REGIONAL HAZE CONTROL TECHNOLOGY RESULTS.....</b>	<b>4-1</b>
------------	--	------------



## LIST OF TABLES

	<u><b>Page No.</b></u>
Table 1-1: MRYS Unit 1 Baseline Emissions (2016-2018) .....	1-5
Table 1-2: MRYS Unit 2 Baseline Emissions (2016-2018) .....	1-5
Table 1-3: Economic Factors .....	1-6
Table 2-1: NO <sub>x</sub> Control Technologies Identified for RHCT Analysis .....	2-2
Table 2-2: MRYS RHCT NO <sub>x</sub> Control Feasibility Analysis Results .....	2-4
Table 2-3: Feasible NO <sub>x</sub> Control Technologies Identified for RHCT Analysis .....	2-4
Table 2-4: Capital Cost Estimate for MRYS Unit 1 & 2 RRI + SNCR System .....	2-8
Table 2-5: Capital Cost Estimate for MRYS Unit 1 & 2 Optimized SNCR System .....	2-9
Table 2-6: O&M Cost Estimate for MRYS Unit 1 & 2 RRI + SNCR System .....	2-10
Table 2-7: O&M Cost Estimate for MRYS Unit 1 & 2 Optimized SNCR System .....	2-11
Table 2-8: Annualized Total Cost of MRYS Unit 1 NO <sub>x</sub> Control Technologies .....	2-12
Table 2-9: Annualized Total Cost of MRYS Unit 2 NO <sub>x</sub> Control Technologies .....	2-12
Table 2-10: Auxiliary Energy Requirement of MRYS Unit 1 NO <sub>x</sub> Control Technologies .....	2-14
Table 2-11: Auxiliary Energy Requirement of MRYS Unit 2 NO <sub>x</sub> Control Technologies .....	2-14
Table 3-1: SO <sub>2</sub> Control Technologies Identified for RHCT Analysis .....	3-2
Table 3-2: MRYS RHCT SO <sub>2</sub> Control Feasibility Analysis Results .....	3-6
Table 3-3: Feasible SO <sub>2</sub> Control Technologies Identified for RHCT Analysis .....	3-6
Table 3-4: Capital Cost Estimate for MRYS Unit 2 New Wet Lime FGD System .....	3-8
Table 3-5: Capital Cost Estimate for MRYS Unit 1 Wet FGD System Modification .....	3-10
Table 3-6: O&M Cost Estimate for a New MRYS Unit 2 Wet Lime FGD System .....	3-11
Table 3-7: O&M Cost Estimate for MRYS Unit 1 and 2 Wet Lime FGD System Modification .....	3-12
Table 3-8: MRYS Unit 1 SO <sub>2</sub> Control System Annualized Total Cost .....	3-12
Table 3-9: MRYS Unit 2 SO <sub>2</sub> Control System Annualized Total Cost .....	3-13
Table 3-10: Auxiliary Energy Requirement of MRYS Unit 1 FGD Upgrades .....	3-14
Table 3-11: Auxiliary Energy Requirement of MRYS Unit 2 New FGD .....	3-14
Table 4-1: RHCT Step 5 Annual Average Emission Rate, MRYS Unit 1 .....	4-2
Table 4-2: RHCT Step 5 Annual Average Emission Rate, MRYS Unit 2 .....	4-2

**LIST OF ABBREVIATIONS**

<b><u>Abbreviation</u></b>	<b><u>Term/Phrase/Name</u></b>
ASOFA	Advanced separated over fire air
ATC	Annualized Total Cost
B&W	Babcock & Wilcox
BACT	Best Available Control Technology
BART	Best Available Retrofit Technology
BOP	Balance of plant
Burns & McDonnell	Burns & McDonnell Engineering Company, Inc.
CD	Consent decree
CDS	Circulating dry scrubber
CFD	Computational fluid dynamics
CO	Carbon monoxide
CO <sub>2</sub>	Carbon dioxide
CRF	Capital recovery factor
EPA	United States Environmental Protection Agency
ESP	Electrostatic precipitator
FDA	Flash dryer absorber
FGD	Flue gas desulfurization
Minnkota	Minnkota Power Cooperative, Inc.
MRYS	Milton R. Young Station
NDDEQ	North Dakota Department of Environmental Quality
NO <sub>x</sub>	Nitrogen oxides

<b><u>Abbreviation</u></b>	<b><u>Term/Phrase/Name</u></b>
NPV	Net present value
O&M	Operation & maintenance
OEM	Original equipment manufacturer
RBLC	RACT/BACT/LAER Clearinghouse
RHCT	Regional Haze Control Technology
RHR	Regional Haze Regulations
RRI	Rich reagent injection
RO	Reverse Osmosis
SCR	Selective catalytic reduction
SDA	Spray dryer absorber
SNCR	Selective non-catalytic reduction
SO <sub>2</sub>	Sulfur dioxide
Square Butte	Square Butte Electric Cooperative
TPI	Total plant investment
URGE	Ultimate short-term maximum gross output
VOCs	Volatile organic compounds
WRAP	Western Regional Air Partnership

## EXECUTIVE SUMMARY

This report presents the Regional Haze Control Technology (RHCT) analysis for nitrogen oxides (NO<sub>x</sub>), and sulfur dioxide (SO<sub>2</sub>) for Minnkota Power Cooperative, Inc.'s Unit 1 and Square Butte Electric Cooperative's Unit 2 at the Milton R. Young Station (MRYS)

The MRYS is a two-unit station, located near Center, North Dakota. Unit 1 (257 MWg) commenced commercial operation in 1970, and Unit 2 (477 MWg) commenced operation in 1977. Both units employ Babcock and Wilcox cyclone boilers, and both boilers fire North Dakota lignite supplied from BNI Coal, Ltd's Center Mine. Each unit is equipped with Advanced Separated Over Fire Air (ASOFA) and selective non-catalytic reduction (SNCR) for NO<sub>x</sub> control. Each unit is equipped with wet flue gas desulfurization (FGD) for SO<sub>2</sub> control. Each unit employs an electrostatic precipitator (ESP) for particulate control. Each unit employs halide injection and activated carbon injection for the control of mercury.

On July 6, 2005, the United States Environmental Protection Agency (U.S. EPA or EPA) finalized the Regional Haze Regulations (RHR) and Guidelines for BART Determinations. In July of 2016, the EPA issued draft guidance for the second implementation period of the RHR. The guidance document requires a "four factor analysis" to be conducted for sources that have the potential to impair visibility in Class 1 areas. The four statutory factors are:

- The cost of compliance
- The time necessary for compliance
- The energy and non-air quality environmental impacts of compliance
- The remaining useful life of the source

This report presents the required "four factor analysis" for MRYS. Note that for MRYS, Minnkota has determined that the "remaining useful life of the source" is not a relevant factor in the analysis. The term "RHCT analysis" is used throughout this report to refer to the analysis that has been conducted in compliance with the requirements of EPA's July 2016 draft guidance.

The guidance document, in general, indicates that the goal of the second implementation period is to evaluate all sources for incremental visibility improvement, including those sources that were previously determined to be Best Available Retrofit Technologies (BART)-eligible. MRYS Unit 1 and Unit 2 were previously determined to be BART-eligible by the North Dakota Department of Environmental Quality (NDDEQ).

This RHCT evaluation is intended to inform NDDEQ of the future potential to reduce emissions at MRYS and the cost associated with these reductions. This evaluation is based on a top down evaluation of control technologies and will provide NDDEQ an emission rate for visibility impairment modeling.

There are five predefined steps for conducting a RHCT analysis. Steps 1 through 3 include identifying control technologies, evaluating feasibility, and ranking feasible options by control effectiveness. Step 4 involves a technical evaluation of economic, energy, and non-air environmental impacts related to each feasible control technology. This evaluation addresses these first four steps, resulting in an emission rate for the Step 5 Class 1 area visibility impairment impact analysis.

Unlike the previous BART analysis, this analysis reviews technologies on a ‘Top Down’ basis. The best (lowest emitting) feasible technology that is acceptable (considering economic, energy and non-air impacts) will be evaluated by NDDEQ for visibility impact reduction. The results of conducting the four step analysis will provide a recommendation to NDDEQ of a potential RHCT and the associated emission rate.

This analysis used several reference works, including the RACT/BACT/LAER Clearinghouse (RBLC), to identify which control technologies to evaluate. The technologies were reviewed for feasibility and those deemed infeasible were eliminated from further study. The feasible control technologies were then ranked by control efficiency with estimates of costs necessary to implement, operate, and maintain such technologies. The top ranked technology was evaluated based upon the average cost (dollars per ton removed) to determine if it was acceptable. The final RHCT results are summarized in the tables below. The RHCT emission rates are presented as annual average emission rates to account for variations in boiler operation, and fuel quality (including sulfur content). These are the emission rates utilized in the economic evaluation.

**MRYS Unit 1 RHCT Annual Average Emission Rates**

<b>Pollutant</b>	<b>Control Technology</b>	<b>Emission Rate (lb/million Btu)</b>
NO <sub>x</sub>	Existing Selective Non-Catalytic Reduction and Advanced Separated Over Fire Air	0.332
SO <sub>2</sub>	Modify the existing Wet Flue Gas Desulfurization system	0.061

**MRYS Unit 2 RHCT Annual Average Emission Rates**

<b>Pollutant</b>	<b>Control Technology</b>	<b>Emission Rate (lb/million Btu)</b>
NO <sub>x</sub>	Existing Selective Non-Catalytic Reduction and Advanced Separated Over Fire Air	0.334
SO <sub>2</sub>	Modify the existing Wet Flue Gas Desulfurization system	0.057

The four factor analysis was completed based on a request by NDDEQ while utilizing the EPA 2016 Guidance document. The NDDEQ has requested this information for the purpose of Western Regional Air Partnership (WRAP) modeling, and potentially for emissions reductions for the second implementation period. The emission rates in this report are for WRAP modeling and are not proposed permit emission limits. As EPA has indicated, the Regional Haze Roadmap may be updated, and the results of the WRAP modeling will provide new information to be considered. Minnkota reserves the right to modify the four factor analysis once the Regional Haze Roadmap, any additional guidance and the results of the WRAP modeling are available. In addition, Minnkota reserves the right to conduct a 5<sup>th</sup> factor analysis based on visibility modeling once the results of the WRAP modeling are available.

This analysis is provided to assist the NDDEQ in the WRAP modeling and is not intended to serve as an agreement by Minnkota to any changes in permitted emission limits or permit conditions.

## 1.0 INTRODUCTION

This report presents the Regional Haze Control Technology (RHCT) analysis for nitrogen oxides (NO<sub>x</sub>), and sulfur dioxide (SO<sub>2</sub>) for Minnkota Power Cooperative, Inc.'s Unit 1 and Square Butte Electric Cooperative's Unit 2 at the Milton R. Young Station (MRYS)

The MRYS is a two-unit station, located near Center, North Dakota. Unit 1 (257 MWg) commenced commercial operation in 1970, and Unit 2 (477 MWg) commenced operation in 1977. Both units employ Babcock and Wilcox cyclone boilers, and both boilers fire North Dakota lignite supplied from BNI Coal, Ltd's Center Mine. Each unit is equipped with Advanced Separated Over Fire Air (ASOFA) and selective non-catalytic reduction (SNCR) for NO<sub>x</sub> control. Each unit is equipped with wet flue gas desulfurization (FGD) for SO<sub>2</sub> control. Each unit employs an electrostatic precipitator (ESP) for particulate control. Each unit employs halide injection and activated carbon injection for the control of mercury.

The United States Environmental Protection Agency (U.S. EPA or EPA) finalized the Regional Haze Regulations (RHR) and Guidelines for Best Available Retrofit Technology (BART) Determinations<sup>1</sup> in the Federal Register on July 6, 2005 (70 FR 39104). In July 2016, the EPA issued draft guidance for the second implementation period of the RHR<sup>2</sup>. The draft guidance for the second implementation period retains many aspects of the BART guidelines.

The guidance documents, in general, indicate the goal of the second implementation period is to evaluate all sources for incremental visibility improvement including those sources that were previously BART-eligible. Both units at MRYS were previously determined to be BART-eligible by the North Dakota Department of Environmental Quality (NDDEQ). BART is defined as "an emission limitation based on the degree of reduction achievable through the application of the best system of continuous emission reduction for each pollutant which is emitted by a BART-eligible source. The emission limitation must be established on a case-by-case basis, taking into consideration the technology available, the costs of compliance, the energy and non-air quality environmental impacts of compliance, any pollution control equipment in use at the source, the remaining useful life of the source, and the degree of improvement in

---

<sup>1</sup> "Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations"; Environmental Protection Agency; Federal Register, Volume 70, No. 128; July 6, 2005.

<sup>2</sup> "Draft Guidance on Progress Tracking Metrics, Long-Term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period", Environmental Protection Agency; Federal Register, Volume 81, No. 131; July 8, 2016.

visibility which may reasonably be anticipated to result from the use of such technology” (70 FR 39163). Note that for MRYS, Minnkota has determined that the “remaining useful life of the source” is not a relevant factor in the analysis.

The second implementation period guidance indicates a similar review to BART should be performed but in the second round the technology evaluation should be based on a ‘top down’ approach. The evaluation criteria are the same as the previous BART analysis, which is on a case-by-case basis considering availability, cost, energy and non-air quality impacts. However, in a ‘top down’ analysis the highest ranked technology that meets the acceptable criteria in the first four steps is the selected technology. The final determination of what top ranked technologies across the utility fleet will be accepted, if any, as the Regional Haze Control Technology (RHCT) is dependent on Step 5 (visibility modeling) and will be based on the modeling performed by the Western Regional Air Partnership (WRAP). This RHCT evaluation will be used by the NDDEQ as a tool to evaluate the potential to reduce emissions at MRYS and the cost associated with these reductions.

## **1.1 RHCT Analysis Process**

The general steps for determining RHCT for each pollutant are virtually the same as the previous BART steps (70 FR 39164) and are as follows:

STEP 1 - Identify all available retrofit control technologies.

STEP 2 - Eliminate technically infeasible options.

STEP 3 - Evaluate control effectiveness of remaining control technologies.

STEP 4 - Evaluate the following impacts for each feasible control technology and document results:

The cost of compliance.

The time required for compliance.

The energy and non-air quality environmental impacts of compliance.

The remaining useful life of the source.

STEP 5 – Evaluate the visibility impacts.

Unlike the previous BART analysis where all five steps were performed at once, the 2016 EPA Draft Guidance’s approach for the second implementation period of the regional haze program is breaking the first four steps apart from the fifth step. The first four steps are performed on a ‘top down’ basis to determine the top ranked control technology that is applicable to each source. The fifth step, evaluation of visibility impacts, is being conducted by WRAP. The WRAP evaluation of visibility impacts will then



be used by the State (as part of the development of the State Implementation Plan) to determine which sources, if any, are needed to fulfill the Reasonable Progress Goals required by the RHR.

Minnkota retained Burns & McDonnell to assist in the completion of the first four steps of the RHCT analysis for MRYS. Burns & McDonnell is a full service engineering, architectural, construction and environmental firm. The company plans, designs and constructs electric generating facilities and has been providing environmental services to the power industry since the 1970s. As a result of their long history providing these services, Burns & McDonnell has extensive experience in permitting, Best Available Control Technology (BACT) studies, BART studies and control technology analysis similar to a RHCT analysis.

### **1.1.1 Identification of Available Retrofit Control Technologies**

The initial step in the RHCT determination is the identification of available retrofit control technologies. In order to identify the available control technologies, several reference works are consulted. A preliminary list of control technologies and their estimated capabilities is then developed.

### **1.1.2 Elimination of Technically Infeasible Options**

The second step of the RHCT process is to evaluate the control processes that have been identified and determine if any of the processes are technically infeasible. The BART guidelines are applicable to this RHCT analysis. These guidelines discuss consideration of two key concepts during this step in the analysis. The two concepts to consider are the “availability” and “applicability” of each control technology.

A control technology is considered available “if the source owner may obtain it through commercial channels, or it is otherwise available in the common sense meaning of the term,” or “if it has reached the stage of licensing and commercial availability.” On the contrary, a control technology is not considered available, “in the pilot scale testing stages of development.” (70 FR 39165) When considering a source’s applicability, technical judgment must be exercised to determine “if it can reasonably be installed and operated on the source type.” The EPA also does not “expect a source owner to conduct extended trials to learn how to apply a technology on a totally new and dissimilar source type.” (70 FR 39165) “A technology that is available and applicable is technically feasible.” (70 FR 39165)

A control technology is considered technically infeasible if physical, chemical or engineering principles conclude that technical difficulties would preclude use of the control option on the emission unit under review.

### **1.1.3 Evaluate Technically Feasible Control Option by Effectiveness**

The third step in the RHCT analysis is to evaluate the control effectiveness of the technically feasible alternatives. During the feasibility determination in step 2 of the analysis, the control efficiency is reviewed and presented with the description of each technology. The evaluation of the technically feasible alternatives concludes with the alternatives ranked in descending order of control effectiveness.

### **1.1.4 Four Factor Impact Analysis**

Step four in the analysis procedure is the impact analysis. The BART Determination Guidelines (70 FR 39166) and the draft guidelines for the second implementation period (81 FR 44608) each list four factors to be considered in the impact analysis. The RHCT evaluation will consider the following four factors in the impact analysis:

- The costs of compliance
- The time required for compliance
- The energy and non-air quality environmental impacts of compliance
- The remaining useful life of the source.

The first three of the four factors considered in the impact analysis are discussed in the associated pollutant section. The remaining useful life of the source would have been included as part of the cost of compliance, however for MRYS, Minnkota has determined that the “remaining useful life of the source” is not a relevant factor in the analysis.

In the second implementation period, the impact analysis is performed on a ‘top down’ basis. The highest ranked (lowest emitting) technology is evaluated on the above factors for acceptability. If the top-ranked control technology is unacceptable, then the next highest ranked control technology is evaluated. This process continues until the highest ranked acceptable technology is identified.

### **1.1.5 Baseline Emissions**

The cost of compliance evaluation is typically performed on an annualized dollars per ton of pollutant removed basis. In order to determine the tons removed by a proposed technology, a baseline emission rate must be determined as a basis for the comparison. The MRYS units both have existing SO<sub>2</sub> and NO<sub>x</sub> pollution control systems in service, and the baseline is calculated with those systems in operation. Since the control costs are based on annual costs, the baseline emission rates need to be based on a similar long-term basis.

The baseline emission rates were developed by evaluating the three most recent years (2016-2018) for Unit 1 and for Unit 2. This baseline was established in consultation with the NDDEQ. The baseline period, for each unit, contains two non-major outage years and one major outage year. Previously submitted emissions data as required by 40 CFR Part 75 were used to determine the baseline emissions. A summary of the baseline emission rates and annual tons of emissions is provided in Table 1-1 and Table 1-2 for Unit 1 and Unit 2, respectively.

The scrubber inlet SO<sub>2</sub> conditions for each unit at MRYS are measured using continuous emissions monitors (CEMS). These inlet conditions during the baseline period for Unit 1 (2.327 lb/MMBtu) and Unit 2 (2.487 lb/MMBtu) will be used as the basis for future sulfur content at the inlet of each scrubber.

**Table 1-1: MRYS Unit 1 Baseline Emissions (2016-2018)**

<b>Pollutant</b>	<b>Control Technology</b>	<b>Emissions, lb/MMBtu</b>	<b>Emissions, tpy</b>	<b>Heat Input, MMBtu/year</b>
SO <sub>2</sub>	Wet FGD	0.0739	777	20,726,417
NO <sub>x</sub>	ASOFA/SNCR	0.332	3,435	20,726,417

**Table 1-2: MRYS Unit 2 Baseline Emissions (2016-2018)**

<b>Pollutant</b>	<b>Control Technology</b>	<b>Emissions, lb/MMBtu</b>	<b>Emissions, tpy</b>	<b>Heat Input, MMBtu/year</b>
SO <sub>2</sub>	Wet FGD	0.126	2165	34,354,956
NO <sub>x</sub>	ASOFA/SNCR	0.334	5,735	34,354,956

### 1.1.6 Methodology for Estimated Costs

The cost summary of each control technology alternative is presented in the section for each pollutant. Installed capital and annual operating and maintenance (O&M) cost estimates for each alternative are presented individually. The Annualized Total Cost (ATC) represents the annual cost of procurement, construction and operation over a 20-year design life, in current day dollars. The ATC is the sum of the annualized capital cost and the first year O&M cost and represents an annual payment in current day dollars sufficient to finance the project over its entire life.

In determining the ATC, a Capital Recovery Cost (CRC) is calculated to annualize the ‘overnight’ capital cost. The CRC is determined by multiplying the Net Present Value (NPV) by a Capital Recovery Factor (CRF). The CRF was calculated from the project economic conditions and then applied separately to the estimated capital costs. The equations used are shown below.

$$CRF = \left( \frac{i(1+i)^n}{(1+i)^n - 1} \right)$$

$$CRC = CRF \times NPV$$

Where,

CRF = Capital Recovery Factor

CRC = Capital Recovery Cost

NPV = Net Present Value of the capital investments required (overnight cost).

i = discount rate

n = design life in years

For the economic conditions described in Table 1-3, the CRF was calculated to be 0.08368.

**Table 1-3: Economic Factors**

Factor	Value
Total Possible Operating Hours per Year	8,760
Unit 1 Plant Capacity Factor, 2016-2018 baseline average	79.9%
Unit 2 Plant Capacity Factor, 2016-2018 baseline average	78.7%
Amortization Life, Years	20
Allowance for Funds Used During Construction	Not Included
Property Taxes, Insurance, %	Not Included
Amortization Rate for APC Capital Costs	Not Included
Interest Rate used in Capital Recovery Cost calculation	5.5%
Construction Cost Escalation	Not Included
Maintenance Material and Labor Cost, % of Direct Capital	3%
Non-Fuel O&M Escalation	Not Included
Fuel (coal and natural gas) Escalation	Not Included
Lost Electrical Generation Cost, \$/MW-hr	\$22.00
Auxiliary Electric Power Cost, \$/MW-hr	\$48.07
Reverse Osmosis Water, \$/kgal	\$9.03
Condensate water, \$/kgal	\$9.85
Urea 70% Solution, \$/ton	\$419.00
Lime, \$/ton	\$192.00
FGD Byproduct Disposal, \$/ton	\$6.00

(1) All costs are in 2019 dollars unless noted otherwise.

The capital cost (NPV in the equation above) is an ‘overnight’ installed cost for the equipment, in current day dollars, that does not include income tax effects, owners’ costs, escalation during construction, or interest costs from financing. The O&M cost used is the first-year costs, in 2019 dollars. The O&M cost

was not further inflated or otherwise annualized. The ATC is the sum of the annualized capital cost and the first year O&M cost. Therefore:

$$\text{ATC} = \text{CRC} + 1^{\text{st}} \text{ Year O\&M} = (\text{CRF} \times \text{NPV}) + 1^{\text{st}} \text{ Year O\&M} = 0.08368 \times \text{NPV} + 1^{\text{st}} \text{ Year O\&M}$$

The economic analyses presented in this report not only includes the estimated capital and annual O&M costs for each top ranked control technology, but also the ATC for economic comparison.

## 1.2 Background

MRYS is a steam electric generating plant with two units. Unit 1 employs ASOFA + SNCR for NO<sub>x</sub> control, achieving 59% NO<sub>x</sub> reduction. Particulate control is provided by a Research-Cottrell Electrostatic Precipitator (ESP) rated at approximately 99% control. Unit 1 has a Wet Flue Gas Desulfurization (FGD) system provided by Marsulex Environmental Technologies achieving compliance with a 30-day rolling average 95% SO<sub>2</sub> removal efficiency, based on inlet and outlet SO<sub>2</sub> CEMS, and exhausts to a 564-foot-tall chimney.

Unit 2 employs ASOFA + SNCR for NO<sub>x</sub> control, achieving 60% NO<sub>x</sub> reduction. Particulate control for Unit 2 is provided by a Wheelabrator-Lurgi ESP rated at approximately 99% control. Unit 2 has a Combustion Equipment Associates wet FGD system (modified by Combustion Engineering) achieving compliance with a 30-day rolling average 90% SO<sub>2</sub> removal efficiency, based on inlet and outlet SO<sub>2</sub> CEMS, and a 30-day rolling average 0.15 lb/MMBtu emission rate, and exhausts to a 550-foot-tall chimney.

Unit 1 began commercial operation on November 20, 1970 and Unit 2 on May 11, 1977.

## 2.0 NO<sub>x</sub> RHCT EVALUATION

The RHCT analyses for NO<sub>x</sub> emissions from MRYS Unit 1 and Unit 2 are described in this section. Technical descriptions of MRYS Unit 1 and Unit 2 boilers and existing air pollution control equipment are provided. Minnkota previously entered into a Consent Decree (CD) that required MRYS to install BACT for NO<sub>x</sub>, which was determined to be SNCR systems with ASOFA on both units. These technologies are the current baseline condition for the two units.

### 2.1 NO<sub>x</sub> Evaluation Basis

MRYS Unit 1 includes a B&W steam generator installed in 1970. The steam generator is a lignite-fired boiler with multiple cyclone-furnaces installed in parallel using balanced-draft and natural circulation. The boiler is fired by seven ten-foot diameter cyclone furnaces, arranged “three over four” across the front wall of the lower boiler. The unit has a tubular air heater installed between the boiler and the flue gas ductwork leading to the ESP. Unit 1’s boiler serves a turbine generator with a nameplate rating of 257 MWg<sup>3</sup>. The Unit 1 boiler at MRYS includes a unique coal conditioning system (drying, crushing, and feeding) for each cyclone furnace specifically designed to aid in proper combustion of the lignite fuel. Lignite fuel is the sole solid fuel for the plant and is supplied from the Center Mine, operated by BNI Coal, LTD, located adjacent to the site. The baseline emission rate of the Unit 1 boiler using the existing ASOFA/SNCR system is 0.332 lb NO<sub>x</sub>/MMBtu, as described previously in Section 1.1.5.

MRYS Unit 2 is a B&W steam generator installed in 1977. The steam generator is a lignite-fired boiler with multiple cyclone-furnaces installed in parallel using balanced-draft and natural circulation assisted with circulation pumps. The boiler is fired by twelve ten-foot diameter cyclone furnaces, arranged “three over three” across the front and rear walls of the lower boiler. The unit has a tubular air heater installed between the boiler and the flue gas ductwork leading to the ESP. Unit 2’s boiler serves a turbine-generator with a nameplate rating of 477 MWg<sup>4</sup>. The Unit 2 boiler at MRYS includes a unique coal conditioning system (drying, crushing, and feeding) for each cyclone furnace specifically designed to aid in proper combustion of the lignite fuel. Lignite fuel is the sole solid fuel for the plant and is supplied from the Center Mine located adjacent to the site. The baseline emission rate of the Unit 2 boiler using the existing ASOFA/SNCR system is 0.334 lb NO<sub>x</sub>/MMBtu, as described previously in Section 1.1.5.

---

<sup>3</sup> Ibid EPA’s eGRID database; April 2003.

<sup>4</sup> Ibid EPA’s eGRID database; April, 2003.

## 2.2 Identification of Retrofit NO<sub>x</sub> Control Technologies

The initial step in the RHCT determination is the identification of retrofit NO<sub>x</sub> control technologies. In order to identify the applicable NO<sub>x</sub> control technologies, several reference works were consulted, including the RACT/BACT/LAER Clearinghouse (RLBC). From this and other literature sources, a preliminary list of control technologies and their estimated capabilities for potential application to MRYS was developed. However, as discussed in the introduction, Minnkota already has ASOFA and SNCR systems installed on both units to achieve 30-day rolling average removal rates of 60% and 59% on Unit 1 and Unit 2, respectively. Thus, the control technologies included in the RHCT analysis either meet this minimum level of control or have more stringent removal efficiency. Table 2-1 contains the results of this effort.

**Table 2-1: NO<sub>x</sub> Control Technologies Identified for RHCT Analysis**

<b>Control Technology</b>	<b>Approximate Annual Control Efficiency*</b>
Selective Catalytic Reduction and ASOFA	90%
Rich Reagent Injection and SNCR and ASOFA	66-68%
Optimized SNCR and ASOFA	60-61%
Existing SNCR* and ASOFA	Baseline 59-60%

\*Based on pre SNCR/ASOFA baseline of 0.820/0.817 lb NO<sub>x</sub>/MMBtu for Units 1 and 2, respectively.

## 2.3 Technical Description and Feasibility Analysis

The second step in the RHCT analysis procedure is a technical feasibility analysis of the options identified in Step 1. The RHCT guidelines discuss consideration of two key concepts during this step in the analysis. The two concepts to consider are the “availability” and “applicability” of each control technology. A control technology is considered available, “if it has reached the stage of licensing and commercial availability.” (70 FR 39165) On the contrary, a control technology is not considered available, “if it is in the pilot scale testing stages of development.” (70 FR 39165) When considering a control technology’s applicability, technical judgment must be exercised to determine “if it can reasonably be installed and operated on the source type.” (70 FR 39165) The technical feasibility analysis is presented below for each identified option.

### 2.3.1 Selective Catalytic Reduction

The lowest NO<sub>x</sub> emission levels from coal-fired utility boilers are typically achieved by installing and operating selective catalytic reduction (SCR) technology. In the SCR process, the gas stream is passed through a catalyst bed in the presence of ammonia to reduce NO<sub>x</sub> to molecular nitrogen and water. The process is termed “selective” because the ammonia preferentially reacts with the NO<sub>x</sub> rather than with the oxygen in the flue gas. A large reactor containing catalyst is used to enhance NO<sub>x</sub> reduction and ammonia utilization at lower flue gas temperatures than required by an SNCR system. SCR is usually

applied to flue gas in the 600°F to 750°F temperature range. There are variations in the SCR process for coal-fired boilers that mostly involve locations in the flue gas path where the catalyst is placed in order to promote the desired NO<sub>x</sub> emission reduction effect. This technology was reviewed in the previous BART and BACT analysis (2008-2010) and it was concluded by NDDEQ that SCR systems (of all types) are technically infeasible at MRYS. No new information or experience has occurred since 2010 to change the conclusion of this analysis and this technology remains technically infeasible.

### **2.3.2 Rich Reagent Injection & Selective Non-Catalytic Reduction**

Rich Reagent Injection (RRI) has been demonstrated and placed in continuous operation on multiple cyclone boilers. RRI is specifically intended for NO<sub>x</sub> emissions control on cyclone boilers. RRI adds dilute urea reagent to the hot boiler gases near the cyclones, which must be devoid of free oxygen in order to avoid oxidation of the urea and formation of additional NO<sub>x</sub>. This system is combined with SNCR to further reduce NO<sub>x</sub> emissions within the boiler. The ASOFA system would be operated in conjunction with the RRI and SNCR systems. RRI is considered technically feasible under limited conditions for application on the Unit 1 and Unit 2 cyclone boilers at MRYS.

### **2.3.3 Optimized Selective Non-Catalytic Reduction**

Taking into consideration the past operating experience of the existing system and vendor experience since the original installation, there is potential to reduce the emission rate further with enhancements to the existing system. These enhancements could include changing the nozzles on existing lances, replacing the existing lances, and adding lances in new locations. Additionally, allowing for higher ammonia slip rates than originally designed (i.e., 10 ppm vs. 5 ppm) will allow for higher levels of urea injection, which has the potential to further reduce NO<sub>x</sub> emission rates. The ASOFA system would be operated in conjunction with the optimized SNCR system. Optimized SNCR is considered technically feasible for application on the Unit 1 and Unit 2 cyclone boilers at MRYS.

### **2.3.4 Results of Feasibility Analysis**

The evaluations of the identified RHCT alternatives following the feasibility analysis are summarized in Table 2-2.



**Table 2-2: MRYS RHCT NO<sub>x</sub> Control Feasibility Analysis Results**

<b>Control Technology</b>	<b>In full-scale service on Existing Utility Boilers</b>	<b>In Service on Other Combustion Sources</b>	<b>Commercially Available</b>	<b>Technically Applicable to MRYS</b>
SCR	Yes	Yes	No*	No
RRI + SNCR	Yes	Yes	Yes	Yes**
Optimized SNCR	Yes	Yes	Yes	Yes
Existing SNCR	Yes	Yes	Yes	Yes

\*Not available on cyclone fired units firing North Dakota lignite.

\*\*Under limited operating conditions

## 2.4 Evaluate the Technically Feasible NO<sub>x</sub> Control Options by Effectiveness

The third step in the RHCT analysis procedure is to evaluate the control effectiveness of the technically feasible alternatives. In step 2 of the RHCT analysis, the NO<sub>x</sub> control efficiency was reviewed and presented as part of the technical description for each technology. The evaluations of the remaining RHCT alternatives following the feasibility analysis are summarized in Table 2-3. The alternatives are ranked in ‘top down’ descending order according to their annual effectiveness in NO<sub>x</sub> control.

**Table 2-3: Feasible NO<sub>x</sub> Control Technologies Identified for RHCT Analysis**

<b>Control Technology</b>	<b>Unit 1 Annual lb/MMBtu</b>	<b>Unit 2 Annual lb/MMBtu</b>
Applied RRI + SNCR/ASOFA	0.28	0.26
Applied Optimized SNCR/ASOFA	0.33	0.32
Existing SNCR/ASOFA	0.332	0.334

The ‘applied’ emission rates identified in Table 2-3 were developed as annual emission rates taking into account vendor supplied information, variations in load, variations in boiler operating conditions, and experience in the long-term variations in effectiveness of boiler NO<sub>x</sub> control technologies. The variable quality of mine-mouth lignite coal is responsible for most of the operating variation experienced. The vendor information is based on MRYS unit-specific measured data of boiler temperature and species of NO<sub>x</sub>, CO and O<sub>2</sub>. This data was mapped and used to perform computational fluid dynamics (CFD) modeling to determine the equipment, approximate injection locations, and subsequent emission rate able to be achieved. The ‘applied’ emission rates take into account that the rates must be continuously achievable on an annual basis including the impacts of changing unit loads, control equipment limitations, and variability in coal quality.

Load variation must be considered because at lower loads the ability to control NO<sub>x</sub> is reduced. The RRI and SNCR systems are designed to inject dilute urea into the correct temperature zones in the boiler for NO<sub>x</sub> control. The maximum NO<sub>x</sub> reductions from both RRI and SNCR systems occur when steady-state

conditions are achieved when the boiler is at or near full load. At all other conditions, the ability to control NO<sub>x</sub> can be significantly impacted. RRI operation depends on oxygen-deprived conditions, and without this (such as with one or more cyclones out of service and/or at lower loads), using the RRI system will increase NO<sub>x</sub> emissions. Multiple levels of injection are included to introduce reagent into the correct temperature zone at varying unit loads. However, even with multiple injection levels, emission reductions are reduced at lower loads.

MRYS is a mine-mouth plant that utilizes run-of-mine fuel, which results in significant coal quality variability. Within any 30-day period, the plant can, and has, experienced multiple days of lower quality coal that in turn, creates conditions that make NO<sub>x</sub> harder to control, increasing emissions and reagent usage rates.

These factors, along with unit-specific vendor information, were considered in developing the ‘applied’ annual evaluation rate. The emission rates stated by vendors are based on stable, steady state operating conditions, and do not reflect the varying conditions that occur over the life of the equipment, or even in a 30-day or annual operating period. An emission rate must account for operating during periods such as the transition period between two planned stable load conditions, and other unplanned operating variations described above.

During normal high load operations at MRYS, the lower portions of the Unit 1 and Unit 2 boiler are in an oxygen deficient, fuel rich environment. These conditions in the boiler reduce the amount of thermal NO<sub>x</sub> being produced as the fuel is combusted. These are the conditions required for optimal use of RRI. As the stoichiometric ratio (oxygen to fuel ratio) in the lower portion of the boiler increases, the performance of a RRI system decreases, with the urea becoming oxidized to create additional NO<sub>x</sub> in the presence of oxygen. Several operating conditions can cause lower boiler stoichiometric ratio to increase. Some of these conditions, which are frequently experienced at MRYS, are discussed below:

- Cyclone(s) out of service - Both Unit 1 and Unit 2 boilers are designed to operate with one cyclone out of service and still achieve full load. It is not unusual for single cyclones to be out of service for routine maintenance. Air leaking through the combustion air dampers of an out-of-service cyclone will increase NO<sub>x</sub> formation due to addition of oxygen in the fuel-rich zone.
- Main fuel oil in service – Due to variations in coal quality, cyclone(s) may become fouled, meaning that insufficient temperature exists for the slag to flow properly from the cyclone. During these times, it becomes necessary to co-burn fuel oil in the fouled cyclone(s), which

results in increased oxygen in the fuel-rich zone and the formation of additional NO<sub>x</sub>. When main fuel oil is in service, the ASOFA system for the cyclone(s) is deactivated because it is ineffective. The deactivation of the ASOFA for the cyclone(s) will increase the stoichiometric ratio in the lower boiler.

- Fuel Variability - With the variability of the coal that is being combusted, the carbon content of the coal also changes. Because the carbon content of the fuel is not known in real-time, the oxygen to fuel carbon ratio continuously changes as the coal composition naturally varies with deliveries from the mine.

As described above, the ‘applied’ annual emission rates established in Table 2-3, for both the RRI + SNCR/ASOFA and Optimized SNCR/ASOFA control technologies, have been determined based on MRYS unit-specific operations and represent annual average emission rates. Note that these projected emission rates do not equate to achievable annual emission permit limits, however.

## **2.5 Evaluation of Impacts for Feasible NO<sub>x</sub> Controls**

Step four in the RHCT analysis procedure is the impact analysis. The draft Guidelines (81 FR 44608) lists four factors to be considered in the impact analysis.

- The costs of compliance
- The time required for compliance
- The energy and non-air quality environmental impacts of compliance
- The remaining useful life of the source

Three of the four impacts required by the RHCT Guidelines are discussed in the following sections. The remaining useful life of the source was determined to be greater than the project life definition in the EPA’s OAQPS Control Cost Manual (EPA/453/B-96-001) and thus had no impact on the RHCT determination for MRYS.

### **2.5.1 Cost Estimates**

The following sections evaluate the top two ranked NO<sub>x</sub> control options on Unit 1 and Unit 2: replacing the existing SNCR systems with new RRI + SNCR systems and optimizing the existing SNCR systems (with both units maintaining the existing ASOFA systems). Cost estimates for the RRI + SNCR control technology were developed based on proposals from an RRI + SNCR vendor, and installation estimates were based upon Burns & McDonnell’s in-house experience for additional water treatment, compressed air, balance of plant (BOP) piping, access, and installation. The RRI + SNCR vendor utilized CFD

modeling results completed by another vendor as well as conducted on-site data measurement of boiler temperature and species of NO<sub>x</sub>, CO and O<sub>2</sub>. The measured data was mapped and used to perform additional CFD modeling to determine the equipment and optimum injection locations. The data collected by these vendors and the proposal of the RRI + SNCR technology vendor provide good assurance that the application of these technologies, and their associated costs, are well understood for the boilers at MRYS. Economic information utilized as inputs to the model are provided in Table 1-3.

#### **2.5.1.1 RRI + SNCR Capital Cost Estimate**

The vendor equipment cost estimate for the RRI + SNCR system is based on the vendor proposal and includes new RRI injectors and associated equipment as well as equipment necessary to modify the existing SNCR system. A proposal from the vendor has been submitted to NDDEQ under separate cover to protect confidential business information. The remaining capital cost estimate includes installation of the vendor equipment, supply and installation of necessary equipment access, and BOP costs.

Because boiler testing, data from CFD modeling, and detailed RRI injection analysis was performed by the vendors as part of the RRI + SNCR system evaluation, it is known that the necessary injection locations are not in easily accessible locations on either unit. Because of the detailed evaluation by the vendor, the proposed system is specific to MRYS and identified the need for significant BOP modifications. The BOP design accounted for the new recommended RRI + SNCR injection locations by including: new platforms and stairs to access the new injection elevations/locations; significant new piping for increased urea, cooling water, dilution water and atomization air; expansion of the microfiltration and reverse osmosis water system due to the increased dilution water usage; and supply and installation of the boiler bent tube openings for the new RRI + SNCR injectors, including the necessary boiler scaffolding. Appendix A includes a breakdown of major cost categories.

The NO<sub>x</sub> control system cost (Table 2-4) is representative of a typical furnish and erect contract.

**Table 2-4: Capital Cost Estimate for MRYS Unit 1 & 2 RRI + SNCR System**

<b>DIRECT COSTS</b>	<b>Unit 1 Estimated Cost (\$)</b>	<b>Unit 2 Estimated Cost (\$)</b>
<b>RRI and SNCR System</b>		
Equipment Cost	\$4,283,000	\$5,507,000
<b>BOP Costs</b>		
Mechanical Contract	\$1,611,000	\$4,709,000
Foundations and Steel	\$559,000	\$900,000
Electrical and Controls	\$131,000	\$179,000
<b>BOP Total Direct Cost</b>	<b>\$2,301,000</b>	<b>\$5,788,000</b>
<b>Total Direct Cost</b>	<b>\$6,584,000</b>	<b>\$11,295,000</b>
<b>INDIRECT COSTS</b>		
Engineering 10% of DC	\$647,000	\$1,129,000
Escalation	Not Included	Not Included
<b>Indirect Cost Subtotal</b>	<b>\$647,000</b>	<b>\$1,129,000</b>
Contingency (20% of DC)	\$723,000	\$1,242,000
Prime Contractor's Fee (3% of DC)	\$557,000	\$957,000
<b>Total Capital Requirement</b>	<b>\$8,511,000</b>	<b>\$14,623,000</b>

The total estimated capital cost estimate to upgrade the existing Unit 1 SNCR system to a RRI + SNCR system is \$8,511,000, or \$33.1/kW. The total estimated capital cost estimate to upgrade the existing Unit 2 SNCR system to a RRI + SNCR system is \$14,623,000, or \$30.7/kW.

### **2.5.1.2 Optimized SNCR Capital Cost Estimate**

The vendor equipment cost estimate for optimizing the SNCR system is based on the vendor proposal and includes equipment necessary to modify the existing SNCR system. Because of the detailed evaluation by the vendor, the proposed system is specific to the MRYS and identified the need for additional modifications. The design accounted for the new recommended SNCR injection locations by including the supply and installation of the boiler bent tube openings for the new SNCR injectors including the necessary boiler work platforms. The NO<sub>x</sub> control system cost (Table 2-5) is representative of a typical furnish and erect contract. Appendix B includes a breakdown of major cost categories.

**Table 2-5: Capital Cost Estimate for MRYS Unit 1 & 2 Optimized SNCR System**

	Unit 1 Estimated Cost (\$)	Unit 2 Estimated Cost (\$)
<b>DIRECT COSTS</b>		
<b>Optimized SNCR System</b>		
Equipment Cost	\$1,238,000	\$1,265,000
<b>BOP Costs</b>		
Mechanical Contract	\$321,000	\$958,000
Foundations and Steel	\$259,000	\$409,000
Electrical and Controls	\$38,000	\$48,000
<b>BOP Total Direct Cost</b>	\$618,000	\$1,415,000
<b>Total Direct Cost</b>	\$1,857,000	\$2,680,000
<b>INDIRECT COSTS</b>		
Engineering 10% of DC	\$183,000	\$268,000
Escalation	Not Included	Not Included
<b>Indirect Cost Subtotal</b>	\$183,000	\$268,000
Contingency (20% of DC)	\$204,000	\$295,000
Prime Contractor's Fee (3% of DC)	\$157,000	\$227,000
<b>Total Capital Requirement</b>	<b>\$2,400,000</b>	<b>\$3,470,000</b>

The total estimated capital cost estimate to optimize the Unit 1 SNCR system is \$2,400,000 or \$9.3/kW.

The total estimated capital cost estimate to optimize the Unit 2 SNCR system is \$3,470,000 or \$7.3/kW.

### 2.5.1.3 RRI + SNCR O&M Cost Estimate

The annual O&M costs are comprised of fixed costs (maintenance and labor) and variable cost (consumables). The fixed costs include operating labor, administrative and support labor, and the maintenance material and labor costs. No change in administrative, support and operating labor cost was assumed. The maintenance material and labor cost is estimated at 3% of the system direct capital costs in Table 2-4. Table 2-6 summarizes the O&M cost estimates for the RRI + SNCR systems.

Variable costs include reagent, cooling water, dilution water, auxiliary power costs and the loss of electrical generation revenues. The estimated annual costs for these consumables are the estimated change from the baseline conditions based on vendor provided consumption rates, unit operating assumptions and the unit cost information provided in Table 1-3. The costs associated with loss of electrical generation capacity (i.e. revenue lost) are because of the significant quantity of urea and water that is introduced to the boiler with increased dilute urea injection. This additional urea and water is evaporated and

negatively impacts the unit efficiency. Since the assumption of this RHCT analysis is that heat input is the same in the baseline case as for the future control alternatives, the loss in unit efficiency equates to a decrease in generation. While lost electricity sales revenues are not in actuality an O&M expense, they represent an opportunity cost of installing RRI + SNCR and are thus important to include for the purposes of this analysis.

**Table 2-6: O&M Cost Estimate for MRYS Unit 1 & 2 RRI + SNCR System**

<b>Fixed Costs</b>	<b>Unit 1</b>	<b>Unit 2</b>
Operating Labor	\$0	\$0
Admin and Support labor	\$0	\$0
Maintenance Material and Labor	\$47,000	\$54,000
<b>Total Fixed O&amp;M Costs</b>	<b>\$47,000</b>	<b>\$54,000</b>
<b>Variable Costs</b>		
Urea Reagent	\$4,522,000	\$4,590,000
Water	\$209,000	\$471,000
Auxiliary Power	\$45,000	\$44,000
Lost Generation	\$469,000	\$1,119,000
<b>Total Variable O&amp;M Costs</b>	<b>\$5,245,000</b>	<b>\$6,224,000</b>
<b>Total Annual O&amp;M Costs</b>	<b>\$5,292,000</b>	<b>\$6,278,000</b>
<b>Net Annual O&amp;M Cost (\$/MWh)</b>	<b>2.94</b>	<b>1.91</b>

O&M Cost represent costs above the baseline (existing system)

#### 2.5.1.4 Optimized SNCR O&M Cost Estimate

The annual O&M costs are comprised of fixed costs (maintenance and labor) and variable cost (consumables). The fixed costs include operating labor, administrative and support labor and the maintenance material and labor costs. The maintenance material and labor cost is estimated at 3% of the new direct capital costs in Table 2-5. No change in administrative, support and operating labor cost was assumed. Table 2-7 summarizes the O&M cost estimates for the Optimized SNCR system.

Variable costs include reagent, dilution water, auxiliary power costs and loss of electrical generation revenues. The estimated annual costs for these consumables are the estimated change from the baseline conditions based on vendor provided consumption rates, unit operating assumptions and the unit cost information provided in Table 1-3. The costs associated with loss of electrical generation capacity (i.e. revenue lost) are because of the significant quantity of urea and water that is introduced to the boiler with increased urea injection. This additional urea and water is evaporated and negatively impacts the unit efficiency. Since the assumption of this RHCT analysis is that heat input is the same in the baseline case as for the future control alternatives, the loss in unit efficiency equates to a decrease in power generation.

**Table 2-7: O&M Cost Estimate for MRYS Unit 1 & 2 Optimized SNCR System**

<b>Fixed Costs</b>	<b>Unit 1</b>	<b>Unit 2</b>
Operating Labor	\$0	\$0
Admin and Support labor	\$0	\$0
Maintenance Material and Labor	\$35,000	\$36,000
<b>Total Fixed O&amp;M Costs</b>	<b>\$35,000</b>	<b>\$36,000</b>
<b>Variable Costs</b>		
Urea Reagent	\$1,661,000	\$909,000
Water	\$19,000	\$116,000
Auxiliary Power	\$23,000	\$22,000
Lost Generation	\$95,000	\$414,000
<b>Total Variable O&amp;M Costs</b>	<b>\$1,798,000</b>	<b>\$1,461,000</b>
<b>Total Annual O&amp;M Costs</b>	<b>\$1,833,000</b>	<b>\$1,497,000</b>
<b>Net Annual O&amp;M Cost (\$/MWh)</b>	<b>1.02</b>	<b>0.46</b>

O&M Cost represent costs above the baseline (existing system)

### 2.5.1.5 Annualized Total Cost

In order to effectively compare the cost of installing, operating and maintaining the NO<sub>x</sub> control systems, capital and O&M costs can be evaluated on an annualized basis.

The Annualized Total Cost (ATC) for NO<sub>x</sub> control systems was calculated based on a 20-year project life and is presented in Table 2-8 and Table 2-9, for Unit 1 and Unit 2, respectively, along with the emissions reduction, resultant emissions rate and the Unit Control Cost. No salvage value was assumed at the end of the service life. The Unit Control Cost is the ATC divided by the annual tons of NO<sub>x</sub> emissions that would be controlled by implementation of the respective control technology. The ATC and Unit Control Cost are used to evaluate the control technologies on a cost effectiveness basis.



**Table 2-8: Annualized Total Cost of MRYS Unit 1 NO<sub>x</sub> Control Technologies**

NO <sub>x</sub> Control Alternative	Emission Rate lb/10 <sup>6</sup> Btu	Annual Emissions (tpy) <sup>1</sup>	Annual Emission Reduction (tpy) <sup>1</sup>	Installed Capital Cost (\$) <sup>2</sup>	Annual O&M Cost (\$)	Annualized Total Cost (\$) <sup>3</sup>	Actual Unit Control Cost (\$/ton) <sup>4</sup>	Incremental Unit Control Cost (\$/ton)
Applied RRI+SNCR/ASOFA	0.28	2,902	539	8,500,000	5,300,000	6,000,000	11,100	7,700
Applied Optimized SNCR/ASOFA	0.33	3,420	21	2,400,000	1,800,000	2,000,000	96,500	
Existing SNCR/ASOFA <sup>5</sup>	0.332	3,441	Baseline					

1. Based on baseline heat input of 20,726,417 MMBtu/yr
2. All Costs in 2019 dollars.
3. For ATC calculation, Capital Recovery Factor = 0.08368 and first year O&M Cost.
4. Overall control cost is ATC divided by actual annual emissions reduction of each alternative.
5. Baseline emission rate based on average emission rate between 2016-2018.

**Table 2-9: Annualized Total Cost of MRYS Unit 2 NO<sub>x</sub> Control Technologies**

NO <sub>x</sub> Control Alternative	Emission Rate lb/10 <sup>6</sup> Btu	Annual Emissions (tpy) <sup>1</sup>	Annual Emission Reduction (tpy) <sup>1</sup>	Installed Capital Cost (\$) <sup>2</sup>	Annual O&M Cost (\$)	Annualized Total Cost (\$) <sup>3</sup>	Actual Unit Control Cost (\$/ton) <sup>4</sup>	Incremental Unit Control Cost (\$/ton)
Applied RRI+SNCR/ASOFA	0.26	4,466	1271	14,600,000	6,300,000	7,500,000	5,900	5,500
Applied Optimized SNCR/ASOFA	0.32	5,497	240	3,500,000	1,500,000	1,800,000	7,500	
Existing SNCR/ASOFA <sup>5</sup>	0.334	5,737	Baseline					

1. Based on baseline heat input of 34,354,956 MMBtu/yr
2. All Costs in 2019 dollars.
3. For ATC calculation, Capital Recovery Factor = 0.08368 and first year O&M Cost.
4. Overall control cost is ATC divided by actual annual emissions reduction of each alternative.
5. Baseline emission rate based on average emission rate between 2016-2018.

### 2.5.1.6 Cost Estimate Conclusion

In the RHCT guidelines, EPA does not provide definition, or even discussion of what Unit Control Costs are considered reasonable or unreasonable. NDDEQ has indicated that costs below \$4,500 per ton may be considered to be reasonable.

The cost analysis portion of the RHCT determination for MRYS Unit 1 and 2 indicates that Actual Unit Control Costs for the top ranked RRI + SNCR for Unit 1 is more than double \$4,500 per ton and the Unit 2 cost is almost \$6,000 per ton. The incremental rate (cost of removal between two options) of controlling NO<sub>x</sub> with RRI + SNCR is also over \$4,500 per ton on both Units. From an economic analysis

viewpoint, the RRI+SNCR system, although the top ranked technology, is not an economically feasible NO<sub>x</sub> control alternative for either Unit 1 or Unit 2.

The Actual Unit Control Costs for the next top ranked control technology, optimized SNCR system, for Unit 1 is more than an order of magnitude greater than \$4,500 per ton and the Unit 2 cost is over \$7,000 per ton. From an economic analysis viewpoint, the optimized SNCR system is not an economically feasible NO<sub>x</sub> control alternative for Unit 1 or Unit 2.

### **2.5.2 Energy Impacts**

The primary energy impact of the RRI + SNCR and Optimized SNCR systems is reduced boiler efficiency due to evaporation of large amounts of dilute urea. For the purposes of this RHCT analysis, it was assumed that the heat input rate (MMBtu/yr) for the baseline and each control technology case were the same. Therefore, no additional coal usage was assumed; rather, it was assumed that a loss of electrical generation capacity would occur for the control cases. However, for the Optimized SNCR for Unit 1, the equivalent of an additional 8 tons of coal per day would be required to evaporate the expected amount of dilute urea to be injected into the boiler. For Optimized SNCR for Unit 2, the equivalent of an additional 34 tons of coal per day would be required to evaporate the expected amount of dilute urea to be injected into the boiler. For the RRI + SNCR for Unit 1, the equivalent of an additional 39 tons of coal per day would be required to evaporate the expected amount of dilute urea to be injected into the boiler. For RRI + SNCR for Unit 2, the equivalent of an additional 94 tons of coal per day would be required to evaporate the expected amount of dilute urea to be injected into the boiler. Increasing heat input to maintain present unit production capacity may have New Source Review, Prevention of Significant Deterioration implications that could add significant cost and permitting considerations. Without a heat input increase, electrical generation would decrease, meaning that generation from another unit, with unknown environmental profile, would be required to make up for the loss.

Other energy impacts include an incremental increase in water consumption due to the need for additional cooling water, and an incremental increase in energy related to providing more compressed air for reagent atomization. Auxiliary power requirements for each of the control technologies are presented in Table 2-10 and Table 2-11 for Unit 1 and Unit 2, respectively.

**Table 2-10: Auxiliary Energy Requirement of MRYS Unit 1 NO<sub>x</sub> Control Technologies**

<b>RHCT Alternative</b>	<b>Energy Demand (kW)</b>	<b>Percent of Nominal Generation</b>
Existing SNCR	200	0.09%
Optimized SNCR	266	0.11%
RRI + SNCR	332	0.14%

**Table 2-11: Auxiliary Energy Requirement of MRYS Unit 2 NO<sub>x</sub> Control Technologies**

<b>RHCT Alternative</b>	<b>Energy Demand (kW)</b>	<b>Percent of Nominal Generation</b>
Existing SNCR	300	0.07%
Optimized SNCR	366	0.08%
RRI + SNCR	432	0.10%

### 2.5.3 Non-Air Quality Environmental Impacts

The addition of the RRI system to the SNCR system is not expected to significantly impact emissions of CO or volatile organic compounds (VOCs).

Operation of the existing SNCR system creates a small amount of unreacted ammonia to be emitted. In the future, the settings for the new RRI+SNCR or Optimized SNCR system may increase the amount of ammonia slip produced. Higher NO<sub>x</sub> reduction performance involves greater amounts of reagent usage and consequently, the increased ammonia slip. This is typically controlled to less than 10 ppmvd, especially when the possible formation of sulfates such as ammonium sulfate [(NH<sub>4</sub>)<sub>2</sub>SO<sub>4</sub>] and ammonium bisulfate [NH<sub>4</sub>HSO<sub>4</sub>] will be more problematic at higher slip levels. Sulfur trioxide (SO<sub>3</sub>) formed during combustion in the boiler can combine with ammonia during passage through the flue gas ductwork to form the sulfates.

Some of the unreacted ammonia (ammonia slip) will be collected with the fly ash in the ESP. Any remaining ammonia slip that is not collected or condensed in the air pollution control system will be collected in the wet scrubber or emitted from the chimney as an aerosol or condensable particulate. Increasing the ammonia slip has the potential to increase atmospheric visibility impairment downwind of the facility compared with a pristine condition. Although the predicted amount of such potential impact from ammonia slip emissions has not been determined, it is expected to be small in comparison with the

significant anticipated reduction in far-field ozone and improvement in atmospheric visibility as a result of the overall NO<sub>x</sub> emission reduction.

One mole of carbon dioxide (CO<sub>2</sub>) will be created and emitted for every mole of urea injected for reaction with NO<sub>x</sub>. The consumption rate of urea will significantly increase with the use of RRI + SNCR or optimized SNCR and thus the CO<sub>2</sub> rate will also increase. However, this is a relatively small increase in the total amount of CO<sub>2</sub> produced as part of the combustion of carbon-based fossil fuel in the form of lignite.

Delivery of the urea reagent to the MRYS and storage of aqueous urea reagent on-site creates the potential for accidents, leaks, and subsequent releases to air, ground, and surface water immediately surrounding the facility. Urea is much less volatile than anhydrous or aqueous ammonia, and these risks are expected to be manageable.

Increased dilution water and urea usage rates will require the production of greater volumes of microfiltration/reverse osmosis (MF/RO) and condensate quality water for dilution of concentrated urea deliveries and injection into the boiler. The production of MF/RO and condensate quality water results in a discharge of a concentrated brine solution, which is ultimately discharged under the requirements of the MRYS facility NDPDES permit. This waste stream typically represents 20% of the RO product volume produced. This would result in millions of gallons of additional water treatment wastewaters being discharged from the MRYS facility on an annual basis.

#### **2.5.4 NO<sub>x</sub> Control Technology Evaluation Conclusion**

The energy impacts of a new RRI + SNCR system or an optimized SNCR system are only incrementally higher than the existing system. These incremental increases are acceptable.

The non-air quality impacts of a new RRI + SNCR system or an optimized SNCR system are very similar to the impacts of the existing SNCR system. There will be an increase in the ammonia carry over from the systems but a majority of that will be captured in the wet FGD system. There will be insignificant increases in CO<sub>2</sub> due to the increased consumption of urea. There will be additional RO/condensate waste due to the increase in demand from the systems. All of these non-air quality impacts are considered acceptable.

The average control cost to add an RRI system or to optimize the SNCR system is above \$4,500 per ton. This evaluation results in the determination that maintaining operation of the existing SNCR system is the RHCT top ranked control technology.

This evaluation determined maintaining the existing annual emission rates of 0.332 lb NO<sub>x</sub>/MMBtu and 0.334 lb NO<sub>x</sub>/MMBtu for Unit 1 and Unit 2, respectively, should be modeled by WRAP as appropriate annual emission rates for the Step 5 review. Maintaining the existing 30-day emission limits of 0.36 lb NO<sub>x</sub>/MMBtu and 0.35 lb NO<sub>x</sub>/MMBtu for Unit 1 and Unit 2, respectively, are appropriate permit limits.

The emission rates in this report are for WRAP modeling and are not proposed permit emission limit. As EPA has indicated, the Regional Haze Roadmap may be updated, and the results of the WRAP modeling will provide new information to be considered. Minnkota reserves the right to modify the four factor analysis once the Regional Haze Roadmap, any additional guidance and the results of the WRAP modeling are available. In addition, Minnkota reserves the right to conduct a 5<sup>th</sup> factor analysis based on visibility modeling once the results of the WRAP modeling are available.

This analysis is provided to assist the NDDEQ in the WRAP modeling and is not intended to serve as an agreement by Minnkota to any changes in permitted emission limits or permit conditions.

### 3.0 SO<sub>2</sub> RHCT EVALUATION

The RHCT determination process has five predefined steps as described in Section 1. In this section, steps 1 through 4 of the RHCT determination for MRYS are described for SO<sub>2</sub> and a presentation is made of the results. Potentially applicable SO<sub>2</sub> control technologies are first identified. A brief description of the processes and their capabilities are reviewed for availability and feasibility. Subsequently, those available technologies deemed feasible for retrofit application are ranked according to nominal SO<sub>2</sub> control capability. The impacts analysis then reviews the estimated capital and O&M costs for each alternative. Following the cost determination, the energy impacts and non-air quality impacts are reviewed for each technology. The impact based on the remaining useful life of the source is reviewed as part of the cost analysis. The results of the impact analyses are tabulated and potential RHCT options are listed.

#### 3.1 SO<sub>2</sub> Evaluation Basis

MRYS Unit 1 includes a B&W steam generator installed in 1970. The steam generator is a lignite-fired boiler with multiple cyclone-furnaces installed in parallel using balanced-draft and natural circulation. The boiler is fired by seven ten-foot diameter cyclone furnaces, arranged “three over four” across the front wall of the lower boiler. The unit has a tubular air heater installed between the boiler and the flue gas ductwork leading to the ESP. Unit 1’s boiler serves a turbine generator with a nameplate rating of 257 MW<sup>5</sup>. The Unit 1 boiler at MRYS includes a unique coal conditioning system (drying, crushing, and feeding) for each cyclone furnace specifically designed to aid in proper combustion of the lignite fuel. Lignite fuel is the sole solid fuel for the plant and is supplied from a mine located adjacent to the site. The baseline emission rate of the Unit 1 boiler using the existing wet FGD system is 0.0739 lb SO<sub>2</sub>/MMBtu, as described previously in Section 1.1.5.

MRYS Unit 2 is a B&W steam generator installed in 1977. The steam generator is a lignite-fired boiler with multiple cyclone-furnaces installed in parallel using balanced-draft and natural circulation assisted with circulation pumps. The boiler is fired by twelve ten-foot diameter cyclone furnaces, arranged “three over three” across the front and rear walls of the lower boiler. The unit has a tubular air heater installed between the boiler and the flue gas ductwork leading to the ESP. Unit 2’s boiler serves a turbine-generator with a nameplate rating of 477 MW<sup>6</sup>. The Unit 2 boiler at MRYS includes a unique coal conditioning system (drying, crushing, and feeding) for each cyclone furnace specifically designed to aid

<sup>5</sup> Ibid EPA’s eGRID database; April, 2003.

<sup>6</sup> Ibid EPA’s eGRID database; April, 2003.

in proper combustion of the lignite fuel. Lignite fuel is the sole solid fuel for the plant and is supplied from a mine located adjacent to the site. The baseline emission rate of the Unit 2 boiler using the existing wet FGD system is 0.126 lb SO<sub>2</sub>/MMBtu, as described previously in Section 1.1.5.

### 3.2 Identification of Retrofit SO<sub>2</sub> Control Technologies

The initial step in the RHCT determination is the identification of retrofit SO<sub>2</sub> control technologies. In order to identify the applicable SO<sub>2</sub> control technologies, several reference works were consulted, including “Controlling SO<sub>2</sub> Emissions: A Review of Technologies (EPA-600/R-00-093, October 2000) and the RACT/BACT/LAER Clearinghouse (RLBC). From these and other literature sources, a preliminary list of control technologies and their estimated capabilities for potential application to MRYS was developed. However, Minnkota already has wet FGD systems installed on both units to achieve annual average removal rates of 96.8% and 94.9% on Unit 1 and 2, respectively (based on 3-year average baseline emissions). Additionally, Unit 2 complies with a 0.15 lb/MMBtu 30-day rolling average emission limit. Thus, the control technologies included in the RHCT analysis either meet this minimum level of control or have more stringent removal efficiency. Table 3-1 contains the results of this effort.

**Table 3-1: SO<sub>2</sub> Control Technologies Identified for RHCT Analysis**

<b>Control Technology</b>	<b>Approximate Annual Control Efficiency</b>
ReACT Scrubber	92-98%
New Wet FGD	98%
Modify Existing Wet FGD	96-98%
Circulating Semi-Dry FGD	90-97%
Semi-Dry FGD	90-95%

### 3.3 Technical Description and Feasibility Analysis

The second step in the RHCT analysis procedure is a technical feasibility analysis of the options identified in Step 1. The RHCT guidelines, which reference the prior BART Guidelines, discuss consideration of two key concepts during this step in the analysis. The two concepts to consider are the “availability” and “applicability” of each control technology. A control technology is considered available “if it has reached the stage of licensing and commercial availability” (70 FR 39165). On the contrary, a control technology is not considered available “if it is in the pilot scale testing stages of development” (70 FR 39165). When considering a source’s applicability, technical judgment must be exercised to determine “if it can reasonably be installed and operated on the source type” (70 FR 39165). The technical and feasibility analysis is presented below for each identified option.

### 3.3.1 Wet Flue Gas Desulfurization

Wet FGD technology utilizing lime or limestone as the reagent is commonly applied to coal-fired boilers. Wet FGD utilizes an absorber, such as an open spray tower or a spray tower with a perforated plate contactor, to expose flue gas to the neutralizing slurry. Absorbed SO<sub>2</sub> is converted to calcium sulfite and then may be oxidized to calcium sulfate dihydrate (gypsum) which is filtered from the scrubber solution and either disposed of in a permitted disposal facility, or possibly sold for either wallboard or cement production. Lime is utilized as the reagent in the wet FGD technology analysis because the plant currently uses lime in the FGD processes and has existing lime reagent preparation equipment. Lime, rather than limestone, is used at the plant because it is the most cost-effective reagent to truck to the plant. The MRYS is not equipped with rail service.

An alternative reagent to lime or limestone is ammonia. The scrubbing technology is similar to other wet FGD systems; however, the byproduct handling is significantly different. The advantage of utilizing ammonia is the production of a high value fertilizer byproduct (ammonium sulfate). This byproduct is a commodity that can be sold worldwide all year. The byproduct, if sold in liquid form, may not require any treatment and limited handling. A potential disadvantage of utilizing ammonia reagent is if the byproduct is not sold in liquid form, it could require significant handling/treatment depending on the final product requirements (delivery, target clients, etc). This handling/treatment could include some or all of the following steps; concentration, crystallization, drying, prilling and storage. As fertilizer demand near MRYS is seasonal, the product will need to be shipped to other parts of the United States or the world market.

Historically, wet FGD systems have operated with SO<sub>2</sub> control efficiency anywhere from 70% to 98%. New coal-fired power plant SO<sub>2</sub> control projects have achieved coal to chimney SO<sub>2</sub> control efficiency of  $\geq 99$  percent. However, considering a reasonable degree of margin is appropriate to allow for continuous compliance including upsets, fuel variability, and operational variability, 98% removal is evaluated as an appropriate removal rate for a new state of the art scrubber.

For the purposes of this analysis, new wet FGD performance was evaluated at 98% SO<sub>2</sub> removal. Due to the relative ages of Unit 1 and Unit 2 scrubbers, a new wet scrubber was considered only for Unit 2, as the Unit 1 wet scrubber was placed in service relatively recently, in 2011. Based on the ability of a new wet FGD system to achieve 98% percent SO<sub>2</sub> removal efficiency and considering the commercial availability and applicability, a new wet FGD system was found to be a technically feasible RHCT alternative for MRYS Unit 2 SO<sub>2</sub> emission control.



This report also evaluates the modification of the existing wet FGD process currently operating on Unit 1 and Unit 2 as a possible RHCT alternative. The original equipment manufacturer (OEM) of the Unit 1 scrubber was engaged to evaluate modifications required to increase the removal efficiency of the existing wet FGD processes. The same OEM has previously studied upgrading the Unit 2 scrubber to achieve higher removal efficiency, and was engaged to update and confirm the results of that study. Upgrades evaluated include increasing the liquid-to-gas ratio, installation of new types of spray nozzles, running additional pumps, and adjusting the operating conditions of the scrubber. The OEM study evaluated the scrubbers based on the highest sulfur coal (3.16 lb SO<sub>2</sub>/MMBtu) identified by core samples collected and analyzed by the mine that supplies MRYS. The high sulfur fuel is utilized in this evaluation to ensure the updated scrubber is capable of the necessary long-term fuel flexibility associated with a mine mouth plant. The removal rates referenced in the confidential vendor proposal (submitted separately under confidentiality) are coal to chimney short term (test period) removal rates reflective of vendor determined performance. This RHCT evaluation, however, has applied selected removal rates across the scrubber.

The selected rates applied across the scrubber is considered a reasonable balance of the difference between: the baseline scrubber inlet SO<sub>2</sub> and the studied sulfur content of the coal, consideration of the need for margin between a guarantee and long term continuously achievable performance, and long term (annual performance) basis of this evaluation. Optimizing Unit 1 is assumed to increase removal across the scrubber to 97.4% by increasing stoichiometry (Ca/S) to 1.025. Upgrading Unit 2 is assumed to increase removal across the scrubber to 97.6% utilizing the recommended nozzle changes, additional spray header, and increasing the stoichiometry to 1.020. MRYS did not increase the stoichiometry in Unit 2 to the same level as Unit 1 because MRYS experience on Unit 2 is that operating at higher pH (associated with higher stoichiometry) will cause increased scaling and plugging of the suction screens to the spray recycle pumps that will reduce the liquid to gas ratios, and hence lower SO<sub>2</sub> removal.

### **3.3.2 Semi-Dry Flue Gas Desulfurization**

As an alternative to wet FGD technology, the control of SO<sub>2</sub> emissions can be accomplished using semi-dry FGD technology. The most common semi-dry FGD system is the lime Spray Dryer Absorber (SDA) using a fabric filter for downstream particulate collection. There are several variations of the semi-dry process in use today. Two other variations, the Flash Dryer Absorber (FDA) and Circulating Dry Scrubber (CDS) are similar in nature. They primarily differ by the type of reactor vessel used, the method in which water and lime are introduced into the reactor and the degree of solids recycling. This section addresses the SDA process and the CDS process.

No SDA process has clearly demonstrated the ability to achieve SO<sub>2</sub> removal levels similar to wet FGD systems in the U.S. The application of high SO<sub>2</sub> removal SDA system for high sulfur coal have been limited in the industry due to multiple factors. For purposes of completeness an SDA system is assumed to be able to achieve 93% removal in this application.

The CDS system can increase the lime injection rate independent of the water injection and higher removal rates can be achieved. The CDS system removal is assumed to be equivalent to the retrofit wet FGD system achieving 95-97% removal.

### **3.3.3 ReACT Dry Scrubbing Process**

ReACT (Regenerative Activated Coke Technology) is a multipollutant control system that utilizes activated coke to remove SO<sub>2</sub>, NO<sub>x</sub> and mercury. The process is divided into three main processes: 1) adsorption, 2) regeneration, and 3) recovery. In the first step, ammonia is injected into the flue gas and the flue gas is passed through an adsorber filled with a moving bed of activated coke pellets where the SO<sub>2</sub> and mercury are adsorbed and the NO<sub>x</sub> is reduced to N<sub>2</sub>. In the second step, the activated coke pellets are transferred to a second vessel to be regenerated for recycle/reuse through thermal desorption. The captured mercury is concentrated in the lower portion of the regenerator vessel. The resulting gas from the regeneration step is a concentrated stream of SO<sub>2</sub> that must be further treated in a separate acid recovery plant to produce a sellable sulfuric acid byproduct. Sulfuric acid is a worldwide commodity that, with access, can be sold year-round. This ReACT process is installed and operating on multiple low sulfur coal fired units achieving ≥99% SO<sub>2</sub> removal. Burns & McDonnell contacted the supplier of the ReACT process and discussed the application of the technology to an application like MRYS. It was determined that MRYS is ‘not a good application’ for the technology, however, the technology could be applied and would work. Factors in this application at MRYS that would impact performance and cost of ReACT include that the inlet temperature is too high, higher oxidation of the activated coke can be expected, and the sulfuric acid production rates would be very high. This technology is still considered a viable alternative and previous ReACT pilot tests on high sulfur coals have shown ReACT can achieve 92-98% SO<sub>2</sub> removal rates.

### **3.3.4 Results of Feasibility Analysis**

The evaluations of the identified RHCT alternatives following the feasibility analysis are summarized in Table 3-2.

**Table 3-2: MRYS RHCT SO<sub>2</sub> Control Feasibility Analysis Results**

<b>Control Technology</b>	<b>In full-scale service on Existing Utility Boilers</b>	<b>In Service on Other Combustion Sources</b>	<b>Commercially Available</b>	<b>Technically Applicable To MRYS</b>
ReACT Scrubber	Yes	Yes	Yes	Yes
Wet FGD	Yes	Yes	Yes	Yes
CDS Dry FGD	Yes	Yes	Yes	Yes
SDA Dry FGD	Yes	Yes	Yes	Yes

### 3.4 Evaluate Technically Feasible SO<sub>2</sub> Control Options by Effectiveness

The third step in the RHCT analysis procedure is to evaluate the control effectiveness of the technically feasible alternatives. During the feasibility determination in step 2 of the RHCT analysis, the SO<sub>2</sub> control efficiency was reviewed and presented as part of the technical description for each technology. The evaluations of the remaining RHCT alternatives following the feasibility analysis are summarized in Table 3-3. The alternatives are ranked in descending order according to their effectiveness in SO<sub>2</sub> control. The control efficiencies listed in Table 3-3 are representative of annual average removal rates and do not represent a permit limit that would be continuously achievable over a 30-day rolling average.

**Table 3-3: Feasible SO<sub>2</sub> Control Technologies Identified for RHCT Analysis**

<b>Control Technology</b>	<b>Unit 1<sup>1</sup></b>	<b>Unit 2<sup>1</sup></b>
New Wet FGD	Not Reviewed <sup>2</sup>	98% Control
ReACT	98% Control	98% Control
Retrofit Existing Wet FGD	97.4% Control	97.6% Control
CDS Semi-Dry FGD	NA <sup>3</sup>	NA <sup>3</sup>
SDA FGD	NA <sup>3</sup>	NA <sup>3</sup>

1. Control rates are reflective of conservative (high) annual removal rates and do not reflect maintainable/guaranteed 30-day rates.
2. Existing system was installed in 2011, so replacement with a like-kind system was not reviewed.
3. SDA and semi-dry FGDs are not evaluated for Unit 1 or 2 because the existing wet FGD can be used to achieve equivalent removal efficiency while using existing equipment.

### 3.5 Evaluation of Impacts for Feasible SO<sub>2</sub> Controls

Step four in the RHCT analysis procedure is the impact analysis. The draft Guidelines (81 FR 44608) lists four factors to be considered in the impact analysis.

- The costs of compliance;
- The time required for compliance;
- Energy and non-air quality environmental impacts of compliance
- The remaining useful life of the source.

Three of the four impacts required by the RHCT Guidelines are discussed in the following sections. The remaining useful life of the source was determined to be greater than the project life definition in the

EPA's OAQPS Control Cost Manual (EPA/453/B-96-001) and thus had no impact on the RHCT determination for MRYS.

Unlike the Best Available Retrofit Technology (BART) evaluation performed in the last round for the RHCT evaluation, the technologies in the second implementation period are evaluated on a 'Top Down' basis similar to a Best Available Control Technology (BACT) approach. Where multiple technologies achieve similar removal rates, a single technology is evaluated to represent that level of performance. The top rated SO<sub>2</sub> removal rate is 98% removal and can be achieved by replacing the existing wet FGD system with either a new wet FGD system or a ReACT system. As a wet FGD system is a well demonstrated technology for high sulfur fuel and ReACT has only been applied on low sulfur fuel, this evaluation will focus on the new wet FGD option to evaluate the top-rated option. As shown in Table 3-3, ReACT is not expected to have better performance than wet FGD in operating conditions encountered at MRYS.

### **3.5.1 Cost Evaluation**

The following sections evaluate the top two ranked control options for Unit 2, replacing the existing wet FGD system with a new wet FGD system, and upgrading the Unit 2 scrubber. A new wet FGD was not considered for Unit 1, as the existing wet FGD began operations in 2011 as part of the previous BART/BACT analysis and is within the previously evaluated useful life. The top ranked control option for Unit 1, modify the existing wet FGD, is evaluated.

#### **3.5.1.1 New Wet FGD Capital Cost Estimate**

Cost estimates for the new wet FGD SO<sub>2</sub> control technologies were completed utilizing the 'IPM Model – Updates to Cost and Performance for APC Technologies Wet FGD Cost Development Methodology' available from the U.S. Environmental Protection Agency and supplemented with engineering estimates based upon Burns & McDonnell's in-house experience. The IPM Model Update is a formula-based report that was specifically developed to estimate the cost of wet FGD technologies for utility power plants. The report was prepared for the EPA in January 2017. The report is available for download from the U.S. EPA website<sup>7</sup>.

As a conservative (lowest cost) approach, this evaluation only considered the 'Absorber Island' portion of the new scrubber cost at a retrofit factor of 1.0 and supplemented this with engineering estimates for new duct work, connecting piping and space modifications required to fit the absorber. This approach

---

<sup>7</sup> [www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6](http://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6)

assumes all of the existing balance of plant (BOP) systems are capable of supporting the new system with no upgrades. Further, it is assumed there is no change in operating staff and only a proportional change in the variable operating cost. These conservative assumptions minimize the overall project cost resulting in a conservatively low dollars per ton control cost.

For the addition of a new wet FGD, Unit 2 will require new ductwork to connect to the new wet FGD system, modifications to the coal pile to create space for the new system and electrical replacement/ upgrades for the new scrubber or a significantly extended outage to allow for the existing wet FGD system to be shut down while the new system is tied in, commissioned and started up. The SO<sub>2</sub> control system cost is representative of a typical furnish and erect contract by a wet FGD system supplier. Economic information utilized as input into the model is given in Table 1-3. The results of the capital cost estimates are given in Table 3-4.

**Table 3-4: Capital Cost Estimate for MRYS Unit 2 New Wet Lime FGD System**

<b>DIRECT COSTS</b>	<b>Unit 2 Estimated Cost (\$)</b>
<b>New FGD Absorber</b>	
FGD Island Equipment Cost	\$51,586,000
<b>BOP Costs</b>	
Mechanical Contract	\$54,000,000
Foundations and Steel	\$4,461,000
<b>BOP Total Direct Cost</b>	<b>\$58,461,000</b>
<b>Total Direct Cost</b>	<b>\$110,047,000</b>
<b>INDIRECT COSTS</b>	
Engineering 10% of DC	\$11,005,000
Escalation	Not Included
<b>Indirect Cost Subtotal</b>	<b>\$11,005,000</b>
Contingency (20% of DC)	\$12,105,000
Prime Contractor's Fee (3% of DC)	\$9,321,000
Owners Cost	Not Included
<b>Total Capital Requirement</b>	<b>\$142,478,000</b>

The total estimated capital cost estimate for a complete new wet FGD absorber is \$142,478,000 or \$299/kW.

### **3.5.1.2 Wet FGD Modification Capital Cost Estimate**

Cost estimates for retrofitting the existing wet FGD systems were based on the equipment modification and associated pricing provided by the OEM (provided separately under confidentiality) and supplemented with engineering estimates for installation based upon Burns & McDonnell's in-house experience.

This evaluation assumes all of the existing BOP systems are capable of supporting the new system with no further upgrades. Further, it is assumed there is no change in operating staff and only a proportional change in the variable operating cost. These conservative assumptions minimize the overall project cost resulting in a conservatively low dollars per ton control cost.

The capital cost estimate for the Unit 1 wet FGD system modification includes the OEM recommendation to replace three out of the four recirculation pump motors to increase the liquid to gas ratio in the scrubber. During this investigation, the existing electrical system and foundation associated with the pump was reviewed and is believed to be sufficient to support this upgrade with no further modifications.

The capital cost estimate for the Unit 2 wet FGD system modification includes the OEM recommendation to replace all of the absorber spray nozzles with dual flow nozzles. The OEM did not recommend upgrading the pumps on Unit 2 due to velocity limitations in the riser pipe and headers and did not recommend upgrading the riser headers and spray headers to accommodate more flow as these upgrades could compromise or complicate the conditions of the existing towers. The results of the capital cost estimates for the FGD system modifications are given in Table 3-5.

**Table 3-5: Capital Cost Estimate for MRYS Unit 1 Wet FGD System Modification**

<b>DIRECT COSTS</b>	<b>Unit 1 Estimated Cost (\$)</b>	<b>Unit 2 Estimated Cost (\$)</b>
<b>Modified FGD System</b>		
Equipment Cost	\$569,000	\$1,011,000
<b>BOP Costs</b>		
Mechanical Contract	\$0	\$280,000
Electrical and Controls	\$16,000	\$0
<b>BOP Total Direct Cost</b>	<b>\$16,000</b>	<b>\$280,000</b>
<b>Total Direct Cost</b>	<b>\$585,000</b>	<b>\$1,291,000</b>
<b>INDIRECT COSTS</b>		
Engineering 10% of DC	\$58,000	\$129,000
Escalation	Not Included	Not Included
<b>Indirect Cost Subtotal</b>	<b>\$58,000</b>	<b>\$129,000</b>
Contingency (20% of DC)	\$64,000	\$142,000
Prime Contractor's Fee (3% of DC)	\$50,000	\$109,000
<b>Total Capital Requirement</b>	<b>\$757,000</b>	<b>\$1,671,000</b>

The total estimated capital cost for upgrades to the Unit 1 wet FGD system is \$757,000, or \$3.00/kW.

The total estimated capital cost for upgrades to the Unit 2 wet FGD system is \$1,671,000, or \$3.50/kW.

### 3.5.1.3 New Wet FGD O&M Cost Estimate

The annual O&M costs are comprised of fixed costs (maintenance and labor) and variable cost (consumables). The O&M costs are evaluated as additional costs beyond the existing wet FGD system as the current costs are part of the baseline operating conditions. The operating labor cost of a new system is not expected to be significantly different than the existing system over the life of the equipment. No additional operating labor has been assumed.

Variable costs include reagent, makeup water, FGD byproduct disposal and auxiliary power costs. The estimated annual costs for these consumables are based on the incremental consumption rates change between the existing removal rate and the new removal rate and the unit cost information provided in Table 1-3. Table 3-6 provides the O&M cost estimate.

**Table 3-6: O&M Cost Estimate for a New MRYS Unit 2 Wet Lime FGD System**

<b>Fixed Costs</b>	<b>Unit 2</b>
Operating Labor	\$0
Admin and Support labor	\$0
Maintenance Material and Labor	\$3,301,000
<b>Total Fixed O&amp;M Costs</b>	<b>\$3,301,000</b>
<b>Variable Costs</b>	
Lime Reagent	\$21,000
Byproduct Disposal	\$233,000
Auxiliary Power	\$727,000
<b>Total Variable O&amp;M Costs</b>	<b>\$981,000</b>
<b>Total Annual O&amp;M Costs</b>	<b>\$4,282,000</b>
<b>Net Annual O&amp;M Cost (\$/MWh)</b>	<b>1.30</b>

#### 3.5.1.4 Wet FGD Modification O&M Cost Estimate

The annual O&M costs are comprised of fixed costs (maintenance and labor) and variable cost (consumables). The O&M costs are evaluated as additional costs beyond the existing wet FGD system as the current costs are part of the baseline operating conditions. The operating labor cost of a new system is not expected to be significantly different than the existing system over the life of the equipment. No additional operating labor has been assumed.

Variable costs include reagent, FGD byproduct disposal and auxiliary power costs. The estimated annual costs for these consumables are based on the incremental consumption rates change between the existing removal rate and the new removal rate and the unit cost information provided in Table 1-3. Table 3-7 provides the O&M cost estimate.



**Table 3-7: O&M Cost Estimate for MRYS Unit 1 and 2 Wet Lime FGD System Modification**

<b>Fixed Costs</b>	<b>Unit 1</b>	<b>Unit 2</b>
Operating Labor	\$0	\$0
Admin and Support labor	\$0	\$0
Maintenance Material and Labor	\$18,000	\$39,000
<b>Total Fixed O&amp;M Costs</b>	<b>\$18,000</b>	<b>\$39,000</b>
<b>Variable Costs</b>		
Lime Reagent	\$108,000	\$286,000
Byproduct Disposal	\$2,000	\$19,000
Auxiliary Power	\$197,000	\$320,000
<b>Total Variable O&amp;M Costs</b>	<b>\$307,000</b>	<b>\$625,000</b>
<b>Total Annual O&amp;M Costs</b>	<b>\$325,000</b>	<b>\$664,000</b>
<b>Net Annual O&amp;M Cost (\$/MWh)</b>	<b>0.18</b>	<b>0.20</b>

O&M Cost represent costs above the baseline (existing system)

### 3.5.1.5 Annualized Total Cost

In order to effectively compare the cost of installing, operating, and maintaining the SO<sub>2</sub> control systems, capital and O&M costs should be evaluated on an annualized basis. The Annualized Total Cost (ATC) for SO<sub>2</sub> control systems was calculated based on overnight construction period (2019), followed by a 20-year service life. O&M costs were based on first year (2019) cost. No salvage value was assumed at the end of the service life for any of the control technology alternatives. The results are presented in Table 3-8 and Table 3-9 for Unit 1 and Unit 2, respectively, along with the emissions reduction, resultant emissions rate and the Unit Control Cost. The Unit Control Cost is the ATC divided by the annual tons of additional SO<sub>2</sub> emissions that would be controlled by implementation of the respective alternative.

**Table 3-8: MRYS Unit 1 SO<sub>2</sub> Control System Annualized Total Cost**

<b>SO<sub>2</sub> Control Alternative</b>	<b>Percent Removal</b>	<b>Emission Rate lb/10<sup>6</sup> Btu</b>	<b>Annual Emission (tpy)<sup>1</sup></b>	<b>Annual Emission Reduction (tpy)<sup>1</sup></b>	<b>Installed Capital Cost (\$)<sup>2</sup></b>	<b>Annual O&amp;M Cost (\$)</b>	<b>Annualized Total Cost (\$)<sup>3</sup></b>	<b>Actual Unit Control Cost (\$/ton)<sup>4</sup></b>
Modified Wet FGD	97.4%	0.061	632	145	800,000	300,000	400,000	2,800
Baseline	96.8%	0.075	777	Baseline				

1. Based on baseline heat input of 20,726,417 MMBtu/yr

2. All Costs in 2019 dollars.

3. For ATC calculation, Capital Recovery Factor = 0.08368 and first year O&M Cost.

4. Overall control cost is ATC divided by actual annual emissions reduction of each alternative.

**Table 3-9: MRYs Unit 2 SO<sub>2</sub> Control System Annualized Total Cost**

SO <sub>2</sub> Control Alternative	Percent Removal	Emission Rate lb/10 <sup>6</sup> Btu	Annual Emission (tpy) <sup>1</sup>	Annual Emission Reduction (tpy) <sup>1</sup>	Installed Capital Cost (\$) <sup>2</sup>	Annual O&M Cost (\$) <sup>2</sup>	Annualized Total Cost (\$) <sup>3</sup>	Actual Unit Control Cost (\$/ton) <sup>4</sup>	Incremental Unit Control Cost (\$/ton)
New Wet FGD	98.0%	0.050	859	1,305	142,500,000	4,300,000	16,200,000	12,400	128,000
Modified Wet FGD	97.7%	0.057	979	1,185	1,700,000	700,000	800,000	700	
Baseline	94.9%	0.126	2,164	Baseline					

1. Based on baseline heat input of 34,354,956 MMBtu/yr

2. All Costs in 2019 dollars.

3. For ATC calculation, Capital Recovery Factor = 0.08368 and first year O&M Cost.

4. Overall control cost is ATC divided by actual annual emissions reduction of each alternative.

The annual tons of SO<sub>2</sub> reduction in this RHCT analysis are calculated as the difference between the baseline emission rate and the controlled emissions and are assumed to be at the same heat input and unit operating time.

### 3.5.1.6 Cost Estimate Conclusion

In the RHCT guidelines, EPA does not provide definition, or even discussion of what Unit Control Costs are considered reasonable or unreasonable. NDDEQ has indicated that costs below \$4,500 per ton may be considered to be reasonable.

The Actual Unit Control Cost are used to evaluate the technology alternatives on a cost effectiveness basis. As can be seen from a review of Table 3-9, the cost of the new Unit 2 wet FGD alternative is excessively high with an actual and incremental control cost far greater than \$4,500 dollars per ton.

As can be seen from a review of Table 3-8 and Table 3-9, the wet FGD modification alternatives for both units are considered reasonable, with an Actual Unit Control Cost of \$2,800 and \$700 per ton for Unit 1 and Unit 2, respectively.

### 3.5.2 Energy Impacts

The energy impacts of replacing the existing Unit 2 wet FGD with a new wet FGD, or of upgrades to the existing wet FGD in the case of Unit 1, in terms of auxiliary power requirements, are given in Table 3-10 and Table 3-11. The primary energy impacts of the wet FGD alternative consists of the additional electrical load resulting from pumps and reagent preparation. Building HVAC and interior and exterior lighting loads are considered minimal.

**Table 3-10: Auxiliary Energy Requirement of MRYS Unit 1 FGD Upgrades**

<b>RHCT Alternative</b>	<b>Energy Demand (kW)</b>	<b>Percent of Nominal Generation</b>
Existing Wet FGD	5,170	2.2%
Upgraded Wet FGD	5,756	2.5%

**Table 3-11: Auxiliary Energy Requirement of MRYS Unit 2 New FGD**

<b>RHCT Alternative</b>	<b>Energy Demand (kW)</b>	<b>Percent of Nominal Generation</b>
Existing Wet FGD	9,658	2.2%
Upgraded Wet FGD	10,623	2.4%
New Wet FGD	11,853	2.7%

### 3.5.3 Non-Air Quality Environmental Impacts

Non-air quality environmental impacts of replacing the existing wet FGD with a new wet FGD or retrofitting the existing FGD systems are expected to be very similar to the impacts of the existing system. These may include hazardous waste generation, solid and aqueous waste streams. The primary change anticipated due to the use of a new wet FGD or modifying the existing FGD systems will be an incremental increase in the solids disposal rate as additional removal of SO<sub>2</sub> will result in increased byproduct.

While the economic evaluation of a new wet FGD system assumes overnight installation, the actual process to bid, design, purchase, and install a retrofitted new wet FGD system can take five years to implement. The actual process to bid, design, purchase, and install retrofits to an existing wet FGD system can take two to three years to implement.

### 3.5.4 SO<sub>2</sub> Control Technology Evaluation Conclusion

The energy impacts of a new wet FGD system are only incrementally higher than the existing system and are primarily driven by the increase in SO<sub>2</sub> removal. These incremental increases are acceptable.

The time period to install a new wet FGD system is significantly longer than the second ranked option (modifying the existing wet FGD) and would result in years of higher emission rates to achieve only a marginal increased removal rate. This would result in years of higher emissions before the RHCT would be installed.

Considering the existing systems are being replaced with like systems, there could be years of implementation delay with a new system for marginal removal improvement, and the high dollars per ton control cost includes low capital cost assumptions. This evaluation rejects the top ranked control technology for Unit 2 (new wet FGD) as RHCT.

While this is not used as the reason for the rejection of this top ranked option, comparison to the second ranked option (an upgrade to the existing wet FGD) indicates that the high annualized cost differential and low differential removal rate of the new FGD option result in an excessive incremental dollars per ton removed greater than \$128,000 per ton.

The time period to modify the existing wet FGD systems is significantly shorter than installing other new systems and would result in lower emission rates sooner than other options. The average control cost to modify the existing wet FGD systems is well below \$4,500 per ton. This evaluation results in the determination that modification of the Unit 1 and 2 wet FGD systems is RHCT.

This evaluation determined that 97.4% removal for Unit 1 and 97.7% removal on Unit 2 resulting in annual emission rates of 0.061 lb SO<sub>2</sub>/MMBtu and 0.057 lb SO<sub>2</sub>/MMBtu, respectively, should be modeled by WRAP as appropriate emission rates for the Step 5 review. The emission rates in this report are for WRAP modeling and are not proposed permit emission limits. As EPA has indicated, the Regional Haze Roadmap may be updated, and the results of the WRAP modeling will provide new information to be considered. Minnkota reserves the right to modify the four factor analysis once the Regional Haze Roadmap, any additional guidance and the results of the WRAP modeling are available. In addition, Minnkota reserves the right to conduct a 5<sup>th</sup> factor analysis based on visibility modeling once the results of the WRAP modeling are available.

This analysis is provided to assist the NDDEQ in the WRAP modeling and is not intended to serve as an agreement by Minnkota to any changes in permitted emission limits or permit conditions.

## 4.0 REGIONAL HAZE CONTROL TECHNOLOGY RESULTS

This report presents the analysis of control technologies for nitrogen oxides (NO<sub>x</sub>), and sulfur dioxide (SO<sub>2</sub>) for Minnkota Power Cooperative Inc.'s Milton R. Young Station (MRYS) Units 1 and 2. The final result of this analysis is a Regional Haze Control Technology (RHCT) for each unit based upon “the costs of compliance, the energy and non-air quality environmental impacts of compliance, any pollution control equipment in use at the source, the remaining useful life of the source...” (70 FR 39163). The presented emission rates in this section are the RHCT recommended rates for evaluation in Step 5 of a RHCT evaluation.

The first four steps of RHCT are used to identify technologies, determine feasibility and evaluate cost, energy, non-air quality and useful life impacts. This analysis reviewed technologies on these factors starting from the baseline of the existing units that include ASOFA/SNCR for NO<sub>x</sub> control and wet FGDs for SO<sub>2</sub> control. The RHCT analysis does not review technologies that do not achieve at least the baseline level of performance.

As stated in previous sections of the report, the first four steps of the technology evaluation provided for in the Guidelines were completed for both Units. Each pollutant required a different approach in order to determine RHCT emission rate. This section provides a brief description of the approach used for each pollutant and summarizes the results.

For NO<sub>x</sub> emissions, the top ranked technically feasible control technology for both units is the use of RRI in combination with SNCR and ASOFA. However, the RRI+SNCR system is not an economically effective NO<sub>x</sub> control alternative for either Unit 1 or Unit 2 with control cost of \$11,100 and \$5,900 per ton of NO<sub>x</sub> removed, respectively.

The Unit Control Costs for the next top ranked control technology, optimized SNCR system, is above \$4,500 per ton on Unit 1 (\$96,500 per ton) and Unit 2 (\$7,500 per ton). From an economic analysis viewpoint, optimized SNCR systems are not economically effective NO<sub>x</sub> controls for either unit.

This evaluation concludes that the existing SNCR/ASOFA systems on both units are the top ranked control technologies.

For SO<sub>2</sub> emissions, the top ranked technology for Unit 2 was to replace the existing wet scrubber with a new wet scrubber. This technology was evaluated and rejected primarily because it was determined to be excessively costly on a dollars per ton removed basis (\$12,400 per ton). Furthermore, this top ranked control technology provided only limited additional removal for an order of magnitude additional costs compared to the second ranked control technology and will take years longer to implement than the second ranked technology.

The next highest ranked control technology (and also top ranked for Unit 1) is to retrofit the existing wet FGDs to increase removal. The OEM of the Unit 1 scrubber was engaged to evaluate how to increase the Unit 1 scrubber removal and re-evaluate a previous study they performed to increase removal in the Unit 2 scrubber. The mechanical upgrades the OEM included are replacing pump motors and changing nozzle designs. The various changes to operating conditions were evaluated based on the plant's previous operating history and experience to consider which conditions will improve removal, while working with the existing system and not impacting removal or reliability. There are no sufficient economic or energy reasons to reject modifying the existing scrubbers. There are non-environmental impacts to consider associated with scrubber operational changes due to potential scaling in the absorber and the long-term impact to the scrubber ponds. However, these impacts are considered manageable based on the operational changes to stoichiometric ratio and total suspended solids included in this evaluation. Based upon this analysis, modifying the existing wet FGDs in both Units is the top ranked RHCT option for SO<sub>2</sub> emissions.

Table 4-1 and Table 4-2 summarize the control technologies and associated emission rates recommended for Step 5 evaluation for each pollutant and for each unit. The RHCT emission rates are presented as annual averages based on the economic evaluation.

**Table 4-1: RHCT Step 5 Annual Average Emission Rate, MRYS Unit 1**

<b>Pollutant</b>	<b>Control Technology</b>	<b>Emission Rate (lb/million Btu)</b>
NO <sub>x</sub>	Existing Selective Non-Catalytic Reduction and Advanced Separated Over Fire Air	0.332
SO <sub>2</sub>	Modify the existing Wet Flue Gas Desulfurization system	0.061

**Table 4-2: RHCT Step 5 Annual Average Emission Rate, MRYS Unit 2**

<b>Pollutant</b>	<b>Control Technology</b>	<b>Emission Rate (lb/million Btu)</b>
NO <sub>x</sub>	Existing Selective Non-Catalytic Reduction and Advanced Separated Over Fire Air	0.334
SO <sub>2</sub>	Modify the existing Wet Flue Gas Desulfurization system	0.057

The four factor analysis was completed based on a request by the NDDEQ while utilizing the EPA 2016 RHR Guidance document. The NDDEQ has requested this information for the purpose of WRAP modeling. The emission rates in this report are for WRAP modeling and are not proposed permit emission limits. As EPA has indicated, the Regional Haze Roadmap may be updated, and the results of the WRAP modeling will provide new information to be considered. Minnkota reserves the right to modify the four factor analysis once the Regional Haze Roadmap, any additional guidance and the results of the WRAP modeling are available. In addition, Minnkota reserves the right to conduct a 5<sup>th</sup> factor analysis based on visibility modeling once the results of the WRAP modeling are available.

This analysis is provided to assist the NDDEQ in the WRAP modeling and is not intended to serve as an agreement by Minnkota to any changes in permitted emission limits or permit conditions.



CREATE AMAZING.

Burns & McDonnell World Headquarters  
9400 Ward Parkway  
Kansas City, MO 64114  
O 816-333-9400  
F 816-333-3690  
[www.burnsmcd.com](http://www.burnsmcd.com)



# Appendix A

RRI + SNCR Capital Cost Summary Tables

# CAPITAL COST ESTIMATE

Minnkota Power Coop.

Milton R Young

RRI + SNCR Unit 1

Center, ND

BMCD #107926

Acct	Area / Discipline	Direct MHRS	Labor Cost	Material Cost	Engr Equip/ Subcontract Cost	Const. Equipment Cost	Total Cost		
01	Engineered Equipment	580	\$82,936		\$4,200,500		\$4,283,436		
02	Civil								
03	Deep Foundations								
04	Concrete				\$5,000		\$5,000		
05	Structural Steel	1,978	\$275,424	\$278,551			\$553,975		
06	Architectural								
07	Piping	11,122	\$1,455,540	\$155,044			\$1,610,584		
08	Electrical	300	\$37,367	\$46,000			\$83,367		
09	Instrument & Control				\$48,000		\$48,000		
10	Insulation								
11	Coatings								
12	Specialty								
13	Demolition								
14	Misc Directs								
	Total Direct Cost	13,981	\$1,851,266	\$479,595	\$4,253,500		\$6,584,361		
Rev.	Revision Date								
		Construction Mgmt & Indirects							
		0	01/29/19	Engineering					\$647,243
		1	05/10/19	Start-Up					
		Commercial							
		Escalation							
		Total Indirect Cost					\$647,243		
		Total Direct and Indirect Costs					\$7,231,604		

















**CAPITAL COST ESTIMATE**  
**Minnkota Power Coop.**  
**Milton R Young**  
**RRI + SNCR Unit 2**  
**Center, ND**  
**BMcD #107926**

Acct	Area / Discipline	Direct MHRS	Labor Cost	Material Cost	Engr Equip/ Subcontract Cost	Const. Equipment Cost	Total Cost
01	Engineered Equipment	696	\$99,523		\$5,407,000		\$5,506,523
02	Civil						
03	Deep Foundations						
04	Concrete				\$5,000		\$5,000
05	Structural Steel	3,027	\$422,055	\$472,493			\$894,548
06	Architectural						
07	Piping	32,868	\$4,301,241	\$408,095			\$4,709,336
08	Electrical	450	\$56,051	\$46,000			\$102,051
09	Instrument & Control				\$76,800		\$76,800
10	Insulation						
11	Coatings						
12	Specialty						
13	Demolition						
14	Misc Directs						
	Total Direct Cost	37,041	\$4,878,869	\$926,588	\$5,488,800		\$11,294,257
<div>Rev.      Revision Date</div> <div>0      01/29/19</div> <div>1      05/10/19</div>							
		Construction Mgmt & Indirects					
		Engineering					\$1,129,426
		Start-Up					
		Commercial					
		Escalation					
		Total Indirect Cost					\$1,129,426
		Total Direct and Indirect Costs					\$12,423,683















# Appendix B

Optimized SNCR Capital Cost Summary Tables



**CAPITAL COST ESTIMATE**  
**Minnkota Power Coop.**  
**Milton R Young**  
**Optimized SNCR Unit 1**  
**Center, ND**  
**BMCD #107926**

Acct	Area / Discipline	Direct MHRS	Labor Cost	Material Cost	Engr Equip/ Subcontract Cost	Const. Equipment Cost	Total Cost
01	Engineered Equipment	400	\$57,197		\$1,181,175		\$1,238,372
02	Civil						
03	Deep Foundations						
04	Concrete						
05	Structural Steel	650	\$90,328	\$69,000	\$100,000		\$259,328
06	Architectural						
07	Piping	2,067	\$270,499	\$50,599			\$321,098
08	Electrical				\$38,000		\$38,000
09	Instrument & Control						
10	Insulation						
11	Coatings						
12	Specialty						
13	Demolition						
14	Misc Directs						
	Total Direct Cost	3,117	\$418,024	\$119,599	\$1,319,175		\$1,856,797
<div><div>Rev.</div><div>Revision Date</div></div> <div><div>0</div><div>01/29/19</div></div> <div><div>1</div><div>05/17/19</div></div>							
		Construction Mgmt & Indirects					
		Engineering					\$182,523
		Start-Up					
		Commercial					
		Escalation					
		Total Indirect Cost					\$182,523
		Total Direct and Indirect Costs					\$2,039,320









PROJECT CLIENT: **Minnesota Power Corp.**  
PROJECT DESC: **Milton R Young - Optimized SNCR Unit 1**  
PROJECT #: **107926**

## SUMMARY ELECTRICAL

EST LEVEL:  
ESTIMATE DUE DATE:

ESTIMATOR:

[illegible]

**CAPITAL COST ESTIMATE**  
**Minnkota Power Coop.**  
**Milton R Young**  
**Optimized SNCR Unit 2**  
**Center, ND**  
**BMcD #107926**

Acct	Area / Discipline	Direct MHRS	Labor Cost	Material Cost	Engr Equip/ Subcontract Cost	Const. Equipment Cost	Total Cost
01	Engineered Equipment	516	\$73,784		\$1,191,275		\$1,265,059
02	Civil						
03	Deep Foundations						
04	Concrete						
05	Structural Steel	650	\$90,328	\$69,000	\$250,000		\$409,328
06	Architectural						
07	Piping	6,270	\$820,514	\$137,188			\$957,702
08	Electrical				\$48,000		\$48,000
09	Instrument & Control						
10	Insulation						
11	Coatings						
12	Specialty						
13	Demolition						
14	Misc Directs						
	Total Direct Cost	7,436	\$984,625	\$206,188	\$1,489,275		\$2,680,088
<div>Rev.      Revision Date</div> <div>0      01/29/19</div> <div>1      05/17/19</div>							
		Construction Mgmt & Indirects					
		Engineering					\$268,009
		Start-Up					
		Commercial					
		Escalation					
		Total Indirect Cost					\$268,009
		Total Direct and Indirect Costs					\$2,948,097













## B.5.c – Communications



March 18, 2019

**FILE**

Mr. Kevin Thomas  
Minnkota Power Cooperative, Inc.  
3401 - 24<sup>th</sup> Street SW  
Center, ND 58530-9507

Re: Fours Factors Analysis  
M.R. Young Station

Dear Mr. Thomas:

The Department has conducted an initial review of the Four Factors Analysis that was submitted for the M.R. Young Station. Based on that review, we have the following comments:

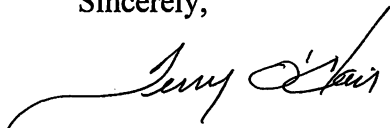
1. All estimates of costs should be based on current (2019) dollars not 2021 dollars. EPA's Control Cost Manual, Section 1, Chapter 2, states "The method for estimating TCI in this Manual is an "overnight" estimation method. This method estimates capital cost as if no interest was incurred during construction and therefore estimates capital cost as if the project is completed "overnight." An alternate way of describing this method is the present value cost that would have to be paid as a lump sum up front to completely pay for a construction project." All estimates of capital cost must be consistent with the Control Cost Manual.
2. Section 1.1.5 and the various tables indicate the baseline emission rates were based on the maximum 30-day rolling average from 2014-2018. Baseline emissions should represent expected future **annual emissions**. Use of the maximum 30-day rolling average will generally overpredict baseline emissions. Annual average emission rates would be a better representation if operating conditions are expected to remain the same. Based on past annual emissions at M.R. Young Station, we do not disagree with the stated baseline emissions at this time (see comment 6); however, we disagree with the methodology.
3. The cost of Rich Reagent Injection (RRI) appears to be excessive. EPA's revised Control Cost Manual estimates the capital cost of RRI at \$8-12/kw for a 500 MW plant. The Unit 2 capital cost estimate for RRI+SNCR/ASOFA was \$15,828,000 with \$2,774,000 for optimized SNCR/ASOFA. It appears that the cost of RRI equates to \$27.47/kw  $((\$15,828,000 - \$2,744,000) / 477,000 \text{ kw})$ , more than double EPA's estimate (Unit 1 calculated at \$30.16/kw). The capital cost estimated for M.R. Young Unit 2 is also more than double the estimated capital cost for RRI at Leland Olds Unit 2 (\$12.44/kw) and the

Coyote Station (\$13.43/kw) which are similar size units. Please revise the estimates for both units or provide a detailed explanation for the high cost.

4. Many cost estimates throughout the analysis are based on vendor budgetary quotes or engineering estimates. When cost estimates are not based on the EPA's Control Cost Manual, evidence for the estimate must be provided. In other words, if vendor quotes or engineering estimates are used for calculations, evidence of those quotes or estimates must be provided in the analysis.
5. Sections 2.5.1.5 and 4.4.1.5 discuss "levelizing" of capital and O&M costs. As discussed in the Round 1 SIP Approval/FIP, "levelizing" of costs using the normal electric utility industry method is not acceptable (see 77 FR 201916 – 201917). Levelizing the "Installed Capital Cost" is not allowed. The cost estimates must be revised to be consistent with the Control Cost Manual.
6. In Tables 3-8 and 3-9, footnote 5 indicates the projected emissions (tpy) for a "Modified Wet FGD" were based on future higher sulfur coal. It appears the baseline emission rates were also based on future higher sulfur coal. If so, footnote 5 should also be placed on the "Baseline" in column 1 and coal sampling data provided to justify the rate. If not, the high baseline emission rates should be explained.

We ask that you revise the analysis and resubmit it as soon as possible. If you 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:saj

B.6 – MDU Heskett

B.6.a – Department Request



May 2, 2018

**FILE**

Ms. Abbie Krebsbach  
Montana Dakota Utilities  
400 N Fourth Street  
Bismarck, ND 58501

Re: Regional Haze  
Second Planning Period

Dear Ms. Krebsbach:

The Department of Health (Department) has begun work on the second planning period (Round 2) State Implementation Plan (SIP) for regional haze. In Round 1 of the regional planning process, the emphasis was on Best Available Retrofit Technology (BART) and making reasonable progress towards the national visibility goal. In Round 2, there are no BART requirements; therefore, we will focus on making reasonable progress. The reasonable progress analysis will be made using the four factors in Section 169A(g)(1) of the Clean Air Act:

The four factors are:

1. The cost of compliance
2. The time necessary to achieve compliance
3. The energy and non-air quality environmental impact of compliance; and
4. The remaining useful life of any existing source subject to such requirements

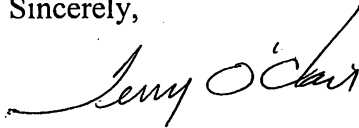
Guidance provided by the U.S. Environmental Protection Agency (Draft Guidance on Progress Tracking Metrics, Long Term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period at [https://www.epa.gov/sites/production/files/2016-07/documents/draft\\_regional\\_haze\\_guidance\\_july\\_2016.pdf](https://www.epa.gov/sites/production/files/2016-07/documents/draft_regional_haze_guidance_july_2016.pdf)) indicates the Department must address 80% of the visibility impairment caused by in-state sources. Data from the IMPROVE monitoring sites at Theodore Roosevelt National Park (TRNP) and Lostwood Wilderness Area (LWA) indicate that sulfates and nitrates continue to be the largest contributors to visibility impairment in these areas. The primary precursors of sulfates and nitrates are emissions of sulfur dioxide (SO<sub>2</sub>) and nitrogen oxides (NO<sub>x</sub>).

Coal-fired electrical generating units have been identified as one of the largest source of sulfur dioxide and nitrogen oxides in North Dakota. Therefore, the Department requests that you prepare a "four factors" analysis for your coal-fired electrical generating units. The analysis should be prepared using the draft EPA guidance noted above. The Department will identify other sources in North Dakota that will be required to submit a four factors analysis.

The Department will be working with the Western Regional Air Partnership (WRAP) to prepare the Round 2 SIP. WRAP will be conducting air quality modeling of regional emissions reductions in early 2019. The Department asks that your "four factors" analysis be submitted by January 31, 2019.

If you have any questions, please contact David Stroh of my staff at (701)328-5188.

Sincerely,



Terry L. O'Clair  
Director  
Division of Air Quality

TLO/TB:saj

xc: Mark Dihle, Montana Dakota Utilities



## B.6.b – Facility Response



**MONTANA-DAKOTA**

**UTILITIES CO.**

*A Subsidiary of MDU Resources Group, Inc.*

400 North Fourth Street  
Bismarck, ND 58501  
701-222-7900

January 31, 2019

Terry L. O'Clair, Director  
North Dakota Department of Health  
Division of Air Quality – 2<sup>nd</sup> Floor  
918 East Divide Avenue  
Bismarck, ND 58501-1947

Re: Regional Haze Round 2 “Four-Factor” Analysis Report for SO<sub>2</sub> and NO<sub>x</sub> Emissions Control at R.M. Heskett Station Unit 1 and Unit 2

Dear Mr. Stroh:

Enclosed is Montana-Dakota Utilities Co. (Montana-Dakota) Regional Haze Round 2 “Four-Factor” Analysis Report for SO<sub>2</sub> and NO<sub>x</sub> Emissions Control at R.M. Heskett Station Unit 1 and Unit 2. This report contains the analysis the North Dakota Department of Health (NDDH) requested (for sulfur dioxide and nitrogen oxides) as applied to the review of emissions controls under the Regional Haze program for our coal-fired electrical generating units.

The NDDH May 2, 2018 letter requested that we prepare this report according to Draft Guidance provided by the U.S. Environmental Protection Agency (EPA). EPA has made known in the agency's September 11, 2018 Regional Haze Reform Roadmap that updated guidance, replacing the current Draft Guidance, as well as implementation tools, for this planning period will be available in future. However, the updated guidance has not yet been published. Montana-Dakota also understands other states in Region 8 have not yet requested a similar review process be completed by industry. Considering the information gained in the regional modeling process, future updated guidance from EPA, the short timeframe to complete and submit the attached report, and the potential need to consider site-specific conditions and costs, Montana-Dakota reserves the right to review and modify this analysis.

If you have any questions or would like to discuss the report conclusions, please contact me at (701) 222-7865.

Sincerely,

Mark Dihle  
Sr. Environmental Scientist

Enclosure

cc: Jay Skabo, Vice President of Electric Supply  
Alan Welte, Director Power Production Generation  
Cory Zentner, Manager Heskett Station  
Abbie Krebsbach, Environmental Director  
David Stroh, NDDH

## **R.M. Heskett Station**

### ***“Four-Factor Analysis” for SO<sub>2</sub> and NO<sub>x</sub> Emissions Control at Unit 1 and Unit 2***

Prepared for  
Montana-Dakota Utilities Co.

January 2019



## R.M. Heskett Station

### *"Four-Factor Analysis" for SO<sub>2</sub> and NO<sub>x</sub> Emissions Control at Unit 1 and Unit 2*

Prepared for  
Montana-Dakota Utilities Co.

January 2019

A handwritten signature in black ink, appearing to read "J. Trinkle", is positioned above a horizontal line.

Joel Trinkle, QEP  
Sr. Air Quality Consultant, Vice President

# R.M. Heskett Station “Four-Factor Analysis” for SO<sub>2</sub> and NO<sub>x</sub> Emissions Control at Unit 1 and Unit 2

January 2019

## Contents

1	Introduction .....	1
1.1	Background, Historical and Current Emissions Summary and Future Operational Considerations .....	2
1.1.1	Emissions Summary .....	3
1.1.1.1	Heskett Station Unit 1 .....	3
1.1.1.2	Heskett Station Unit 2 .....	5
1.1.2	Operating Capacity .....	7
1.2	Four-Factor Analysis Approach .....	9
1.2.1	Identify all Emissions Control Options .....	9
1.2.2	Factor #1 – The Cost of Compliance .....	9
1.2.3	Factor #2 – Time Necessary for Compliance .....	10
1.2.4	Factor #3 – Energy and Non-Air Environmental Impacts .....	10
1.2.5	Factor #4 – Remaining Useful Life of the Source .....	11
2	Unit 1 Nitrogen Oxides (NO <sub>x</sub> ) Four-Factor Analysis .....	12
2.1	NO <sub>x</sub> Emissions Control Measures .....	12
2.1.1	Combustion Controls .....	13
2.1.1.1	Low NO <sub>x</sub> Burners (LNB) .....	13
2.1.1.2	Overfire Air (OFA) .....	14
2.1.1.3	External Flue Gas Recirculation (FGR) .....	14
2.1.1.4	Burner Tempering (Water Injection) .....	14
2.1.2	Post-Combustion Controls .....	14
2.1.2.1	Selective Non-Catalytic Reduction (SNCR) .....	15
2.1.2.2	Selective Catalytic Reduction (SCR) .....	16
2.1.3	Innovative Controls .....	17
2.2	Factor 1 – The Cost of Compliance .....	17
2.3	Factor 2 – Time Necessary for Compliance .....	17
2.4	Factor 3 – Energy and Non-Air Quality Environmental Impacts .....	18
2.5	Factor 4 – Remaining Useful Life of the Source .....	18

2.6	Proposed Controls and Emissions Rates .....	18
3	Unit 1 Sulfur Dioxide (SO <sub>2</sub> ) Four-Factor Analysis .....	19
3.1	SO <sub>2</sub> Emissions Control Measures.....	19
3.1.1	Pre-Combustion Controls .....	19
3.1.2	Post-Combustion Controls .....	20
3.1.2.1	Wet Lime/Limestone Scrubbing.....	20
3.1.2.2	Spray Dry Absorption (SDA).....	21
3.1.2.3	Dry Sorbent Injection (DSI).....	22
3.2	Factor 1 – The Cost of Compliance.....	22
3.3	Factor 2 – Time Necessary for Compliance .....	23
3.4	Factor 3 – Energy and Non-Air Quality Environmental Impacts .....	23
3.4.1	Wet Lime/Limestone Scrubbing .....	23
3.4.2	Dry Flue Gas Desulfurization (FGD) .....	24
3.5	Factor 4 – Remaining Useful Life of the Source.....	24
3.6	Proposed Controls and Emissions Rates .....	24
4	Unit 2 Nitrogen Oxides (NO <sub>x</sub> ) Four-Factor Analysis .....	25
4.1	NO <sub>x</sub> Emissions Control Measures .....	25
4.1.1	Combustion Controls.....	26
4.1.1.1	Fluidized Bed Combustion (FBC) .....	26
4.1.1.2	Low NO <sub>x</sub> Burners (LNB) .....	27
4.1.1.3	Overfire Air (OFA).....	27
4.1.1.4	External Flue Gas Recirculation (FGR).....	27
4.1.1.5	Burner Tempering (Water Injection) .....	28
4.1.2	Post-combustion Controls.....	28
4.1.2.1	Selective Non-Catalytic Reduction (SNCR) .....	28
4.1.2.2	Selective Catalytic Reduction (SCR).....	29
4.1.3	Innovative Controls.....	30
4.2	Factor 1 – The Cost of Compliance.....	31
4.3	Factor 2 – Time Necessary for Compliance .....	31
4.4	Factor 3 – Energy and Non-Air Quality Environmental Impacts .....	31
4.5	Factor 4 – Remaining Useful Life of the Source.....	31
4.6	Proposed Controls and Emissions Rates .....	32
5	Unit 2 Sulfur Dioxide (SO <sub>2</sub> ) Four-Factor Analysis .....	33
5.1	SO <sub>2</sub> Emissions Control Measures.....	33

5.1.1	Pre-Combustion Controls .....	33
5.1.2	Combustion Controls: Limestone Injection at AFBC.....	34
5.1.3	Post-Combustion Controls .....	34
5.1.3.1	Wet Lime/Limestone Scrubbing.....	35
5.1.3.2	Spray Dry Absorption (SDA).....	35
5.1.3.3	Dry Sorbent Injection (DSI).....	36
5.2	Factor 1 – The Cost of Compliance.....	36
5.3	Factor 2 – Time Necessary for Compliance.....	37
5.4	Factor 3 – Energy and Non-Air Quality Environmental Impacts.....	37
5.4.1	Limestone Injection at AFBC .....	37
5.4.2	Wet Lime/Limestone Scrubbing .....	37
5.4.3	Dry Flue Gas Desulfurization (FGD).....	38
5.5	Factor 4 – Remaining Useful Life of the Source.....	38
5.6	Proposed Controls and Emissions Rates .....	38
6	Summary and Conclusion.....	39

## List of Tables

Table 1-1	Preliminary Q/D for Heskett Station.....	3
Table 1-2	Annual Capacity Factor at MONTANA-DAKOTA Heskett Station Unit 1 and Unit 2 .....	7
Table 2-1	List of Potentially Available Retrofit NOx Control Options .....	13
Table 2-2	NOx Control Cost Evaluation for Heskett Station Unit 1.....	17
Table 3-1	SO <sub>2</sub> Control Options with Potential Applications to Heskett Station Unit 1 .....	19
Table 3-2	SO <sub>2</sub> Control Cost Evaluation for Heskett Station Unit 1 .....	23
Table 4-1	List of Potentially Available Retrofit NOx Control Options .....	26
Table 4-2	NOx Control Cost Evaluation for Heskett Station Unit 2.....	31
Table 5-1	SO <sub>2</sub> Control Options with Potential Applications to Heskett Station Unit 2.....	33
Table 5-2	SO <sub>2</sub> Control Cost Evaluation for Heskett Station Unit 2.....	36

## List of Figures

Figure 1	Heskett Station Unit 1 Total Annual NOx Emissions.....	4
Figure 2	Heskett Station Unit 1 Average Monthly SO <sub>2</sub> Emissions.....	5
Figure 3	Heskett Station Unit 2 Average Monthly NOx Emissions .....	6
Figure 4	Heskett Station Unit 2 Average Monthly SO <sub>2</sub> Emissions.....	7
Figure 5	Heskett Station Unit 1 Total Annual NOx and SO <sub>2</sub> Emissions.....	8
Figure 6	Heskett Station Unit 2 Total Annual NOx and SO <sub>2</sub> Emissions.....	8



## Abbreviations

AEIR	Annual Emissions Inventory Report
AFBC	Atmospheric Fluidized Bed Combustion
BACT	Best Available Retrofit Technology
BART	Best Available Retrofit Technology
BOFA	Boosted Overfire Air
CAA	Clean Air Act
CaCO <sub>3</sub>	Limestone
CaO	Lime
CCR	Coal Combustion Residuals
CEMS	Continuous Emissions Monitoring System
CERCLA	Comprehensive Environmental Response, Compensation, and Liability Act
CO	Carbon Monoxide
Control Cost Manual	EPA Air Pollution Control Cost Manual
D	Distance
DSI	Dry Sorbent Injection
Draft Guidance	September 11, 2018 Regional Haze Reform Roadmap
EGU	Electric Generating Unit
EPA	U.S. Environmental Protection Agency
ESP	Electrostatic Precipitator
FBC	Fluidized Bed Combustion
FGD	Flue Gas Desulfurization
FGR	Flue Gas Recirculation
Heskett Station	R.M. Heskett Station Station
Hg++	Oxidized Mercury
Hg <sup>0</sup>	Elemental Mercury
Hgp	Particulate Mercury
IRP	Integrated Resource Planning
LNB	Low NO <sub>x</sub> Burner
LOI	Loss on Ignition
LWA	Lostwood Wilderness Area
MONTANA-DAKOTA	Montana-Dakota Utilities
N <sub>2</sub>	Molecular Nitrogen
NDDH	North Dakota Department of Health
NH <sub>3</sub>	Ammonia
NO <sub>x</sub>	Nitrogen Oxides
O&M	Operation and Maintenance
OFA	Overfire Air
PM	Particulate Matter
PRB	Powder River Basin

Q	Emission Rate
RH	Regional Haze
Roadmap	Regional Haze Reform Roadmap
ROFA	Rotating Overfire Air
RUS	Rural Utility Service
SCR	Selective Catalytic Reduction
SDA	Spray Dry Absorption
SIP	State Implementation Plan
SNCR	Selective Non-Catalytic Reduction
SO <sub>2</sub>	Sulfur Dioxide
SO <sub>3</sub>	Sulfur Trioxide
TDF	Tire-Derived Fuel
TRNP	Theodore Roosevelt National Park
WRAP	Western Regional Air Partnership

---

# 1 Introduction

The Regional Haze (RH) Rule published on July 15, 2005 by the U.S. Environmental Protection Agency (EPA) defines regional haze as “visibility impairment that is caused by the emission of air pollutants from numerous sources located over a wide geographic area. Such sources include, but are not limited to, major and minor stationary sources, mobile sources, and area sources.” The RH rule requires states to submit a series of state implementation plans (SIPs) to protect visibility in certain national parks and wilderness areas, known as mandatory Federal Class I areas. The original State SIPs were due on December 17, 2007 and included milestones for establishing reasonable progress towards the visibility improvement goals, with the ultimate goal to achieve natural background visibility by 2064. The original SIP was informed by best available retrofit technology (BART) analyses that were completed on all subject-to-BART sources. The second planning period (Round 2) requires development and submittal of updated state SIPs by July 31, 2021.

The North Dakota Department of Health (NDDH) has requested Montana-Dakota Utilities Co. (MONTANA-DAKOTA) R.M. Heskett Station (Heskett Station) complete a four-factor analysis, as outlined in Section 169A(g)(1) of the Clean Air Act (CAA) as part of RH Round 2. Per the May 2, 2018 letter from the NDDH and separate confirmation from NDDH, the four-factor analysis is only required for direct emissions of sulfur dioxide (SO<sub>2</sub>) and nitrogen oxides (NO<sub>x</sub>). The reasonable progress analysis is made using the following four factors:

1. The cost of compliance;
2. The time necessary to achieve compliance;
3. The energy and non-air quality environmental impact of compliance; and
4. The remaining useful life of any existing source subject to such requirements.

This report describes the background and methods for conducting a four-factor analysis for sulfur dioxide (SO<sub>2</sub>) and nitrogen oxides (NO<sub>x</sub>) as applied to the review of emissions controls under the RH program at Heskett Station located two miles north of Mandan, ND. Heskett Station operates two coal fired electric generating units. Commercial operation commenced on Heskett Station Unit 1 (25 megawatt) in 1954 and Heskett Station Unit 2 (75 megawatt) in 1963. In 1987, Unit 2 was converted from a Riley Stoker Spreader boiler to an atmospheric fluidized-bed combustor (discussed below in Section 1.1.1.2).

The primary precursors of sulfates and nitrates are emissions of sulfur dioxide (SO<sub>2</sub>) and nitrogen oxides (NO<sub>x</sub>). Guidance provided by the U.S. Environmental Protection Agency (EPA) indicates the Department must address 80% of the visibility impairment caused by in-state sources. Data from the IMPROVE monitoring sites at Theodore Roosevelt National Park (TRNP) and Lostwood Wilderness Area (LWA) indicate that sulfates and nitrates continue to be the largest contributors to visibility impairment in these areas.

MONTANA-DAKOTA understands that NDDH is requesting the four-factor analysis and subsequent emissions performance numbers for submittal to the Western Regional Air Partnership (WRAP) for modeling of visibility impacts at Class I areas (i.e., TRNP and LWA).

MONTANA-DAKOTA also understands, to-date, no other states have yet requested a similar review process be completed by industry. Considering that no other WRAP industry partners are providing information, the short timeframe to complete this work, and the September 11, 2018 Regional Haze Reform Roadmap (roadmap) from EPA indicating impending implementation tools and updated guidance for the second planning period is not yet available, MONTANA-DAKOTA reserves the right to review and modify the assumptions used in this analysis, primarily concerning site-specific conditions for cost (including capital costs and actual emissions reductions potential/performance) and remaining useful life of the affected sources.

## 1.1 Background, Historical and Current Emissions Summary and Future Operational Considerations

MONTANA-DAKOTA Heskett Station was not subject to a formal BART review as part of Round 1 of RH. Unit 1 was not considered a BART-eligible source due to an operation commencement date before 1962 and NDDH determined it was further exempted from detailed analysis based on a calculated Q/D (emission rate (Q) divided by the distance (D) to the nearest Class I area) of less than 10. Unit 1 does not operate with any add-on SO<sub>2</sub> or NO<sub>x</sub> controls currently. While Unit 2 was originally considered a BART-eligible source, it was ultimately exempted from formal BART requirements due to modeling that demonstrates a contribution of less than 0.5 deciviews of visibility degradation in any Class I area. However, MONTANA-DAKOTA initiated a draft BART evaluation on Unit 2 in early 2006 with excerpts of that draft submitted to NDDH, as documented in Supplement No. 1 to the North Dakota State Implementation Plan (SIP) for RH. R.M. Heskett Station was reviewed for controls under the reasonable progress goals of North Dakota's RH SIP. Under that portion of the SIP, the NDDH included a federally enforceable permit requiring Heskett Station to comply with an SO<sub>2</sub> emissions rate of 0.60 lb/mmBtu, which is equal to a 70% reduction of SO<sub>2</sub> emissions (coal-to-stack)<sup>1</sup>. Heskett Station accomplished this in 2017 by implementing a project that replacing a portion of the sand utilized in the Unit 2 boiler fluidized bed with limestone. In 2017, the limestone addition project was completed. Unit 2 does not operate with add-on NO<sub>x</sub> controls currently, although the lower temperatures of the AFBC provides some NO<sub>x</sub> combustion control benefit. Both Units currently cycle load as called upon for generation needs (Unit 1 typically down to 9 MW; Unit 2 typically down to 56 MW), and these decreased operating levels result in less overall air pollution.

EPA's draft guidance allows states to use a screening step to select sources or groups of sources for which a four-factor analysis shall be completed. While the current draft guidance does not provide clear definition on conducting that screening step, the September 2018 roadmap explicitly states that the areas

---

<sup>1</sup> R.M. Heskett Station Air Pollution Control Title V Permit to Operate, T5-F76001.

of focus in the updated guidance will include “providing states with additional information and context regarding screening sources before in-depth analysis”.

As a reference point, MONTANA-DAKOTA has calculated a preliminary Q/D Analysis for both Unit 1 and Unit 2. For Unit 1, the preliminary Q/D is determined using the average of the annual tons of NO<sub>x</sub> and SO<sub>2</sub> (combined) emitted from 2012 to 2017, as reported to NDDH through the Annual Emissions Inventory Report (AEIR), and the distance to the nearest class 1 area consistent with the ND RH SIP (182 kilometers). For Unit 2, the preliminary Q/D is determined using the annual tons of NO<sub>x</sub> and SO<sub>2</sub> (combined) emitted in 2017, as reported to NDDH, and the distance to the nearest Class I area consistent with the ND RH SIP. 2017 was assumed representative of current of and future emissions due to implementation of limestone injection at Unit 2 in 2017. Preliminary Q/D values are shown below:

**Table 1-1 Preliminary Q/D for Heskett Station**

Unit	SO <sub>2</sub> + NO <sub>x</sub> (tons)	Distance (km)	Q/D (tons/km)
Unit 1	1,194	182	6.6
Unit 2	2,899	182	13.5
Combined Source	4,094	182	18.0

MONTANA-DAKOTA notes that the combined source emissions are less than the individual Unit 2 source Q/D from the ND RH SIP for Round 1. Considering the lower emissions trend for both units, it is expected that visibility modeling for Heskett Station would demonstrate commensurately lower visibility impairment. MONTANA-DAKOTA reserves the right to review and modify the assumptions used in this analysis.

## **1.1.1 Emissions Summary**

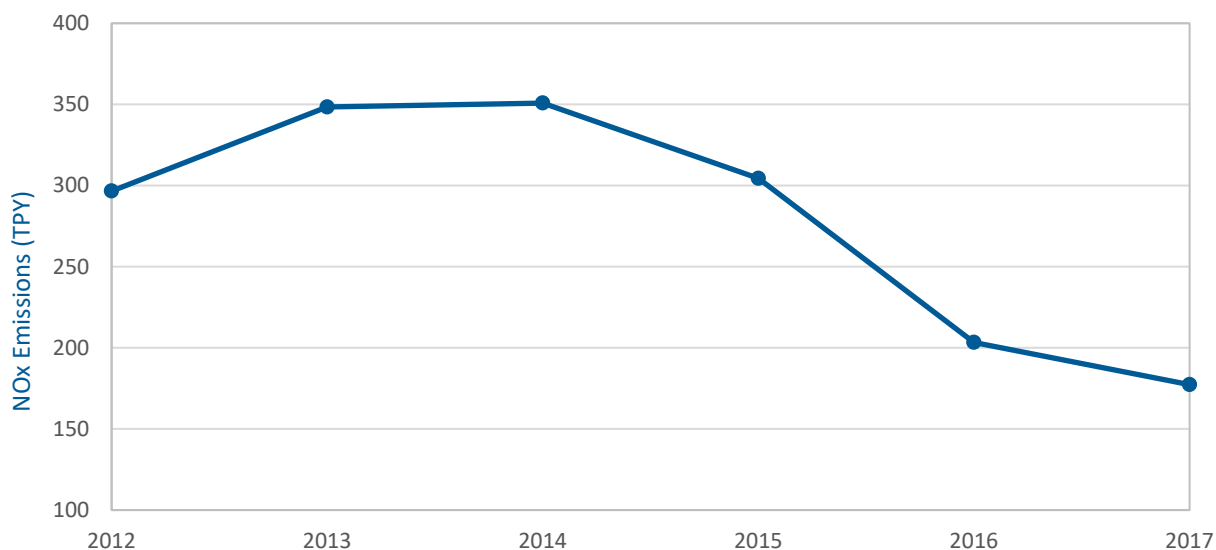
### **1.1.1.1 Heskett Station Unit 1**

Heskett Station Unit 1 is a 25 MW, lignite fired, spreader stoker boiler rated at 387.63 MMBtu/hour. The boiler is capable of burning up to approximately 30 tons of coal per hour. Unit 1 also has the capability to blend (with lignite) and combust tire derived fuel (TDF), and does so as a method to comply with the Mercury and Air Toxics Standard (MATS) mercury (Hg) emissions limit for units designed to burn low-rank virgin coal. As permitted, TDF can account for up to 4 tons/hr of the fuel combusted on a calendar quarter average, but the actual amount combusted is much less. Unit 1 was constructed in 1954 and an Electrostatic Precipitator (ESP) was later installed to control particulate emissions. Unit 1 currently utilizes over-fire air techniques to assist with NO<sub>x</sub> emissions mitigation. As is common with older units, there is limited ductwork and space between the boiler and the stack for any emissions control additions.

#### **Unit 1 NO<sub>x</sub> Emissions Summary**

Heskett Station Unit 1 is estimated to have the potential to emit 762 tons of NO<sub>x</sub> annually, if operated 100% of the year. Potential NO<sub>x</sub> emissions are calculated using AP-42, Vol. I, Chapter 1.7 for lignite combustion emissions factor of 5.8 lb NO<sub>x</sub>/ton of coal combusted and assuming firing at the combustion capability of the unit (30 tons per hour) for a full year. There is no continuous emissions monitoring

system (CEMS) for NO<sub>x</sub> at station 1. However, based on the actual amount of coal combustion, since 2012, annual NO<sub>x</sub> emissions reported at Heskett Station Unit 1 total less than half of what the unit can potentially emit. The lower annual emissions are due to operating at a rate lower than maximum capacity. Actual emissions reported since 2012 are shown in Figure 1 below. Section 1.1.2 of this report discusses the operating capacity at Heskett Station.



**Figure 1** Heskett Station Unit 1 Total Annual NO<sub>x</sub> Emissions

### *Unit 1 SO<sub>2</sub> Emissions Summary*

Heskett Station Unit 1 actual SO<sub>2</sub> emissions from 2012 through 2017 are shown below in Figure 2. The figure demonstrates that, since 2012, Unit 1 actual SO<sub>2</sub> performance on a lb/MMBtu basis has been much less than the permitted limit of 3.0 lb/MMBtu (3-hour rolling average). The data points shown on the graph are presented as monthly averages and are not to be construed as a compliance demonstration against the 3-hour rolling average permitted limit. Unit 1 actual mass emissions are determined as measured from the unit's CEMS. Emissions data are shown as a lb/MMBtu on a monthly average basis and includes all periods of operation.

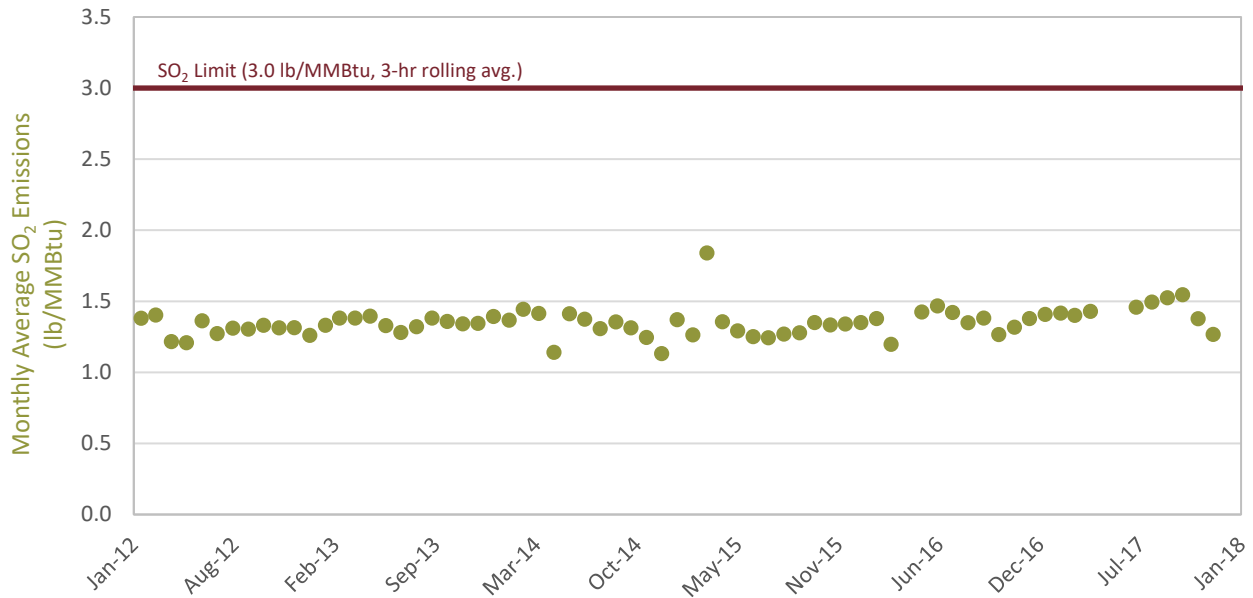


Figure 2 Heskett Station Unit 1 Average Monthly SO<sub>2</sub> Emissions

### 1.1.1.2 Heskett Station Unit 2

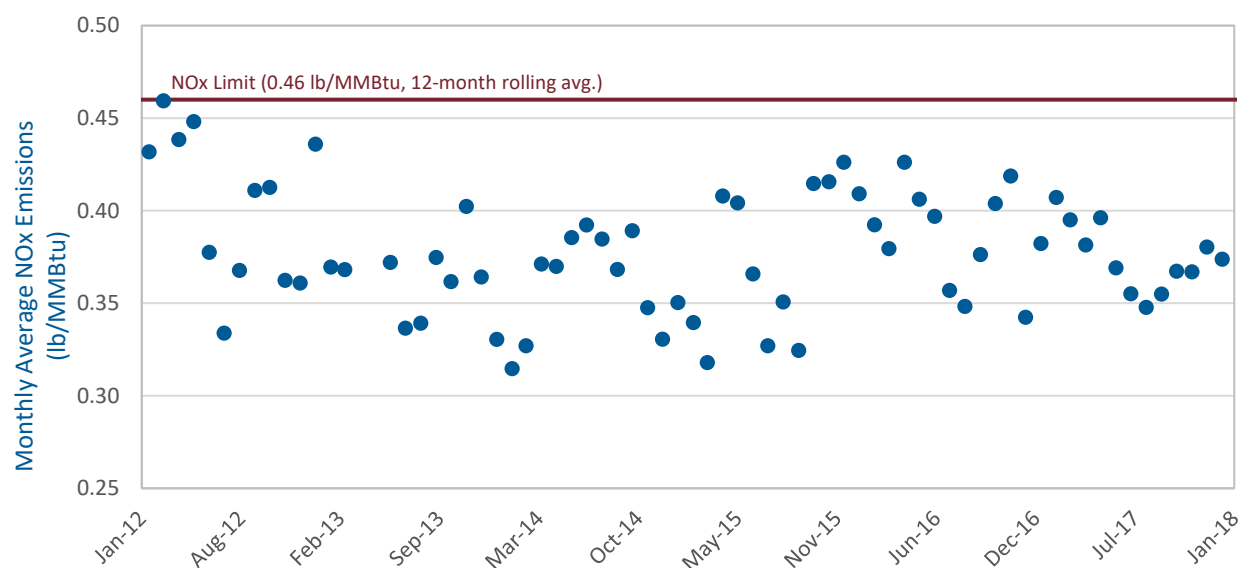
Heskett Station Unit 2 is a 75 MW, lignite-fired, atmospheric fluidized-bed combustor (AFBC) rated at 916.5 MMBtu/hour. The boiler is capable of firing up to approximately 75 tons of coal per hour. In atmospheric fluidized bed combustion, coal is burned in a hot sand (and limestone) bed that is aerated from bubble caps underneath. Unit 2 also has the capability to combust TDF. Unit 2 was constructed in 1963 as a Riley Stoker Spreader boiler, was converted to an AFBC in 1987 and later installed an ESP to control particulate matter emissions. Unit 2 also has limited ductwork and space between the boiler and the stack.

The conversion of the original boiler was to an AFBC, which is different from a circulating fluidized bed boiler design. The Unit 2 AFBC media is maintained in the bottom of the boiler at approximately 4 feet or less in height and has boiler tubes immersed within the bed. Transfer of heat to the tubes in the bed is optimal with certain blends of sand, limestone, and ash. Feed rate of new material to the bed and drainage of spent material can be adjusted for system management. An AFBC is also different from circulating fluidized bed boilers where the bed media circulates higher in the boiler with the flue gas; any carryover media is captured, separated from the flue gas, and returned to the boiler. An AFBC has minimal sand media carryover since the bed height is relatively low.

### Unit 2 NO<sub>x</sub> Emissions Summary

Heskett Station Unit 2 actual NO<sub>x</sub> emissions from 2012 through 2017 are shown below in Figure 3. The figure demonstrates that, since 2012, Unit 2 actual NO<sub>x</sub> performance on a lb/MMBtu monthly average basis has been less than the permitted limit of 0.46 lb/MMBtu (12-month rolling average). The permitted limit is incorporated into the below figure as a reference point for comparison to current actual emissions. The data points shown on the graph are presented as monthly averages and are not to be construed as a

compliance demonstration against the 12-month rolling average permitted limit. Unit 2 actual mass emissions are determined as measured from the unit's CEMS. Emissions performance data is shown as a lb/MMBtu on a monthly average basis and includes all periods of operation.



**Figure 3 Heskett Station Unit 2 Average Monthly NOx Emissions**

### *Unit 2 SO<sub>2</sub> Emissions Summary*

Heskett Station Unit 2 actual SO<sub>2</sub> emissions from 2012 through 2017 are shown below in Figure 4. Heskett Station implemented a limestone addition to the sand bed for Unit 2 for RH emission reductions in 2017. An SO<sub>2</sub> limit of 0.60 lb/MMBtu was applied to Unit 2 and Heskett Station has demonstrated compliance with this 12-month rolling average limit. The permitted limits are incorporated into the below figure as a reference point for comparison to current actual emissions. The data points shown on the graph are presented as monthly averages and are not to be construed as a compliance demonstration against the rolling average permitted limits. Emissions performance data is shown as a lb/MMBtu on a monthly average basis and includes all periods of operation. Since implementation of the limestone injection project, actual SO<sub>2</sub> emissions have decreased from approximately 165 lb/hr to 110 lb/hr on a monthly average basis.



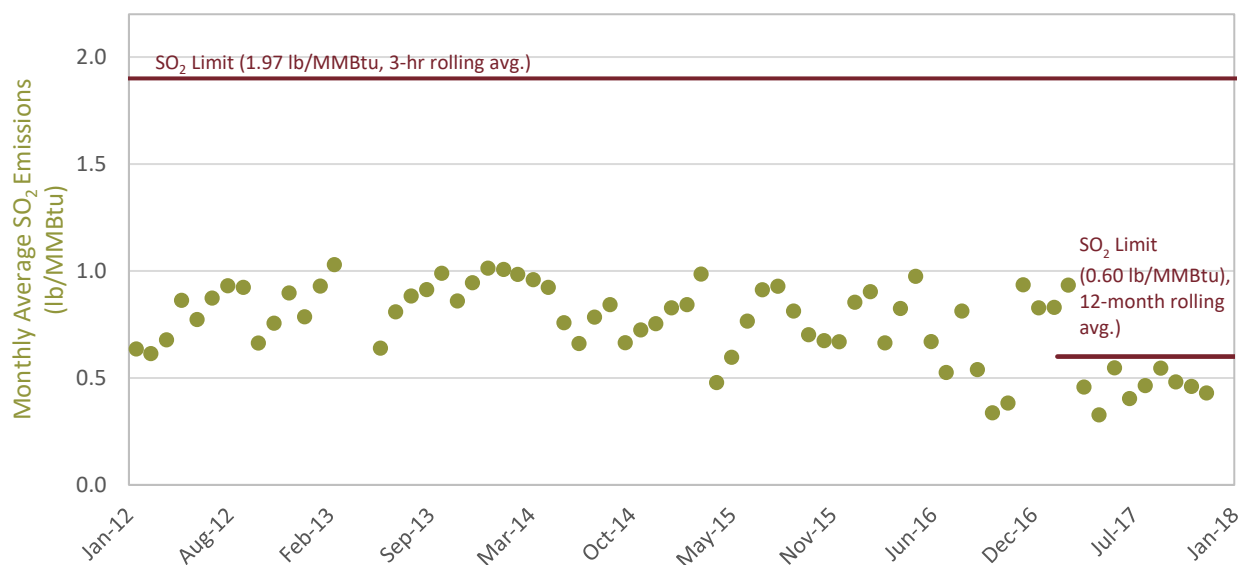


Figure 4 Heskett Station Unit 2 Average Monthly SO<sub>2</sub> Emissions

### 1.1.2 Operating Capacity

Since the early 2000's, baseload operations at coal-fired power plants located across the Western United States has decreased significantly in annual utilization. Since 2011, the majority of coal fired electric generating units (EGU) have spent less than 30% of their operating days in baseload operating mode.<sup>2</sup> Heskett Station is no exception to that trend. Since 2012, the annual capacity factors (on a lb/MMBtu basis) are as follows:

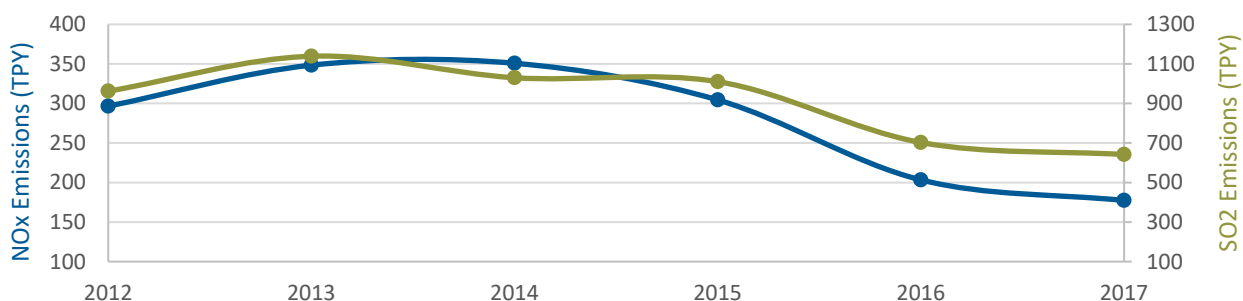
Table 1-2 Annual Capacity Factor at MONTANA-DAKOTA Heskett Station Unit 1 and Unit 2

Year	Annual Capacity Factor (lb/MMBtu basis)	
	Unit 1	Unit 2
2012	43%	60%
2013	50%	52%
2014	46%	69%
2015	44%	66%
2016	31%	65%
2017	27%	65%
2018 (through October 2018)	37%	65%
<b>Average</b>	<b>40%</b>	<b>63%</b>

The average capacity factors (on a lb/MMBtu basis) since 2012 are 40% for Unit 1 and 63% for Unit 2. MONTANA-DAKOTA does not anticipate a change in the trend of decreasing firing moving into the future

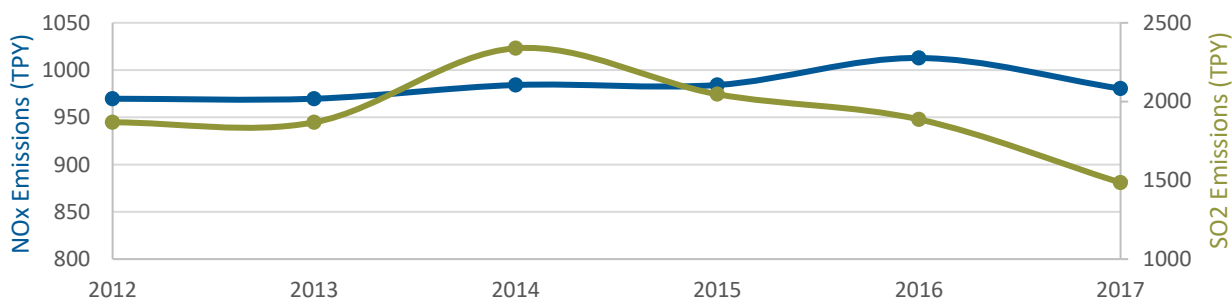
<sup>2</sup> Western Interstate Energy Board (2018). "The Role of Coal in the West" [PowerPoint slides]. Retrieved from <http://www.wrapair2.org/pdf/The%20Role%20of%20Coal%20in%20the%20West-Presentation.pdf>

and, therefore, is appropriately utilizing a baseline emissions estimate for both NO<sub>x</sub> and SO<sub>2</sub> according to the average operating capacity factor (utilization rate) and the existing emissions limits for Unit 1 and Unit 2. The current EPA draft guidance states that baseline emissions can be determined according to past practice.<sup>3</sup> MONTANA-DAKOTA reserves the right to change (or update) the operating capacity factors in future rounds of RH review, as warranted. Figure 5 and Figure 6 show the annual tons of NO<sub>x</sub> and SO<sub>2</sub> emitted from Unit 1 and Unit 2, respectively since 2012.



**Figure 5 Heskett Station Unit 1 Total Annual NO<sub>x</sub> and SO<sub>2</sub> Emissions**

The declining annual actual emissions for Unit 1 are not specifically a result of additional pollution control equipment additions, but more a result of declining unit utilization year-over-year from 2013 through 2017, as listed in Table 1-2.



**Figure 6 Heskett Station Unit 2 Total Annual NO<sub>x</sub> and SO<sub>2</sub> Emissions**

Unit 2 has operated at a fairly consistent, but reduced, capacity since 2012, which is confirmed by the total annual NO<sub>x</sub> emissions from 2012 through 2017. The reduction in annual SO<sub>2</sub> emissions starting in 2016 at Unit 2 is a result of the initial operation and testing of the limestone injection project that was fully implemented in early 2017.

<sup>3</sup> EPA July 2016 Draft Guidance, Section 6.2 (pg. 59): "In projecting future baseline emissions, typical past actual emission rates may be assumed even if lower than permitted emission rates, assuming there is no evident basis for assuming a change in emission rates"

---

## 1.2 Four-Factor Analysis Approach

The four-factor analysis is completed following the approach summarized below, as outlined in EPA's July 2016 draft guidance.

### 1.2.1 Identify all Emissions Control Options

Prior to completing the required four-factor analysis, all potentially available and technically feasible emissions control options for review are identified. Potentially available emissions control options include both add-on control equipment and process improvement applications. To be considered available and technically feasible, a control must have been previously installed and operated successfully on a similar source under similar physical and operating conditions. Novel controls that have not been demonstrated on full-scale, coal-fired utilities are not considered as part of this analysis. Instead, this evaluation focuses on commercially demonstrated control options.

All control options identified as available and technically feasible are then evaluated against the "four factors". Under this analysis, NO<sub>x</sub> and SO<sub>2</sub> emissions control options are evaluated for each unit individually.

### 1.2.2 Factor #1 – The Cost of Compliance

As part of Factor #1, the capital and annual operating and maintenance (O&M) costs of a control measure are estimated. As directed by the draft guidance, for purposes of Round 2, costs of emissions controls follow the accounting principles and generic factors from the EPA Air Pollution Control Cost Manual (Control Cost Manual) unless site specific factors are available and required to develop an accurate and representative control costs estimate. Under this step, the costs of compliance (dollar per ton basis) will be compared to the costs that other similar sources have had to bear in other regulatory actions to determine whether a control measure is reasonable.

The cost of compliance is calculated on a \$/ton basis following the Control Cost Manual site-specific information is referenced and utilized when appropriate. However, if key information is unavailable, and should further cost refinement be necessary, a study would be required. This would mandate additional time and cost to determine the impact due to constraints of the current system, such as an extended need for shutdown, rerouting of piping to allow necessary residence time, potential redesign of backend heat recovery and associated costs that have not been evaluated. MONTANA-DAKOTA reserves the right to amend all items related to cost in the future.

The cost of compliance are categorized into capital and annual costs. Capital costs generally refer to the money required to design and build the system, and this includes direct costs, such as equipment purchases, and installation costs, such as foundations and installation of mechanical equipment. Indirect costs, such as engineering and construction field expenses, are also considered. Also taken into account when completing the economic feasibility (cost effectiveness) analysis are the baseline emissions (calculated as described above) and expected performance of the control device.

At the direction of the NDDH, this analysis uses an interest rate of 5.25% for the Round 2 four-factor economic analysis when determining annualized costs, MONTANA-DAKOTA reserves the right to use the default 7% (or another appropriate percentage) interest rate in future iterations of the economic analysis for RH Round 2 purposes. The Control Cost Manual states that “EPA policy specifies 7% interest for BACT review cost calculations”. NDDH is following the EPA guidance from December 18, 2018<sup>4</sup> email in which EPA suggests using the bank prime rate in method outline in Section 2.5.2 of the Control Cost Manual. However, the December 18, 2018 email also notes that the recommended rate can vary. This variability has recently been demonstrated by an increase to raise the rate quoted in the email from 5.25% to 5.5%. MONTANA-DAKOTA is an investor-owned utility and finances projects differently than other utilities that are able to participate in Rural Utility Service (RUS) Electric Loan Program financing.

The emissions reduction or degree of control for each evaluated technology that is used to determine the cost of compliance is expressed as a 12-month average basis and represents the annual tons of pollutant removed to account for expected variability in emissions and provide a comparable basis for each of the control options. Baseline emissions are determined relying on permitted emissions limits and actual/expected unit operation.

### **1.2.3 Factor #2 – Time Necessary for Compliance**

Under Factor #2, the time necessary for a source to implement a control measure to achieve compliance with a proposed emissions limitation is given consideration by setting reasonable deadlines for selected control. This includes the planning and installation of new emissions controls.

### **1.2.4 Factor #3 – Energy and Non-Air Environmental Impacts**

The energy and non-air environmental impacts of each control technology are evaluated under Factor #3.

The environmental impact analysis assesses collateral environmental impacts associated with control of the pollutant in question. Impacts considered may include solid or hazardous waste generation, wastewater discharges from a control device, increased water consumption, and land use. The environmental impact analysis is conducted based on consideration of site-specific circumstances.

The energy impact analysis considers whether use of an emissions control technology results in any significant or unusual energy penalties or benefits. Energy use may be evaluated on an energy used per unit of production basis; energy used per ton of pollutant controlled or total annual energy use. Energy impacts may consider whether use of an emissions control technology will have an adverse impact on local energy supplies due to increased fuel consumption or the loss of fuel production or power generation.

---

<sup>4</sup> Wortstell, Aaron (EPA). “RE: Regional Haze Economic Analysis.” Message to Tom Bachman. December 18, 2018. Email.

---

### 1.2.5 Factor #4 – Remaining Useful Life of the Source

The remaining useful life of a source is considered the difference between the date that controls will be put in place and the date the facility permanently ceases operation. The remaining useful life of the source is typically longer than the useful life of the emissions control measure unless there is an enforceable cease-operation requirement. However, under Factor #4, if the useful life of the source is less than the remaining useful life of the control measure through a federally or state enforceable requirement, then that can be taken into consideration when evaluating emissions reductions, amortized costs, and cost per ton.

The remaining useful life of the two coal-fired units (Heskett Station Unit 1 and Unit 2) continues to be reviewed through MONTANA-DAKOTA'S Integrated Resource Planning (IRP) process, as required by state utility regulatory commissions. This IRP analysis considers many factors including facility age, major maintenance needs, future environmental compliance costs, and economic competitiveness to other alternatives, to determine appropriate planning for retirement of units. Until the IRP is concluded, MONTANA-DAKOTA will assume a 20-year remaining useful life for purposes of this four-factor analysis. It is possible that retirement could occur earlier than the assumed 20 years considering the culmination of additional environmental regulatory requirements and economic competitiveness of these units.

## 2 Unit 1 Nitrogen Oxides (NOx) Four-Factor Analysis

There are three mechanisms by which NOx production occurs: thermal, fuel, and prompt NOx. Fuel bound NOx is a primary concern with solid and liquid fuel combustion sources; it is formed as nitrogen compounds in the fuel are oxidized in the combustion process. The secondary mechanism of NOx production is through thermal NOx formation. This mechanism arises from the thermal dissociation of nitrogen and oxygen molecules in combustion air. The thermal oxidation reaction is as follows:



Downstream of the flame, significant amounts of NO<sub>2</sub> can be formed when NO is mixed with air. The reaction is as follows:



Thermal oxidation is a function of the residence time, concentration of combustion gases (primarily nitrogen and oxygen) in the inlet air, and peak reaction temperature. Prompt NOx is a form of thermal NOx which is generated at the flame boundary. It is the result of reactions between nitrogen and carbon radicals generated during combustion. Only minor amounts of NOx are emitted as prompt NOx.

### 2.1 NOx Emissions Control Measures

There are several potentially available methods to control NOx emissions (see Table 2-1); however, not all are applicable for implementation at Unit 1. Accordingly, as part of this four-factor analysis, MONTANA-DAKOTA has narrowed the list of NOx control technology options for review to those that are functionally applicable for a retrofit installation at the Heskett Station Unit 1. The NOx retrofit control options are identified based on a review of available technical information.

Retrofit NOx control technologies can be divided into two general categories: (1) combustion controls, and (2) post-combustion controls. Combustion controls reduce the amount of NOx that is generated in the boiler, while post-combustion controls remove NOx from the boiler exhaust gas.

**Table 2-1 List of Potentially Available Retrofit NOx Control Options**

Control Technology
Combustion Controls
<ul style="list-style-type: none"> <li>• Low NOx Burners</li> <li>• Overfire Air (OFA)</li> <li>• Flue Gas Recirculation (FGR)</li> <li>• Burner Tempering (Water Injection)</li> </ul>
Post-Combustion Controls
<ul style="list-style-type: none"> <li>• Selective Non-Catalytic Reduction (SNCR)</li> <li>• Selective Catalytic Reduction (SCR) <ul style="list-style-type: none"> <li>◦ High-Dust SCR</li> <li>◦ Low-Dust SCR</li> </ul> </li> </ul>
Innovative Control Technologies
<ul style="list-style-type: none"> <li>• Rotating Overfire Air (ROFA)</li> <li>• Boosted Overfire Air (BOFA)</li> <li>• ROFA + SNCR (Rotamix™)</li> <li>• NOxStar™</li> <li>• Exxon Thermal DeNOx™</li> <li>• Pahlman Process</li> <li>• Wet NOx Scrubbing LOTox™</li> </ul>

## 2.1.1 Combustion Controls

The rate of NOx formation in the combustion zone is a function of free oxygen, peak flame temperature and residence time. Combustion techniques designed to minimize the formation of NOx will minimize one or more of these variables. Combustion control options considered for Heskett Station Unit 1 are summarized below.

### 2.1.1.1 Low NOx Burners (LNB)

LNB technology utilizes advanced burner design to reduce NOx formation through the restriction of oxygen, flame temperature, and/or residence time. LNB is a staged combustion process that is designed to split fuel combustion into two zones. In the primary zone, NOx formation is limited by either one of two methods. Under staged air rich (high fuel) condition, low oxygen levels limit flame temperatures resulting in less NOx formation. The primary zone is then followed by a secondary zone in which the incomplete combustion products formed in the primary zone act as reducing agents. Alternatively, under staged fuel lean (low fuel) conditions, excess air will reduce flame temperature to reduce NOx formation. In the secondary zone, combustion products formed in the primary zone act to lower the local oxygen concentration, resulting in a decrease in NOx formation.

LNB technology is not a technically feasible control option at a stoker fired traveling grate furnace, and therefore, will not be considered further for implementation at Unit 1.

### 2.1.1.2 Overfire Air (OFA)

Overfire air (OFA) diverts a portion of the total combustion air from the burners and injects it through separate air ports above the top level of burners. OFA is the typical NO<sub>x</sub> control technology used in lignite-fired boilers and is primarily geared to thermal NO<sub>x</sub> reductions. Staging of the combustion air creates an initial fuel-rich combustion zone for a cooler fuel-rich combustion zone. This reduces the production of thermal NO<sub>x</sub> by lowering combustion temperature and limiting the availability of oxygen in the combustion zone where NO<sub>x</sub> is most likely to be formed.

OFA technology is currently used to control NO<sub>x</sub> emissions at Unit 1.

### 2.1.1.3 External Flue Gas Recirculation (FGR)

Flue gas recirculation is a flame-quenching technique that involves recirculating a portion of the flue gas from the economizer or air heater outlet and returning it to the furnace through the burner or windbox. The primary effect of FGR is to reduce the peak flame temperature through adsorption of the combustion heat by the relatively inert flue gas, and to reduce the oxygen concentration in the combustion zone. FGR reduces thermal NO<sub>x</sub> generation in high-temperature emissions sources.

Additional ductwork and a blower would be required to recirculate flue gas. These elements must fit in the limited space around the burner. To integrate a blower and inject flue gas into the combustion zone of the existing unit would require a full design review and likely costly modifications to the existing combustion control scheme. Unit 1 currently utilizes OFA as a way to reduce thermal NO<sub>x</sub> emissions; it is unlikely that FGR would result in any additional significant NO<sub>x</sub> reductions. Further, FGR could result in reduced boiler capacity at an already small unit operating at reduced capacity.

For these reasons, FGR is not a technically feasible control option for implementation at Unit 1 and will not be considered further.

### 2.1.1.4 Burner Tempering (Water Injection)

The principle behind combustion tempering is to inject an atomized water spray into the high NO<sub>x</sub> production zones of the furnace flame. The water spray reduces the temperature within the zone, resulting in lower NO<sub>x</sub> production within the zone.

To integrate water injection into the combustion zone of the existing unit would require a full design review and likely costly modifications to the existing combustion control scheme. Burner tempering has been used on wall- and tangential-fired pulverized coal-fired units but not at a stoker fired traveling grate furnace and is therefore not a technically feasible control option for implementation at Unit 1. This technology is not considered further.

## 2.1.2 Post-Combustion Controls

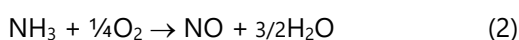
NO<sub>x</sub> can be reduced to molecular nitrogen (N<sub>2</sub>) in add-on systems located downstream of the furnace area of the combustion process. The two main techniques in commercial service include the selective non-catalytic reduction (SNCR) process and the selective catalytic reduction (SCR) process. There are a number of different process systems in each of these categories of control techniques.



In addition to these treatment systems, there are a large number of other processes being developed and tested on the market. These approaches involve innovative techniques of chemically reducing, absorbing, or adsorbing NO<sub>x</sub> downstream of the combustion chamber. One example of these alternatives is nonselective catalytic reduction (NSCR).

#### 2.1.2.1 Selective Non-Catalytic Reduction (SNCR)

In the SNCR process, urea or ammonia-based chemicals are injected into the flue gas stream to convert NO to N<sub>2</sub> and water. SNCR control efficiency is typically 25% to 50%. Without the participation of a catalyst, the reaction requires a high temperature range to obtain activation energy. The relevant reactions are as follows:



At temperature ranges of 1470°F to 1830°F, reaction (1) dominates. At temperatures above 2000°F, reaction (2) will dominate. Flue gas temperature at the point of reagent injection can greatly affect removal efficiencies and the quantity of ammonia (NH<sub>3</sub>) that will pass through unreacted (ammonia slip). At temperatures below the desired operating range, the NO<sub>x</sub> reduction reactions diminish and unreacted NH<sub>3</sub> emissions increase. Above the desired temperature range, NH<sub>3</sub> is oxidized to NO<sub>x</sub> resulting in low NO<sub>x</sub> reduction efficiencies.

Mixing of the reactant and flue gas within the reaction zone is also an important factor to SNCR performance. The SNCR system must be designed to deliver the reagent in the proper temperature window, and allow sufficient residence time of the reagent and flue gas in that temperature window. In addition to temperature, mixing, and residence time, several other factors influence the performance of an SNCR system including reagent-to-NO<sub>x</sub> ratio and NO<sub>x</sub> concentration in the flue gas.

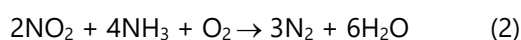
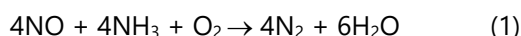
SNCR systems are capable of achieving a NO<sub>x</sub> emissions reduction as high as 50 to 60 percent in optimum conditions (adequate reaction time, temperature, and reagent/flue gas mixing, high baseline NO<sub>x</sub> conditions, multiple levels of injectors) with ammonia slips of 10 to 50 ppmvd. Typically, optimum conditions are difficult to achieve, resulting in emissions reduction levels of 20 to 40 percent. Potential performance is very site-specific and varies with fuel type, steam generator size, allowable ammonia slip, furnace carbon monoxide (CO) concentrations, and steam generator heat transfer characteristics.

The application of SNCR to Heskett Station Unit 1 has the potential to be technically feasible because furnace temperatures are assumed (note that there is not instrumentation currently in place to measure temperature) to be within the temperature window needed for NO<sub>x</sub> reduction, and flue gas mixing and residence time within the boiler should promote the reaction kinetics. However, the effectiveness of an SNCR system at Heskett Station Unit 1 will be limited because of the design and boiler operating temperatures. The optimal condition locations are small due to the boiler size and type, and a boiler study would be required to more correctly predict feasibility and effectiveness at Unit 1. Even so, for purposes of this review, MONTANA-DAKOTA has assumed that SNCR could potentially be implemented at Unit 1 and has therefore included this in the four-factor analysis. Based on the calculated default control efficiency

from EPA, an SNCR could potentially provide a NO<sub>x</sub> reduction of approximately 27% at Unit 1. With the uncertainty due to small boiler size and other issues, we reserve the right to refine this analysis in the future if necessary. MONTANA-DAKOTA is unaware of an SNCR system that is in operation today at a similar source utilizing an ESP for particulate matter control. A full review of the ESP's ability to accept and properly clean the flue gas would be needed to determine feasibility and possible costs.

#### 2.1.2.2 Selective Catalytic Reduction (SCR)

Selective catalytic reduction (SCR) is a post combustion NO<sub>x</sub> control technology in which NH<sub>3</sub> is injected into the flue gas stream in the presence of a catalyst. SCR control efficiency is typically 70% to 90%. NO<sub>x</sub> is removed through the following chemical reaction:



The catalyst bed lowers the activation energy required for NO<sub>x</sub> decomposition. The catalyst contains an active phase, such as vanadium pentoxide, on a carrier, such as titanium dioxide, and these are used for their ability to lower the activation energy required for NO<sub>x</sub> decomposition. SCR requires an optimum temperature range of 650 to 800°F.

A "high-dust" SCR arrangement in which the reactor is located between the outlet of the economizer and the inlet of the air heater and upstream of particulate control is typically the preferred arrangement where technically feasible. These arrangements typically require soot blowers for catalyst cleaning. In a "low-dust" arrangement, the SCR reactor is located after the particulate control device. This arrangement is preferred when the fly ash contains a high level of contaminants that would block catalyst actions, and removing most of the fly ash from the flue gas will help prolong the catalyst life. Firing ND lignite coal that contains high amounts of organically bound inorganics (and has a higher total sodium content), results in a stream heavily laden with particulate matter and sodium that combine to plug (block) catalyst passages. Due to the likelihood of catalyst plugging and the ability of phosphorus, sodium, other alkali and alkaline earth cations organically bound in ND lignite to mask or blind a catalyst reactions if not already plugged, a high-dust SCR system is considered technically infeasible on both Units 1 and 2. A low-dust SCR (downstream of particulate control) would require reheat to bring the stream temperature back to the effective control range after it is cooled for particulate removal. There would still be important concerns with this arrangement due to the contaminants' unique properties to inhibit the catalyst from operating, but in theory the issues would be less than with a high-dust system.

Although it would appear to be a potentially a technically feasible control option, MONTANA-DAKOTA notes that installing SCR (even a low-dust system) at similar types of sources remains limited or is altogether not feasible. MONTANA-DAKOTA is unaware of an SCR system that has been installed at a source firing North Dakota lignite. Issues associated with SCR on lignite boilers are discussed in additional

detail in a 2009 study completed by the NDDH, which supports the limited feasibility of SCR.<sup>5</sup> Additionally, physical space constraints at Heskett Station greatly limit the opportunity for SCR system equipment and tie-ins. Even so, for purposes of this review, MONTANA-DAKOTA has assumed that a low-dust SCR system could potentially be implemented at Unit 1 and has therefore included this in the four-factor analysis (even though it is considered by MONTANA-DAKOTA as technically infeasible). Based on current NO<sub>x</sub> emissions, an SCR could potentially provide an additional NO<sub>x</sub> reduction in the range of 70%-80%. Again, due to the issues stated above, we reserve the right to refine this analysis in the future if necessary.

### 2.1.3 Innovative Controls

NO<sub>x</sub> controls grouped under the “Innovative Control Technologies” are not being considered in this analysis. These technologies are not considered commercially available and are not applicable at MONTANA-DAKOTA Heskett Station.

## 2.2 Factor 1 – The Cost of Compliance

The pollution control costs are presented on a dollar per ton of pollutant removed, calculated according to Equation 2.73 of the Cost Manual and 40 CFR 51, Appendix Y, Section IV, Subsection D. The cost effectiveness analysis compares the annualized cost of the technology per ton of pollutant removed and is evaluated on dollar per ton (\$/ton) basis using the annual operating cost (\$/yr) divided by the annual emissions reduction achieved by the control device (ton/yr). Additional details regarding the control equipment cost data and evaluation are noted in the control cost worksheets in Attachment A.

Table 2-2 NO<sub>x</sub> Control Cost Evaluation for Heskett Station Unit 1

Control Technology	Estimated Control Efficiency (%)	Installed Capital Cost (\$)	Annualized Capital Cost (\$/yr)	Pollution Control Cost (\$/ton) <sup>1</sup>
SNCR	27%	\$4,180,000	\$744,000	\$9,100
Low-Dust SCR	80%	\$21,700,000	\$2,540,000	\$10,400

<sup>1</sup> The NDDH original BART ceiling costs were based on the June 1999 WRAP Annex to Grand Canyon Visibility Transport Report. Scaled to today's dollars, the average cost effectiveness threshold is approximately \$4,460 per ton.

SNCR and SCR are both considered economically infeasible for implementation at Unit 1 as the average cost effectiveness is not justified on a dollar per ton basis.

## 2.3 Factor 2 – Time Necessary for Compliance

Under Factor #2, the amount of time needed for full implementation of different control strategies is reviewed. Typically, the time necessary for compliance will include the time needed to develop and implement the regulation and/or the time needed to install the necessary emissions control equipment.

---

<sup>5</sup> *Best Available Retrofit Technology – Selective Catalytic Reduction Technical Feasibility Analysis for North Dakota Lignite*. North Dakota Department of Health, Division of Air Quality. 7/1/2009

---

This analysis does not support the installation of any new retrofit NOx emissions control methods at Heskett Station Unit 1 and therefore a review of the time necessary for compliance is not applicable.

## **2.4 Factor 3 – Energy and Non-Air Quality Environmental Impacts**

Energy impacts are primarily related to the auxiliary power consumption of the SCR and SNCR systems and are included in the cost estimates under the variable annual costs. Other indirect energy impacts, such as the energy to produce reagents, are not considered in this study.

The operation of an SCR or SNCR system could have other non-air environmental impacts. For example, the storage of ammonia on-site creates the potential for accidents due to an ammonia release.

Depending on the type, concentration, and quantity of ammonia used, the material will be subject to regulation as a hazardous substance under the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), Section 313 of the Emergency Planning and Community Right-to-Know Act, Section 112(r) of the CAA, and Section 311(b)(4) of the Clean Water Act.

## **2.5 Factor 4 – Remaining Useful Life of the Source**

At this time, MONTANA-DAKOTA has assumed that the remaining useful life of the Unit 1 will be longer than the useful life of the emissions control measures evaluated in this analysis. Accordingly, as directed by the July 2006 EPA draft guidance, the useful life of the individual control measures is used to calculate emissions reductions, amortized costs, and cost effectiveness on a dollar per ton basis.

## **2.6 Proposed Controls and Emissions Rates**

This analysis does not support the installation of any new retrofit NOx emissions controls at Heskett Station Unit 1. The available and potential technically feasible control strategies (SCNR and SCR) are economically infeasible and have significant technical and other implementation concerns for commercial scale operation at a North Dakota lignite fired boiler. Therefore, MONTANA-DAKOTA is proposing to maintain current operational practices consistent with the parameters and limits included as part of the facility's existing Air Pollution Control Title V Permit to Operate (T5-F76001). Due to the uncertainty of the actual feasibility of NOx emissions controls that was assumed as part of this four-factor analysis and the additional detailed analysis for cost refinement, MONTANA-DAKOTA reserve the right to refine this analysis in the future if necessary.

## 3 Unit 1 Sulfur Dioxide (SO<sub>2</sub>) Four-Factor Analysis

Sulfur emissions from coal combustion consist primarily of SO<sub>2</sub>, with a much lower quantity of sulfur trioxide (SO<sub>3</sub>) and gaseous sulfates. These compounds form as the organic and pyritic sulfur in the coal is oxidized during the combustion process. The generation of SO<sub>2</sub> is directly related to the sulfur content and heating value of the fuel burned. The sulfur content and heating value of coal can vary dramatically depending on the source of the coal. Heskett Station uses North Dakota lignite and, for a short period in the past, used a blend of lignite and small amounts of Powder River Basin (PRB) coal as its fuel source.

### 3.1 SO<sub>2</sub> Emissions Control Measures

Several techniques can be used to reduce SO<sub>2</sub> emissions from coal combustion sources. SO<sub>2</sub> control techniques can be divided into pre- and post-combustion strategies.

Table 3-1 SO<sub>2</sub> Control Options with Potential Applications to Heskett Station Unit 1

Control Technology
Pre-Combustion Controls
<ul style="list-style-type: none"><li>Fuel Switching</li><li>Fuel Washing</li></ul>
Post-Combustion SO <sub>2</sub> Control Technologies
<ul style="list-style-type: none"><li>Wet Flue Gas Desulfurization</li><li>Dry Flue Gas Desulfurization<ul style="list-style-type: none"><li>Spray Dryer Absorber</li><li>Dry Sorbent Injection</li></ul></li></ul>

#### 3.1.1 Pre-Combustion Controls

A potential control strategy for reducing SO<sub>2</sub> emissions from a coal-fired boiler is to reduce the amount of sulfur contained in the coal. This can be accomplished through reducing inherent impurities via coal washing or potentially, more drastically, through switching to a lower sulfur fuel source.

In general, coal washing is accomplished by separating and removing inorganic impurities from organic coal particles. Inorganic impurities, including inorganic ash constituents and inorganic iron disulfide (FeS<sub>2</sub> or pyrite), are typically denser than the coal particles. This property is generally used in a wet cleaning process to separate coal particles from the inorganic impurities.

While washing may be effective in removing rock inclusions from coal, including sulfur-bearing pyrites, a significant amount of coal may also be lost in the washing process requiring the mine to process significantly more coal to make up for coal lost in the washing process. Further, an inherent consequence of coal washing is the generation of wastewater and solid waste streams.

No information was identified regarding the washability, or effectiveness of washing, lignite or subbituminous PRB coals, and it is unlikely that coal washing will result in a significant decrease in

controlled SO<sub>2</sub> emissions. Therefore, coal washing is not considered a technically feasible or commercially available retrofit control option at Heskett Station.

North Dakota lignite has a relatively high moisture content, low heating value, and low sulfur content. PRB coal typically also has relatively lower heating values compared to other fuel sources but lower sulfur content than lignite. In theory, if a boiler could utilize it for fuel and a fuel feed system could receive it; burning 100% PRB would result in lower uncontrolled SO<sub>2</sub> emissions rates. However, lower uncontrolled emissions rates do not necessarily translate into lower controlled emissions rates. The efficiency of pollution control equipment is a function of several operating variables, including the uncontrolled pollutant concentration. At a lower uncontrolled pollution concentration, it becomes more difficult to maintain a high emissions control efficiency.

Unit 1 is designed for lignite combustion and cannot burn 100% PRB without significant boiler modifications, including changes to the internal boiler materials of construction and modifications to provide flue gas recirculation. The amount of tube surface area required for lignite combustion is much larger than needed for PRB combustion. Burning even high blends of PRB would result in increased furnace temperatures that are too high and require changes to the superheater (and other boiler tubes) and changes to keep fly ash from becoming molten and fouling the boiler. Further, the viability of the Heskett Station is dependent upon an economic supply of fuel. As a result, switching to burning a lower sulfur subbituminous coal in amounts is not supported by the existing equipment and is not considered a technically feasible option for Heskett Station Unit 1.

### **3.1.2 Post-Combustion Controls**

Post-combustion controls or flue gas desulfurization (FGD) systems commonly used to control SO<sub>2</sub> emissions can be classified as either wet or dry systems. Both systems rely on creating turbulence in the gas stream to increase contact with the absorbing medium. Wet systems are commonly capable of achieving higher removal efficiencies than dry systems because it is easier to mix a gas with a liquid than a solid. FGD requires the use of an alkali powder slurry, and lime (or limestone) as the most widely used compound for acid gas absorption. Sodium based reagents are also available, and while they provide better SO<sub>2</sub> solubility, they are significantly more expensive.

Wet FGD systems may discard all the waste by-product streams or regenerate and reuse them. Wet systems generally require more extensive networks of pumps and piping than dry systems to recirculate, collect and treat the scrubbing liquid. As implied by the name, dry scrubbers require less water than wet systems but also require higher temperatures to ensure that all moisture has been evaporated before leaving the scrubber. There are many available FGD systems including wet scrubbing, spray dryer absorption, and dry sorbent injection.

#### **3.1.2.1 Wet Lime/Limestone Scrubbing**

Wet lime/limestone scrubbing involves scrubbing the exhaust gas stream with a slurry comprised of lime (CaO) or limestone (CaCO<sub>3</sub>) in suspension. The process takes place in a wet scrubbing tower located downstream of a particular matter (PM) control device to prevent the plugging of spray nozzles and other

problems caused by the presence of particulates in the scrubber. The SO<sub>2</sub> in the gas stream reacts with the lime or limestone slurry to form calcium sulfite (CaSO<sub>3</sub>•2H<sub>2</sub>O) and calcium sulfate (CaSO<sub>4</sub>).

Physical space constraints at Heskett Station greatly limit the opportunity for construction and operation of an add-on control equipment such as wet gas scrubber system. However, for purposes of this analysis, a wet scrubber is considered a technically feasible retrofit control option. It is assumed, based on available information, that the wet FGD system would be able achieve an SO<sub>2</sub> emissions reduction of approximately 99%.<sup>6</sup>

Control efficiencies assumed achievable for purposes of this analysis are considered conservative due to being based on operation at high load conditions. The high rate of assumed capture may not be achieved at low load operation. Installation of a wet scrubbing system would require removal of the existing dry electrostatic precipitator (ESP) control system. Environmental and cost implications associated with said required retrofit have not been included as part of the analysis at this time. MONTANA-DAKOTA reserves the right to refine the assumptions and impacts to the cost of controls if further study is needed.

### 3.1.2.2 Spray Dry Absorption (SDA)

Spray dry absorption (SDA) is a dry scrubbing system that sprays a fine mist of lime slurry into an absorption tower where the SO<sub>2</sub> is absorbed by the droplets. The absorption of the SO<sub>2</sub> leads to the formation of calcium sulfite (CaSO<sub>3</sub>•2H<sub>2</sub>O) and calcium sulfate (CaSO<sub>4</sub>).

The liquid-to-gas ratio is such that the heat from the exhaust gas causes the water to evaporate before the droplets reach the bottom of the tower. This leads to the formation of a dry powder that is carried out with the gas and collected with a fabric filter. The process equipment associated with a spray dryer typically includes an alkaline storage tank, mixing and feed tanks, an atomizer, spray chamber, particulate control device and a recycle system.

Designing an SDA for an existing unit presents significant design challenges. The SDA must be located upstream of the unit's particulate matter control device and the reactor vessel must be located within existing site parameters. Retrofitting Heskett Station Unit 1 with an SDA would require extensive ductwork to direct flue gas flow from the boiler to the SDA and back to the ESP. An SDA will require additional unreacted hydrated lime to the flue gas and increase particulate loading to the particulate control device. Second, to maximize utilization of the lime reactant (which is more expensive compared to limestone), the system must be designed with a solids recycling system to mix some of the controlled particulate solids product with fresh lime slurry and re-inject the mixture into the SDA. The Unit would need an in-depth study, including a full review of the existing ESP's ability to accept and properly clean the flue gas, to determine if truly feasible. Historically, SDA systems have typically been permitted as best available controls on pulverized coal-fired boilers firing low-sulfur PRB coal. Nevertheless, for purposes of this analysis, SDA is considered a technically feasible retrofit control option. It was been assumed that a

---

<sup>6</sup> <https://www3.epa.gov/ttn/catc/dir1/fsprytwr.pdf>

baghouse, requiring retrofit of the existing particulate matter control system, would be required for proper operation and particulate matter control.

SDA control efficiency is typically in the 70% to 90% range. The high rate of assumed capture may not be achieved at low load operation. Due to expected low load operation and other unknowns, MONTANA-DAKOTA has assumed a control efficiency of 70%. MONTANA-DAKOTA reserves the right to refine the assumptions and impacts to the cost of controls if further study is needed.

### 3.1.2.3 Dry Sorbent Injection (DSI)

Dry sorbent injection (DSI) involves the injection of a lime or limestone powder into the exhaust gas stream. The stream is then passed through a baghouse to remove the sorbent and entrained SO<sub>2</sub>. The process was developed as a lower cost FGD option because the mixing occurs directly in the exhaust gas stream instead of in a separate tower. DSI systems are simple systems, and generally require a sorbent storage tank, feeding mechanism, transfer line and blower, and an injection device. The dry sorbent is typically injected countercurrent to the gas flow. An expansion chamber is often located downstream of the injection point to increase residence time and efficiency. Particulates generated in the reaction are controlled in the systems particulate control device. Depending on the residence time and gas stream temperature, sorbent injection control efficiency is typically between 50% and 70%. Although a dry sorbent injection system may be technically feasible at Unit 1, it is not practical to assume a high level of control efficiency would be achievable due to space constraints limiting the reaction time. Further, Unit 1 exhaust gas temperature is higher (420°F) than the ideal gas stream temperature range of 300°F to 350°F and the impact on control efficiency would require further evaluation. For purposes of this analysis MONTANA-DAKOTA has assumed a control efficiency of 50% and that the existing ESP could not handle additional loading, requiring retrofit of the existing particulate matter control system for proper operation and particulate matter control.

DSI is considered a technically feasible retrofit control option for this analysis, but due to space constraints and other issues, MONTANA-DAKOTA reserves the right to more analysis in the future to determine actual feasibility with the Unit. A full review of the ESP's ability to accept and properly clean the flue gas with changed properties would be needed to determine feasibility and possible costs. MONTANA-DAKOTA reserves the right to refine the assumptions and impacts to the cost of controls if further study is needed.

## 3.2 Factor 1 – The Cost of Compliance

The pollution control costs are presented on a dollar per ton of pollutant removed calculated according to Equation 2.73 of the Cost Manual and 40 CFR 51, Appendix Y, Section IV, D. The cost effectiveness compares the annualized cost of the technology per ton of pollutant removed and is evaluated on dollar per ton (\$/ton) basis using the annual operating cost (\$/yr) divided by the annual emissions reduction achieved by the control device (ton/yr). Additional details regarding the control equipment cost data and evaluation are noted in the control cost worksheets in Attachment B.



**Table 3-2 SO<sub>2</sub> Control Cost Evaluation for Heskett Station Unit 1**

Control Technology	Estimated Control Efficiency (%)	Installed Capital Cost (\$)	Annualized Capital Cost (\$/yr)	Pollution Control Cost (\$/ton)
Wet Scrubber	98%	\$71,500,000	\$10,300,000	\$5,100
Spray Dry Absorption	70%	\$55,700,000	\$8,000,000	\$5,600
Dry Sorbent Injection	50%	\$32,300,000	\$5,150,000	\$5,100

<sup>1</sup> The NDDH original BART ceiling costs were based on the June 1999 WRAP Annex to Grand Canyon Visibility Transport Report. Scaled to today's dollars, the average cost effectiveness threshold is approximately \$4,460 per ton.

The SO<sub>2</sub> control options evaluated as part of this analysis are considered economically infeasible for implementation at Unit 1; costs are not justified on a dollar per ton basis.

### 3.3 Factor 2 – Time Necessary for Compliance

Under Factor #2, the amount of time needed for full implementation of different control strategies is reviewed. Typically, time for compliance includes the time needed to develop and implement the regulation and/or the time needed to install the necessary emissions control equipment. This analysis does not support the installation of any new retrofit SO<sub>2</sub> emissions controls at Heskett Station Unit 1 and therefore a review of the time necessary for compliance is not applicable.

### 3.4 Factor 3 – Energy and Non-Air Quality Environmental Impacts

The energy and non-air environmental impacts associated with implementation of the above-identified SO<sub>2</sub> control measures are discussed in the following sections.

#### 3.4.1 Wet Lime/Limestone Scrubbing

In addition to the economic impacts of a wet FGD system, there are several collateral environmental impacts associated with its operation. Wet FGD systems generate a calcium sulfate waste by-product that must be properly managed. Historically, solid wastes generated from wet FGD systems have been dewatered and disposed of in landfills. Most new wet FGD systems utilize a forced oxidation system that results in a gypsum by-product that can sometimes be sold into the local gypsum market. If an adequate local gypsum market is not available, the gypsum by-product will require proper disposal. Currently, there is not a viable market in proximity to Heskett Station and usable quantity would be likely limited. A study of disposal at our current facility would be required and, if feasible, additional permitting needed. If not acceptable for sale, disposal costs may be significant and would have to include transport costs. In a northern climate this may be a significant issue.

A wet FGD system will also result in greater particulate matter emissions. Wet FGD systems must be located downstream of the unit's particulate control device; therefore, dissolved solids from the wet FGD system will be emitted with the wet FGD moisture plume. In addition, any SO<sub>3</sub> remaining in the flue gas could react with moisture in the wet FGD to generate sulfuric acid mist.

Wet FGD systems also require significantly more water than dry FGD systems or limestone injection systems. Wet FGD control systems typically require approximately 1.0 gpm of water per gross MW output.

Additional costs may result from a potential need to increase Heskett Station's existing water rights for withdrawal of water. Finally, wet FGD systems generate a wastewater stream that must be treated and discharged in compliance with Effluent Limitations Guidelines for electric steam generating units. The site faces challenges for space due to rail lines, historical disposal and archeological issues. Coal combustion residual (CCR) considerations would need to be evaluated (including location restrictions); state and federal discharge permitting requirements (from the new system) would also be applicable. These would take significant study and time.

### **3.4.2 Dry Flue Gas Desulfurization (FGD)**

Collateral environmental impacts are less significant with dry scrubbing systems. Using a dry FGD system at Unit 1 requires the facility to handle two reactants; limestone for injection in the AFBC (Unit 2) and pebble lime for use in the dry scrubber. The receipt, storage, management and use of two reactants will result in increased material handling PM emissions.

Lime used in dry FGD systems must be hydrated prior to use, increasing the facility's overall consumption of water. However, water used to hydrate the lime reactant is evaporated in the dry scrubbing system, eliminating the need for additional wastewater treatment and discharge.

## **3.5 Factor 4 – Remaining Useful Life of the Source**

At this time, MONTANA-DAKOTA has assumed that the remaining useful life of the Unit 1 will be longer than the useful life of the emissions control measures evaluated in this analysis. Accordingly, as directed by the July 2006 EPA draft guidance, the useful life of the individual control measures is used to calculate emissions reductions, amortized costs and cost effectiveness on a dollar per ton basis. MONTANA-DAKOTA relied on EPA's Control Cost Manual to determine the appropriate value for use in the evaluation (20 years).

## **3.6 Proposed Controls and Emissions Rates**

This analysis does not support the installation of any new retrofit SO<sub>2</sub> emissions controls at Heskett Station Unit 1. The available and potential technically feasible control strategies are economically infeasible and have significant technical and other concerns for operation Heskett Station. Therefore, MONTANA-DAKOTA is proposing to maintain current operational practices consistent with the parameters and limits included as part of the facility's existing Air Pollution Control Title V Permit to Operate (T5-F76001). Due to the uncertainty of the actual performance of the potentially available control technologies evaluated, the uncertainty of technically feasible SO<sub>2</sub> emissions controls that we assumed as part of this four-factor analysis, the implementation concerns and the additional detailed analysis for cost refinement, MONTANA-DAKOTA reserves the right to refine this analysis in the future if necessary.

## 4 Unit 2 Nitrogen Oxides (NOx) Four-Factor Analysis

There are three mechanisms by which NOx production occurs: thermal, fuel and prompt NOx. Fuel bound NOx is a primary concern with solid and liquid fuel combustion sources; it is formed as nitrogen compounds in the fuel are oxidized in the combustion process. The secondary mechanism of NOx production is through thermal NOx formation. This mechanism arises from the thermal dissociation of nitrogen and oxygen molecules in combustion air. The thermal oxidation reaction is as follows:



Downstream of the flame, significant amounts of NO<sub>2</sub> can be formed when NO is mixed with air. The reaction is as follows:



Thermal oxidation is a function of the residence time, concentration of combustion gases (primarily nitrogen and oxygen) in the inlet air, and peak reaction temperature. Prompt NOx is a form of thermal NOx which is generated at the flame boundary. It is the result of reactions between nitrogen and carbon radicals generated during combustion. Only minor amounts of NOx are emitted as prompt NOx.

### 4.1 NOx Emissions Control Measures

There are several potentially available methods to control NOx emissions, as show in Table 4-1, however not all are applicable for implementation at Unit 2. Accordingly, as part of this four-factor analysis, MONTANA-DAKOTA has narrowed the list of NOx control technology options for review to those that are truly applicable for a retrofit installation at the Heskett Station Unit 2. The NOx retrofit control options are identified based on a review of available technical information.

Retrofit NOx control technologies can be divided into two general categories: (1) combustion controls, and (2) post-combustion controls. Combustion controls reduce the amount of NOx that is generated in the boiler, while post-combustion controls remove NOx from the boiler exhaust gas.

**Table 4-1 List of Potentially Available Retrofit NOx Control Options**

Control Technology
Combustion Controls
<ul style="list-style-type: none"> <li>• Fluidized Bed Combustion</li> <li>• Low NOx Burners</li> <li>• Overfire Air (OFA)</li> <li>• Flue Gas Recirculation (FGR)</li> <li>• Burner Tempering (Water Injection)</li> </ul>
Post-Combustion Controls
<ul style="list-style-type: none"> <li>• Selective Non-Catalytic Reduction (SNCR)</li> <li>• Selective Catalytic Reduction (SCR) <ul style="list-style-type: none"> <li>○ High-Dust SCR</li> <li>○ Low-Dust SCR</li> </ul> </li> </ul>
Innovative Control Technologies
<ul style="list-style-type: none"> <li>• Rotating Overfire Air (ROFA)</li> <li>• Boosted Overfire Air (BOFA)</li> <li>• ROFA + SNCR (Rotamix™)</li> <li>• NOxStar™</li> <li>• Exxon Thermal DeNOx™</li> <li>• Pahlman Process</li> <li>• Wet NOx Scrubbing LOTox™</li> </ul>

### 4.1.1 Combustion Controls

The rate of NOx formation in the combustion zone is a function of free oxygen, peak flame temperature and residence time. Combustion techniques designed to minimize the formation of NOx will minimize one or more of these variables. Combustion control considered Heskett Station Unit 2 are summarized below.

#### 4.1.1.1 Fluidized Bed Combustion (FBC)

Fluidized bed combustion offers the potential for lower NOx emissions due to inherently lower combustion temperatures. In an atmospheric fluidized bed combustion (AFBC) boiler, like Unit 2, fuel is burned in a bed of hot combustible particles suspended by an upward flow of combustion air. The fuel (coal) can be mixed with an inert sand or limestone (used for SO<sub>2</sub> control) to form the combustion bed. Bed temperatures are usually maintained around 1550°F to 1750°F because this temperature is optimal for the chemical processes needed to capture SO<sub>2</sub> and control NOx emissions. Efficient combustion in the AFBC is achieved because of the relatively long residence time of fuel in the bed and good gas/fuel contact. At the low combustion temperatures, the formation of thermal NOx is essentially eliminated; however, nearly all of the fuel nitrogen will be converted to nitrogen oxides. Unit 2 is an AFBC boiler and has inherently different properties than the typical FBC.

#### 4.1.1.2 Low NOx Burners (LNB)

Low NOx burner (LNB) technology utilizes advanced burner design to reduce NOx formation through the restriction of oxygen, flame temperature, and/or residence time. LNB is a staged combustion process that is designed to split fuel combustion into two zones. In the primary zone, NOx formation is limited by either one of two methods. Under staged air rich (high fuel) condition, low oxygen levels limit flame temperatures resulting in less NOx formation. The primary zone is then followed by a secondary zone in which the incomplete combustion products formed in the primary zone act as reducing agents. Alternatively, under staged fuel lean (low fuel) conditions, excess air will reduce flame temperature to reduce NOx formation. In the secondary zone, combustion products formed in the primary zone act to lower the local oxygen concentration, resulting in a decrease in NOx formation. Low NOx burners typically achieve NOx emissions reductions of 25% to 50%.

AFBC boilers do not use burners during normal operation, as combustion takes place within the fluidized bed. Therefore, LNB combustion control technologies are not technically feasible, and not applicable to Heskett Station Unit 2.

#### 4.1.1.3 Overfire Air (OFA)

Overfire air (OFA) diverts a portion of the total combustion air from the burners and injects it through separate air ports above the top level of burners. OFA is the typical NOx control technology used in lignite-fired boilers and is primarily geared to thermal NOx reductions. Staging of the combustion air creates an initial fuel-rich combustion zone for a cooler fuel-rich combustion zone. This reduces the production of thermal NOx by lowering combustion temperature and limiting the availability of oxygen in the combustion zone where NOx is most likely to be formed.

Heskett Station Unit 2 is currently designed with nominal staged combustion. The boiler is designed with one row of OFA ports located on the front and back wall of the furnace. Both banks of OFA ports are located relatively low in the furnace, just above the coal feeder systems and combustion bed. The degree of staging is unit-specific, and limited by operational problems since the staged combustion could result in conditions that favor incomplete combustion. Adding additional staged combustion would require the installation of more OFA ports above the existing ports or on the furnace sidewalls. Retrofitting an existing boiler with OFA ports can be challenging, and MONTANA-DAKOTA may be required to model flow within the boiler to ensure new OFA ports are properly located to provide staged combustion air. Adding OFA ports may also require the installation of additional booster fans to support mixing of the air and flue gas.

Moreover, thermal NOx emissions are essentially eliminated as a result of the AFBC, and it is therefore unlikely that additional staged combustion/OFA would result in any further significant NOx reductions. For these reasons, MONTANA-DAKOTA considers adding additional staged combustion is not technically feasible for additional NOx control at Heskett Station Unit 2.

#### 4.1.1.4 External Flue Gas Recirculation (FGR)

Flue gas recirculation (FGR) is a flame-quenching technique that involves recirculating a portion of the flue gas from the economizer or air heater outlet and returning it to the furnace through the burner or windbox. The primary effect of FGR is to reduce the peak flame temperature through adsorption of the

combustion heat by the relatively inert flue gas, and to reduce the oxygen concentration in the combustion zone. FGR reduces thermal NO<sub>x</sub> generation in high-temperature emissions sources.

Additional ductwork and a blower would be required to recirculate flue gas. These elements must fit in the limited space around the burner. The space constraints and the lowered flame temperature created by FGR make it incompatible with the existing combustion controls on Units 2. To integrate a blower and inject flue gas into the combustion zone of the existing unit would require a full design review and likely costly modifications to the existing combustion control scheme. To date, MONTANA-DAKOTA is unaware of another lignite fired AFBC boiler utilizing FGR technology. Further, the addition of FGR could further result in reduced boiler capacity. Flue gas recirculation is therefore a technically infeasible control option and is not be considered further.

#### 4.1.1.5 Burner Tempering (Water Injection)

The principle behind combustion tempering is to inject an atomized water spray into the high NO<sub>x</sub> production zones of the furnace flame. The water spray reduces the temperature within the zone, resulting in lower NO<sub>x</sub> production within the zone. Burner tempering has been used on wall- and tangential-fired pulverized coal-fired units. The risk of any water so close to the bed material that would form concretions and encase our boiler tubes in the bed is immediately concerning.

However, FBC boilers do not use burners during normal operation, and burner tempering would not be applicable to FBC units. Therefore, burner tempering is not a technically feasible NO<sub>x</sub> control technology for Unit 2 and is not considered further.

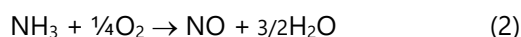
### 4.1.2 Post-combustion Controls

NO<sub>x</sub> can be reduced to N<sub>2</sub> in add-on systems located downstream of the furnace area of the combustion process. The two main techniques in commercial service include the selective non-catalytic reduction (SNCR) process and the selective catalytic reduction (SCR) process. There are a number of different process systems in each of these categories of control techniques.

In addition to these treatment systems, there are a large number of other processes being developed and tested on the market. These approaches involve innovative techniques of chemically reducing, absorbing, or adsorbing NO<sub>x</sub> downstream of the combustion chamber. One example of these alternatives is nonselective catalytic reduction (NSCR).

#### 4.1.2.1 Selective Non-Catalytic Reduction (SNCR)

In the selective non-catalytic reduction (SNCR) process, urea or ammonia-based chemicals are injected into the flue gas stream to convert NO to N<sub>2</sub> and water. SNCR control efficiency is typically 25% to 50%. Without the participation of a catalyst, the reaction requires a high temperature range to obtain activation energy. The relevant reactions are as follows:



At temperature ranges of 1470°F to 1830°F, reaction (1) dominates. At temperatures above 2000°F, reaction (2) will dominate. Flue gas temperature at the point of reagent injection can greatly affect removal efficiencies and the quantity of NH<sub>3</sub> that will pass through unreacted (ammonia slip). At temperatures below the desired operating range, the NO<sub>x</sub> reduction reactions diminish and unreacted NH<sub>3</sub> emissions increase. Above the desired temperature range, NH<sub>3</sub> is oxidized to NO<sub>x</sub> resulting in low NO<sub>x</sub> reduction efficiencies.

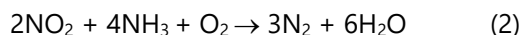
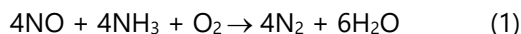
Mixing of the reactant and flue gas within the reaction zone is also an important factor to SNCR performance. The SNCR system must be designed to deliver the reagent in the proper temperature window, and allow sufficient residence time of the reagent and flue gas in that temperature window. In addition to temperature, mixing, and residence time, several other factors influence the performance of an SNCR system including reagent-to-NO<sub>x</sub> ratio and NO<sub>x</sub> concentration in the flue gas.

SNCR systems are capable of achieving a NO<sub>x</sub> emissions reduction as high as 50 to 60 percent in optimum conditions (adequate reaction time, temperature, and reagent/ flue gas mixing, high baseline NO<sub>x</sub> conditions, multiple levels of injectors) with ammonia slips of 10 to 50 ppmvd. Typically, optimum conditions are difficult to achieve, resulting in emissions reduction levels of 20 to 40 percent. Potential performance is very site-specific and varies with fuel type, steam generator size, allowable ammonia slip, furnace CO concentrations, and steam generator heat transfer characteristics.

The application of SNCR to Heskett Station Unit 2 has the potential to be technically feasible because furnace temperatures are assumed (note that there is not instrumentation currently in place to measure temperature) to be within the temperature window needed for NO<sub>x</sub> reduction, and flue gas mixing and residence time within the boiler should promote the reaction kinetics. However, the effectiveness of an SNCR system at Heskett Station Unit 2 would be limited because of the design and boiler operating temperatures. The optimal condition locations are small due to the boiler size and type and a boiler study would be required to more correctly predict feasibility and effectiveness at Unit 2. Even so, for purposes of this review, MONTANA-DAKOTA has assumed that SNCR could potentially be implemented at Unit 2 and has therefore included this in the four-factor analysis. Based on the calculated default control efficiency from EPA, a SNCR could potentially provide a NO<sub>x</sub> reduction of approximately 27% at Unit 2. As mentioned in the discussion of Unit 1, with the uncertainty due to limited space and other issues, we reserve the right to refine this analysis in the future if necessary. A full review of the ESP's ability to accept and properly clean the flue gas with changed properties would be needed to determine feasibility and possible costs.

#### 4.1.2.2 Selective Catalytic Reduction (SCR)

Selective catalytic reduction (SCR) is a post combustion NO<sub>x</sub> control technology in which NH<sub>3</sub> is injected into the flue gas stream in the presence of a catalyst. SCR control efficiency is typically 70% to 90%. NO<sub>x</sub> is removed through the following chemical reaction:



The catalyst bed lowers the activation energy required for NO<sub>x</sub> decomposition. The catalyst contains an active phase, such as vanadium pentoxide, on a carrier, such as titanium dioxide, and these are used for their ability to lower the activation energy required for NO<sub>x</sub> decomposition. SCR requires an optimum temperature range of 650 to 800°F.

A “high-dust” SCR arrangement in which the reactor is located between the outlet of the economizer and the inlet of the air heater and upstream of particulate control is typically the preferred arrangement where technically feasible. These arrangements typically require soot blowers for catalyst cleaning. In a “low-dust” arrangement, the SCR reactor is located after the particulate control device. This arrangement is preferred when the fly ash contains a high level of contaminants that would block catalyst actions, and removing most of the fly ash from the flue gas will help prolong the catalyst life. Firing ND lignite coal that contains high amounts of organically bound inorganics (and has a higher total sodium content), results in a stream heavily laden with particulate matter and sodium that combine to plug (block) catalyst passages. Due to the likelihood of catalyst plugging and the ability of phosphorus, sodium, other alkali and alkaline earth cations organically bound in ND lignite to mask (or blind) a catalyst and its reactions if not fully plugged, a high-dust SCR system is considered technically infeasible on both Units 1 and 2. A low-dust SCR (downstream of particulate control), would require reheat to bring the stream temperature back to the effective control range after it is cooled for particulate removal. There would still be important concerns with this arrangement due to the contaminants’ unique properties to inhibit the catalyst from operating, but in theory, the issues would be less than with a high-dust system.

Although it would appear to be a potentially a technically feasible control option, MONTANA-DAKOTA notes that installing SCR (even a low-dust system) at similar types of sources remains limited or is altogether not feasible. MONTANA-DAKOTA is unaware of an SCR system that has been installed at a source firing North Dakota lignite. Issues associated with SCR on lignite boilers are discussed in additional detail in a 2009 study completed by the NDDH that supports the limited feasibility of SCR.<sup>7</sup> Additionally, physical space constraints at Heskett Station greatly limit the opportunity for SCR system equipment and tie-ins. Even so, for purposes of this review, MONTANA-DAKOTA has assumed that a low-dust SCR system could potentially be implemented at Unit 2 and has therefore included this in the four-factor analysis (even though it is considered by MONTANA-DAKOTA as technically infeasible). Based on current NO<sub>x</sub> emissions, an SCR could potentially provide an additional NO<sub>x</sub> reduction in the range of 70%-80%. As mentioned before, we reserve the right to refine this analysis in the future if necessary.

### 4.1.3 Innovative Controls

NO<sub>x</sub> controls grouped under the “Innovative Control Technologies” are not being considered in this analysis. These technologies are not considered commercially available and are not applicable at MONTANA-DAKOTA Heskett Station.

---

<sup>7</sup> *Best Available Retrofit Technology – Selective Catalytic Reduction Technical Feasibility Analysis for North Dakota Lignite*. North Dakota Department of Health, Division of Air Quality. 7/1/2009



## 4.2 Factor 1 – The Cost of Compliance

The pollution control costs are presented on a dollar per ton of pollutant removed calculated according to Equation 2.73 of the Cost Manual and 40 CFR 51, Appendix Y, Section IV, D. The cost effectiveness analysis compares the annualized cost of the technology per ton of pollutant removed and is evaluated on dollar per ton (\$/ton) basis using the annual operating cost (\$/yr) divided by the annual emissions reduction achieved by the control device (ton/yr). Additional details regarding the control equipment cost data and evaluation are noted in the control cost worksheets in Attachment A.

Table 4-2 NOx Control Cost Evaluation for Heskett Station Unit 2

Control Technology	Estimated Control Efficiency (%)	Installed Capital Cost (\$)	Annualized Capital Cost (\$/yr)	Pollution Control Cost (\$/ton)
Low-Dust SCR	80%	\$41,600,000	\$5,630,000	\$6,100
SNCR	27%	\$5,000,000	\$1,680,000	\$5,300

<sup>1</sup> The NDDH original BART ceiling costs were based on the June 1999 WRAP Annex to Grand Canyon Visibility Transport Report. Scaled to today's dollars, the average cost effectiveness threshold is approximately \$4,460 per ton.

SNCR and SCR are both considered economically infeasible for implementation at Unit 2 as the average cost effectiveness is not justified on a dollar per ton basis.

## 4.3 Factor 2 – Time Necessary for Compliance

Under Factor #2, the amount of time needed for full implementation of different control strategies is reviewed. Typically, the time necessary for compliance includes the time needed to develop and implement the regulation and/or the time needed to install the necessary emissions control equipment. This analysis does not support the installation of any new retrofit NOx emissions control methods at Heskett Station Unit 2 and therefore a review of the time necessary for compliance is not applicable.

## 4.4 Factor 3 – Energy and Non-Air Quality Environmental Impacts

Energy impacts are primarily related to the auxiliary power consumption of the SCR and SNCR systems and are included in the cost estimates under the variable annual costs. Other indirect energy impacts, such as the energy to produce reagents, are not considered in this study.

The operation of an SCR or SNCR system could have other non-air environmental impacts. For example, the storage of ammonia on-site creates the potential for accidents due to an ammonia release. Depending on the type, concentration, and quantity of ammonia used, the material will be subject to regulation as a hazardous substance under CERCLA, Section 313 of the Emergency Planning and Community Right-to-Know Act, Section 112(r) of the CAA, and Section 311(b)(4) of the Clean Water Act.

## 4.5 Factor 4 – Remaining Useful Life of the Source

At this time, MONTANA-DAKOTA has assumed that the remaining useful life of the Unit 2 will be longer than the useful life of the emissions control measures evaluated in this analysis. Accordingly, as directed

---

by the July 2006 EPA draft guidance, the useful life of the individual control measures is used to calculate emissions reductions, amortized costs and cost effectiveness on a dollar per ton basis.

## 4.6 Proposed Controls and Emissions Rates

This analysis does not support the installation of any new retrofit NO<sub>x</sub> emissions controls at Heskett Station Unit 2. The available and potential technically feasible control strategies (SNCR and SCR) are economically infeasible and have significant technical and other concerns for commercial scale operation at a lignite fired boiler. Therefore, MONTANA-DAKOTA is proposing to maintain current operational practices consistent with the parameters and limits included as part of the facility's existing Air Pollution Control Title V Permit to Operate (T5-F76001). As mentioned in the discussion under Unit 1, with the uncertainty of the actual feasibility for implementation of the NO<sub>x</sub> controls evaluated as part of this four-factor analysis and the required additional cost refinement evaluation, MONTANA-DAKOTA reserves the right to refine this analysis in the future if necessary.

## 5 Unit 2 Sulfur Dioxide (SO<sub>2</sub>) Four-Factor Analysis

Sulfur emissions from coal combustion consist primarily of SO<sub>2</sub>, with a much lower quantity of SO<sub>3</sub> and gaseous sulfates. These compounds form as the organic and pyritic sulfur in the coal is oxidized during the combustion process. The generation of SO<sub>2</sub> is directly related to the sulfur content and heating value of the fuel burned. The sulfur content and heating value of coal can vary dramatically depending on the source of the coal. Heskett Station uses North Dakota lignite and, in the past, had occasionally used a blend of lignite and PRB coal as its fuel source.

### 5.1 SO<sub>2</sub> Emissions Control Measures

Several techniques can be used to reduce SO<sub>2</sub> emissions from coal combustion sources. SO<sub>2</sub> control techniques can be divided into pre- and post- combustion strategies.

Table 5-1 SO<sub>2</sub> Control Options with Potential Applications to Heskett Station Unit 2

Control Technology
Pre-Combustion Controls
<ul style="list-style-type: none"><li>Fuel Switching</li><li>Fuel Washing</li></ul>
Combustion Control: Limestone injection at existing AFCB
Post-Combustion SO <sub>2</sub> Control Technologies
<ul style="list-style-type: none"><li>Wet Flue Gas Desulfurization</li><li>Dry Flue Gas Desulfurization<ul style="list-style-type: none"><li>Spray Dryer Absorber</li><li>Dry Sorbent Injection</li></ul></li></ul>

#### 5.1.1 Pre-Combustion Controls

A potential control strategy for reducing SO<sub>2</sub> emissions from a coal-fired boiler is to reduce the amount of sulfur contained in the coal. This can be accomplished through reducing inherent impurities via coal washing or potentially, more drastically, through switching to a lower sulfur fuel source. Coal washing is discussed above in Section 3.1.

As also noted above, North Dakota lignite has a relatively high moisture content, low heating value, and low sulfur content. PRB coal typically also has relatively lower heating values compared to other fuel sources but lower sulfur content than lignite. In theory, if a boiler could utilize it for fuel and a fuel feed system could receive it; burning 100% PRB would result in lower uncontrolled SO<sub>2</sub> emissions rates. However, lower uncontrolled emissions rates do not necessarily translate into lower controlled emissions rates. The efficiency of pollution control equipment is a function of several operating variables, including the uncontrolled pollutant concentration. At a lower uncontrolled pollution concentration, it becomes more difficult to maintain a high emissions control efficiency.

MONTANA-DAKOTA has studied the feasibility of firing lower sulfur PRB coal at Unit 2. Test burns conducted at Heskett Station Unit 2 indicated that significant boiler modifications, including changes to the internal boiler materials of construction and modifications to provide flue gas recirculation, would be needed to fire 100% PRB. Based on these test burns, the Unit 2 boiler is limited to firing a limited amount of PRB. Unit 2 is designed to fire lignite and any coal viability implemented for short periods of time is dependent upon an economic supply of fuel. Switching to PRB would require significant boiler modifications, essentially replacing and rebuilding the boiler internals and combustion control systems. Therefore, switching to burning a lower sulfur subbituminous coal in amounts not supported by the existing equipment is not considered a technically feasible option for Unit 2.

Additionally, PRB is not currently offered in a size that Heskett Station is able to receive and process, meaning the facility cannot accept fuel or get it to the boiler without significant modifications and equipment changes.

### **5.1.2 Combustion Controls: Limestone Injection at AFBC**

Heskett Station has implemented a limestone addition to the sand bed for Unit 2 for RH emissions reductions in 2017. An SO<sub>2</sub> limit of 0.60 lb/MMBtu was applied to Unit 2 and Heskett Station has demonstrated compliance with this 12-month rolling average limit. Unit 2 has been operating at a mid to low load range over the past two to three years (a recent load range report indicates 52-66 MW for 95% of the time, only 5% operation at higher load of about 72 MW). During the same timeframe, our compliance with the 12-month rolling average was 0.46 lb/MMBtu. The relatively low 12-month rolling average compliance values represent operation at a lower load range and does not indicate improved capture efficiency that would occur within the mid to high load range as confirmed in our optimization study. All SO<sub>2</sub> emissions limits currently imposed from utilization of limestone for SO<sub>2</sub> control should remain unchanged.

### **5.1.3 Post-Combustion Controls**

Post-combustion controls or FGD systems commonly used to control SO<sub>2</sub> emissions can be classified as either wet or dry systems. Both systems rely on creating turbulence in the gas stream to increase contact with the absorbing medium. Wet systems are commonly capable of achieving higher removal efficiencies than dry systems because it is easier to mix a gas with a liquid than a solid. FGD requires the use of an alkali powder slurry, with lime (or limestone) as the most widely used compound for acid gas absorption. Sodium based reagents are also available, and while they provide better SO<sub>2</sub> solubility, they are significantly more expensive.

Wet FGD systems may discard all of the waste by-product streams or regenerate and reuse them. Wet systems generally require more extensive networks of pumps and piping than dry systems to recirculate, collect, and treat the scrubbing liquid. As implied by the name, dry scrubbers require less water than wet systems but also require higher temperatures to ensure that all moisture has been evaporated before leaving the scrubber. There are many available FGD systems including wet scrubbing, spray dryer absorption, and dry sorbent injection.

### 5.1.3.1 Wet Lime/Limestone Scrubbing

Wet lime/limestone scrubbing involves scrubbing the exhaust gas stream with a slurry comprised of CaO or CaCO<sub>3</sub> in suspension. The process takes place in a wet scrubbing tower located downstream of a PM control device to prevent the plugging of spray nozzles and other problems caused by the presence of particulates in the scrubber. The SO<sub>2</sub> in the gas stream reacts with the lime or limestone slurry to form calcium sulfite (CaSO<sub>3</sub>•2H<sub>2</sub>O) and calcium sulfate (CaSO<sub>4</sub>).

Physical space constraints at Heskett Station greatly limit the opportunity for construction and operation of an add-on control equipment such as wet gas scrubber system. However, for purposes of this analysis, a wet scrubber is considered a technically feasible retrofit control option. It will be assumed, based on available information, that the wet FGD system would be able achieve an SO<sub>2</sub> emissions reduction of approximately 99%.<sup>8</sup>

Control efficiencies assumed achievable for purposes of this analysis are conservative due to being based on operation at high load conditions. The high rate of assumed capture may not be achieved at low load operation. MONTANA-DAKOTA reserves the right to refine the assumptions and impacts to the cost of controls if further study is needed. A full review of the ESP's ability to accept and properly clean the flue gas with changed properties would be needed to determine feasibility and possible costs. MONTANA-DAKOTA reserves the right to refine the assumptions and impacts to the cost of controls if further study is needed.

### 5.1.3.2 Spray Dry Absorption (SDA)

Spray dry absorption (SDA) is a dry scrubbing system that sprays a fine mist of lime slurry into an absorption tower where the SO<sub>2</sub> is absorbed by the droplets. The absorption of the SO<sub>2</sub> leads to the formation of calcium sulfite (CaSO<sub>3</sub>•2H<sub>2</sub>O) and calcium sulfate (CaSO<sub>4</sub>).

The liquid-to-gas ratio is such that the heat from the exhaust gas causes the water to evaporate before the droplets reach the bottom of the tower. This leads to the formation of a dry powder that is carried out with the gas and collected with a fabric filter. The process equipment associated with a spray dryer typically includes an alkaline storage tank, mixing and feed tanks, an atomizer, spray chamber, particulate control device and a recycle system.

Designing an SDA for an existing unit presents significant design challenges. The SDA must be located upstream of the unit's particulate matter control device, at a point where the flue gas is already laden with combustion ash, calcium sulfite solids, and unreacted lime from the combustion bed (assuming lime or limestone is used as the bed material). The reactor vessel must also be located within existing site parameters requiring extensive ductwork to direct flue gas flow from the boiler to the SDA and back to the ESP. An SDA will add additional unreacted hydrated lime to the flue gas, and increase particulate loading to the particulate control device. Second, to maximize utilization of the lime reactant (which is expensive compared to limestone), the system must be designed with a solids recycling system to mix

---

<sup>8</sup> <https://www3.epa.gov/ttn/catc/dir1/fsprytwr.pdf>

some of the controlled particulate solids product with fresh lime slurry and re-inject the mixture into the SDA. Finally, the SO<sub>2</sub> concentration at the inlet to the SDA will already have been reduced in the AFBC to a level generally associated with the SDA outlet SO<sub>2</sub> concentration, which will limit the efficiency of the system. Nevertheless, for purposes of this analysis, SDA is considered a technically feasible retrofit control option. It was been assumed that a baghouse, requiring retrofit of the existing particulate matter control system, would be required for proper operation and particulate matter control. SDA control efficiency is typically in the 70% to 90% range.

Control efficiencies assumed achievable for purposes of this analysis are conservative due to being based on operation at high load conditions. The high rate of assumed capture may not be achieved at low load operation. MONTANA-DAKOTA reserves the right to refine the assumptions and impacts to the cost of controls if further study is needed. A full review of the ESP's ability to accept and properly clean the flue gas with changed properties would be needed to determine feasibility and possible costs.

### 5.1.3.3 Dry Sorbent Injection (DSI)

Dry sorbent injection (DSI) involves the injection of a lime or limestone powder into the exhaust gas stream. The stream is then passed through a baghouse to remove the sorbent and entrained SO<sub>2</sub>. The process was developed as a lower cost FGD option because the mixing occurs directly in the exhaust gas stream instead of in a separate tower. Depending on the residence time and gas stream temperature, sorbent injection control efficiency is typically between 50% and 70%. Although a dry sorbent injection system may be technically feasible, it is not practical for use with an AFBC with limestone bed material. The AFBC flue gas already contains excess unreacted lime and fly ash will be reinjected back into the AFBC combustion bed. A dry sorbent injection system would simply add additional unreacted lime to the flue gas. Because the dry sorbent injection system is not practical with an AFBC the system will not be evaluated further.

## 5.2 Factor 1 – The Cost of Compliance

The pollution control costs are presented on a dollar per ton of pollutant removed calculated according to Equation 2.73 of the Cost Manual and 40 CFR 51, Appendix Y, Section IV, D. The cost effectiveness compares the annualized cost of the technology per ton of pollutant removed and is evaluated on dollar per ton (\$/ton) basis using the annual operating cost (\$/yr) divided by the annual emissions reduction achieved by the control device (ton/yr). Additional details regarding the control equipment cost data and evaluation are noted in the control cost worksheets in Attachment B.

Table 5-2 SO<sub>2</sub> Control Cost Evaluation for Heskett Station Unit 2

Control Technology	Estimated Control Efficiency (%)	Installed Capital Cost (\$)	Annualized Capital Cost (\$/yr)	Pollution Control Cost (\$/ton)
Wet Scrubber	98%	\$80,300,000	\$11,400,000	\$7,700
Spray Dry Absorption	90%	\$70,200,000	\$9,990,000	\$7,300

<sup>1</sup> The NDDH original BART ceiling costs were based on the June 1999 WRAP Annex to Grand Canyon Visibility Transport Report. Scaled to today's dollars, the average cost effectiveness threshold is approximately \$4,460 per ton.

The SO<sub>2</sub> control options evaluated as part of this analysis are considered economically infeasible for implementation at Unit 2 as the average cost effectiveness is not justified on a dollar per ton basis.

### 5.3 Factor 2 – Time Necessary for Compliance

Under Factor #2, the amount of time needed for full implementation of different control strategies is reviewed. Typically, time for compliance includes the time needed to develop and implement the regulation and/or the time needed to install the necessary emissions control equipment. This analysis does not support the installation of any new retrofit SO<sub>2</sub> emissions controls at Heskett Station Unit 2 and therefore a review of the time necessary for compliance is not applicable.

### 5.4 Factor 3 – Energy and Non-Air Quality Environmental Impacts

The energy and non-air environmental impacts associated with implementation of the above-identified SO<sub>2</sub> control measures are discussed in the following sections.

#### 5.4.1 Limestone Injection at AFBC

Limestone addition is currently in place at Unit 2 and MONTANA-DAKOTA is implementing best practices to mitigate energy and non-air environmental impacts. The system has been fully operating less than two years and feed rates are still under evaluation for control performance. As discussed with NDDH, when the system was first implemented in 2017, MONTANA-DAKOTA expects increases in the feed of limestone to result in additional handling and disposal issues, diminishing returns for SO<sub>2</sub> control (variable with load levels), and can change bed properties including transfer of energy and fouling.

#### 5.4.2 Wet Lime/Limestone Scrubbing

In addition to the economic impacts of a wet FGD system, there are several collateral environmental impacts associated with its operation. Wet FGD systems generate a calcium sulfate waste by-product that must be properly managed. Historically, solid wastes generated from wet FGD systems have been dewatered and disposed of in landfills. Most new wet FGD systems utilize a forced oxidation system that results in a gypsum by-product that can sometimes be sold into the local gypsum market. If an adequate local gypsum market is not available, the gypsum by-product will require proper disposal. Currently, there is not a viable market in proximity to Heskett Station and usable quantity would be likely limited. A study of disposal at our current facility would be required and, if feasible, additional permitting needed. If not acceptable for sale, disposal costs may be significant and would have to include transport costs. In a northern climate this may be a significant issue.

A wet FGD system will also result in greater particulate matter emissions. Wet FGD systems must be located downstream of the unit's particulate control device therefore, dissolved solids from the wet FGD system will be emitted with the wet FGD moisture plume. In addition, any SO<sub>3</sub> remaining in the flue gas could react with moisture in the wet FGD to generate sulfuric acid mist.

Wet FGD systems also require significantly more water than dry FGD systems or limestone injection systems. Wet FGD control systems typically require approximately 1.0 gpm of water per gross MW output. Additional costs may result from a potential need to increase Heskett Station's existing water rights for

withdrawal of water from the Missouri River for Wet FGD operation. The site faces challenges for space due to rail lines, historical disposal and archeological issues. CCR considerations would need to be evaluated (including location restrictions); state and federal discharge permitting requirements (from the new system) would also be applicable. These would take significant study and time.

### **5.4.3 Dry Flue Gas Desulfurization (FGD)**

Collateral environmental impacts are less significant with dry scrubbing systems. Using a dry FGD system in conjunction with a FBC with limestone injection would require the facility to handle two reactants; limestone for injection in the FBC and pebble lime for use in the dry scrubber. The receipt, storage, management and use of two reactants will result in increased material handling PM emissions.

Lime used in dry FGD systems must be hydrated prior to use, increasing the facility's overall consumption of water. However, water used to hydrate the lime reactant is evaporated in the dry scrubbing system, eliminating the need for additional wastewater treatment and discharge.

## **5.5 Factor 4 – Remaining Useful Life of the Source**

At this time, MONTANA-DAKOTA has assumed that the remaining useful life of the Unit 2 will be longer than the useful life of the emissions control measures evaluated in this analysis. Accordingly, as directed by the July 2006 EPA draft guidance, the useful life of the individual control measures is used to calculate emissions reductions, amortized costs and cost effectiveness on a dollar per ton basis.

## **5.6 Proposed Controls and Emissions Rates**

This analysis does not support the installation of any new retrofit SO<sub>2</sub> emissions controls at Heskett Station Unit 2. The available and potential technically feasible control strategies are economically infeasible and have significant technical and other concerns for operation Heskett Station. Therefore, MONTANA-DAKOTA is proposing to maintain current operational practices consistent with the parameters and limits included as part of the facility's existing Air Pollution Control Title V Permit to Operate (T5-F76001). As discussed throughout this document, the uncertainty around assumed SO<sub>2</sub> emissions control performance, the potential feasibility concerns tied to the operation of the control technologies evaluated and also the required additional cost refinement analysis that would be required prior to implementation, MONTANA-DAKOTA reserves the right to refine this analysis in the future if necessary.



---

## 6 Summary and Conclusion

In conclusion, as requested by the NDDH, MONTANA-DAKOTA completed a four-factor analysis evaluating direct emissions of SO<sub>2</sub> and NO<sub>x</sub> at Heskett Station Unit 1 and Heskett Station Unit 2. Based on the four- factor evaluation completed in this report, MONTANA-DAKOTA is proposing to maintain current operational practices consistent with the parameters and limits in the R. M. Heskett Station Air Pollution Control Title V Permit to Operate.

All available and potential technically feasible control strategies evaluated are economically infeasible for implementation at Heskett Station. Retrofit control options present significant technical and other operational concerns that would require detailed and extensive study to determine actual feasibility and emissions reduction potential at Unit 1 and Unit 2. Such studies would be costly and only serve to add to the probable highly elevated site-specific costs associated with implementation of retrofit control technologies at Heskett Station and would greatly increase the presented price of emissions reductions on a \$/ton basis.

Further, MONTANA-DAKOTA reserves the right to review and modify the assumptions used in this analysis, primarily concerning site-specific conditions for cost (including capital costs and actual emissions reductions potential/performance) and remaining useful life of the affected sources.

## Attachment A

### NOx Control Costs

Montana-Dakota Utilities Co. R.M. Heskett Station  
Regional Haze Rule Reasonable Progress Goals Four-Factor Analysis  
Attachment A  
Table A1: NOx Cost Evaluation Summary

**Unit Summary**

Unit	Unit 1		Unit 2	
Fuel Type	Lignite		Lignite	
Boiler Type	Normal		Fluidized Bed	
Maximum Hourly Production	25	MWh	75	lb/MMBtu
Maximum Hourly Heat Input Rate	387.63	MMBtu/hr	916.5	MMBtu/hr
Standardized Exhaust Flow Rate	95,133	scfm @ 68° F	235,167	scfm @ 68° F
Exhaust Temperature	420	° F	320	° F
Exhaust Moisture Content	15	%	15	%
Capacity Factor (CF) / Utilization	40	%	63	%
Fuel Sulfur Content	0.91	%		
Expected Annual Hours of Operation	8760	hours	8760	hours
Baseline Emission Rate	5.80	lb/ton lignite	0.46	lb/MMBtu
Hourly Emissions	174	lb/hr	421.59	lb/hr
Annual Emissions	304.8	tons/yr	1,163.3	tons/yr

**Control Equipment Costs**

Control Technology Name		Low-dust SCR	SNCR	Low-dust SCR	SNCR
Expected Equipment Life (years)		20	20	20	20
NOx Control Efficiency		80%	27%	80%	27%
Ammonia Slip		5	-	5	-
Controlled Emissions (tons/yr)		61.0	223.0	232.7	848.1
Reduction (tons/yr)		243.9	81.8	930.7	315.3
<b>Capital Costs</b>					
Total Capital Investment (TCI = DC + IC)	[1]	\$21,729,380	\$4,178,922	\$41,629,238	\$4,997,248
<b>Operating Costs</b>					
Direct Operating Costs (\$/year)	[2]	\$673,534	\$399,546	\$2,124,053	\$1,270,494
Indirect Operating Costs (\$/year)	[3]	\$1,864,942	\$344,472	\$3,509,034	\$411,536
Total Annual Cost (\$/year)	[4]	\$2,538,476	\$744,018	\$5,633,087	\$1,682,030
<b>Control Cost Effectiveness (\$/ton)</b>		<b>\$10,400</b>	<b>\$9,100</b>	<b>\$6,100</b>	<b>\$5,300</b>

**Footnotes**

- [1] Capital Cost Estimates from EPA Air Pollution Control Cost Manual - Section 4 - NOx Controls (updated 12/07/17) and adjusted for inflation based on Chemical Engineering Plant Cost Index
- [2] Labor, supervision, materials, replacement parts, utilities, etc.
- [3] Sum indirect oper costs + capital recovery cost
- [4] Total Annual Cost = Direct Operating Costs + Indirect Operating Costs
- [5] Controlled Emissions = (1 - Control Efficiency) \* Baseline Emissions
- [6] Control Cost Effectiveness = Total Annual Cost / Tons Removed from Exhaust

Montana-Dakota Utilities Co. R.M. Heskett Station  
Regional Haze Rule Reasonable Progress Goals Four-Factor Analysis  
Attachment A  
Table A2: Control Costs Summary for Low-dust SCR for NOx Control

	Unit 1		Unit 2		Notes
	SCR	Reheat	SCR	Reheat	
<b>Total Annual Cost</b>	<b>\$2,538,476</b>		<b>\$5,633,087</b>		annualized Capital Cost + Operating Cost
<b>Total Capital Investment</b>	<b>\$21,729,380</b>		<b>\$41,629,238</b>		sum of SCR + Reheat System Equipment Costs
SCR Reactor System in 2018 \$'s	\$20,472,432	-	\$40,070,344		Revised Control Cost Manual for SCR incorporates all installation and indirect capital costs into the calculated Total Capital Investment (TCI). Retrofit (1.25 for difficult retrofit) and elevation cost (calculated as 1.06; plant elevation at 1657.5) factors per EPA Air Pollution Control Cost Manual Section 1, Chapter 2 Section 2.5.4.2
SCR Reactor System in 2012 \$'s	\$10,055,473	-	\$22,556,085		SCR Cost Estimate from EPA Air Pollution Control Cost Manual - Section 4 - Nox Controls (updated 12/07/17) and adjusted for inflation based on Chemical Engineering Plant Cost Index
Reagent Preparation System Costs in 2012 \$'s	\$2,051,740	-	\$2,571,115	-	
Air Pre-Heater Costs in 2012 \$'s	-	-	-	-	
Balance of Plant Costs in 2012 \$'s	\$2,796,941	-	\$4,044,446	-	
<b>Reheat Purchased Equipment Total</b>	-	\$1,256,948	-	\$1,558,893	
Flue Gas Re-Heat Equipment Cost Estimate	-	\$678,881	-	\$841,962	EPA control cost guideline for catalytic oxidizers used for operating cost analysis. EPA Air Pollution Control Cost Manual 6th Ed 2002. Basis Thermal Oxidizer with 70% Heat Recovery
Instrumentation	-	\$67,888	-	\$84,196	10% of control device cost; EPA control cost guideline
Sales Tax	-	-	-	-	N/A of control device cost; EPA control cost guideline
Freight	-	\$33,944	-	\$42,098	5% of control device cost; EPA control cost guideline
<b>Installation Costs</b>					
Foundations and Supports	-	\$62,457	-	\$77,461	8% of purchased equip cost; EPA control cost guideline
Handling & Erection	-	\$109,300	-	\$135,556	14% of purchased equip cost; EPA control cost guideline
Electrical	-	\$31,229	-	\$38,730	4% of purchased equip cost; EPA control cost guideline
Piping	-	\$15,614	-	\$19,365	2% of purchased equip cost; EPA control cost guideline
Insulation	-	\$7,807	-	\$9,683	1% of purchased equip cost; EPA control cost guideline
Painting	-	\$7,807	-	\$9,683	1% of purchased equip cost; EPA control cost guideline
<b>Indirect Capital Costs</b>					
Engineering, supervision	-	\$78,071	-	\$96,826	10% of purchased equip cost; EPA control cost guideline
Construction & field expenses	-	\$39,036	-	\$48,413	5% of purchased equip cost; EPA control cost guideline
Contractor fees	-	\$78,071	-	\$96,826	10% of purchased equip cost; EPA control cost guideline
Start-up	-	\$15,614	-	\$19,365	2% of purchased equip cost; EPA control cost guideline
Performance test	-	\$7,807	-	\$9,683	1% of purchased equip cost; EPA control cost guideline
Model Studies	-	-	-	-	N/A of purchased equip cost; EPA control cost guideline
Contingencies	-	\$23,421	-	\$29,048	3% of purchased equip cost; EPA control cost guideline
<b>Direct Annual Operating</b>	<b>\$673,534</b>		<b>\$2,124,053</b>		
<b>Labor &amp; Maintenance</b>					
Operator Labor	\$62,780	\$23,543	\$62,780	\$23,543	43.00 \$/Hr, 4.5 hr/day
Supervisor Labor	-	\$3,531	-	\$3,531	0% of Operator Costs for SCR System; 15% of Operator Costs for Reheat System
Maintenance Labor	\$102,362	\$23,986	\$200,352	\$23,986	0.5% of Total Capital Investment for SCR system; 43.80 \$/Hr, 0.5 hr/day for Reheat System
Maintenance Materials	-	\$240	-	\$240	0% of Maintenance Labor for SCR System; 100% of Maintenance Labor for Reheat System
<b>Utilities, Supplies, Replacements &amp; Waste Management</b>					
Electricity	\$32,973	\$125,108	\$141,706	\$412,946	auxiliary power requirement for operation of SCR and reheat systems
Natural Gas	-	\$209,096	-	\$963,598	based on heat input required to reheat flue gas to temperature for proper operation of SCR system
Ammonia - Anhydrous	\$54,054	-	\$206,278	-	based on ammonia use, capacity factor calculated assuming NOx removal rate, and cost of reagent
SCR Catalyst	\$35,861	-	\$85,092	-	\$/yr by Method 1 in EPA Air Pollution Control Cost Manual - Section 4
<b>Indirect Annual Operating</b>	<b>\$1,864,942</b>		<b>\$3,509,034</b>		
Overhead	-	\$30,780	-	\$30,780	60% of total labor and material costs for reheat system only
Administration	\$3,112	\$25,139	\$4,288	\$31,178	3% * (Labor +40% of maintenance costs) for SCR system; 2% of total capital costs for reheat system only
Property tax	-	\$12,569		\$15,589	1% of total capital costs for reheat system only
Insurance	-	\$12,569		\$15,589	1% of total capital costs for reheat system only
Capital Recovery	\$1,677,763	\$103,010	\$3,283,856	\$127,755	0.0820 for a 20-year equipment life and a 5.25% interest rate

Montana-Dakota Utilities Co. R.M. Heskett Station  
 Regional Haze Rule Reasonable Progress Goals Four-Factor Analysis  
 Attachment A  
 Table A3: Control Costs Summary for SNCR for NOx Control

	Unit 1	Unit 2	Notes
<b>Total Annual Cost</b>	<b>\$744,018</b>	<b>\$1,682,030</b>	annualized Capital Cost + Operating Cost
<b>Total Capital Investment</b>	<b>\$4,178,922</b>	<b>\$4,997,248</b>	sum of SCR + Reheat System Equipment Costs
<b>SNCR Reactor System in 2018 \$'s</b>	\$4,178,922	\$4,997,248	Revised Control Cost Manual Incorporates all of these factors into the calculated Total Capital Investment. Retrofit (1.25) and Elevation Cost (1.06) Factors per EPA Air Pollution Control Cost Manual Section 1, Chapter 2 Section 2.5.4.2
SNCR Reactor System in 2012 \$'s	\$1,206,956	\$1,435,964	SCR Cost Estimate from EPA Air Pollution Control Cost Manual - Section 4 - NOx Controls (updated 12/07/17) and adjusted for inflation based on Chemical Engineering Plant Cost Index
Reagent Preparation System Costs in 2012 \$'s	-	-	
Air Pre-Heater Costs in 2012 \$'s	-	-	
Balance of Plant Costs in 2012 \$'s	\$1,835,345	\$2,202,086	
<b>Direct Annual Operating Costs</b>	<b>\$399,546</b>	<b>\$1,270,494</b>	
<b>Labor &amp; Maintenance</b>			
Operator Labor	\$31,390	\$31,390	43.00 \$/Hr, 2 hr/day
Supervisor Labor	-	-	0% of Operator Costs
Maintenance Labor	\$62,684	\$74,959	1.5% of Total Capital Investment
Maintenance Materials	-	-	0% of Maintenance Labor
<b>Utilities, Supplies, Replacements &amp; Waste Management</b>			
Electricity	\$1,546	\$5,891	auxiliary power requirement for operation of SNCR system
Coal	\$8,460	\$32,240	additional fuel use requirements for SNCR operation
Water	\$117	\$446	based on urea feed rate
Urea 50% Solution	\$295,349	\$1,125,567	based on urea use rate calculated assuming NOx removal rate (per EPA method)
<b>Indirect Annual Operating Costs</b>	<b>\$344,472</b>	<b>\$411,536</b>	
Overhead	-	-	
Administration	\$2,000	\$2,000	3% of maintenance costs
Property tax	-	-	
Insurance	-	-	
Capital Recovery	\$342,472	\$409,536	0.0820 for a 20-year equipment life and a 5.25% interest rate

Montana-Dakota Utilities Co. R.M. Heskett Station  
Regional Haze Rule Reasonable Progress Goals Four-Factor Analysis  
Attachment A  
Table A4: Summary of Utility, Chemical and Supply Costs for NOx

Item	Unit Cost		Reference Cost	Year	Data Source	Notes
Study Year:				2018	Costs are adjusted for 3% inflation	
Labor						
Operating Labor	43.00	\$/hr	43.00	2018	MDU	Level 2 Operator
Maintenance Labor	43.81	\$/hr	43.81	2018	MDU	Mechanic
Utilities						
Electricity	0.06	\$/kW-h	56.45	2018	\$/MWh from MDU	
Natural Gas	3.77	\$/kscf	3.77	2018	DOE Average (5 Month) Retail Price of Natural Gas for Electric Power	<a href="https://www.eia.gov/totalenergy/data/monthly/pdf/sec9_15.pdf">https://www.eia.gov/totalenergy/data/monthly/pdf/sec9_15.pdf</a>
Coal	2.75	\$/MMBtu	2.30	2012	EPA Air Pollution Control Cost Manual May 2016, Section 4 Chapter 1 SNCR.	Paragraph 1.5 - Example Problem. Example problem cost data; 2012 dollars. Price adjusted for inflation.
Water	0.32	\$/kgal	0.20	2002	EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 2.6.1.2.	Example Problems uses \$0.20/1000 gal. Cost adjusted for 3% inflation Sec 5.2 Ch 1 also lists \$0.20/1,000 gal.
Chemicals & Supplies						
Urea 50% Solution	3.69	\$/ton	2.59	2006	MDU, 2006 BART Evaluation	\$550/ton for urea solution; converted to \$/gal for costing purposes.
Ammonia - Anhydrous	0.29	\$/lb	0.20	2006	MDU, 2006 BART Evaluation	
Catalyst & Replacement Parts						
SCR Catalyst	160.00	\$/ft3				
Other						
Sales Tax	0.00%					
Interest Rate	5.25%				EPA/NDDH guidance	

## Attachment B

### SO<sub>2</sub> Control Costs

Montana-Dakota Utilities Co. R.M. Heskett Station  
Regional Haze Rule Reasonable Progress Goals Four-Factor Analysis  
Attachment B

Table B1: SO<sub>2</sub> Cost Evaluation Summary

**Unit Summary**

Unit	Unit 1		Unit 2	
Fuel Type	Lignite		Lignite	
Boiler Type	Normal		Fluidized Bed	
Maximum Hourly Production	25	MWh	75	lb/MMBtu
Maximum Hourly Heat Input Rate	387.63	MMBtu/hr	916.5	MMBtu/hr
Standardized Exhaust Flow Rate	95,133	scfm @ 68° F	235,167	scfm @ 68° F
Exhaust Temperature	420	° F	320	° F
Exhaust Moisture Content	15	%	15	%
Capacity Factor (CF) / Utilization	40	%	63	%
Expected Annual Hours of Operation	8760	hours	8760	hours
Baseline Emission Rate	3.00	lb/MMBtu	0.60	lb/MMBtu
Hourly Emissions	1,162.9	lb/hr	549.9	lb/hr
Annual Emissions	2,037.4	tons/yr	1,517.4	tons/yr

**Control Equipment Costs**

Control Technology Name		Wet Scrubber	Spray Dry Absorption	Dry Sorbent Injection	Wet Scrubber	Spray Dry Absorption
Expected Equipment Life (years)		20	20	20	20	20
SO <sub>2</sub> Control Efficiency		98%	70%	50%	98%	90%
Controlled Emissions (tons/yr)		40.7	611.2	1018.7	30.3	151.7
Reduction (tons/yr)		1996.6	1426.2	1018.7	1487.0	1365.7
<b>Capital Costs</b>						
Total Capital Investment (TCI = DC + IC)	[1]	\$71,535,252	\$55,671,830	\$32,267,572	\$80,335,051	\$70,273,560
<b>Operating Costs</b>						
Direct Operating Costs (\$/year)	[2]	\$1,111,404	\$882,135	\$875,539	\$1,214,929	\$1,081,768
Indirect Operating Costs (\$/year)	[3]	\$9,156,496	\$7,124,449	\$4,270,246	\$10,229,651	\$8,905,163
Total Annual Cost (\$/year)	[4]	\$10,267,899	\$8,006,584	\$5,145,785	\$11,444,580	\$9,986,931
<b>Control Cost Effectiveness (\$/ton)</b>		<b>\$5,100</b>	<b>\$5,600</b>	<b>\$5,100</b>	<b>\$7,700</b>	<b>\$7,300</b>

**Footnotes**

- [1] See individual control cost summary tables  
[2] Labor, supervision, materials, replacement parts, utilities, etc.  
[3] Sum indirect oper costs + capital recovery cost  
[4] Total Annual Cost = Direct Operating Costs + Indirect Operating Costs  
[5] Controlled Emissions = (1 - Control Efficiency) \* Baseline Emissions  
[6] Control Cost Effectiveness = Total Annual Cost / Tons Removed from Exhaust



Montana-Dakota Utilities Co. R.M. Heskett Station  
Regional Haze Rule Reasonable Progress Goals Four-Factor Analysis  
Attachment B  
Table B2: Control Costs Summary for Wet Scrubber for SO<sub>2</sub> Control

	Unit 1	Unit 2	Notes
<b>Total Annual Cost</b>	<b>\$10,267,899</b>	<b>\$11,444,580</b>	annualized Capital Cost + Operating Cost
<b>Total Capital Investment</b>	<b>\$71,535,251.82</b>	<b>\$80,335,050.77</b>	
<b>Purchased Equipment Cost (2018 \$'s)</b>	<b>\$28,274,803</b>	<b>\$51,745,604</b>	Total Direct Capital Cost adjusted for inflation based on Chemical Engineering Plant Cost Index
Purchased Equipment Cost	\$17,691,778	\$41,852,200	Unit 1 cost estimate scaled from DC from IAPCS program estimate; Unit 2 cost estimate per 2006 BART review.
Instrumentation	\$2,827,480.31	\$5,174,560.44	10% of control device cost; EPA control cost guideline
Sales Tax	-	-	N/A of control device cost; EPA control cost guideline
Freight	\$1,413,740	\$2,587,280	5% of control device cost; EPA control cost guideline
<b>Installation Costs</b>			
Foundations and Supports	\$3,901,923	-	12% of purchased equip cost for U1; included in U2 cost estimate
Handling & Erection	\$13,006,409	-	40% of purchased equip cost for U1; included in U2 cost estimate
Electrical	\$325,160	-	1% of purchased equip cost for U1; included in U2 cost estimate
Piping	\$9,754,807	-	30% of purchased equip cost for U1; included in U2 cost estimate
Insulation	\$325,160	-	1% of purchased equip cost for U1; included in U2 cost estimate
Painting	\$325,160	-	1% of purchased equip cost for U1; included in U2 cost estimate
<b>Indirect Capital Costs</b>			
Engineering, supervision	\$3,251,602	\$5,950,745	10% of purchased equip cost; EPA control cost guideline
Construction & field expenses	\$3,251,602	\$5,950,745	10% of purchased equip cost; EPA control cost guideline
Contractor fees	\$3,251,602	\$5,950,745	10% of purchased equip cost; EPA control cost guideline
Start-up	\$325,160	\$595,074	1% of purchased equip cost; EPA control cost guideline
Performance test	\$325,160	\$595,074	1% of purchased equip cost; EPA control cost guideline
Model Studies	-	-	N/A of purchased equip cost; EPA control cost guideline
Contingencies	\$975,481	\$1,785,223	3% of purchased equip cost; EPA control cost guideline
<b>Direct Annual Operating Costs</b>	<b>\$1,111,404</b>	<b>\$1,214,929</b>	
<b>Labor &amp; Maintenance</b>			
Operator Labor	\$376,680	\$376,680	43.00 \$/Hr, 8 hr/8 hr shift
Supervisor Labor	\$56,502	\$56,502	15% of Operator Costs for SCR System; 15% of Operator Costs for Reheat System
Maintenance Labor	\$143,916	\$143,916	43.00 \$/Hr, 3 hr/8 hr shift
Maintenance Materials	\$143,916	\$143,916	100% of maintenance labor
<b>Utilities, Supplies, Replacements &amp; Waste Management</b>			
Electricity	\$48,504	\$166,882	auxiliary power requirement for operation
Water	\$14,103	\$6,863	Liquid/Gas ratio = 10 L/G = Gal/1,000 acf
Wastewater Disposal Neutralization	\$105,769	\$51,475	water makeup rate/wastewater discharge = 20% of circulating water rate
Solid Waste Disposal	\$35,031	\$42,397	includes lime disposal costs but does not include fly ash
Lime	\$186,983	\$226,298	based on SO <sub>2</sub> removal rate and 0.96lb lime/lb SO <sub>2</sub>
<b>Indirect Annual Operating Costs</b>	<b>\$9,156,496</b>	<b>\$10,229,651</b>	
Overhead	\$432,608.22	\$432,608.22	60% of total labor and material costs
Administration	\$1,430,705	\$1,606,701	2% of total capital costs
Property tax	\$715,353	\$803,351	1% of total capital costs
Insurance	\$715,353	\$803,351	1% of total capital costs
Capital Recovery	\$5,862,477	\$6,583,641	0.0820 for a 20-year equipment life and a 5.25% interest rate

Montana-Dakota Utilities Co. R.M. Heskett Station  
Regional Haze Rule Reasonable Progress Goals Four-Factor Analysis  
Attachment B  
Table B3: Control Costs Summary for SDA Baghouse for SO<sub>2</sub> Control

	Unit 1	Unit 2	Notes
<b>Total Annual Cost</b>	<b>\$8,006,584</b>	<b>\$9,986,931</b>	annualized Capital Cost + Operating Cost
<b>Total Capital Investment</b>	<b>\$55,671,830.05</b>	<b>\$70,273,560.37</b>	
<b>Purchased Equipment Cost (2018 \$'s)</b>	\$22,105,154	\$42,143,065	Total Direct Capital Cost adjusted for inflation based on Chemical Engineering Plant Cost Index
Purchased Equipment Cost	\$13,831,378	\$34,085,600	Unit 1 cost estimate scaled from DC from IAPCS program estimate; Unit 2 cost estimate per 2006 BART review. Dry scrubbing SO2 costs include addition of a baghouse. Assumed that the existing ESP could not handle additional loading.
Instrumentation	\$2,210,515.39	\$4,214,306.47	10% of control device cost; EPA control cost guideline
Sales Tax	-	-	N/A of control device cost; EPA control cost guideline
Freight	\$1,105,258	\$2,107,153	5% of control device cost; EPA control cost guideline
<b>Installation Costs</b>			
Foundations and Supports	\$1,016,837	-	4% of purchased equip cost for U1; included in U2 cost estimate
Handling & Erection	\$12,710,463	-	50% of purchased equip cost for U1; included in U2 cost estimate
Electrical	\$2,033,674	-	8% of purchased equip cost for U1; included in U2 cost estimate
Piping	\$254,209	-	1% of purchased equip cost for U1; included in U2 cost estimate
Insulation	\$1,779,465	-	7% of purchased equip cost for U1; included in U2 cost estimate
Painting	\$1,016,837	-	4% of purchased equip cost for U1; included in U2 cost estimate
<b>Indirect Capital Costs</b>			
Engineering, supervision	\$2,542,093	\$4,846,452	10% of purchased equip cost; EPA control cost guideline
Construction & field expenses	\$5,084,185	\$9,692,905	20% of purchased equip cost; EPA control cost guideline
Contractor fees	\$2,542,093	\$4,846,452	10% of purchased equip cost; EPA control cost guideline
Start-up	\$254,209	\$484,645	1% of purchased equip cost; EPA control cost guideline
Performance test	\$254,209	\$484,645	1% of purchased equip cost; EPA control cost guideline
Model Studies	-	-	N/A of purchased equip cost; EPA control cost guideline
Contingencies	\$762,628	\$1,453,936	3% of purchased equip cost; EPA control cost guideline
<b>Direct Annual Operating Costs</b>	<b>\$882,135</b>	<b>\$1,081,768</b>	
<b>Labor &amp; Maintenance</b>			
Operator Labor	\$235,425	\$235,425	43.00 \$/Hr, 5 hr/8 hr shift
Supervisor Labor	\$35,314	\$35,314	15% of Operator Costs for SCR System; 15% of Operator Costs for Reheat System
Maintenance Labor	\$143,916	\$143,916	43.00 \$/Hr, 3 hr/8 hr shift
Maintenance Materials	\$143,916	\$143,916	100% of maintenance labor
<b>Utilities, Supplies, Replacements &amp; Waste Management</b>			
Electricity	\$60,246	\$207,904	auxiliary power requirement for operation
Water	\$675	\$3,188	based on 0.75 gpm per MW-gross
Compressed Air	\$31,949	\$110,252	compressed air for baghouse assumed to be 2 scfm / 1000 acfm EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1.5.1.8
Wastewater Disposal Neutralization	\$5,061	\$23,911	based on 0.75 gpm per MW-gross
Solid Waste Disposal	\$35,123	\$26,159	includes lime disposal costs but does not include fly ash
Lime	\$187,470	\$139,623	based on SO2 removal rate and 0.96lb lime/lb SO2
Filter Bags	\$3,042	\$12,159	bag replacement at 10 min/bag EPA Cost Cont Manual 6th ed Section 6 Chapter 1.5.1.4 lists replacement times from 5 - 20 min per bag
<b>Indirect Annual Operating Costs</b>	<b>\$7,124,449</b>	<b>\$8,905,163</b>	
Overhead	\$335,142.27	\$335,142.27	60% of total labor and material costs
Administration	\$1,113,437	\$1,405,471	2% of total capital costs
Property tax	\$556,718	\$702,736	1% of total capital costs
Insurance	\$556,718	\$702,736	1% of total capital costs
Capital Recovery	\$4,562,434	\$5,759,079	0.0820 for a 20-year equipment life and a 5.25% interest rate

Montana-Dakota Utilities Co. R.M. Heskett Station  
Regional Haze Rule Reasonable Progress Goals Four-Factor Analysis  
Attachment B  
Table B4: Control Costs Summary for DSI Baghouse for SO<sub>2</sub> Control

	Unit 1	Notes
<b>Total Annual Cost</b>	<b>\$5,145,785</b>	annualized Capital Cost + Operating Cost
<b>Total Capital Investment</b>	<b>\$32,267,572.30</b>	
<b>Purchased Equipment Cost (2018 \$'s)</b>	<b>\$12,812,219</b>	Total Direct Capital Cost adjusted for inflation based on Chemical Engineering Plant Cost Index
Purchased Equipment Cost	\$8,016,711	Unit 1 cost estimate scaled from DC from IAPCS program estimate. Dry scrubbing SO2 costs include addition of a baghouse. Assumed that the existing ESP could not handle additional loading.
Instrumentation	\$1,281,221.85	10% of control device cost; EPA control cost guideline
Sales Tax	-	N/A of control device cost; EPA control cost guideline
Freight	\$640,611	5% of control device cost; EPA control cost guideline
<b>Installation Costs</b>		
Foundations and Supports	\$589,362	4% of purchased equip cost
Handling & Erection	\$7,367,026	50% of purchased equip cost
Electrical	\$1,178,724	8% of purchased equip cost
Piping	\$147,341	1% of purchased equip cost
Insulation	\$1,031,384	7% of purchased equip cost
Painting	\$589,362	4% of purchased equip cost
<b>Indirect Capital Costs</b>		
Engineering, supervision	\$1,473,405	10% of purchased equip cost; EPA control cost guideline
Construction & field expenses	\$2,946,810	20% of purchased equip cost; EPA control cost guideline
Contractor fees	\$1,473,405	10% of purchased equip cost; EPA control cost guideline
Start-up	\$147,341	1% of purchased equip cost; EPA control cost guideline
Performance test	\$147,341	1% of purchased equip cost; EPA control cost guideline
Model Studies	-	N/A of purchased equip cost; EPA control cost guideline
Contingencies	\$442,022	3% of purchased equip cost; EPA control cost guideline
<b>Direct Annual Operating Costs</b>	<b>\$875,539</b>	
<b>Labor &amp; Maintenance</b>		
Operator Labor	\$235,425	43.00 \$/Hr, 5 hr/8 hr shift
Supervisor Labor	\$35,314	15% of Operator Costs for SCR System; 15% of Operator Costs for Reheat System
Maintenance Labor	\$143,916	43.00 \$/Hr, 3 hr/8 hr shift
Maintenance Materials	\$143,916	100% of maintenance labor
<b>Utilities, Supplies, Replacements &amp; Waste Management</b>		
Electricity	\$60,246	auxiliary power requirement for operation
Compressed Air	\$31,949	compressed air for baghouse assumed to be 2 scfm / 1000 acfm EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1.5.1.8
Solid Waste Disposal	\$35,123	includes lime disposal costs but does not include fly ash
Lime	\$187,470	based on SO2 removal rate and 0.96lb lime/lb SO2
Filter Bags	\$2,181	bBag replacement at 10 min/bag EPA Cost Cont Manual 6th ed Section 6 Chapter 1.5.1.4 lists replacement times from 5 - 20 min per bag
<b>Indirect Annual Operating Costs</b>	<b>\$4,270,246</b>	
Overhead	\$335,142.27	60% of total labor and material costs
Administration	\$645,351	2% of total capital costs
Property tax	\$322,676	1% of total capital costs
Insurance	\$322,676	1% of total capital costs
Capital Recovery	\$2,644,401	0.0820 for a 20-year equipment life and a 5.25% interest rate

Montana-Dakota Utilities Co. R.M. Heskett Station  
Regional Haze Rule Reasonable Progress Goals Four-Factor Analysis  
Attachment B  
Table B5: Summary of Utility, Chemical and Supply Costs for SO<sub>2</sub>

Item	Unit Cost		Reference Cost	Year	Data Source	Notes
Study Year:				2018	Costs are adjusted for 3% inflation	
Labor						
Operating Labor	43.00	\$/hr	43.00	2018	MDU	Level 2 Operator
Maintenance Labor	43.81	\$/hr	43.81	2018	MDU	Mechanic
Utilities						
Electricity	0.06	\$/kW-h	56.45	2018	\$/MWh from MDU	
Natural Gas	3.77	\$/kscf	3.77	2018	DOE Average (5 Month) Retail Price of Natural Gas for Electric Power	<a href="https://www.eia.gov/totalenergy/data/monthly/pdf/sec9_15.pdf">https://www.eia.gov/totalenergy/data/monthly/pdf/sec9_15.pdf</a>
Water	0.32	\$/kgal	0.20	2002	EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 2.6.1.2.	Example Problems uses \$0.20/1000 gal. Cost adjusted for 3% inflation Sec 5.2 Ch 1 also lists \$0.20/1,000 gal.
Compressed Air	0.45	\$/kscf	0.25	1998	EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1.	Example problem; Dried & Filtered, Ch 1.6 1998 cost adjusted for 3% inflation.
Wastewater Disposal Neutralization	2.41	\$/kgal	1.50	2002	EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 5 Chapter 1.	Section 2 lists \$1- \$2/1000 gal. Cost adjusted for 3% inflation. Sec 6 Ch 3 lists \$1.30 - \$2.15/1,000 gal.
Solid Waste Disposal	17.91	\$/ton	15.00	2012	EPA Air Pollution Control Cost Manual May 2016, Section 4 Chapter 1 SNCR.	Paragraph 1.5 Example calculations - price for ash disposal. Cost adjusted for 3% inflation.
Chemicals & Supplies						
Lime	95.60	\$/ton	95.60	2018	MDU	
Catalyst & Replacement Parts						
Filter Bags	54.09	\$/bag	33.71	2002	EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6, Chapter 1	Example problem cost for 10 ft bags. Cost adjusted for 3% inflation
Other						
Sales Tax	0.00%					
Interest Rate	5.25%				EPA/NDDH guidance	

## B.6.c – Communications

**Stroh, David E.**

---

**From:** Dihle, Mark <Mark.Dihle@mdu.com>  
**Sent:** Tuesday, February 19, 2019 4:01 PM  
**To:** Glatt, Dave D.; O'Clair, Terry L.; Bachman, Tom A.; Stroh, David E.; Rockeman, Karl H.; Haroldson, Marty R.; Hyatt, Chuck R.  
**Cc:** Fong, Cory; Skabo, Jay; Dever, Justin; Welte, Alan; Davies, Samantha; Dihle, Mark; Godel, Kalle; McDonald, Andy; Peterson, Todd; Krebsbach, Abbie  
**Subject:** Montana-Dakota Utilities Co. Generation Announcement (NDDEQ officials)  
**Attachments:** News Release MDU Resources Subsidiary Plans Retirement of Aging Generation Units; New Generation Build 02192019.pdf

---

**CAUTION:** This email originated from an outside source. Do not click links or open attachments unless you know they are safe.

---

***Sending on behalf of Abbie Krebsbach and Jay Skabo***

Good afternoon,

I am writing to you because I want you to know about the announcement that Montana-Dakota Utilities made regarding its generation fleet. In case you haven't seen it, the news release is attached. Feel free to share with others in your organization, particularly with air quality, water quality, and waste management permitting areas, where we work closely with you and your staff on permits for our generation facilities discussed below. We will plan to reach out directly to our permitting contacts in the future to discuss our current permitting activities and any permit modifications needed as our plan moves forward.

Montana-Dakota Utilities' plan is to retire three aging coal fired units at two electric generation stations and construct a new simple cycle combustion turbine within the next two to three years.

Montana-Dakota Utilities' mission is to provide safe, reliable and cost-effective service to its customers. Our coal facilities at R.M. Heskett Station and Lewis & Clark Station have done just that for nearly six decades, but we are finding they are no longer cost-competitive.

The decision was made as part of Montana-Dakota's integrated resource plan and will cost-effectively meet the needs of its customers. The company intends to retire the coal unit at Lewis & Clark Station in Sidney, Montana around the end of 2020 and Units 1 & 2 at R.M. Heskett Station near Mandan, North Dakota around the end of 2021. The new natural gas unit will go online in early 2023 at the R.M. Heskett Station. Both stations have existing natural gas fired units that will continue to operate.

If you have questions, please feel free to get back to Abbie Krebsbach at 701-222-7844/701-663-9178 or [abbie.krebsbach@mdu.com](mailto:abbie.krebsbach@mdu.com), me at the contact info further below, or reach out to others on our communications team:

Cory Fong, Director of Communications [Cory.Fong@mduresources.com](mailto:Cory.Fong@mduresources.com) 701.226.7743

Justin Dever, Senior Public Affairs Specialist, MDU Resources Group [Justin.Dever@mduresources.com](mailto:Justin.Dever@mduresources.com)  
701.220.0185

Sincerely,

Mark Dihle  
Sr. Environmental Scientist  
Montana Dakota Utilities  
400 North Fourth Street  
Bismarck, ND 58501-4092  
Bus: 701.222.7865  
Fax: 701.222.7845



**\*\*Confidentiality Statement\*\***

Privileged/Confidential Information may be contained in this message. If you are not the addressee indicated in this message (or responsible for the delivery of the message to such person), you may not copy or deliver this message to anyone. In such case, you should destroy this message without copying it or further reading, and notify me by telephone.



# MDU RESOURCES

## GROUP, INC.

## Press Release

[Home](#) [Our Company](#) [Newsroom](#) [Integrity](#) [Investors](#) [Care](#)

## MDU Resources Subsidiary Plans Retirement of Aging Generation Units; New Generation Build

Company Release - 2/19/2019 4:30 PM ET

BISMARCK, N.D., Feb. 19, 2019 /PRNewswire/ -- MDU Resources Group, Inc., (NYSE: MDU) subsidiary Montana-Dakota Utilities announced today that it intends to retire three aging coal-fired electric generation units at two locations within the next two to three years and construct a new simple-cycle natural gas combustion turbine to cost-effectively meet the needs of its customers.



The analysis done while preparing the integrated resource plan (IRP), which the company puts together every two years and files with regulatory commissions, points to the retirement of two aging coal-fired plants and the construction of the natural gas combustion turbine. Low-cost power available on the market, due to low-cost natural gas and increasing wind resources, as well as rising costs to operate these facilities, led to the decision to retire the coal plants. The retirements are expected around the end of 2020 for Lewis & Clark Station in Sidney, Montana, and around the end of 2021 for units 1 and 2 at Heskett Station in Mandan, North Dakota. These dates may be impacted by the company's coal supplier's pending bankruptcy proceeding.

The company has begun the development process to construct an 88-megawatt simple-cycle peaking unit at the Heskett Station site, and anticipates submitting an advance determination of prudence request with the North Dakota Public Service Commission this fall.

The new generation resource was selected as part of Montana-Dakota's IRP. The company believes a second combustion turbine at Heskett will be cost-effective because the site has existing infrastructure and natural gas supply that serves an existing combustion unit that went online in 2014.

"Our main objective is to provide our customers with safe, reliable and low-cost service," said Nicole Kivisto, president and CEO of Montana-Dakota. "The IRP process helps guide us in making decisions to meet those objectives. Heskett and Lewis & Clark have met that objective for many years, but our analysis is showing those units are no longer cost competitive for our customers."

The total cost of building and operating a new simple-cycle combustion turbine, coupled with market purchases, is expected to be about half the total cost of continuing to run the Heskett and Lewis & Clark coal-fired units.

The first coal-fired unit at Heskett went online in 1954 and the second unit in 1963. They combine for 100 MW of power. Lewis & Clark went online in 1958 and provides 44 MW power. If the company meets the proposed retirement timeline, the plants will range in age from 58-67 years old.

"The plants have served our customers well, providing low-cost energy for many years, operating roughly twice as long as expected when they were constructed in the mid-1950s and early 1960s," Kivisto said. "The age of the plants, low-cost competition on the market, and the ongoing cost to operate the plants all have contributed to the plants being too expensive to operate much longer."

Montana-Dakota has conducted an IRP for many years. The IRP is a way to consider all resource options reasonably available to meet the end-use customer's demand for reliable and cost-effective energy, and provide a road map for Montana-Dakota's future resources. The IRP process includes four areas: Load forecasting, demand-side analysis, supply side analysis, and integration and risk analysis.

Montana-Dakota's customers also have benefited from low-cost energy available on the MISO market and the long-range forecast calls for similar savings in future years. MISO, the Midcontinent Independent System Operator, is a not-for-profit member-based organization that ensures reliable, least-cost delivery of electricity across all or parts of 15 U.S. states and one Canadian province. In cooperation with stakeholders, MISO manages approximately 65,000 miles of high-voltage transmission and 200,000 MW of power-generating resources across its footprint.

Montana-Dakota currently employs 77 people between the two coal stations. Once the units are no longer in operation, Montana-Dakota estimates approximately 10 employees will be needed to operate the two natural gas-fired combustion turbine units at Heskett and the two natural gas-fired reciprocating internal combustion engines at Lewis & Clark. The plan is in place intended to maintain staff until the plant retirements, and the company will offer training for employees who wish to fill open positions in other areas of the company.

### About MDU Resources

MDU Resources Group, Inc., a member of the S&P MidCap 400 index and the S&P High-Yield Dividend Aristocrats index, is Building a Strong America® by providing essential products and services through its regulated energy delivery and construction materials and services businesses. For more information about MDU Resources, see the company website at [www.mdu.com](http://www.mdu.com) or contact the Investor Relations Department at [investor@mduresources.com](mailto:investor@mduresources.com).

### About Montana-Dakota Utilities

Montana-Dakota Utilities Co., a subsidiary of MDU Resources, distributes natural gas and generates, transmits and distributes electricity and provides related services in the northern Great Plains. The company serves approximately 143,000 electric customers and 275,000 natural gas customers in 262 communities in North Dakota, South Dakota, Montana and Wyoming.

### Forward-Looking Statement

The information in this release includes certain forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934, as amended. The forward-looking statements contained in this release, including statements made by the president and CEO of Montana-Dakota and statements relating to plans and expectations regarding the construction of a simple cycle combustion turbine, retirement of existing generating stations, related costs and other benefits, and Montana-Dakota's integrated resource plan are expressed in good faith and are believed by the company to have a reasonable basis. Nonetheless, actual results may differ materially from the projected results expressed in the forward-looking statements. For a discussion of important factors that could cause actual results to differ materially from those expressed in the forward-looking statements, refer to Item 1A-Risk Factors in MDU Resources' most recent Form 10-Q and 10-K.

**Media Contact:** Mark Hanson, senior public relations representative, 701-530-1093



B.7 – Little Knife Gas Plant  
B.7.a – Department Request



May 18, 2018

**FILE**

Mr. Derek Enderud  
Petro-Hunt, LLC  
390 - 119<sup>th</sup> Avenue SW  
Killdeer, ND 58640

Re: Regional Haze  
Second Planning Period

Dear Mr. Enderud:

The Department of Health (Department) has begun work on the second planning period (Round 2) State Implementation Plan (SIP) for regional haze. In Round 1 of the regional planning process, the emphasis was on Best Available Retrofit Technology (BART) and making reasonable progress towards the national visibility goal. In Round 2, there are no BART requirements; therefore, we will focus on making reasonable progress. The reasonable progress analysis will be made using the four factors in Section 169A(g)(1) of the Clean Air Act:

The four factors are:

1. The cost of compliance
2. The time necessary to achieve compliance
3. The energy and non-air quality environmental impact of compliance; and
4. The remaining useful life of any existing source subject to such requirements

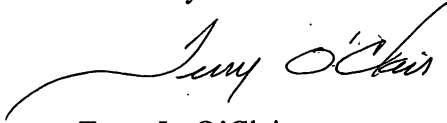
Guidance provided by the U.S. Environmental Protection Agency (Draft Guidance on Progress Tracking Metrics, Long Term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period at [https://www.epa.gov/sites/production/files/2016-07/documents/draft\\_regional\\_haze\\_guidance\\_july\\_2016.pdf](https://www.epa.gov/sites/production/files/2016-07/documents/draft_regional_haze_guidance_july_2016.pdf)) indicates the Department must address 80% of the visibility impairment caused by in-state sources. Data from the IMPROVE monitoring sites at Theodore Roosevelt National Park (TRNP) and Lostwood Wilderness Area (LWA) indicate that sulfates and nitrates continue to be the largest contributors to visibility impairment in these areas. The primary precursors of sulfates and nitrates are emissions of sulfur dioxide (SO<sub>2</sub>) and nitrogen oxides (NO<sub>x</sub>).

The Little Knife Gas Plant emits a significant amount of SO<sub>2</sub> and is located close to a Class I area. Therefore, the Department requests that you prepare a "four factors" analysis for the plant. The analysis should be prepared using the draft EPA guidance noted above. The analysis should address emissions from the amine sweetening unit (Emission Unit A-1) and the flare (Emission Unit F-1).

Preparation of the Round 2 Regional Haze SIP will require extensive planning and review of emission sources in North Dakota. The Department will be working with the Western Regional Air Partnership (WRAP) to prepare the SIP. WRAP will be conducting air quality modeling of potential regional emissions reductions in early 2019. The Department asks that your "four factors" analysis be submitted by January 31, 2019.

If you have any questions, please contact David Stroh of my staff at (701)328-5188.

Sincerely,

A handwritten signature in cursive script, reading "Terry O'Clair".

Terry L. O'Clair  
Director  
Division of Air Quality

TLO/TB:saj

## B.7.b – Facility Response

**Stroh, David E.**

---

**From:** Gary Kohler <gkohler@petrohunt.com>  
**Sent:** Friday, January 25, 2019 3:40 PM  
**To:** Stroh, David E.; O'Clair, Terry L.  
**Cc:** Royce Kennedy; Derek Enderud; Elvis Entzel; Donaven Palahniuk; Ryan Solberg; Ruth R. Ehrmantraut  
**Subject:** Petro Hunt - Regional Haze - Round Two  
**Attachments:** Regional Haze Round Two 01-25-19.pdf  
  
**Categories:** RH Facility

---

**CAUTION:** This email originated from an outside source. Do not click links or open attachments unless you know they are safe.

---

David,

Attached is a summary of the four factor analysis requirements relating to the second planning period of the State Implementation Plan (SIP) for Regional Haze.

The summary includes the projected reduction of sulfur dioxide with potential additional controls. The attachments include the estimated cost of the controls along with the estimated energy and non-air environmental impacts.

Thank you for proving me with the additional information you sent, as well as explaining the history of these studies. It was a great help. If you have additional questions please give me a call.

*Gary A. Kohler*  
*Plant Manager*  
*Petro-Hunt, LLC*  
*Little Knife Gas Plant*

W: 701.863.6500

D: 701.863.6445

C: 701.290.7397

F: 701.863.6999

[gkohler@petrohunt.com](mailto:gkohler@petrohunt.com)



[www.petrohunt.com](http://www.petrohunt.com)

**Petro Hunt Little Knife Gas Plant**  
**State Implementation Plan (SIP) for Regional Haze Round 2**  
**Four Factor Analysis**

**Table 1: Outlines the emission control measures that have already been applied to these sources, the baseline levels of emissions with these current controls, and potential additional control measures that could be adopted to further reduce emissions. The table also gives the estimated control efficiency and annual emission reduction for each potential future control measure.**

<b>(1) Existing Control Measures and Potential Additional Control Options for Natural Gas Processing Operations</b>							
<b>Source</b>	<b>Pollutant</b>	<b>Existing Controls</b>	<b>Baseline Emissions (tons/yr.)</b>	<b>Potential additional control measures</b>	<b>Estimated Control efficiency (%)</b>	<b>Potential emission reduction (tons/yr.)</b>	<b>References</b>
Sulfur recovery unit, 2-stage, 2-bed, 120 long tons/day sulfur	Sulfur Dioxide	2- stage unit with cold bed adsorption, > 88 % efficiency	432	Replacement of catalyst in Reactors 1 & 2	90%	39.42	Catalyst Replacement in Reactors 1 & 2 Attachment
Sulfur recovery unit, 2-stage, 2-bed, 120 long tons/day sulfur	Sulfur Dioxide	2- stage unit with cold bed adsorption, > 88 % efficiency	432	Acid Gas Injection Well	100%	320	Acid Gas Injection Well and Catalyst Replacement Reactor 1 & 2 Attachments

**Table 2 Factor 1: Provides cost estimates for the emission control options which have been identified for the North Dakota gas processing facilities. For each option, the table gives an estimate of the capital cost to install the necessary equipment, and the total annual cost of control, including the amortized cost associated with the capital equipment cost. The table also shows the estimated cost effectiveness for each control measure, in terms of the cost per ton of emission reduction.**

**Factor 2: Once the regional haze control strategy is formulated for North Dakota, up to 2 years will be needed for the state to develop the necessary rules to implement the strategy. We have estimated that sources may then require up to a year to procure the necessary capital to purchase control equipment. The ICAC has estimated that approximately 13 months is required to design, fabricate, and install SCR or SNCR technology for NOX control. However, state regulators' experience indicates that closer to 18 months is required to install this technology. In the Clean Air Interstate Rule (CAIR) analysis, EPA estimated that approximately 30 months is required to design, build, and install SO2 scrubbing technology for a single emission source. The analysis also estimated that up to an additional 12 months may be required for staging the installation process if multiple sources are to be controlled at a single facility. Based on these figures, the total time required achieve emission reductions for the Petro Hunt facility would be up to 6½ years. This includes 2 years for regulatory development, 1 year for capital acquisition, and 2½ years for designing, building and installing. This estimate includes the same components as the estimate for Petro Hunt, with an additional year for staging the installation of controls for multiple emission sources.**

<b>(2) Estimated Costs of Control for Natural Gas Processing Operations - Factor 1</b>								
<b>Source</b>	<b>Control Option</b>	<b>Pollutant</b>	<b>Estimated control efficiency (%)</b>	<b>Potential emission reduction (tons/yr.)</b>	<b>Estimated capital cost (\$1000)</b>	<b>Estimated annual cost (\$1000/yr.)</b>	<b>Cost effectiveness (\$/ton)</b>	<b>References</b>
Sulfur recovery unit, 2-stage, 2-bed, 120 long tons/day sulfur	Replacement of catalyst in Reactors 1 & 2	Sulfur Dioxide	90%	39.42	103.95	10.39	2,636.99	Catalyst Replacement in Reactors 1 & 2 (attachment)
Amine Treating Unit	Acid Gas Injection Well	Hydrogen Sulfide and Carbon Dioxide	100%	320	4,229.58	624.71	13,665.53	Acid Gas Injection Well, Estimated Cost of Control, & Catalyst Replacement in Reactors 1 & 2 Attachments

**Table 3 Factor 3:** Shows the estimated energy and non-air pollution impacts of control measures for sources at the Petro Hunt facility. The table shows the additional fuel, electricity, and steam requirements resulting required to operate the control equipment; and the additional solid waste would be produced. CO2 emissions associated with the generation of the additional electricity and steam are also estimated in the table.

**(3) Estimated Energy and Non-Air Environmental Impacts of Potential Control Measures for Natural Gas Processing**

Energy and non-air pollution impacts (per ton of emission reduced)

Source Type	Control Technology	Pollutant Controlled	Potential emission reduction (ton/yr.)	Additional Fuel Req. (%)	Electricity Req. (kw-hr)	Steam Req. (tons steam)	Solid waste Produced (tons)	Additional CO2 emitted (tons)
Sulfur recovery unit, 2-stage, 2-bed, 120 long tons/day sulfur	Activated Alumina Promoted Claus Catalyst	Sulfur Dioxide	39.42	0	0	0	0	0
Amine Treating Unit	Downhole Formation Injection	Hydrogen Sulfide and Carbon Dioxide	320	0	3,504,000	0	0	0

**Factor 4:** It is not possible to compute the remaining service lifetimes of these sources since emission sources at industrial facilities are often refurbished. The remaining lifetimes of the SRUs and compressors are expected to be longer than 15 year figure which has been used to amortize the capital costs of add-on emission controls or equipment modifications to reduce emissions. If the remaining life of an emission source is less than the projected lifetime of a pollution control device, then the capital cost of the control device would have to be amortized over a shorter period of time, corresponding to the remaining lifetime of the emission source. This would cause an increase in the amortized capital cost of the pollution control option, and a corresponding increase in the total annual cost of control.



# Attachments:

## Little Knife Plant SO<sub>2</sub> Reduction Options

### Option #1

### Catalyst Replacement in Reactors

Replacement of catalyst in CBA reactor bed #1 and #2

This change would take efficiency levels from 88% to 90% and reduce hourly SO<sub>2</sub> emissions by approximately 9 pounds per hour.

#### COST

\$ 29,481.40	Catalyst reactor #1
\$ 17,339.50	Catalyst reactor #2
\$ 25,000.00	Labor
\$ 20,000.00	Catalyst removal
\$ 1,000.00	Catalyst disposal 30 tons
\$ 750.00	Disposal transportation
\$ 3,360.00	Sulfur production lost
	Residue flared for complete conversion of H <sub>2</sub> S to SO <sub>2</sub> in process flare = 2.35 times acid gas to flare
\$ 2,021.00	430 x 2.35 = 1010.5 MCF/D 1010.5 x \$2.00 = \$2,021.00
\$ 12,600.00	Crane
<b>\$ 111,551.90</b>	<b>Total</b>

#### Time to complete

14 days      Shutdown unit, cool, disassemble, enter reactor, remove catalyst, replace catalyst, warmup unit, restart

#### ENVIRONMENTAL IMPACT

788 pounds of H<sub>2</sub>S to flare per hour  
1100 MCF residue gas flared per day  
1000 MCF residue gas burned to reheat unit for restart  
9 pounds of SO<sub>2</sub> less per hour 73 lb/hr @ 88.63% efficiency versus 64 lb/hr @ 90% efficiency  
9 x 8760 hrs. / 2000 lbs = 39.42 tons.

#### USEFUL LIFE OF EQUIPMENT

7-10 years      After this time efficiency will be back to 88% levels

2017 Average	Acid gas to CBA	Sulfur LT	So2 lb/hr
January	338	5.73	
February	354	6.32	
March	364	6.47	
April	352	6.56	
May	399	6.21	
June	449	7.31	
July	428	6.74	
August	408	6.45	
September	364	6.11	
October	338	5.53	
November	315	4.88	
December	329	4.94	
Average	370	6.1	73

73 x 8760 hrs. / 2000 lbs. = 319.74 tons

2018 Average	Acid gas to CBA	Sulfur LT	So2 lb/hr
January	328	4.95	
February	311	4.11	
March	305	4.08	
April	335	5.02	
May	332	5.39	
June	357	5.52	
July	341	5.66	
August	407	6.62	
September	417	6.54	
October	421	6.68	
November	395	6.14	
December	418	6.48	
Average	364	5.6	85

Option #2

# Acid Gas Injection Well

AFE DATA - WORKSHEET								RIG TYPE - LAND OBM TO CSG PT, SBM IN LAT			
				DRILLING							
Lease.....		Acid Gas Well				AFE NO		DATE			
Location.....		SURFACE.....									
		BOTTOM HOLE.....									
Section.....		Township.....				Range.....		COUNTY			
Field.....				Prospect Name.....				STATE ND			
Type of Well..		OIL/GAS		Estimated Depth...				Horizontal Length			
District Manager.....		Tommy Moffett				Address		2101 Cedar Spring Rd. STE 600		Target.....	
Cost Estimated By .....		Scott Peacock						DALLAS, TX 75201			
SUB		EXPENDITURES									
ACCT	DRY HOLE	COMPLETED	TOTAL								
259				CSG/TBG FEET	CASING:	COST / FT:					
	\$4,000		\$4,000	80	DRIVE PIPE:	\$50.00	16" CONDUCTOR	Drilled in conductor			
	\$				CONDUCTOR:	\$0.00					
	\$50,400		50,400	2,000	SURFACE:	\$25.20	9 5/8" 36# K-55				
	\$				INTER. CSG:	\$0.00					
	\$				INTER. CSG:	\$0.00					
	\$240,000		240,000	8,000	PROD. LNR/CSG:	\$30.00	7" L80				
	\$				TIEBACK CSG:	\$0.00					
259					TUBING:						
	\$175,000		175,000	7,000	TUBING:	\$25.00	2 7/8" chrome				
	\$					\$1.80	Sucker Rods				
259					OTHER EQUIPMENT:						
					LINER HANGER						
	10,000	20,000	30,000		WELLHEAD, CSG HANGER, TBG HANGER						
		10,000	10,000		PACKER, ANCHOR CATCHER, ROD PUMP						
					NON-CONTROLLABLE:						
260											
214					FACILITIES						
221					PIPELINE						
241											
240											
	\$64,400	\$445,000	\$509,400	TOTAL EQUIPMENT							

--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--

<i>preliminary</i>		<b>PETRO-HUNT, L. L. C.</b>				RIG TYPE - LAND	
		AUTHORIZATION FOR EXPENDITURE				OBM TO CSG PT, SBM IN LAT	
		DRILLING		AFE NO		Date .... 01/00/00	
Lease.....	Acid Gas Well						
Location.....	SURFACE.....	0					
	BOTTOM HOLE.....	0					
Section.....	0	Township.....	0	Range.....	0	County.....	0
Field.....	0	Prospect Name.....	0		State.....	ND	
Type of Well..	OIL/GAS	Estimated Depth.....	0		Horizontal Length.....	0	
District Manager.....	Elvis Entzel	Address	2101 Cedar Spring Rd. STE 600			Target.....	0
Cost Estimated By .....	Scott Peacock	DALLAS, TX 75201					
TANGIBLE EQUIPMENT							
EQUIPMENT/ QUANTITY		DESCRIPTION		SUB	EXPENDITURES		
DRY HOLE	PRODUCER			ACCT	DRY HOLE	COMPLETED	TOTAL
		Casing	Cost/Ft	259			
80		16" CONDUCTOR			4,000		4,000
					0		0
2,000		9 5/8" 36# K-55			50,400		50,400
					0		0
					0		0
	8,000	7" L80				240,000	240,000
						0	0
		Tubing		259			
	7,000	2 7/8" chrome				175,000	175,000
		Sucker Rods				0	0
		Other Equipment		259			
		LINER HANGER			0	0	0
		0			0	0	0
		WELLHEAD, CSG HANGER, TBG HANGER		259	10,000	20,000	30,000
		PACKER, ANCHOR CATCHER, ROD PUMP				10,000	10,000
		FACILITIES				0	0
		PIPELINE				0	0
		TOTAL EQUIPMENT .....			\$64,400	\$445,000	\$509,400

<b>INTANGIBLES</b>									
Drilling Contract, Footage						001			
Drilling Contract, Day Work w/Topdrive			Days @		+ taxes	002			
Drilling Contract, Day Work	6	3	Days @	\$18,000	+ taxes	002	108,000	54,000	162,000
Completion / P&A Contract-Day Work			Days @	\$10,000	+ taxes	003	0	0	0
Drill Pipe and Tubing Rental						004	0	0	0
Drive Conductor						009	18,000	0	18,000
Labor						010	7,200	11,600	18,800
Transportation						014	10,000	7,000	17,000
Drilling Contract - Rig MI, RU, & RD						019	572,000	150,000	722,000
Fuel				\$2.75	P/GAL	020	33,000	8,300	41,300
Water						022	66,200	10,600	76,800
Bits and Mills						031	15,000	0	15,000
Drilling and Completion Fluids + Disposal						032	105,000	25,000	130,000
Welding and Repairs						034	8,000	0	8,000
Tubular and Wellhead Inspection and Testing						037	20,000	10,000	30,000
Rental Equipment						039	99,000	51,500	150,500
Mud Logging						040	7,400	0	7,400
Insurance						047	28,100	0	28,100
Road and Location Costs, Permittin						049	200,000	50,000	250,000
Communication						058	2,000	1,500	3,500
Geological, Engineering, and Drilling Foreman (Well Site)						060	19,800	5,000	24,800
Miscellaneous						063	0	0	0
Supervision, District, Camp and Warehouse						065	4,800	2,400	7,200
Electrical Logging, Sidewall Coring, and Directional Surveys & VSP						070	0	20,000	20,000
Coreheads, Conventional Coring, and Core Analysis						071	0	0	0
Production Test						072	0	15,000	15,000
Cement and Cementing Services						074	20,000	55,000	75,000
Stimulation and Sand Control						077	0	0	0
Perforating						078	0	25,000	25,000
Contingency					10 %	089	134,400	50,200	184,600
<b>TOTAL INTANGIBLES .....</b>							<b>\$1,477,900</b>	<b>\$552,100</b>	<b>\$2,030,000</b>
<b>TOTAL WELL COSTS .....</b>							<b>\$1,542,300</b>	<b>\$997,100</b>	<b>\$2,539,400</b>
<b>(LESS CONTRIBUTIONS)</b>							<b>\$0</b>	<b>\$0</b>	<b>\$0</b>
<b>NET WELL COSTS .....</b>							<b>\$1,542,300</b>	<b>\$997,100</b>	<b>\$2,539,400</b>
<b>NON-OPERATOR</b>									
Approval of this AFE constitutes NON-OPERATOR'S approval of and commitment to pay all costs incurred in connection with the performance of the operations proposed herein and agreement to bear all risks and liabilities associated with such operations as to NON-OPERATOR'S interest as specified herein and as required by any applicable operating agreement. It is specifically recognized that the costs indicated in this AFE are estimates only and the actual costs may vary from the estimate.									
APPROVED BY: _____						DATE: _____			
This AFE includes Operator's Extra Expense (Blowout) insurance which provides coverage during drilling and completion operations. If you do not desire to have Operator provide the coverage for you, please indicate so in the space below and enclose a copy of your Insurance Certificate outlining your coverage. NO RESPONSE shall result in a conclusive presumption of acceptance.									
NOT APPROVED: _____						DATE: _____			
GEN. FORM 360 - REVISED 1/91									

Afe Category Description	Code	Budget(USD)	Budget Supplement(USD)	
IDC - DRLG CONTRACT FOOT TURNK	118.807.001	\$0		
IDC - DRLG CONTRACT DAY WORK	118.807.002	\$108,000		
IDC - COMPLETION / P&A DAY WRK	118.807.003	\$0		
IDC - DRILL PIPE & TUBING RENT	118.807.004	\$0		
IDC - CAPITALIZED INTEREST	118.807.005	\$0		
IDC - DRIVE CONDUCTOR	118.807.009	\$18,000		
IDC - LABOR	118.807.010	\$7,200		
IDC - TRANSPORTATION	118.807.014	\$10,000		
IDC - OUTSIDE PROFESSIONAL SVC	118.807.016	\$0		
IDC - RIG UP / DN MOVE IN /OUT	118.807.019	\$572,000		
IDC - FUEL	118.807.020	\$33,000		
IDC - WATER	118.807.022	\$66,200		
IDC - INSURANCE	118.807.024	\$0		
IDC - INITIAL LOCATION COSTS	118.807.025	\$0		
IDC - BITS & MILLS	118.807.031	\$15,000		
IDC - DRILLING & COMPL FLUID	118.807.032	\$105,000		
IDC - WELDING & REPAIRS	118.807.034	\$8,000		
IDC - TUBULAR / WELLHEAD TEST	118.807.037	\$20,000		
IDC - RENTAL EQUIPMENT	118.807.039	\$99,000		
IDC - MUD LOGGING	118.807.040	\$7,400		
IDC - GEN LIABILITY / OEE INS	118.807.047	\$28,100		
IDC - ROAD & LOCATION COSTS	118.807.049	\$200,000		
IDC - COMMUNICATIONS	118.807.058	\$2,000		
IDC - GEOL ENG DRLG FOREMAN	118.807.060	\$19,800		
IDC - MISCELLANEOUS	118.807.063	\$0		
IDC - SUPERVISION DST CAMP WHS	118.807.065	\$4,800		
IDC - ADMINISTRATIVE OVERHEAD	118.807.066	\$0		
IDC - ELECTRICAL LOGGING	118.807.070	\$0		
IDC - CORING & CORE ANALYSIS	118.807.071	\$0		
IDC - FORMATION TESTS	118.807.072	\$0		
IDC - CEMENT & CEMENTING SERVI	118.807.074	\$20,000		
IDC - STIMULATION & SAND CONTR	118.807.077	\$0		
IDC - PERFORATING CASED HOLE	118.807.078	\$0		
IDC - MEALS & ENTERTAIN 50%DED	118.807.087	\$0		
IDC - CONTINGENCY	118.807.089	\$134,400		
IDC - DRY HOLE CONTRIBUTIONS	118.807.092	\$0		
IDC - ADMIN OVERHEAD COM FIX R	118.807.095	\$0		
IDC - AUDIT ADJUSTMENTS	118.807.099	\$0		
ICC - DRLG CONTRACT FOOT/TURNK	118.808.001	\$0		
ICC - DRLG CONTRACT - DAY WORK	118.808.002	\$54,000		
ICC - COMPLETION / P&A DAY WRK	118.808.003	\$0		
ICC - DRILL PIPE & TUBING RENT	118.808.004	\$0		
ICC - CAPITALIZED INTEREST	118.808.005	\$0		
ICC - DRIVE CONDUCTOR	118.808.009	\$0		
ICC - LABOR	118.808.010	\$11,600		
ICC - TRANSPORTATION	118.808.014	\$7,000		

ICC - OUTSIDE PROFESSIONAL SVC	118.808.016	\$0		
ICC - RIG UP / DN MOVE IN /OUT	118.808.019	\$150,000		
ICC - FUEL	118.808.020	\$8,300		
ICC - WATER	118.808.022	\$10,600		
ICC - INSURANCE	118.808.024	\$0		
ICC - BITS AND MILLS	118.808.031	\$0		
ICC - DRILLING & COMPL FLUID	118.808.032	\$25,000		
ICC - WELDING & REPAIRS	118.808.034	\$0		
ICC - TUBULAR / WELLHEAD TEST	118.808.037	\$10,000		
ICC - RENTAL EQUIPMENT	118.808.039	\$51,500		
ICC - MUD LOGGING	118.808.040	\$0		
ICC - GEN LIABILITY / OEE INS	118.808.047	\$0		
ICC - ROAD AND LOCATION	118.808.049	\$50,000		
ICC - COMMUNICATIONS	118.808.058	\$1,500		
ICC - GEOLOG ENGR DRLG FOREMAN	118.808.060	\$5,000		
ICC - MISCELLANEOUS	118.808.063	\$0		
ICC - SUPER DISTR CAMP & WHSE	118.808.065	\$2,400		
ICC - ADMINISTRATIVE OVERHEAD	118.808.066	\$0		
ICC - ELECTRICAL LOGGING	118.808.070	\$20,000		
ICC - CORING & CORE ANALYSIS	118.808.071	\$0		
ICC - FORMATION TESTS	118.808.072	\$15,000		
ICC - CEMENT & CEMENTING SERV I	118.808.074	\$55,000		
ICC - STIMULATION & SAND CONTR	118.808.077	\$0		
ICC - PERFORATING CASED HOLE	118.808.078	\$25,000		
ICC - MEALS & ENTERTAIN 50%DED	118.808.087	\$0		
ICC - CONTINGENCY	118.808.089	\$50,200		
ICC - DRY HOLE CONTRIBUTIONS	118.808.092	\$0		
ICC - ADMIN OVERHEAD COM FIX R	118.808.095	\$0		
ICC - AUDIT ADJUSTMENTS	118.808.099	\$0		
TDC - EQUIP FROM CONVERSION	118.809.200	\$0		
TDC - CONTROLLABLE EQUIPMENT	118.809.259	\$64,400		
TDC - NON - CONTROLLABLE EQUIP	118.809.260	\$0		
TDC - COST OF EQUIP SALVAGED	118.809.285	\$0		
TDC - VALUATION ADJUSTMENT	118.809.289	\$0		
TDC - CONTINGENCY	118.809.290	\$0		
TDC - AUDIT ADJUSTMENTS	118.809.299	\$0		
TDC - EXCISE TAX DIESEL FUEL	118.809.785	\$0		
TCC - CONTROLLABLE EQUIPMENT	118.810.259	\$445,000		
TCC - NON - CONTROLLABLE EQUIP	118.810.260	\$0		
TCC - COST OF EQUIP SALVAGED	118.810.285	\$0		
TCC - VALUATION ADJUSTMENT	118.810.289	\$0		
TCC - CONTINGENCY	118.810.290	\$0		
TCC - AUDIT ADJUSTMENTS	118.810.299	\$0		
TCC - EXCISE TAX DIESEL FUEL	118.810.785	\$0		
			\$0	\$2,539,400
	Data Check	All Good		
Sum total from above		\$2,539,400		
Total from 'AFE' tab		\$2,539,400		



## Estimated Cost Of Control

Table 2

### Estimated Capitol Cost:

Injection Well: \$2,539,400.00

Acid Gas Compressor: \$1,670,000.00

Compressor piping and associated equipment, installation and labor: \$20,183.71

**Total: \$4,229,583.71**

### Estimated Annual Cost:

Maintaining the compressor with pistons, rods, rings, rider bands, packings, valves, oil etc. would be approximately \$15,000.00 / year.

Electrical Cost: \$128,385.00

Injection Well, Acid Gas Compressor, & Piping amortization cost over seven years: \$4,229,583.71

**Total Cost: \$4,372,968.71 / 7 = \$624,709.82**

### Cost Effectiveness \$/ton:

**\$4,372,968.71 / 320 tons = \$13,665.53**

Table 3

### Electricity Required (kw-hr)

Operating a 2400-volt, 500 HP motor, drawing 107 amps, using 400 KWH cost \$351.74 / day.

$351.74 \times 365 = \$128,385.00$  / year.

**400 kwh x 8760 = 3,504,000**

# Acid Gas Compressor Cost

Good morning Gary / Ryan,

I had a look at some acid gas injection compressor packages Bidell has recently completed and have the following summary;

Typical design conditions

Suction pressure range – 4 – 9 psig

Discharge pressure range – 2000 – 3200 psig with a couple at 1000 psig and one at 200 psig

Flow rates -0.4 – 1.32 mmscfd

Horsepower required – 100 – 450 hp

Cost - \$800,000.0 - \$1,670,000.00 c/w with full installed arctic building

I had a look at your conditions and provided the attached performance summary to give you an idea of the compressor size and horsepower required to inject 0.4 mmscfd at 3 psig suction and 900 psig discharge pressure. The frame that fits well is the Ariel JG-4 with 4 stages of compression and driven by ~ 150 hp electric motor. The flow rate is as follows;

Target - 0.4 mmscfd @973 rpm

Low flow – 0.308 mmscfd @ 750 rpm

High flow – 0.576 mmscfd @ 1400 rpm

I would estimate this package would run in the \$900,000.00 – \$1,100,000.00 range (to give you a cost idea) and would estimate delivery lead times to be about 30 – 32 weeks. I have attached a number of pictures to show some AGI packages during fabrication and after completion.. The package would come with its own control panel mounted in the package that could be connected to the plant PLC and a full arctic style building with heaters (which can be deleted if you plan to put this package into an existing building)

Please review the attached pictures and performance summary and let me know if you have any additional questions... if you would like, I could have a proposal generated and submitted to you for consideration in the next couple of weeks (this would provide a better idea of the full scope of supply). As I indicated in our meeting, Bidell has placed about 70,000 hp of compression on the ground in ND in the last 12 – 18 months, if you would like some local references or would like to go and look at one of the Bidell supplied packages, let me know and I will arrange a site visit...

I look forward to your initial comments...

Thanks again for your time...

Steve Watson | Technical Services Manager



6900 – 112th Ave. SE, Calgary AB T2C 4Z1

Dir: 403-723-5368

Cell: 403-816-9334

Website: [www.bidell.com](http://www.bidell.com)



Company: Bidell Gas Compression  
 Quote:  
 Case 3:

## Ariel Performance

Customer: Petro Hunt  
 Inquiry:  
 Project: Acid Gas Injection



7.7.6.0

### Compressor Data:

Elevation,ft:	2600.00	Barmtr,psia:	13.350	Ambient,F:	100.00
Frame:	JG/4	Stroke, in:	3.50	Rod Dia, in:	1.125
Max RL Tot, lbf:	18000	Max RL Tens, lbf:	9000	Max RL Comp, lbf:	10000
Rated RPM:	1500	Rated BHP:	504.0	Rated PS FPM:	875.0
Calc RPM:	1400.0	BHP:	154	Calc PS FPM:	816.7

### Driver Data:

Type:	Unselected
Mfg:	
Model:	
BHP:	0
Avail:	0

### SOUR GAS-2

#### Services

#### Service 1

Gas Model	VMG-APRNL2			
Stage Data:	1	2	3	4
Target Flow, MMSCFD	0.450	0.450	0.450	0.450
Flow Calc, MMSCFD	0.574	0.574	0.568	0.565
BHP per Stage	46.9	39.3	26.5	35.9
Specific Gravity	1.2696	1.2696	1.2763	1.2797
Ratio of Sp Ht (N)	1.3009	1.3001	1.3156	1.3315
Comp Suct (Zs)	0.9924	0.9800	0.9426	0.8832
Comp Disch (Zd)	0.9884	0.9718	0.9292	0.8521
Pres Suct Line, psig	3.00	N/A	N/A	N/A
Pres Suct Flg, psig	2.84	40.71	140.12	289.23
Pres Disch Flg, psig	42.05	143.77	295.89	910.00
Pres Disch Line, psig	N/A	N/A	N/A	900.00
Pres Ratio F/F	3.422	2.906	2.015	3.052
Temp Suct, F	70.00	120.00	120.00	120.00
Temp Clr Disch, F	120.00	120.00	120.00	120.00
Cylinder Data:	Throw 1	Throw 2	Throw 4	Throw 3
Cyl Model	11JG	6-1/2JG	3-5/8JG	3JG
Cyl Bore, in	11.000	6.125	3.375	2.750
Cyl RDP (API), psig	125.0	577.3	1154.5	2318.2
Cyl MAWP, psig	150.0	635.0	1270.0	2550.0
Cyl Action	DBL	DBL	DBL	DBL
Cyl Disp, CFM	536.1	164.3	47.9	30.9
Pres Suct Intl, psig	0.93	37.79	127.95	276.29
Temp Suct Intl, F	79	126	124	125
Pres Disch Intl, psig	47.78	151.15	319.81	944.79
Temp Disch Intl, F	295	307	257	329
HE Suct Gas Vel, FPM	7943	5648	6934	5069
HE Disch Gas Vel, FPM	7331	4997	6283	4522
HE Spcrs Used/Max	0/4	0/4	0/1	0/1
HE Vol Pkt Avail	1.50+51.93	1.40+56.40	1.15+48.99	0.62+33.05
Vol Pkt Used	0.00 (V) %	0.00 (V) %	0.00 (V) %	0.00 (V) %
HE Min Clr, %	14.61	15.63	14.95	20.24
HE Total Clr, %	16.11	17.03	16.09	20.86
CE Suct Gas Vel, FPM	7860	5457	6164	4220
CE Disch Gas Vel, FPM	7255	4829	5585	3765
CE Spcrs Used/Max	0/4	0/4	0/1	0/1
CE Min Clr, %	14.87	16.65	18.95	26.61
CE Total Clr, %	14.87	16.65	18.95	26.61
Suct Vol Eff HE/CE, %	67.3/69.2	71.8/72.3	83.8/81.8	64.4/56.5
Disch Event HE/CE, ms	6.8/8.1	7.5/8.9	9.9/11.2	7.0/7.7
Suct Pseudo-Q HE/CE	13.2/12.9	4.8/4.5	9.1/7.2	4.9/3.4
Gas Rod Ld Comp, %	44.6 C	33.8 C	18.6 C	42.7 C
Gas Rod Ld Tens, %	48.9 T	35.4 T	15.4 T	33.5 T
Gas Rod Ld Total, %	49.2	36.5	18.0	40.5
Xhd Pin Deg/%RvrsI lbf	164/100.0	173/96.8	164/84.3	179/54.0
Flow Calc, MMSCFD	0.574	0.574	0.568	0.565
Cyl BHP	46.9	39.3	26.5	35.9

# Acid Gas Discharge Piping and Components

P.O. Num:	Validity Period 01/17/2019 to 01/20/2019	Date: 01/17/2019 Project Bid Quote
<b>Sold-To</b> Cust Num: 100189 PETROHUNT LLC 1801 CALIFORNIA ST STE 3500 DENVER CO 80202	<b>Ship-to</b> PETRO HUNT - LITTLE KNIFE PLANT 813 123RD AVE SW KILLDEER ND 58640-9001 USA	<b>Interim Ship To</b>
BUYER: RYAN SOLBERG	REFERENCE 1:701-260-2083	

Item	Material	Description	Qty	UM	Unit Price	Disc%	Net Price	Net Total
10	383242	PIPE I 1 IN NPS 1.315 IN OD S80S .179 IN WALL SEAMLESS A/SA312 TP316/L STAINLESS STEEL SINGLE RANDOM LENGTH PLAIN ENDS ASME B36.19M 2.17 LB/FT Notes: *** NOT THREADED *** **** SEE LINE 15 FOR THREADING CHARGES **** 175 FT STOCK BEULAH, ND 485 FT TO COME FROM HOUSTON, TX SUBJECT TO PRIOR SALES	660.000	FT	11.64 /FT		11.64	7,682.40
15	S973000	SERVICE CHARGE FOR LABOR & THREADING SS Notes: 2-3 DAYS FOR STOCK PIPE ARO ONCE HOUSTON, TX PIPE IS RECIEVED 3-4 DAYS FOR THREADING ARO	1	EA	0.00		1,500.00	1,500.00
20	13340	COUPLING I 1 IN CLASS 3000 THREADED F316/L FORGED STAINLESS STEEL A/SA182 ASME B16.11 Notes: 5 STOCK BEULAH, ND 35 TO COME FROM HOUSTON, TX SUBJECT TO PRIOR SALES	40	EA	5.63 /EA		5.63	225.20
30	9245	ELBOW I 1 IN 90 DEGREE CLASS 3000 F316/L THREADED FORGED STAINLESS STEEL A/SA182 ASME B16.11 Notes: 6 STOCK BEULAH, ND 34 TO COME FROM HOUSTON, TX SUBJECT TO PRIOR SALES	20	EA	18.13 /EA		18.13	362.60
Item Total.....							9,770.20	
Subtotal for Taxes.....							413.51	
Quotation Amount.....							10,183.71	

Subject to terms on back Payment Terms: Net 90 Days Delivery Terms: FOB Shipping Point Currency: USD

Questions: DNOW L.P. BEULAH ND Phone: 701-873-2104

KOELLERRA NOP  
Page 1 of 2  
01/17/2019 10:40:55

## B.7.c – Communications

**PETRO-HUNT, LLC  
LITTLE KNIFE PLANT  
813 123<sup>RD</sup> AVE.SW  
KILLDEER, ND 58640**

November 29, 2018

Mr. Terry O'Clair, Director  
North Dakota Department of Health  
Environmental Health Section  
Gold Seal Center, 918 E. Divide Ave.  
Bismarck, North Dakota 58501-1947

RE: Reginal Haze  
Second Planning Period

Dear Mr. O'Clair

Attached is the response to the letter referencing the Reginal Haze.

If you have any questions, or need additional information, please contact me at 701-863-6500.

Sincerely,

PETRO-HUNT, LLC

Gary Kohler  
Plant Manager  
Little Knife Gas Plant

Cc: Royce Kennedy / with attachments  
Derek Enderud / with attachments

**PETRO-HUNT, LLC  
LITTLE KNIFE PLANT  
813 123<sup>RD</sup> AVE.SW  
KILLDEER, ND 58640**

Mr. Terry O'Clair

RE: Regional Haze  
Second Planning Period

This letter is regarding the second period State Implementation Plan (SIP) for regional haze. In the past forty years the Little Knife Gas Plant has always strived to achieve the very best it can to minimize emission sources and increase the national visibility utilizing the Best Available Retrofit Technology (BART) as well as making reasonable progress through ongoing process analysis.

The reports sent to the State of North Dakota Health Department are not only a requirement but an indication of our efforts to reduce emissions and improve air quality. Reports are sent on an Annual, Semi-annual and Quarterly basis documenting our emission sources, the quantity of pollutants and reliability of our emission monitoring equipment.

Though the Little Knife Plant emits a significant amount of SO<sub>2</sub> our records show the sulfur plant operates at 32.3% below the established hourly threshold set by the State with a recovery rate between 92 -94%. In addition to monitoring sulfur dioxide, we also monitor for GHG and VOC detection.

With the discovery of the Bakken formation, our inlet gas to the amine sweetening unit containing Hydrogen Sulfide has reduced significantly, therefore a significant reduction in sulfur dioxide. There has never been an exceedance in our process flare and only five one-hour exceedances from the incinerator on the Sulfur Plant in the past ten years.

Petro Hunt will continue to communicate with the appropriate agencies, as well as continue making reasonable progress to improve air quality. If the volume of Hydrogen Sulfide continues to decline, Petro Hunt will research the possibility of Acid Gas injection.

We are aware of the Plant's location to the Theodore Roosevelt National Park. It has always been our goal to continually improve operations to minimize the amount of sulfur dioxide, nitrous oxides, particulates, and organic compounds along with any other source of emissions to protect the environment and improve visibility impairment.

Sincerely,  
Gary Kohler





December 5, 2018

**FILE**

Mr. Gary Kohler  
Plant Manager  
Petro-Hunt, LLC  
813 - 123<sup>rd</sup> Avenue SW  
Killdeer, ND 58640

Re: Regional Haze  
Second Planning Period

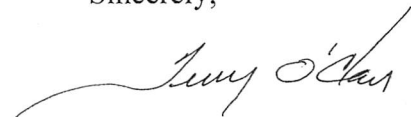
Dear Mr. Kohler:

We have reviewed your November 29, 2018 email response to the Department's request for a four factors analysis for the Little Knife Gas Plant. Your response did not provide the requested analysis and does not adequately address the requirements of the Regional Haze Program. An appropriate analysis must address options for reducing sulfur dioxide at the plant including acid gas injection. The analysis must provide a cost analysis of the various options, the time necessary to achieve the reductions, the energy and non-air quality environmental impacts of the options and you may consider the remaining useful life of the equipment. The required analysis is very technical and may require Petro-Hunt, LLC to retain the services of an engineering consultant. Based on your analysis and our own, the Department will require appropriate actions to aid in achieving reasonable progress toward the national visibility goal.

Under NDCC 23-25, the Department has the authority to require this analysis. We suggest a meeting be arranged between Petro-Hunt and the Department to discuss the analysis. If you have a consultant, they are free to attend the meeting. We will be in contact you to set up this meeting.

If you have any questions, please feel free to contact David Stroh of my staff at (701) 328-5188.

Sincerely,



Terry L. O'Clair  
Director  
Division of Air Quality

TLO/TB:saj

xc: Maggie Olson, Asst. Attorney General



B.8 – Hess Tioga Gas Plant  
B.8.a – Department Request



May 18, 2018

**FILE**

Mr. Tony St. Clair  
Hess Corporation  
1501 McKinney Street  
Office 11.012B  
Houston, TX 77010

Re: Regional Haze  
Second Planning Period

Dear Mr. St. Clair:

The Department of Health (Department) has begun work on the second planning period (Round 2) State Implementation Plan (SIP) for regional haze. In Round 1 of the regional planning process, the emphasis was on Best Available Retrofit Technology (BART) and making reasonable progress towards the national visibility goal. In Round 2, there are no BART requirements; therefore, we will focus on making reasonable progress. The reasonable progress analysis will be made using the four factors in Section 169A(g)(1) of the Clean Air Act:

The four factors are:

1. The cost of compliance
2. The time necessary to achieve compliance
3. The energy and non-air quality environmental impact of compliance; and
4. The remaining useful life of any existing source subject to such requirements

Guidance provided by the U.S. Environmental Protection Agency (Draft Guidance on Progress Tracking Metrics, Long Term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period at [https://www.epa.gov/sites/production/files/2016-07/documents/draft\\_regional\\_haze\\_guidance\\_july\\_2016.pdf](https://www.epa.gov/sites/production/files/2016-07/documents/draft_regional_haze_guidance_july_2016.pdf)) indicates the Department must address 80% of the visibility impairment caused by in-state sources. Data from the IMPROVE monitoring sites at Theodore Roosevelt National Park (TRNP) and Lostwood Wilderness Area (LWA) indicate that sulfates and nitrates continue to be the largest contributors to visibility impairment in these areas. The primary precursors of sulfates and nitrates are emissions of sulfur dioxide (SO<sub>2</sub>) and nitrogen oxides (NO<sub>x</sub>).

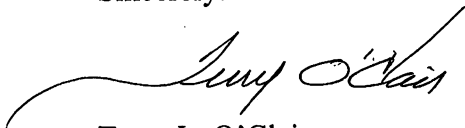
The Tioga Gas Plant has been identified as a significant source of both SO<sub>2</sub> and NO<sub>x</sub>. Therefore, the Department requests that you prepare a "four factors" analysis for the Tioga Gas Plant. The analysis should be prepared using the draft EPA guidance noted above. The following units should be addressed in the analysis:

1. Amine Gas Sweetening Unit (Emission Unit S302)
2. Clark Compressor Engines (Emission Units C1A – C1G)
3. Flares (Emission Units S101 and S102)

Preparation of the Round 2 Regional Haze SIP will require extensive planning and review of emission sources in North Dakota. The Department will be working with the Western Regional Air Partnership (WRAP) to prepare the SIP. WRAP will be conducting air quality modeling of potential regional emissions reductions in early 2019. The Department asks that your “four factors” analysis be submitted by January 31, 2019.

If you have any questions, please contact David Stroh of my staff at (701)328-5188.

Sincerely,



Terry L. O'Clair  
Director  
Division of Air Quality

TLO/TB:saj

## B.8.b – Facility Response



December 20, 2018

Mr. Terry L. O'Clair, P.E.  
Director, Division of Air Quality  
North Dakota Department of Health  
918 East Divide Avenue, 2<sup>nd</sup> Floor  
Bismarck, North Dakota 58501-1947

**Re: REGIONAL HAZE  
SECOND PLANNING PERIOD  
TIOGA GAS PLANT**

Dear Mr. O'Clair:

As requested in your letter to me dated May 18, 2018 concerning the referenced subject matter, please find enclosed the "Four Factors Analysis" report as it pertains to emissions of sulfur dioxide (SO<sub>2</sub>) and nitrogen oxides (NO<sub>x</sub>) at the Hess Tioga Gas Plant, located in Tioga, North Dakota.

The report was developed with consideration of the four factors in Section 169A(g)(1) of the Clean Air Act, using specific guidance provided by the U.S. Environmental Protection Agency (Draft Guidance on Progress Tracking Metrics, Long Term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period).

The four factors are:

1. The cost of compliance
2. The time necessary to achieve compliance
3. The energy and non-air quality environmental impact of compliance; and
4. The remaining useful life of any existing source subject to such requirements

As requested, the following units at the Tioga Gas Plant were addressed due to their significant potential emissions of SO<sub>2</sub> and NO<sub>x</sub> (precursors to sulfates that may lead to visibility impairment):

1. Amine Gas Sweetening Unit (Emission Unit S-302)
2. Clark Compressor Engines (Emission Units C1A – C1G)
3. Flares (Emission Units S-101 and S-102)



If you should have any questions regarding this information, please contact me at (713) 496-5031.

Sincerely,

A handwritten signature in blue ink, appearing to read "Tony St. Clair".

Tony R. St. Clair  
EHS Advisor

Enclosures

cc: D. Schmidt  
D. Morton  
V. Sund  
A. Lindsey  
(route) Tioga Plant Files  
Houston Environmental Files, Tioga Plant, Air

# **Regional Haze 4-Factor Analysis**

## **Tioga Gas Plant Facility Hess Corporation**

**Prepared for:**

**North Dakota Department of Health  
Environmental Health Section  
Gold Seal Center, 918 E. Divide Ave.  
Bismarck, ND 58501-1947**

**Prepared by:**

**Bison Engineering Inc.  
1400 11<sup>th</sup> Ave.  
Helena, MT 59601**

**Prepared on behalf of:**



**Hess Corporation  
1501 McKinney Street  
Office 21.104  
Houston, Texas 77010**

**December 20, 2018**

## EXECUTIVE SUMMARY

---

Bison Engineering, Inc. was retained by Hess Corporation to prepare a 4-Factor analysis for specific units located at their Tioga Gas Plant located at Tioga, ND. The 4-Factor analysis was requested by North Dakota's Environmental Health Section, Division of Air Quality in a letter dated May 18, 2018.

The analysis itself relates to "Round 2" of development of a State Implementation Plan (SIP) to address Regional Haze. Regional haze requirements and goals are found in Section 169A of the Federal Clean Air Act and codified in 40 CFR 51.308. The purpose of the 4-Factor analysis is, to determine if there are control options at Hess to reduce emissions, that could be used to attain "reasonable progress" toward the state's visibility goals.

The 4-Factor analysis was conducted on three source groups at the Hess facility: amine sweetening unit, compressor engines and flares. The results of the analysis have indicated that additional controls on these units are not necessary to make reasonable progress due to costs and other considerations. It is concluded that these sources do not qualify for additional emission controls or limitations based on the 4-Factor analysis.



## **TABLE OF CONTENTS**

EXECUTIVE SUMMARY.....	ii
1.0 INTRODUCTION.....	1
2.0 APPROACH AND METHODOLOGY .....	3
3.0 4-FACTOR ANALYSIS .....	4
3.1 Factor 1: Cost of Compliance .....	14
3.1.1. Amine Gas Sweeting Unit.....	16
3.1.2. Compressor Engines .....	16
3.2 Factor 2: Time Necessary for Compliance .....	19
3.3 Factor 3: Energy and Non-Air Quality Environmental Impacts of Compliance .....	20
3.3.1. AMINE GAS SWEETING UNIT .....	20
3.3.2. COMPRESSOR ENGINES .....	20
3.4 Factor 4: Remaining Useful Life .....	22
4.0 CONCLUSIONS AND RECOMMENDED SELECTION.....	23

## **LIST OF TABLES**

Table 1: Additional Control Options by Source Group.....	5
Table 2: Est. Costs of Control Options for Hess Tioga Gas Plant Sources .....	15

## **LIST OF APPENDICES**

APPENDIX A: COST ANALYSIS	
---------------------------	--

## 1.0 INTRODUCTION

---

With the 1977 amendments to the Federal Clean Air Act (42 USC 7401 *et. seq.*) Congress declared as a national goal “... *the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory class I Federal areas which impairment results from manmade air pollution.*” [42 USC 7491(a)(1)]. That goal, plans and requirements were eventually codified in the Code of Federal Regulations primarily in 40 CFR 51.308. (The entire visibility program is found in 40 CFR 51.300 → 309). Individual states are required to establish “reasonable progress goals” [40 CFR 51.308(d)(1)] in order to “attain natural visibility conditions” by the year 2064 [§308(d)(1)(i)(B)].

The state of North Dakota has met the first round of those obligations with the establishment of Best Available Retrofit Technologies (BART) for various sources. A second round of obligations is now under development. The Regional Haze Rule (RHR) requires an additional step toward ‘reasonable progress’ in meeting the national goal.<sup>1</sup> The RHR identifies four factors which should be considered in evaluating potential emission control measures to make reasonable progress toward the visibility goal. These are as follows:

- Factor 1. Cost of compliance
- Factor 2. Time necessary for compliance
- Factor 3. Energy and non-air quality environmental impacts of compliance
- Factor 4. Remaining useful life of any existing source subject to such requirements

These four factors are collectively known as the 4-Factor analysis.

To implement the requirement, the North Dakota Department of Health (NDDH) submitted a letter to Hess dated May 18, 2018. The letter noted that NDDH needed to address 80% of the visibility impairment caused by ND sources.<sup>2</sup> According to NDDH, visibility data from the IMPROVE ambient monitoring sites at Theodore Roosevelt National Park (TRNP) and Lostwood Wilderness Areas indicate that sulfates and nitrates (via SO<sub>2</sub> and NO<sub>x</sub>; respectively) are the largest contributors to visibility impairment.<sup>3</sup>

In order to determine which ‘nearby’ sources should be subject to a 4-Factor analysis, NDDH conducted a Q/d (emissions/distance) analysis of SO<sub>2</sub> and NO<sub>x</sub> for industrial

---

<sup>1</sup> The national goal is to attain natural visibility conditions in mandatory Class I areas by the year 2064 [40 CFR 51.308(d)(1)(i)(B)].

<sup>2</sup> According to NDDH this value is derived from information contained in EPA’s Draft Guidance on Progress Tracking Metrics, Long Term Strategies found at:  
[https://www.epa.gov/sites/production/files/2016-07/documents/draft\\_regional\\_haze\\_guidance\\_July\\_2016.pdf](https://www.epa.gov/sites/production/files/2016-07/documents/draft_regional_haze_guidance_July_2016.pdf).

<sup>3</sup> Hess does not necessarily agree or disagree with this assessment at this time. Hess is providing the information in this document as requested by NDDH.

sources within the state. That analysis has indicated that there are three Hess sources (or source groups) that warrant the analysis according to NDDH. These sources are:

1. Amine Gas Sweetening Unit (Emission Unit S302)
2. Clark Compressor Engines (Emission Units CIA- CIG)
3. Flares (Emission Units S101 and S102)

Therefore, NDDH has requested HESS conduct a 4-Factor analysis for these units to assess potential reductions in SO<sub>2</sub> and NO<sub>x</sub> emissions. The May 18 letter requested the analysis be completed no later than January 31, 2019.

Although NDDH requested an analysis of both SO<sub>2</sub> and NO<sub>x</sub> for all three source groups, subsequent analysis prompted a small change to the request. Based on correspondence between Hess and NDDH<sup>4</sup>, it was agreed no robust analysis was necessary for SO<sub>2</sub> for the Clark Compressor Engines. Since these engines are fired with pipeline quality natural gas, there are no substantive SO<sub>2</sub> emissions from this source category. A similar conclusion was reached with respect to NO<sub>x</sub> emissions from the Amine Gas Sweetening unit. At the time of the email correspondence it was believed that NO<sub>x</sub> emissions from these units are low, so there would be no real visibility benefit by attempting to add additional NO<sub>x</sub> controls. However, subsequent review found a published emission factor for these units. The published factor indicated a low emission rate, as suspected. However, since an emission rate was available, it was decided to proceed with an analysis even though the reduction in NO<sub>x</sub>, should additional controls be added, would not yield any measurable improvement in visibility.

Based on the discussion above and agreement with NDDH<sup>5</sup>, no formal SO<sub>2</sub> analysis was conducted for the compressor engines. For completeness, an NO<sub>x</sub> review was conducted for the Amine Sweetening Unit albeit with low actual emission rates.

The remainder of this document outlines the approach used to conduct the 4-Factor analyses along with a detailed analysis for each group.

---

<sup>4</sup> Email to David Stroh from Tony St Clair (9/14/18) and associated reply (9/17/18)

<sup>5</sup> Ibid.

## 2.0 APPROACH AND METHODOLOGY

---

The Tioga Gas Plant, the subject of this 4-Factor analysis, is located at 10340 68<sup>th</sup> Street NW in Tioga, North Dakota. The location is W½, NE¼ S26, T157N, R95W in Williams County. The plant is used to process natural gas from well sites for sale to customers.

The May 18, 2018 letter from NDDH provided some recommendations for conducting the 4-Factor analysis. That information was supplemented based on an email from David Stroh (NDDH) to Tony St. Clair (Hess) which provided further discussion and recommendations (June 2018). The matter was again discussed in a phone conference call between the staff of NDDH, Hess, and Bison Engineering on June 20.

The most complicated or in-depth analysis of the four is Factor #1: Cost of Compliance. The NDDH email and phone conversation suggested this analysis should follow, in general terms, the methods conducted for a Best Available Control Technology (BACT) review. The agency made clear that this is not, in and of itself, a pure BACT analysis; only that the typical steps might be followed.

In addition to the direct contact with NDDH described above, EPA has provided draft guidance (EPA Draft Guidance) of its own for the entire Round 2 procedures including suggested methods for assessing the Cost of Compliance as well as the other 3 factors.<sup>6</sup> That guidance was published in July 2016 as a draft. We are not aware that the Draft Guidance has been finalized. Nonetheless, since this was the most up-to-date EPA guidelines available, that document was consulted for conducting this 4-Factor analysis.

In general, the cost analysis uses the general approach for BACT, but is modified by the EPA Draft Guidance<sup>7</sup> and EPA's Control Cost manual<sup>8</sup>. The approach used in this analysis follows these recommendations and guidelines as much as practicable. The other 3 factors employed suggestions from the EPA Draft Guidance as much as reasonable or available data might have allowed.

---

<sup>6</sup> "Draft Guidance on Progress Tracking Metrics, Long-term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period," EPA, EPA-457/P-16-001, July 2016.

[https://www.epa.gov/sites/production/files/2016-07/documents/draft\\_regional\\_haze\\_guidance\\_july\\_2016.pdf](https://www.epa.gov/sites/production/files/2016-07/documents/draft_regional_haze_guidance_july_2016.pdf)

<sup>7</sup> Ibid.

<sup>8</sup> EPA Cost Control Manual (sixth edition): <https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution#cost%20manual>

### 3.0 4-FACTOR ANALYSIS

---

A 4-Factor analysis was completed for the three Hess sources/source groups selected by the NDDH Q/d analysis. The following outlines the analysis for each source using primarily the direction of the EPA Draft Guidance<sup>9</sup> and the WRAP 2009 4-Factor analysis<sup>10</sup>.

The initial step in the 4-Factor analyses was to identify possible additional control options for each source or source group. The options chosen include control techniques addressed in guidelines published by the EPA, emission control cost models such as AirControlNET, Best Available Retrofit Technology (BART) analyses, White Papers prepared by the Midwest Regional Planning Organization (MRPO), and National Association of Clean Air Agencies (NACAA).

The options for each source/source category are summarized in the Table 1.

---

<sup>9</sup> “Draft Guidance on Progress Tracking Metrics, Long-term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period,” EPA, EPA-457/P-16-001, July 2016.

[https://www.epa.gov/sites/production/files/2016-07/documents/draft\\_regional\\_haze\\_guidance\\_july\\_2016.pdf](https://www.epa.gov/sites/production/files/2016-07/documents/draft_regional_haze_guidance_july_2016.pdf)

<sup>10</sup> “Supplementary Information for Four-Factor Analyses for Selected Individual Facilities in North Dakota”, Brad Nelson, William Battye, Janet Hou, EC/R Incorporated, Western Regional Air Partnership (WRAP) and Western Governors’ Association (WGA), May 18, 2009

**Table 1: Additional Control Options by Source Group**

Source	Emission Unit ID	Pollutant	Existing Controls	Control Efficiency (Existing)	Potential Additional Control Measures
Amine Gas Sweetening Unit (Sulfur Recovery Unit)	S302	SO <sub>2</sub>	2-Stage Claus + CBA (cold bed adsorption) + tail gas incinerator	>98%	Tail-Gas Scrubbing Treatment Unit (Oxidation or Reduction Options)
		_____		_____	Traditional Flue Gas Desulfurization (FGD)
		NO <sub>2</sub>		---	SCR
Clark Compressor Engines (Natural gas pipeline compressor engines)	C1A through C1G	NO <sub>2</sub>	Lean Burn Engines	---	Low Emission Combustion (LEC) - Turbocharge - Air-to-fuel - Ignition timing - Etc.
					SCR
					Electric Motor Replacement
Acid/Wet Gas Flare And High Pressure Flare	S101 and S102	SO <sub>2</sub> NO <sub>2</sub>	None	---	None

### *Amine Gas Sweetening Unit (SO<sub>2</sub>)*

The amine gas sweetening unit at the Hess Tioga Gas Plant facility controls sulfur dioxide (SO<sub>2</sub>) emissions via two steps. The first is a 2-stage Claus process. This process converts hydrogen sulfide (H<sub>2</sub>S) and SO<sub>2</sub> into elemental sulfur (S) via the 'Claus' reaction. The general reaction is:  $\text{H}_2\text{S} + \text{SO}_2 \leftrightarrow \text{S} + \text{H}_2\text{O}$  (unbalanced). To drive the reaction toward completion, the facility further utilizes Cold Bed Adsorption (CBA) which allows this reversible reaction to proceed further. The CBA was installed in 1991. All-in-all the unit collectively reduces SO<sub>2</sub> emissions by 98+%.

### *Tail-Gas Scrubbing Treatment*

The most common control measures that may be applied to a typical refinery-based Claus facility (with or without CBA) are generally categorized as Tail-Gas Scrubbing Treatment unit (TGST). These units use either an oxidation or a reduction measure to continue to convert the underlying sulfur gas to elemental sulfur. The other common measure of removing sulfur dioxide from a gas stream is a traditional Flue Gas Desulfurization (FGD) unit that is more typically used at coal or oil-fired electrical generating units.

The TGST control would add an additional scrubbing process to the Claus exhaust stream prior to the tail-gas incinerator. The processes typically convert the Claus exhaust to either H<sub>2</sub>S (reducing process) or SO<sub>2</sub> (oxidizing process). In either case, the 'newly created' H<sub>2</sub>S or SO<sub>2</sub> is then returned in some fashion to the Claus or CBA portion of the facility to extend the elemental sulfur recovery.

There are a number of processes that achieve this aim. Regarding the oxidation method, the exhaust stream from the CBA would oxidize the various sulfur compounds (S, H<sub>2</sub>S, COS ...) to sulfur dioxide. The sulfur dioxide is then concentrated and used in the Claus/CBA process itself. There are several varieties of processes within the oxidation method. They include the Stauffer, Wellman-Lord and Aquaclaus. Only the Wellman-Lord process has been applied successfully in any US refinery.<sup>11</sup>

The reduction process, however, is the more typical refinery-based method of additional sulfur dioxide control. This process converts the sulfur gases from the Claus (or CBA) to H<sub>2</sub>S. The H<sub>2</sub>S is then sent to a scrubber for removal prior to a tail-gas incinerator. The H<sub>2</sub>S scrubber typically uses an amine process (similar to the amine unit itself) to capture the H<sub>2</sub>S and then recycles this captured H<sub>2</sub>S (now in a concentrated stream) back to the Claus plant.

Four common systems utilizing the reduction control method are the Beavon, Beavon MDEA, Shell Claus Off-gas Treatment (SCOT), and ARCO. The most common among these is the SCOT unit.

---

<sup>11</sup> AP-42, Section 8.13, 1995, p 8.13-4.

There are other units designed for refinery-like facilities to remove additional sulfur from the CBA stream. These include the Superclaus<sup>12</sup>, Euroclaus<sup>13</sup> and others. For purposes of this analysis, however, it was decided not to attempt a specific cost analysis for each process. It was reasonable to pick one of the methods described above and conduct an analysis on that process.<sup>14</sup> It seems more than reasonable to presume that the cost of one of these processes is within range of what might be expected for any single process. Additionally, cost estimates for these processes is not readily available. For example, there is no published data for the Superclaus or Euroclaus. Additionally, cost data is very sketchy for many of the other units as well.

It was decided to use the SCOT process as a surrogate for any and all of the TGST discussed above. While there is not a plethora of cost data for this unit, it has the most, albeit limited, available data. In addition, the removal efficiency among all the units, including the SCOT, are similar. They all range in overall sulfur removal from about 98% to 99%+. Should the results of the SCOT (as a representative of TGST) prove favorable, then a more detailed review of some of the options would have been useful.

The SCOT system consists of a reduction process and an alkanol amine absorption process. The process starts by converting (reducing) sulfur compounds to H<sub>2</sub>S via a catalyst, heat, and reducing agent (H<sub>2</sub>, CO, ...). The captured H<sub>2</sub>S is sent back to the Claus feed. The remaining gas is sent to the tail-gas incinerator.

### **Flue Gas Desulfurization (FGD)**

The second class of sulfur dioxide scrubbing for consideration is the traditional Flue Gas Desulfurization (FGD) unit. As noted earlier, this is the typical sulfur dioxide control system found in most coal and oil-fired electrical generation systems across the U.S. The FGD unit may be configured as a wet, semi-dry, or dry scrubber system. In all cases an alkaline compound (typically CaCO<sub>3</sub> or CaO) is used to react with SO<sub>2</sub> (an acidic gas) to form a compound such as CaSO<sub>3</sub>. The CaSO<sub>3</sub> (and its related compounds) are then removed via a particulate control device such as a baghouse. EPA estimates FGD units' reduction emissions in the range of 50% to 98% where typically wet scrubbers achieve the highest control potential.<sup>15</sup>

While this may seem attractive, the FGD scrubbers have significant *a priori* disadvantages for this application. Among them include:

---

<sup>12</sup> Information regarding the Superclaus may be found here:  
[http://www.digitalrefining.com/literature/1000817,Sulphur\\_Recovery\\_SUPERCLAUS\\_\\_\\_Process.html#.W-TGFPZFzDI](http://www.digitalrefining.com/literature/1000817,Sulphur_Recovery_SUPERCLAUS___Process.html#.W-TGFPZFzDI)

<sup>13</sup> Information regarding the Euroclaus may be found here.  
[http://www.digitalrefining.com/literature/1000580,Sulfur\\_recovery\\_\\_\\_EUROCLAUS\\_\\_\\_process.html#.W-TFnfZFzDI](http://www.digitalrefining.com/literature/1000580,Sulfur_recovery___EUROCLAUS___process.html#.W-TFnfZFzDI)

<sup>14</sup> This approach is discussed in the EPA Guidance. (See footnote 9).

<sup>15</sup> EPA Air Pollution Control Technology Fact Sheet – Flue Gas Desulfurization:  
<https://www3.epa.gov/ttnatc1/dir1/ffdg.pdf> \*



- (a) In order to operate an FGD system, it is necessary to have a significant amount of (solid) material handling equipment on site. This would also include a large surface area to store, move and otherwise handle the reagent and spent-reagent material. This equipment and space might typically be available and designed in an FGD installation such as a coal-fired electrical generation station which handles materials (coal, e.g.) on routine basis. For this gas processing facility, however, none of the required space nor handling equipment is readily available. This would require a significant redesign of the facility in both layout and surface disturbance.
- (b) FGD systems require a particulate control device to remove the alkaline scrubbing agent ( $\text{CaCO}_3$ ,  $\text{Ca(OH)}_2$ ,  $\text{CaO}$ , ...). In a typical power plant facility, a control device to remove particulate would be required regardless of the  $\text{SO}_2$  scrubber. For this application, however, no such device is installed nor necessary as particulate emissions from amine sweetening units (with Claus sulfur recovery) is nearly non-existent.

Thus, in order to install and operate an FGD for this facility, not only is an FGD itself necessary, but a complete particulate removal system will be required as well (typically a fabric filter). Thus, the FGD will add a new particulate emissions source at this facility; offsetting some of the reduction achieved by the sulfur-removing FGD system.

- (c) An FGD system, regardless of the type, will require disposal of the spent reagent. Since space is limited at this site, the disposal will most likely take place at a “new” landfill. Thus, in addition to the cost necessary for the FGD, a suitable landfill site would need to be identified and a permit would need to be obtained. This would be a significant undertaking and not especially productive given other non-FGD processes are available.
- (d) The non-FGD processes described earlier are more efficient at reducing sulfur compounds from entering the atmosphere than FGD. The control efficiencies for FGD would likely peak at about 80 to 90% (due to low concentration streams). Non-FGD units are expected to be significantly better.
- (e) For wet scrubber FGD, a complete water system, including disposal, would be required. This is clearly unnecessary given other alternatives and the potential environmental consequences.
- (f) To our knowledge, no FGD system has been installed at any gas processing facility such as the Tioga plant. This fact makes it clear that an FGD system is not a viable option for consideration.
- (g) Finally, it is noted that the WRAP 2009 4-Factor analysis did not itself address nor consider FGD as an available technology. There was no discussion or cost estimates for this control technology.

For all of the reasons above, it was decided to not pursue the FGD option further and it was dropped from analyses that follow.

### **Amine Gas Sweetening Unit (NO<sub>x</sub>)**

The amine gas sweetening unit at the Hess Tioga Gas Plant facility contains no NO<sub>x</sub> post-control technologies. NO<sub>x</sub> emissions from these units are typically very small, negating the need for post controls. Hess had suggested to NDDH that it was not necessary to conduct a 4-Factor analysis for this pollutant/unit. It was later discovered that a published emission factor was available for this unit.<sup>16</sup> Despite a low emission rate for this unit (≈ 50 tons/year) an NO<sub>x</sub> analysis proceeded.

A review of the literature indicates that the only practical technology that might be applied to this unit would be Selective Catalytic Reduction (SCR). SCR technology and its requirements and limitations are explained in detail below in the Compressor Engines section. For the sake of brevity, it will not be repeated here. For purposes of our analysis, however, it has been assumed that such a technology might achieve 90% reduction in actual emissions.

Although a cost analysis has been conducted for this technology, it is not a foregone conclusion that such an application of SCR would be useful for Round 2. The emission reduction is small from a mass point of view. In addition, we are not aware that SCR has ever been applied at an amine unit anywhere in the US or elsewhere.

### **Compressor Engines (NO<sub>x</sub>)**

The compressor engines at the Tioga facility drive compressors that boost the inlet field gas pressure for processing. The engines are fueled by a portion of the gas stream (pipeline quality fuel gas) produced by the plant. The exhaust gases from each compressor engine are released to the atmosphere through individual stacks.

The seven Clark Engines that have been identified by NDDH are large integral engines; i.e. the engines themselves and the compression structure are constructed as a single unit. Thus, replacement of these engines would be extraordinarily expensive and difficult as both the compression and engine would need to be replaced. Regardless, there are five 1,950 horsepower (hp) engines and two 2,250 hp engines. The two 2,250 hp engines were modified in 2004 by adding turbocharging systems and other means to lower emissions. The emissions from these two engines are about 75% less than the other engines and as such were not subject to additional analyses. The remaining five engines have not been substantively updated since they were installed in the 1950's although they have been maintained in good working order since.

---

<sup>16</sup> Emission Factor = 0.1 lb/10<sup>6</sup> BTU (AP-42, Table 8.13-2, April, 2015)

Three control options were assessed for the five 1,950 hp Clark Engines: Low Emission Controls (LEC); Select Catalytic Reduction (SCR), and converting engines from gas to electric power.

i) **Low Emission Controls (LEC)**

LEC application includes various upgrades, modifications, and engine tuning improvements. These typically include a combination of turbocharging [increases air-to-fuel (AFR) ratio], intercooling, enhanced mixing (high pressure fuel injection) and an increase in ignition energy.<sup>17</sup> LEC is the preferred approach to reduce lean burn engine NOx emissions when compared to alternative options such as SCR.<sup>18</sup>

LEC modifications provide additional air to a controlled engine which, as a result, reduces maximum combustion temperature and minimizes NOx formation. Excess air may hinder combustion of the air-to-fuel ratio in the cylinder, so a high energy ignition source is generally required for engines equipped with LEC. Pre-chamber combustions systems are generally used to aid in combustion, however the power operating range may decrease on two-stroke cycle engines as a result of an LEC conversion. The term “LEC” is often used broadly to describe a number of technology approaches that can be used depending on the engine and NOx emission limit. Normally, multiple LEC related technologies may be required. Therefore, LEC system modifications assessed for the 5 Hess compressor engines were assumed to be on the high end of any given range of costs.

The reduction in NOx emission rates expected from the application of LEC is roughly 70% to 90% (The same reduction may be expected for SCR). For purposes of this 4-Factor analysis and as a matter of consistency among the engines and control technologies (LEC vs SCR), it was presumed that each technology can achieve a controlled emission rate of 1 g/bhp-hr. This emission rate is about the same as a 90% reduction depending on the specific engine and technology. In addition, 1 g/bhp-hr is the emission rate applicable to most new internal combustion engines.<sup>19</sup> Since LEC would be applied to a set of older existing engines, the applied emission rate is conservatively low.

ii) **Select Catalytic Reduction (SCR)**

SCR is an exhaust control that could be applied to lean combustion engines which reduces NOx emissions by reacting NOx with ammonia or urea over a catalyst. Ammonia or urea is injected into the stream and requires a precise feed-rate based on the NOx

---

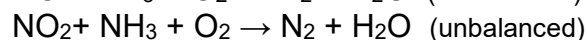
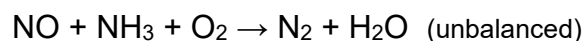
<sup>17</sup> “Potential Impacts of the Ozone and Particulate Matter NAAQS on Retrofit NOx Control for Natural Gas Transmission and Storage Compressor Drivers,” Interstate Natural Gas Association of America (INGAA), Report No. 2016-6, December 2017. <https://www.ingaa.org/File.aspx?id=33789>

<sup>18</sup> “Availability and Limitations of NOx Emission Control Resources for Natural Gas-Fired Reciprocating Engine Prime Movers Used in the Interstate Natural Gas Transmission Industry.” INGAA Foundation. July 2014. <https://www.ingaa.org/Foundation/FDNreports/NOx.aspx>

<sup>19</sup> 40 CFR 60, Subpart JJJJ, Table 1.

concentration and the NO/NO<sub>2</sub> ratio of the NO<sub>x</sub>. This feed rate, coupled with a narrow temperature range, is critical. If the ammonia feed rate is too low, then the targeted reduction in NO<sub>x</sub> is not achieved; thus, failing in the agency's intent to improve regional visibility. If the ammonia rate is too high, then free ammonia is released. The ammonia will itself react in the atmosphere to form compounds such as ammonium sulfate(s) and ammonium nitrate(s). Both compounds are the primary 'culprit' that has led to the already observed regional haze concern. Thus, an improper feed rate will lead to a worsening of regional haze rather than making an improvement.

The process works by ammonia (the reagent) reacting with NO<sub>x</sub> on a catalyst bed to form water and N<sub>2</sub>. The reaction is characterized as follows:



While SCR has enjoyed a fairly wide applicability in power generation sources, its application to U.S. gas transmission sources has been very limited per INGAA 2014. That analysis details a number of the difficulties of applying SCR to gas transmission engines. These include:

- a) There are numerous technical concerns about SCR's application to compressor engines. Among them are exhaust temperature requirements, reagent control, and the treatment of potential variations in the reciprocating engine exhaust NO/NO<sub>2</sub> ratio.
- b) SCR has been more commonly applied to larger utility scale turbines and boilers and rarely used in compressor engines such as the Tioga facility.
- c) The use of SCR is most effective when operating in the exhaust temperature range of 480 to 800°F. The typical exhaust temperature range for some lean burn engines may present challenges because the minimum operating temperature of the catalyst is dependent on the composition of the exhaust gases and the type of catalyst materials used.
- d) Engines that have variable power loads, such as the case here, require more sophisticated controls to inject the proper amount of reagent, and it is not evident that robust control schemes have been developed for transmission applications.
- e) The installation of a continuous emissions monitor could be required to effectively control the amount of reagent necessary to achieve the desired NO<sub>x</sub> emission rate.
- f) SCR catalytic elements can be contaminated by byproducts of combustion (such as oil ash) and more importantly here; engine oil carryover. Cleaning and replacement is required on a periodic basis, and extra management is required to ensure adequate inventories of reagent are maintained.

While EPA claims that SCR is a technology applicable to compressor engines<sup>20</sup> SCR has, in fact, rarely been used in the natural gas transmission and related industry.<sup>21</sup> This does provide strong support for its use in this case.

LEC is nearly universally preferred over SCR for existing lean burn engines due to the issues described above. LEC works to prevent NOx formation while SCR acts to control already formed NOx in the exhaust stream.

### iii) Electric Compressors

The third option under (initial) consideration is replacing these natural gas-fired integral (engine + compressor as a single unit) units with an electric powered unit. This possibility has been rejected, however, because such an option does not fall within the suggested EPA Guidance for the identification of alternative controls.<sup>22</sup>

More specifically, the EPA Draft Guidance document discusses (relying on BART policies) the options that may or should be considered in identifying 4-Factor (via BART) control options. The Draft Guidance contains the following discussion (in identifying technologies outlined by BART and acceptable to the 4-Factor analysis):

*“Potentially applicable retrofit control alternatives can be categorized in three ways. Pollution prevention: use of inherently lower-emitting processes/practices, including the use of control techniques (e.g., low NOx burners) and work practices that prevent emissions and result in lower “production-specific” emissions (note that it is **not our intent to direct States to switch fuel forms, e.g., from coal to gas**), ...”* (emphasis added). EPA Draft Guidance, p 180.<sup>23</sup>

This comment alone suggests that a fuel switch is not necessarily within the realm of a 4-Factor analysis. Clearly a switch from natural gas to electricity is, in effect, a fuel switch and not the intent of the analysis. The document goes on to provide a more specific discussion:

*“We do **not consider** BART as a requirement to **redesign the source** when considering available control alternatives. For example, where the source subject to BART is a coal-fired electric generator, we do not require the BART analysis to consider building a natural gas-fired*

---

<sup>20</sup> “Air Pollution Control Technology Fact Sheet,” SCR, EPA-452/F-03-032.

<sup>21</sup> INGAA Foundation, *op. cit.*

<sup>22</sup> *Draft Guidance on Progress Tracking Metrics, Long-term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period*,” EPA, EPA-457/P-16-001, July 2016.

[https://www.epa.gov/sites/production/files/2016-07/documents/draft\\_regional\\_haze\\_guidance\\_july\\_2016.pdf](https://www.epa.gov/sites/production/files/2016-07/documents/draft_regional_haze_guidance_july_2016.pdf)

<sup>23</sup> *Ibid.*

*electric turbine **although** the turbine may be **inherently less polluting** on a per unit basis.” (emphasis added). EPA Draft Guidance p. 198.<sup>24</sup>*

Again, the Draft Guidance suggests that one does not need, nor should, consider what amounts to be a redefinition or fundamental change in the underlying facility/unit. If EPA rejects changing an electrical generation plant from coal-fired to a gas-fired turbine as inappropriate, the same logic applies here (gas-fired to electric).

For the reasons above, replacing these gas-fired engines with electric engines has been removed from further consideration.

### **Flares (SO<sub>2</sub> & NO<sub>x</sub>)**

The acid/wet gas flare (S-101) and high-pressure flare (S-102) operate intermittently at the Hess facility to combust off-spec gas and to address emergency/malfunction events. Both sources are to be assessed for additional NO<sub>2</sub> and SO<sub>2</sub> control. Additional control equipment systems for flare sources are not known or available for a facility whose emission rate is highly variable in both time and quantity. As a result, we are not able to identify any available control technologies for these two specific flares.

Even if a control technology were to present itself, the annual emissions from these two flares would almost certainly yield cost/ton of removal values that are not cost-effective. As evidence, the most recent 2-year average annual emissions for these two flares were:

#### SO<sub>2</sub>

S-101 = 21 t/yr @ 79 hours of operation per year

S-102 = 40 t/yr @ 103 hours of operation per year

#### NO<sub>x</sub>

S-101 = 0.0 t/yr @ 79 hours of operation per year

S-102 = 4.6 t/yr @ 103 hours of operation per year

The low total emissions produced by the flare sources would result in a high cost effectiveness in \$ per ton of emissions reduced since the total cost of implementation would only have the potential to control a minimal quantity of emissions. As a result, no further analyses were conducted for this source.

---

<sup>24</sup> Ibid.

### 3.1 Factor 1: Cost of Compliance

The cost of compliance estimates the capital cost of purchasing and installing new control equipment along with the annual operation and maintenance (O&M) cost as generally outlined in EPA Draft Guidance. The 2009 WRAP analysis also delineated these cost parameters into the following categories: direct capital cost, indirect capital cost, labor cost, contingency cost, and annual cost. Methodologies given in the EPA Air Pollution Control Cost Manual (Control Cost Manual) are the indicated reference for determining the cost of compliance as directed by the EPA Draft Guidance.<sup>25</sup> Costs were expressed in terms of cost-effectiveness in a standardized unit of dollars per ton of emissions reduced by the proposed control option. The cost of compliance is analyzed by source/source group within Table 2 and the following sections.

---

<sup>25</sup> EPA Cost Control Manual (sixth edition): <https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution#cost%20manual>

**Table 2: Estimated Costs of Control Options for Hess Tioga Gas Plant Sources**

Source	Potential Control Option	Pollutant	Estimated Control Efficiency (%)	Potential Emission Reduction (tons/year)	Estimated Capital Cost (\$1000)	Estimated Annual Cost (\$1000/year)	Cost Effectiveness (\$/ton)
Amine Gas Sweetening Unit (SRU)	SCOT (or equivalent)	SO <sub>2</sub>	90%	539	16,750	6,369	\$11,815
	SCR	NO <sub>2</sub>	90%	53	1,204	1,127	\$23,623
Compressor Engines (Mean among 5 engines)	LEC	NO <sub>2</sub>	1 g/bhp-hr <sup>a</sup>	134	4,000	996	\$7,951 <sup>b</sup>
	SCR	NO <sub>2</sub>	1 g/bhp-hr <sup>a</sup>	134	877	502	\$4,710 <sup>c</sup>
Flares (2)	N/A	SO <sub>2</sub>	--	--	--	--	--
	N/A	NO <sub>2</sub>	--	--	--	--	--

<sup>a</sup> Emission reduction is assumed to achieve approximately 1 gram/bhp-hour.

<sup>b</sup> Cost effectiveness per engine ranged from \$13,123 to \$5,401. Individual values are found in Appendix A.

<sup>c</sup> Cost effectiveness per engine ranged from \$8,917 to \$3,879. Individual values are found in Appendix A.



### 3.1.1. Amine Gas Sweetening Unit

#### **SO<sub>2</sub>**

The cost estimate of a SCOT unit includes the capital cost of constructing the system which comprises the reactor, cooling tower and scrubber systems. Again, the SCOT system has been assessed specifically, however it is presumed to be a representative selection for all potential add-on TGST controls. The cost estimate also includes direct and indirect costs associated with modifying the current 2-Stage Claus / CBA unit to accommodate the SCOT (or equivalent) system. Indirect costs include engineering design, permitting, construction and field expenses, contractor fees, start-up, performance testing, and contingencies. Estimated costs are delineated in Appendix A. The calculated costs included in Table 2 have been adjusted to reflect value in 2017 per the Consumer Price Index. Design, construction, and operation of a SCOT system with the Hess amine sweetening unit is projected to cost approximately \$11,815 per ton of SO<sub>2</sub> removed.

#### **NO<sub>x</sub>**

To complete the analysis, a cost-effectiveness investigation was conducted for NO<sub>x</sub>. As noted earlier, the emission rate at this source is small and has, no doubt, an insignificant impact on regional haze. Regardless, a cost analysis was completed for SCR. Using the capital cost estimates found in EPA's Air Pollution Control Technology Fact Sheet, SCR, EPA-452/F-03-032, Table 1a, the cost effectiveness for controlling NO<sub>x</sub> was estimated at \$23,623/ton removed.<sup>26</sup> This value is well outside normal BACT and BART ranges and thus is removed from further consideration.

### 3.1.2. Compressor Engines

The Clark Engines analysis included estimated costs for updating each of the five 1,950 hp with either LEC or SCR.

#### **LEC.**

The LEC analysis is based on various upgrades and changes to the 5 engines. As a general rule, an upgrade to LEC consists of:

- Hardware and engineering costs for replacing the existing cooling systems with water pump systems to eliminate boil-off cooling.
- Field service, repairs, and parts replacement for zero-hour overhauls.
- Hardware, installation, and commissioning of a HPfi fuel injection upgrade that needs to include:
  - A single "Balance of Plant" engineering and hardware support for multiple engine revamps.
  - Hardware, installation, and start-up of the HPFi equipment.

---

<sup>26</sup> Details of the calculation are found in Appendix A.

The cost of such upgrades is dependent on numerous factors. A literature search did not yield definitive results. There are several earlier reports, NESCAUM – 2000,<sup>27</sup> for example, that provided a wide range of expenses. There is, however, a recent report (December 2017) from the INGAA Foundation that provides a cost range for LEC upgrades.<sup>28</sup> That report addressed the cost of LEC for natural gas-fired compressor engines, among others. In particular, it provided a range for Clark engines of similar size to the 5 engines at Hess.

The report suggests a range of: \$1,250 to \$2,500 per hp from a base model of 1,600 hp. The engines at issue are 1,920 hp. It was decided that an upper range value would be appropriate in this analysis due to the larger size of engine and the age of these 1950-era units.

In addition, the typical calculation for determining the cost effectiveness (\$/ton reduction) begins with the capital expenses. Then adjustments are made to include instrumentation, freight, foundations, electrical, etc. In this case, however, the INGAA report implies that these figures (\$/hp) are the “total cost.” It is not clear from the report if that cost (\$1,250 - \$2,500) includes foundations, electrical, piping, etc. To be conservative, it was decided to assume that the report costs included this direct installation costs. To that end, the presented data in the report and appendix remove the EPA-suggested cost adjustments for foundations and the like by assuming that those costs are already included in the base cost (\$1,250 - \$2,500). Should this not be the case, then the cost effectiveness will be increased appropriately.

Using this information, an annual cost of roughly \$1,000,000 is estimated for each engine. Details of the calculations are found in Appendix A. This cost coupled with the various emission rates for each of the five engines yielded a cost effectiveness ranging from \$5,401 to \$13,123 per ton of NOx removed. The average cost effectiveness among the 5 engines was \$7,951.

### **SCR.**

The capital costs for SCR, if one were to assume this was an ‘achievable technology’ for this application, are varied. There are a number of published cost estimates for typical coal- oil- and gas-fired medium to large sized boilers. The same cannot be said for a retrofit of a natural gas-fired compressor engine/compressor.

In addition, the cost of retrofit SCR is much higher than an original installation which would apply to this analysis. SCR systems used to retrofit an existing unit increase costs around 30%<sup>29</sup> more due to ductwork modification, the cost of structural steel, reactor construction

---

<sup>27</sup> “Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines Technologies & Cost Effectiveness, Northeast States for Coordinated Air Use Management (NESCAUM), December 2000.

<sup>28</sup> “Potential Impacts of the Ozone and Particulate Matter NAAQS on Retrofit NOx Control for Natural Gas Transmission and Storage Compressor Drivers,” Interstate Natural Gas Association of America (INGAA), Report No. 2016-6, December 2017. <https://www.ingaa.org/File.aspx?id=33789>

<sup>29</sup> EPA Air Pollution Control Technology Fact Sheet – SCR: <https://www3.epa.gov/ttn/catc1/dir1/fscr.pdf>

and so forth. O&M costs may also be substantially dependent on reagent usage, catalyst replacement, and increased electrical usage. These costs are also impacted by the overall capacity – which determines reagent and catalyst volume – and annual versus season operations schedule. The average (all 5 engines) cost effectiveness of SCR was \$4,710 per ton removed. Individual engines ranged from \$3,879 to \$8,917. This cost effectiveness range coupled with multiple technical difficulties and its non-use in this general application does not make it an attractive Round 2 candidate.

The derivation of the capital cost figures, emission rates and other general information may be found in the appropriate tables in Appendix A.

### **3.2 Factor 2: Time Necessary for Compliance**

Per the EPA Draft Guidance, the provisions for this factor within the BART guidelines should be utilized to estimate time necessary for compliance. Additionally, the best guide to determine time necessary for compliance is prior experience with the planning and installation of new emission controls. Source-specific factors should be considered as well.

EPA has estimated that it takes approximately 30 months to design, permit, build, and install a typical SO<sub>2</sub> scrubbing control unit for a single source. No specific data was located as it regards the SCOT unit (or its equivalent). Using the EPA estimate as a guide, their analysis also determined that 12-months is additionally required for a project including the installation of control equipment on multiple sources. Another 12 months may be required for staging the installation process across the multiple sources. Finally, it is generally recognized that facilities may require a 1 year (or more) for the procurement of project funding.

As a result, the time necessary for compliance for the SCOT unit is estimated at approximately five years. This time period accounts for about one year of capital acquisition; two to three years for designing, permitting, constructing, and installing the control equipment; and one year for installing controls for multiple components in stages.

A longer timeline would also be expected for the LEC conversion for the five engines discussed in this report. The installation, tuning and integration would need to be executed in a sequential fashion in order to keep the facility in operation during this time. This will stretch the 'time necessary for compliance.' No specific time-line is offered at the time of this report. However, it would be reasonable to suggest that the time needed would be at least five years and possibly more.

Although no specific data was found, it would be reasonable to assume that a five-year period would also be appropriate for the installation of SCR in lieu of LEC should that be required. Finally, it was further reasoned that this five-year period serves as an estimate for the time necessary for installation of an SCR unit on the Amine Sweetening Unit, although its installation is not justified for cost effectiveness reasons.

### 3.3 Factor 3: Energy and Non-Air Quality Environmental Impacts of Compliance

The provisions of the BART Guidelines are recommended for assessing both energy and non-environmental impacts. The EPA Draft Guidance states that an energy impacts assessment should be considered in terms of kilowatt-hours or mass of fuels used accounting for direct energy consumption cause by control implementation. Indirect energy inputs to produce the raw materials for construction of equipment should be excluded from the analysis. The Control Cost Manual is the preferred reference and provides advice on estimating energy requirements. Non-air environmental may include the cost associated with solid waste disposal, wastewater discharge, acid or nitrogen deposition, and climate impacts.

#### 3.3.1. Amine Gas Sweetening Unit

Two secondary waste streams are generated when using the SCOT unit TGST according to the EPA Pollution Control Technical Manuals (PCTMs). A sour water stream is generated from the quench tower due to condensation of water vapor present in the reduction effluent stream. A sour water stripper treats the sour water stream and any remaining  $H_2S$  or  $NH_3$  is recycled into the Claus feed stream. Additionally, a second waste stream consists of spent catalyst from the reduction reactor. A SCOT system initially requires approximately 28% wt of the initial Claus catalyst requirement. According to the EPA PCTMs, this equates to 850 kg catalyst per kmol/hr  $H_2S$  converted from  $SO_2$ ,  $COS$ , and  $CS_2$ . Catalyst has a typical service life of about 24,000 hours. Thus, the spent catalyst will require disposal about every four years. The implications of disposal of this waste stream has not been analyzed at this time since the cost effectiveness does not make its use a practical alternative.

There is also an energy cost associated with this added level of emission controls. It has been estimated that this level of technology would require about 700 kW-hr of use.<sup>30</sup>

#### 3.3.2. Compressor Engines

##### SCR.

SCR control systems require the use of aqueous ammonia, anhydrous ammonia, or urea-to-ammonia reagents for the reduction reaction. Systems that use urea produce aqueous ammonia onsite. Anhydrous ammonia is nearly pure ammonia gas and must be transported and stored under pressure. Anhydrous ammonia is classified as a hazardous material which often requires special permits as well as additional procedures for transportation, handling and storage. Systems using

---

<sup>30</sup> "Supplementary Information for Four-Factor Analyses for Selected Individual Facilities in North Dakota", Brad Nelson, William Battye, Janet Hou, EC/R Incorporated, Western Regional Air Partnership (WRAP) and Western Governors' Association (WGA), May 18, 2009, Table 4-3.

aqueous ammonia transport and store the reagent concentration in water, generally 19% - 29+% ammonia to water.<sup>31</sup> While aqueous ammonia can be safer to transport and store, the diluted ammonia concentration requires more storage capacity than anhydrous ammonia and requires shipping costs for the water solvent in the solution. Hess would be required to account for additional chemical storage, protection, and permitting with the additional reagent solution stored on site.

Additionally, SCR systems utilize catalysts to aid in NOx control. The catalysts are generally composed of active metals or ceramics with a highly porous structure. Activated sites are located within the pores of the catalyst and these sites have an acid group on the end of the compound structure where the catalytic reduction reaction occurs. The catalyst material reactivates via rehydration or oxidation after the reduction reaction occurs. This is a limited process, however, and over time the catalyst activity decreases, requiring replacement, washing/cleaning, rejuvenation, or regeneration of the catalyst. Catalyst storage, transport, and disposal must then be accounted for in the SCR control viability analysis.

An estimate was made of the aqueous ammonia feed rate necessary for the facility. It is estimated that with all 5 engines in operation, a feed rate of about 70 gallons per hour would be necessary.<sup>32</sup> To handle this much material would require a large storage tank ( $\approx$  5,000 gallons) that would need recharged about every 3 days. To provide a more reasonable recharge rate (10+ days) would require a much larger tank(s). In either case, the storage or use of this quantity triggers the requirements of the accidental release program found in 40 CFR 68.<sup>33</sup> Depending upon specifics, a detailed amendment to the risk management plan (RMP) must be developed and implemented under this program. This only adds another layer of regulatory reporting along with an unnecessary risk by itself. The fact that such a plan would be required dampens its attractiveness for consideration.

### LEC.

The LEC technology does not require the handling or storage of hazardous materials as is the case for SCR. The LEC technology does not require, on its face, changes in pressure drop across any system that could create an energy demand penalty.

---

<sup>31</sup> EPA Cost Control Manual (sixth edition): <https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution#cost%20manual>

<sup>32</sup> See general calculations and data found in Appendix A (from EPA Cost Control Manual).

<sup>33</sup> The program is triggered for aqueous ammonia use or storage greater than 20,000 pounds. The quantities described exceed this value.

### 3.4 Factor 4: Remaining Useful Life

The Hess Tioga Gas Plant remaining useful/service life is not specific at this time. As discussed in the 2009 WRAP Analysis, the service life of these emission sources at industrial facilities are difficult to estimate.

The startup dates for these units were:

Amine Sweetening Unit:	1991
Compressor Engines (5):	1954
Flares:	n/a

Regardless of the ability to select a particular time, the service life of the analyzed control technologies was approximately 15 years. The 15-year figure was used to amortize the capital costs of the add-on and modified (LEC for the compressor engines) emission controls. Given the historical perspective, it is reasonable to conclude that the remaining life of the facility (Sweetening Unit and Engines) itself is expected to exceed the 15-year life of the control equipment.

The capital cost of the control equipment would need to be amortized over a shorter period if the remaining life of an emission source is less than the projected life of the new control equipment. Since this was not the case, the remaining equipment life of the facility is expected to equal or exceed the life of the analyzed technology options.

## 4.0 CONCLUSIONS AND RECOMMENDED SELECTION

---

A 4-Factor analysis has been conducted for the Hess Tioga facility. The analysis was conducted to meet the requirements of “Round 2” to develop of a State Implementation Plan (SIP) to address Regional Haze. Regional haze requirements and goals are found in Section 169A of the Federal Clean Air Act and codified in 40 CFR 51.308(d)(1). To implement the requirement, the North Dakota Department of Health (NDDH) submitted a letter to Hess dated May 18, 2018, seeking such an analysis.

The 4 factors to be analyzed based on the NDDH letter and the regional haze rule were:

- Factor 1. Cost of compliance
- Factor 2. Time necessary for compliance
- Factor 3. Energy and non-air quality environmental impacts of compliance
- Factor 4. Remaining useful life of any existing source subject to such requirements

NDDH then requested a 4-Factor analysis for SO<sub>2</sub> and NO<sub>x</sub> for the following source groups:

- 1. Amine Gas Sweetening Unit (S-302)
- 2. Clark Compressor Engines (C1A – C1G)
- 3. Flares (S-101 and S-102)

The emitting units were analyzed for these factors in general accordance with EPA's Draft Guidance.<sup>34</sup> The details of those results were presented in prior sections of this report.

---

<sup>34</sup> *Draft Guidance on Progress Tracking Metrics, Long-term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period*,” EPA, EPA-457/P-16-001, July 2016.  
[https://www.epa.gov/sites/production/files/2016-07/documents/draft\\_regional\\_haze\\_guidance\\_july\\_2016.pdf](https://www.epa.gov/sites/production/files/2016-07/documents/draft_regional_haze_guidance_july_2016.pdf)



## Amine Gas Sweetening Units.

### SO<sub>2</sub>

Two control technologies were originally considered for this unit-pollutant combination: Tail-gas scrubbing treatment (SCOT) and Flue-gas desulfurization (FGD). The SCOT technology (or its equivalent) essentially extends the basic Claus reaction by collecting sulfur gasses (primarily SO<sub>2</sub> and H<sub>2</sub>S), concentrating them, and then recycling the gasses back to the Claus plant. The FGD system, typically found in a coal-fired power plant, treats exhaust gas with an alkaline reagent (usually CaO or CaCO<sub>3</sub>) to remove SO<sub>2</sub>. The spent reagent (CaSO<sub>3</sub> or CaSO<sub>4</sub>) is then collected in a fabric filter unit in which the collected dust must be treated in a licensed landfill.

It is concluded that the FGD system is not practical nor appropriate for this application. Those reasons include (but not limited to):

- A new emitting source (particulate) would be added to the plant offsetting some of the benefits of a reduction in SO<sub>2</sub>;
- A new disposal system would be required to treat the spent reagent,
- FGD has never, to our knowledge, been used in treating SO<sub>2</sub> emissions from any gas processing facility; and
- The prior (2009) 4-Factor analysis for this facility did not identify nor consider FGD as a viable technology.

The SCOT technology (or its equivalent) was analyzed. While the technology may be applied to a facility like the Tioga plant, it was rejected due to its high cost effectiveness (≈ \$12,000/ton).

### NO<sub>x</sub>

Although the emission rate of NO<sub>x</sub> from the unit is very low, an analysis for this unit was conducted for thoroughness. The technology identified most probable for this unit is Selective Catalytic Reduction (SCR). SCR was rejected as inappropriate for numerous reasons, including its high cost effectiveness (≈ \$23,000/ton). Therefore, SCR is not a candidate for Round 2 emission reductions.

## Compressor Engines.

### NO<sub>x</sub>

There were two control technologies identified for reducing NO<sub>x</sub> from these units: SCR and Low Emission Control (LEC).

LEC is a system of upgrades, modifications and tuning of the engines to achieve a lower emission rate. LEC could, theoretically, be applied to each of the 5 compressor engines subject to this analysis.

The cost effectiveness of this technology was excessive. The average cost effectiveness was \$7,951/ton for all 5 engines. The engine-by-engine cost effectiveness ranged from roughly \$5,400 to as high as \$13,100 depending on the engine. Since these values are considered excessive, LEC has been removed from consideration for Round 2.

SCR was also analyzed as a potential control technology. However, SCR is rarely, if ever, used for this type of application. Evidence of that stems from several reports. One recent study (2014) makes the following comment: *“To date, SCR application to U.S. gas transmission sources has been very limited, and SCR has not been applied to an existing integral engine.”*<sup>35</sup> The 5 engines at the Tioga facility are existing integral engines as described in the report. In addition, an even more recent report failed to consider SCR a noteworthy technology for reducing NO<sub>x</sub> emissions from transmission and storage compressors as a means of achieving the ambient NO<sub>x</sub> standards.<sup>36</sup>

Additionally, SCR carries the burden of handling and storing either anhydrous ammonia (NH<sub>3</sub>) or aqueous ammonia (NH<sub>4</sub>OH). This would require new equipment in which to transport and handle this material. In both cases, the storage quantities necessary will trigger the need for a Risk Management Plan (RMP) required by the Accidental Release program (40 CFR 68) in order to address the potential of a spill or release that could have public health implications. The addition of this equipment constitutes an unnecessary risk for the purpose of regional haze.

In addition to the burdens described, the efficacy of the control technology is at issue. For SCR to work effectively, a precise ammonia feed rate

---

<sup>35</sup> “Availability and Limitations of NO<sub>x</sub> Emission Control Resources for Natural Gas-Fired Reciprocating Engine Prime Movers Used in the Interstate Natural Gas Transmission Industry.” INGAA Foundation. July 2014, Page 9. <https://www.ingaa.org/Foundation/FDNreports/NOx.aspx>

<sup>36</sup> “Potential Impacts of the Ozone and Particulate Matter NAAQS on Retrofit NO<sub>x</sub> Control for Natural Gas Transmission and Storage Compressor Drivers,” Interstate Natural Gas Association of America (INGAA), Report No. 2016-6, December 2017. <https://www.ingaa.org/File.aspx?id=33789>

coupled with a narrow temperature range are necessary. Both conditions would be difficult to maintain due to varying loads on the compressor engines themselves.

Finally, the cost effectiveness of SCR is, overall, excessive. The average cost effectiveness was \$4,951 for all 5 engines. The engine-by-engine effectiveness ranged from roughly \$3,900 up to \$8,900. Due to these costs, the technical concerns, the need to handle hazardous materials and the nearly universal lack of use of SCR for legacy compressor engines, SCR is rejected for Round 2 purposes.

## **Flares.**

### **NO<sub>x</sub> and SO<sub>2</sub>**

A review of the literature does not yield any 'available' control technology to control either NO<sub>x</sub> or SO<sub>2</sub> emissions from these highly intermittent sources such as the Tioga flares. The flares primarily serve emergency and other upset conditions. For example, each flare operated 0.1% of the time in the past 2 years. Clearly, any control technology, even if it were available, would not have a measurable impact on the regional haze long-term goals. Because no reasonable technology is available, and no measurable regional haze benefit would be realized, it is concluded that there are no technology options available for these sources.

Following a careful review of the information it is concluded that additional emission controls and limitations for these sources are not necessary to make reasonable progress based on the 4-Factor analysis.

## APPENDIX A: COST CALCULATIONS

---

**Amine Sweetening Unit (S-302)**

**Sulfur Dioxide**

**SCOT (or equivalent) Control Technology**

### Total Capital Costs - SCOT

Total Capital Costs for SCOT		
Cost Item	Factor	Cost
<b>DIRECT COSTS</b>		
Purchased equipment costs		
SCOT Capital	A	\$16,750,000
Instrumentation	0.10 A	\$1,675,000
Sales taxes	0.05 A	\$837,500
Freight	0.05 A	\$837,500
<b>Purchased equipment cost, PEC</b>	<b>B = 1.15 A</b>	<b>\$19,262,500</b>
Direct installation costs		
Foundations & supports	0.08 B	\$1,541,000
Handling & erection	0.14 B	\$2,696,750
Electrical	0.04 B	\$770,500
Piping	0.02 B	\$385,250
Insulation for ductwork	0.01 B	\$192,625
Painting	0.01 B	\$192,625
<b>Direct installation cost</b>	<b>0.30 B</b>	<b>\$5,778,750</b>
Site preparation	As required, SP	-
Buildings	As required, Bldg.	-
<b>Total Direct Cost, DC</b>	<b>1.30 B + SP + Bldg.</b>	<b>\$25,041,250</b>
<b>INDIRECT COSTS (Installation)</b>		
Engineering	0.10 B	\$1,926,250
Construction and field expenses	0.05 B	\$963,125
Contractor fees	0.10 B	\$1,926,250
Start-up	0.02 B	\$385,250
Performance test	0.01 B	\$192,625
Contingencies	0.03 B	\$577,875
<b>Total Indirect Cost, IC</b>	<b>0.31 B</b>	<b>\$5,971,375</b>
<b>TOTAL CAPITAL INVESTMENT (TCI) = DC + IC</b>	<b>1.61 B + SP + Bldg.</b>	<b>\$31,012,625</b>

### Annual Costs - SCOT

Total Annual Costs for SCOT			
Cost Item			Cost
<b>DIRECT ANNUAL COSTS</b>			
Operating Labor			
Operator	0.5 hrs/shift	30.00 \$/hr	\$16,200
Supervisor	15% of operator		\$2,430
Operating Materials			-
Maintenance			
Labor	0.5 hrs/shift	30.00 \$/hr	\$16,200
Material	100% of maint. labor		\$16,200
Utilities			
Natural Gas	0 (kft3/yr)	\$ 5.18 \$/kft3	\$0
Electricity	0 (kWh/yr)	\$0.059 \$/kWh	\$0
<b>INDIRECT ANNUAL COSTS, IC</b>			
Overhead	60% of sum of operating labor and materials and maintenance labor and materials.		\$30,618
Administrative Charges	2% of TCI		\$620,253
Property Taxes	1% of TCI		\$310,126
Insurance	1% of TCI		\$310,126
Capital Recovery Factor (Annualized Capital Cost, 10 yrs at 10%)			\$5,047,161.90
<b>TOTAL ANNUAL COST</b>			<b>\$6,369,315</b>
(2-yr Average)			
Uncontrolled Emissions (tons/yr):			599
Control Efficiency (add'l):			90%
Controlled Emissions (tons/yr):			59.9
Tons Removed (tons/yr):			539.1
<b>Cost-Effectiveness (\$/ton):</b>			<b>\$11,815</b>

### Capital Recovery Factor

[https://www.ajdesigner.com/phpdiscountfactors/capital\\_recovery\\_equation.php#ajscroll](https://www.ajdesigner.com/phpdiscountfactors/capital_recovery_equation.php#ajscroll)

### Capital Cost Derivation:

"Supplementary Information for Four-Factor Analyses for Selected Individual Facilities in North Dakota  
Western Regional Air Partnership (WRAP), May 18, 2009  
Prepared by EC/R Incorporated, Chapel Hill, NC

\$15,000,000 (Table 4-2) - assumed 2009 Dollars

214.5 CPI 2009 <https://www.bls.gov/cpi/tables/historical-cpi-u-201709.pdf>  
240 CPI 2018  
1.12 Inflation value

\$16,783,217 Adjusted Capital for 2017

**Amine Sweetening Unit (S-302)**

**Nitrogen Oxides**

**SCR Control Technology**

## Amine Sweetening Unit (S-302)

Parameter	Year		Units	Reference
	2016	2017		
Fuel burned	1,100	1,131	$10^6$ ft <sup>3</sup>	Annual emissions inventory
Heating Value	950	950	btu/ft <sup>3</sup>	Assumed
Heat input	1,045,000	1,074,450	mmbtu/year	Calculated
Heat input	119	123	mmbtu/hour	Calculated
Emission Factor	0.1	0.1	#/10 <sup>6</sup> BTU	AP-42, Table 8.13-2, April 2015
Emissions	52	54	tons/year	Calculated

Emission Factor Reference:

AP-42, Section 8.13, Table 8.13-2, April 2015

Heat input	121	(average)	mmbtu/hour
Emissions	53		tons/year

### SCR - Input Calculations and Reference Information

Reference: EPA/452/B-02-001 Section 4.2 in Chapter 2

Parameter / Variable	Value	Units	Reference
Selective Catalytic Reduction (% Control);	85.0	percent	Approx = 1g/bhp-hr
Actual Emissions	53	Tons/yr (actual) per Engine	2016/2017 Inventory
$Q_{in}$ = Max. Heat Input at HHV, MMBtu/h	121	MM Btu/hr	Calculated from annual EI report
ASR	1.050	Actual Stoichiometric Ratio	EPA/452/B-02-001
$Q_{in}$ gas	27,309	Inlet to SCR acfm	2017 RATA + 20%
$q_{scfm}$	11,844	dscfm	2017 RATA + 20%
$CF_{plant}$	0.95	system capacity factor, $CF_{plant}$	EPA/452/B-02-001
$\eta_{NOx}$	0.85	NOx removal efficiency	Approx.
NH <sub>3</sub> slip (ppmv)	$(ASR - \eta_{NOx}) * 60 * MW_{NH_3} * dscfm / 359.05 / 10^6$	lb/hr	EPA/452/B-02-001
Catalyst volume	$2.81 * Q_{in} * \eta_{slip} * NO_{xslip} * S_{adj} * T_{adj} / NSCR$	ft <sup>3</sup>	EPA/452/B-02-001
$N_{ASCR}$ (# of SCR reactor chambers)	1		
$\eta_{slip}$	$(0.2869 + (1.058 * \eta_{NOx}))$		EPA/452/B-02-001
$Slip$	$(ASR - \eta_{NOx})$		EPA/452/B-02-001
$Slip_{adj}$	$1.2835 - (0.0567 * Slip)$		EPA/452/B-02-001
$NO_{xslip}$	3.8	lb/MM Btu	2018 stack test (typical)
$NO_{xslip}$	0.8524 + $(0.3208 * NO_{xslip})$		EPA/452/B-02-001
S, sulfur in fuel	7.00E-06	(weight fraction)	
$S_{adj}$	0.9636 + $(0.0455 * S)$		EPA/452/B-02-001
SCR inlet temp	600	F°	Presumed (req'd for SCR)
SCR inlet temp	589	K°	
$T_{adj}$ for inlet T not = 700 F	15.16 - $(0.03937 * T) + (2.74 * 10^{-5} * T^2)$		EPA/452/B-02-001
$A_{catalyst}$	$Q_{in} gas / (16 * 60)$	ft <sup>2</sup>	EPA/452/B-02-001
$\eta_{layer}$	$V_{catalyst} / (\eta_{layer} * A_{catalyst})$	16.4	assume $h = 3.1$
$\eta_{layer} - final$	3	round $\eta_{layer}$ to integer	EPA/452/B-02-001
$\eta_{layer}$	$V_{catalyst} / (\eta_{layer} * A_{catalyst}) + 1$	17.9	EPA/452/B-02-001
$\eta_{layer} - total$	$\eta_{layer} - final + 1$	4	EPA/452/B-02-001
$h_{SCR}$	$\eta_{layer} - total * (C_1 + \eta_{layer}) * C_2$	108.6	ft
SCR height adjustment	$\$6.12 * h_{SCR} - 187.9$	476.7	f( $h_{SCR}$ )
$m_{reagent}$	$(NO_{xslip} * Q_{in} * NSR * \eta_{NOx} * MW_{reagent}) / (MW_{NOx} * SR_T)$	151.9	lb/hr
$MW_{reagent}$	17.0	MW of ammonia	
$MW_{NOx}$	46.0	MW of NO <sub>2</sub>	
NSR	ASR/SR <sub>T</sub>	1.1	normalized stoichiometric rate
SR <sub>T</sub>	1.0	for ammonia	EPA/452/B-02-001
$m_{sol}$	$m_{reagent} / C_{sol}$	523.8	lb/hr
$C_{sol}$	0.29	concentration of aqueous soln	Typical aqueous soln
$p_{sol}$	56	lb/ft <sup>3</sup>	EPA/452/B-02-001
$v_{sol}$	7.5	gal/ft <sup>3</sup>	EPA/452/B-02-001
$q_{sol}$	$m_{sol} / p_{sol} * v_{sol}$	70.0	gal/hr
$t_{store}$	14.0	reagent storage for t days	assumed, EPA/452/B-02-001
Tank volume	$q_{sol} * t$	23,510	gallons
Cost of reagent	RC	0.15	\$/lb
Cost of reagent (per hour)		\$79.57	\$/hour of ammonia
Cost of reagent (per year)		\$696,998	\$/year (8,760) of ammonia
Catalyst Cost	CC <sub>replace</sub>	\$436.12	\$/ft <sup>3</sup>
Catalyst Cost Replacement	$\eta_{SCR} * Vol_{catalyst} * (CC_{replace} / \eta_{layer})$	\$157,248	\$/replacement layer/year
Pressure drop of SCR & ductwork	$\Delta P_{duct}$	2.5	inches H <sub>2</sub> O
Pressure drop for catalyst	$Dp_{catalyst} = 0.875 * \eta_{layer} - final$	2.6	inches H <sub>2</sub> O



***Hess Corporation***  
***4-Factor Cost Analysis***  
***Tioga Facility***  
***Nat'l Gas Compressor Engines***  
***NOx***  
***SCR Control***

**Capital Cost Derivation**

**Primary Reference:**

**Air Pollution Control Technology Fact Sheet, SCR, EPA-452/F-03-032**

<b>Value</b>	<b>Units</b>	<b>Reference</b>
\$2,500	\$/mmBtu	Table 1a : small/large turbines : 1,500 ↔ 3,500 \$/mmbtu : 1999 Dollars (assumed a mid-range value)
121.0	mmBtu/hr	Annual emissions report to NDDH (= mean of 2016 and 2017) 10% added to simulate near full load
133.1	mmBtu/hr	
167	CPI 1999	<a href="https://www.bls.gov/cpi/tables/historical-cpi-u-201709.pdf">https://www.bls.gov/cpi/tables/historical-cpi-u-201709.pdf</a>
240	CPI 2018	
1.44	CPI2018/CPI1999	Inflation rate raio
\$479,352	\$	Adjusted Capital for 2017 - \$/mmBtu
<b>\$623,157</b>	30%	Premium added as a retrofit: Source: EPA Air Pollution Control Technology Fact Sheet

### Annual Costs - SCR - Amine Sweetening Unit

Total Capital Costs for SCR		
Cost Item	Factor	Cost
<b><u>DIRECT COSTS</u></b>		
Purchased equipment costs		
Capital	A	\$623,157
Instrumentation	0.10 A	\$62,316
Sales taxes	0.05 A	\$31,158
Freight	0.05 A	\$31,158
<b>Purchased equipment cost, PEC</b>	<b>B</b>	<b>\$747,789</b>
Direct installation costs		
Foundations & supports	0.08 B	\$59,823
Handling & erection	0.14 B	\$104,690
Electrical	0.04 B	\$29,912
Piping	0.02 B	\$14,956
Insulation for ductwork	0.01 B	\$7,478
Painting	0.01 B	\$7,478
<b>Direct installation cost</b>	<b>0.30 B</b>	<b>\$224,337</b>
Site preparation	As required, SP	-
Buildings	As required, Bldg.	-
<b>Total Direct Cost, DC</b>	<b>1.30 B + SP + Bldg.</b>	<b>\$972,125</b>
<b><u>INDIRECT COSTS (Installation)</u></b>		
Engineering	0.10 B	\$74,779
Construction and field expenses	0.05 B	\$37,389
Contractor fees	0.10 B	\$74,779
Start-up	0.02 B	\$14,956
Performance test	0.01 B	\$7,478
Contingencies	0.03 B	\$22,434
<b>Total Indirect Cost, IC</b>	<b>0.31 B</b>	<b>\$231,815</b>
<b>TOTAL CAPITAL INVESTMENT (TCI) = DC + IC</b>	<b>DC + IC</b>	<b>\$1,203,940</b>

### Annual Costs - SCR - Amine Sweetening Unit

Total Annual Costs for SCR		
Cost Item		Cost
<b><u>DIRECT ANNUAL COSTS</u></b>		
Operating Labor		
Operator	0.5 hrs/shift (5 units)	30.00 \$/hr
Supervisor	15% of operator	\$2,430
Operating Materials	Ammonia consumption	\$696,998
	Catalyst replacement	\$157,248
Maintenance		
Labor	0.5 hrs/shift (5 units)	30.00 \$/hr
Material	100% of maint. labor	\$16,200
Utilities		
Natural Gas	0 (kft3/yr) \$ 5.18 \$/kft3	\$0
Electricity	0 (kWh/yr) \$0.059 \$/kWh	\$0
<b><u>INDIRECT ANNUAL COSTS, IC</u></b>		
Overhead	60% of sum of operating labor and materials and maintenance labor and materials.	\$30,618
Administrative Charges	2% of TCI	\$24,079
Property Taxes	1% of TCI	\$12,039
Insurance	1% of TCI	\$12,039
Capital Recovery Factor (15 yrs & prime rate + 3% = 8.25%)		0.1186
Annual Capital Recovery (Recovery rate * TCI)		\$142,787
<b>TOTAL ANNUAL COST</b>		<b>\$1,126,839</b>
Uncontrolled Emissions (tons/yr):		53
Emission reduction (%)		90%
Controlled Emissions (tons/yr):		5
Tons Removed (tons/yr):		48
<b>Cost-Effectiveness (\$/ton):</b>		<b>\$23,623</b>

#### Capital Recovery Factor

[https://www.ajdesigner.com/phpdiscountfactors/capital\\_recovery\\_equation.php#ajscroll](https://www.ajdesigner.com/phpdiscountfactors/capital_recovery_equation.php#ajscroll)

**Compressor Engines  
(C-1A, C-1B, C-1C, C-1E, C1-G)**

**Nitrogen Oxides**

**LEC Control Technology**

## Input Variables and Derivation

### Nitrogen Oxides – LEC

#### Capital Cost Derivation - NOx - LEC

**Primary Reference:**

INGAA Foundation, Report No. 2016-6, December 2017

"Potential Impacts of the Ozone and Particulate Matter NAAQS on Retrofit  
NOx Control for Natural Gas Transmission and Storage Compressor Drivers"

Value	Units	Reference
\$2,083	\$/hp	Table 6, p. 18: \$1,250 ↔ \$2,500 \$/hp : 2017 Dollars (assumed) (data is for Clark LEC retrofit 2-stroke) (assumed upper 1/3 to account for older engines)
1,920	hp	
\$4,000,000	\$/Engine	

#### Emissions Inventory: Actual

Engine	tons/year (2016/2017)
C-1A	94
C-1B	157
C-1C	191
C-1E	169
C-1G	153

### Total Capital Cost - C-1A - LEC

Total Capital Costs for LEC		
Cost Item	Factor	Cost
<b><u>DIRECT COSTS</u></b>		
Purchased equipment costs		
LEC Capital	A	\$4,000,000
Instrumentation	0.10 A	(included)
Taxes	0.05 A	\$200,000
Freight	0.05 A	\$200,000
<b>Purchased equipment cost, PEC</b>	<b>B</b>	<b>\$4,400,000</b>
Direct installation costs		
Foundations & supports	0.08 B	(included)
Handling & erection	0.14 B	(included)
Electrical	0.04 B	(included)
Piping	0.02 B	(included)
Insulation for ductwork	0.01 B	(included)
Painting	0.01 B	(included)
<b>Direct installation cost</b>	<b>0.30 B</b>	<b>\$0</b>
Site preparation	As required, SP	-
Buildings	As required, Bldg.	-
<b>Total Direct Cost, DC</b>	<b>1.30 B + SP + Bldg.</b>	<b>\$4,400,000</b>
<b><u>INDIRECT COSTS (Installation)</u></b>		
Engineering	0.10 B	\$440,000
Construction and field expenses	0.05 B	\$220,000
Contractor fees	0.10 B	\$440,000
Start-up	0.02 B	\$88,000
Performance test	0.01 B	\$44,000
Contingencies	0.03 B	\$132,000
<b>Total Indirect Cost, IC</b>	<b>0.31 B</b>	<b>\$1,364,000</b>
<b>TOTAL CAPITAL INVESTMENT (TCI) = DC + IC</b>	<b>DC + IC</b>	<b>\$5,764,000</b>

### Annual Costs - C-1A - LEC

Total Annual Costs for LEC			
Cost Item			Cost
<b><u>DIRECT ANNUAL COSTS</u></b>			
<i>Operating Labor</i>			
Operator	0.5 hrs/shift (5 units)	30.00 \$/hr	\$16,200
Supervisor	15% of operator		\$2,430
<i>Operating Materials</i>			
			-
<i>Maintenance</i>			
Labor	0.5 hrs/shift (5 units)	30.00 \$/hr	\$16,200
Material	100% of maint. labor		\$16,200
<i>Utilities</i>			
Natural Gas	0 (kft3/yr)	\$ 5.18 \$/kft3	\$0
Electricity	0 (kWh/yr)	\$0.059 \$/kWh	\$0
<b><u>INDIRECT ANNUAL COSTS, IC</u></b>			
Overhead	60% of sum of operating labor and materials and maintenance labor and materials.		\$30,618
Administrative Charges	2% of TCI		\$115,280
Property Taxes	1% of TCI		\$57,640
Insurance	1% of TCI		\$57,640
Capital Recovery Factor (15 yrs & prime rate + 3% = 8.25%)			0.1186
Annual Capital Recovery (Recovery rate * TCI)			\$683,610
<b>TOTAL ANNUAL COST</b>			<b>\$995,819</b>
Uncontrolled Emissions (tons/yr):			94
Controlled Emission Rate (g/bhp-hr)			1
Controlled Emissions (tons/yr):			19
Tons Removed (tons/yr):			76
<b>Cost-Effectiveness (\$/ton):</b>			<b>\$13,123</b>

### Capital Recovery Factor

[https://www.ajdesigner.com/phpdiscountfactors/capital\\_recovery\\_equation.php#ajscroll](https://www.ajdesigner.com/phpdiscountfactors/capital_recovery_equation.php#ajscroll)

### Total Capital Cost - C-1B - LEC

Total Capital Costs for LEC		
Cost Item	Factor	Cost
<b><u>DIRECT COSTS</u></b>		
Purchased equipment costs		
LEC Capital	A	\$4,000,000
Instrumentation	0.10 A	(included)
Taxes	0.05 A	\$200,000
Freight	0.05 A	\$200,000
<b>Purchased equipment cost, PEC</b>	<b>B</b>	<b>\$4,400,000</b>
Direct installation costs		
Foundations & supports	0.08 B	(included)
Handling & erection	0.14 B	(included)
Electrical	0.04 B	(included)
Piping	0.02 B	(included)
Insulation for ductwork	0.01 B	(included)
Painting	0.01 B	(included)
<b>Direct installation cost</b>	<b>0.30 B</b>	<b>\$0</b>
Site preparation	As required, SP	-
Buildings	As required, Bldg.	-
<b>Total Direct Cost, DC</b>	<b>1.30 B + SP + Bldg.</b>	<b>\$4,400,000</b>
<b><u>INDIRECT COSTS (Installation)</u></b>		
Engineering	0.10 B	\$440,000
Construction and field expenses	0.05 B	\$220,000
Contractor fees	0.10 B	\$440,000
Start-up	0.02 B	\$88,000
Performance test	0.01 B	\$44,000
Contingencies	0.03 B	\$132,000
<b>Total Indirect Cost, IC</b>	<b>0.31 B</b>	<b>\$1,364,000</b>
<b>TOTAL CAPITAL INVESTMENT (TCI) = DC + IC</b>	<b>DC + IC</b>	<b>\$5,764,000</b>

### Annual Costs - C-1B - LEC

Total Annual Costs for LEC			Cost
Cost Item			
<b><u>DIRECT ANNUAL COSTS</u></b>			
<i>Operating Labor</i>			
Operator	0.5 hrs/shift (5 units)	30.00 \$/hr	\$16,200
Supervisor	15% of operator		\$2,430
<i>Operating Materials</i>			
			-
<i>Maintenance</i>			
Labor	0.5 hrs/shift (5 units)	30.00 \$/hr	\$16,200
Material	100% of maint. labor		\$16,200
<i>Utilities</i>			
Natural Gas	0 (kft3/yr)	\$ 5.18 \$/kft3	\$0
Electricity	0 (kWh/yr)	\$0.059 \$/kWh	\$0
<b><u>INDIRECT ANNUAL COSTS, IC</u></b>			
Overhead	60% of sum of operating labor and materials and maintenance labor and materials.		\$30,618
Administrative Charges	2% of TCI		\$115,280
Property Taxes	1% of TCI		\$57,640
Insurance	1% of TCI		\$57,640
Capital Recovery Factor (15 yrs & prime rate + 3% = 8.25%)			0.1186
Annual Capital Recovery (Recovery rate * TCI)			\$683,610
<b>TOTAL ANNUAL COST</b>			<b>\$995,819</b>
Uncontrolled Emissions (tons/yr):			157
Controlled Emission Rate (g/bhp-hr)			1
Controlled Emissions (tons/yr):			19
Tons Removed (tons/yr):			138
<b>Cost-Effectiveness (\$/ton):</b>			<b>\$7,197</b>

### Capital Recovery Factor

[https://www.ajdesigner.com/phpdiscountfactors/capital\\_recovery\\_equation.php#ajscroll](https://www.ajdesigner.com/phpdiscountfactors/capital_recovery_equation.php#ajscroll)

### Total Capital Cost - C-1C - LEC

Total Capital Costs for LEC		
Cost Item	Factor	Cost
<b><u>DIRECT COSTS</u></b>		
Purchased equipment costs		
LEC Capital	A	\$4,000,000
Instrumentation	0.10 A	(included)
Taxes	0.05 A	\$200,000
Freight	0.05 A	\$200,000
<b>Purchased equipment cost, PEC</b>	<b>B</b>	<b>\$4,400,000</b>
Direct installation costs		
Foundations & supports	0.08 B	(included)
Handling & erection	0.14 B	(included)
Electrical	0.04 B	(included)
Piping	0.02 B	(included)
Insulation for ductwork	0.01 B	(included)
Painting	0.01 B	(included)
<b>Direct installation cost</b>	<b>0.30 B</b>	<b>\$0</b>
Site preparation	As required, SP	-
Buildings	As required, Bldg.	-
<b>Total Direct Cost, DC</b>	<b>1.30 B + SP + Bldg.</b>	<b>\$4,000,000</b>
<b><u>INDIRECT COSTS (Installation)</u></b>		
Engineering	0.10 B	\$440,000
Construction and field expenses	0.05 B	\$220,000
Contractor fees	0.10 B	\$440,000
Start-up	0.02 B	\$88,000
Performance test	0.01 B	\$44,000
Contingencies	0.03 B	\$132,000
<b>Total Indirect Cost, IC</b>	<b>0.31 B</b>	<b>\$1,364,000</b>
<b>TOTAL CAPITAL INVESTMENT (TCI) = DC + IC</b>	<b>DC + IC</b>	<b>\$5,364,000</b>

### Annual Costs - C-1 - LEC

Total Annual Costs for LEC			
Cost Item			Cost
<b><u>DIRECT ANNUAL COSTS</u></b>			
<i>Operating Labor</i>			
Operator	0.5 hrs/shift (5 units)	30.00 \$/hr	\$16,200
Supervisor	15% of operator		\$2,430
<i>Operating Materials</i>			
			-
<i>Maintenance</i>			
Labor	0.5 hrs/shift (5 units)	30.00 \$/hr	\$16,200
Material	100% of maint. labor		\$16,200
<i>Utilities</i>			
Natural Gas	0 (kft3/yr)	\$ 5.18 \$/kft3	\$0
Electricity	0 (kWh/yr)	\$0.059 \$/kWh	\$0
<b><u>INDIRECT ANNUAL COSTS, IC</u></b>			
Overhead	60% of sum of operating labor and materials and maintenance labor and materials.		\$30,618
Administrative Charges	2% of TCI		\$107,280
Property Taxes	1% of TCI		\$53,640
Insurance	1% of TCI		\$53,640
Capital Recovery Factor (15 yrs & prime rate + 3% = 8.25%)			0.1186
Annual Capital Recovery (Recovery rate * TCI)			\$636,170
<b>TOTAL ANNUAL COST</b>			<b>\$932,379</b>
Uncontrolled Emissions (tons/yr):			191
Controlled Emission Rate (g/bhp-hr)			1
Controlled Emissions (tons/yr):			19
Tons Removed (tons/yr):			173
<b>Cost-Effectiveness (\$/ton):</b>			<b>\$5,401</b>

### Capital Recovery Factor

[https://www.ajdesigner.com/phpdiscountfactors/capital\\_recovery\\_equation.php#ajscroll](https://www.ajdesigner.com/phpdiscountfactors/capital_recovery_equation.php#ajscroll)

### Total Capital Cost - C-1E - LEC

Total Capital Costs for LEC		
Cost Item	Factor	Cost
<b><u>DIRECT COSTS</u></b>		
Purchased equipment costs		
LEC Capital	A	\$4,000,000
Instrumentation	0.10 A	(included)
Taxes	0.05 A	\$200,000
Freight	0.05 A	\$200,000
<b>Purchased equipment cost, PEC</b>	<b>B</b>	<b>\$4,400,000</b>
Direct installation costs		
Foundations & supports	0.08 B	(included)
Handling & erection	0.14 B	(included)
Electrical	0.04 B	(included)
Piping	0.02 B	(included)
Insulation for ductwork	0.01 B	(included)
Painting	0.01 B	(included)
<b>Direct installation cost</b>	<b>0.30 B</b>	<b>\$0</b>
Site preparation	As required, SP	-
Buildings	As required, Bldg.	-
<b>Total Direct Cost, DC</b>	<b>1.30 B + SP + Bldg.</b>	<b>\$4,400,000</b>
<b><u>INDIRECT COSTS (Installation)</u></b>		
Engineering	0.10 B	\$440,000
Construction and field expenses	0.05 B	\$220,000
Contractor fees	0.10 B	\$440,000
Start-up	0.02 B	\$88,000
Performance test	0.01 B	\$44,000
Contingencies	0.03 B	\$132,000
<b>Total Indirect Cost, IC</b>	<b>0.31 B</b>	<b>\$1,364,000</b>
<b>TOTAL CAPITAL INVESTMENT (TCI) = DC + IC</b>	<b>DC + IC</b>	<b>\$5,764,000</b>

### Annual Costs - C-1E - LEC

Total Annual Costs for LEC			
Cost Item			Cost
<b><u>DIRECT ANNUAL COSTS</u></b>			
<i>Operating Labor</i>			
Operator	0.5 hrs/shift (5 units)	30.00 \$/hr	\$16,200
Supervisor	15% of operator		\$2,430
<i>Operating Materials</i>			
			-
<i>Maintenance</i>			
Labor	0.5 hrs/shift (5 units)	30.00 \$/hr	\$16,200
Material	100% of maint. labor		\$16,200
<i>Utilities</i>			
Natural Gas	0 (kft3/yr)	\$ 5.18 \$/kft3	\$0
Electricity	0 (kWh/yr)	\$0.059 \$/kWh	\$0
<b><u>INDIRECT ANNUAL COSTS, IC</u></b>			
Overhead	60% of sum of operating labor and materials and maintenance labor and materials.		\$30,618
Administrative Charges	2% of TCI		\$115,280
Property Taxes	1% of TCI		\$57,640
Insurance	1% of TCI		\$57,640
Capital Recovery Factor (15 yrs & prime rate + 3% = 8.25%)			0.1186
Annual Capital Recovery (Recovery rate * TCI)			\$683,610
<b>TOTAL ANNUAL COST</b>			<b>\$995,819</b>
Uncontrolled Emissions (tons/yr):			169
Controlled Emission Rate (g/bhp-hr)			1
Controlled Emissions (tons/yr):			19
Tons Removed (tons/yr):			151
<b>Cost-Effectiveness (\$/ton):</b>			<b>\$6,609</b>

### Capital Recovery Factor

[https://www.ajdesigner.com/phpdiscountfactors/capital\\_recovery\\_equation.php#ajscroll](https://www.ajdesigner.com/phpdiscountfactors/capital_recovery_equation.php#ajscroll)



### Total Capital Cost - C-1G - LEC

Total Capital Costs for LEC		
Cost Item	Factor	Cost
<b><u>DIRECT COSTS</u></b>		
Purchased equipment costs		
LEC Capital	A	\$4,000,000
Instrumentation	0.10 A	(included)
Taxes	0.05 A	\$200,000
Freight	0.05 A	\$200,000
<b>Purchased equipment cost, PEC</b>	<b>B</b>	<b>\$4,400,000</b>
Direct installation costs		
Foundations & supports	0.08 B	(included)
Handling & erection	0.14 B	(included)
Electrical	0.04 B	(included)
Piping	0.02 B	(included)
Insulation for ductwork	0.01 B	(included)
Painting	0.01 B	(included)
<b>Direct installation cost</b>	<b>0.30 B</b>	<b>\$0</b>
Site preparation	As required, SP	-
Buildings	As required, Bldg.	-
<b>Total Direct Cost, DC</b>	<b>1.30 B + SP + Bldg.</b>	<b>\$4,400,000</b>
<b><u>INDIRECT COSTS (Installation)</u></b>		
Engineering	0.10 B	\$440,000
Construction and field expenses	0.05 B	\$220,000
Contractor fees	0.10 B	\$440,000
Start-up	0.02 B	\$88,000
Performance test	0.01 B	\$44,000
Contingencies	0.03 B	\$132,000
<b>Total Indirect Cost, IC</b>	<b>0.31 B</b>	<b>\$1,364,000</b>
<b>TOTAL CAPITAL INVESTMENT (TCI) = DC + IC</b>	<b>DC + IC</b>	<b>\$5,764,000</b>

### Annual Costs - C-1G - LEC

Total Annual Costs for LEC			
Cost Item			Cost
<b><u>DIRECT ANNUAL COSTS</u></b>			
<i>Operating Labor</i>			
Operator	0.5 hrs/shift (5 units)	30.00 \$/hr	\$16,200
Supervisor	15% of operator		\$2,430
<i>Operating Materials</i>			
			-
<i>Maintenance</i>			
Labor	0.5 hrs/shift (5 units)	30.00 \$/hr	\$16,200
Material	100% of maint. labor		\$16,200
<i>Utilities</i>			
Natural Gas	0 (kft3/yr)	\$ 5.18 \$/kft3	\$0
Electricity	0 (kWh/yr)	\$0.059 \$/kWh	\$0
<b><u>INDIRECT ANNUAL COSTS, IC</u></b>			
Overhead	60% of sum of operating labor and materials and maintenance labor and materials.		\$30,618
Administrative Charges	2% of TCI		\$115,280
Property Taxes	1% of TCI		\$57,640
Insurance	1% of TCI		\$57,640
Capital Recovery Factor (15 yrs & prime rate + 3% = 8.25%)			0.1186
Annual Capital Recovery (Recovery rate * TCI)			\$683,610
<b>TOTAL ANNUAL COST</b>			<b>\$995,819</b>
Uncontrolled Emissions (tons/yr)			153
Controlled Emission Rate (g/bhp-hr)			1
Controlled Emissions (tons/yr):			19
Tons Removed (tons/yr):			134
<b>Cost-Effectiveness (\$/ton):</b>			<b>\$7,425</b>

### Capital Recovery Factor

[https://www.ajdesigner.com/phpdiscountfactors/capital\\_recovery\\_equation.php#ajscroll](https://www.ajdesigner.com/phpdiscountfactors/capital_recovery_equation.php#ajscroll)

**Compressor Engines  
(C-1A, C-1B, C-1C, C-1E, C1-G)**

**Nitrogen Oxides**

**SCR Control Technology**

## Capital Cost Derivation

### Primary Reference:

Air Pollution Control Technology Fact Sheet, SCR, EPA-452/F-03-032

Value	Units	Reference
\$35,000	\$/mmBtu	Table 1a : small turbines : 17,000 ↔ 35,000 \$/mmbtu : 1999 Dollars (assumed higher number since RICE, old engines and intermittent operation)
1,920	hp	Clark Engine
14.5	mmBtu/hr	Typical heat input to engine (from 2018 stack test)
17.4	mmBtu/hr	20% added since not at 100% load
167	CPI 1999	<a href="https://www.bls.gov/cpi/tables/historical-cpi-u-201709.pdf">https://www.bls.gov/cpi/tables/historical-cpi-u-201709.pdf</a>
240	CPI 2018	
1.44	CPI2018/CPI1999	Inflation rate raio
\$50,420	\$/Engine/mmBtu/hr	Adjusted Capital for 2017 - \$/mmBtu
\$65,546	\$/Engine/mmBtu/hr	Premium added as a retrofit: Source: EPA Air Pollution Control Technology Fact Sheet
\$1,140,504.20	\$/Engine	

**\$1,140,504 Capital Cost per engine (2017 dollars @ 17.4 mmBtu/hr)**

### SCR - Input Calculations and Reference Information

Data is on a per engine basis.

Reference: EPA/452/B-02-001 Section 4.2 in Chapter 2

Parameter / Variable	Value	Units	Reference
Selective Catalytic Reduction (% Control);	85.0	percent	Approx = 1g/bhp-hr
Uncontrolled emissions each RICE	153	Tons/yr (actual) per Engine	2016/2017 Inventory
$Q_b$ =Max. Heat Input at HHV, MMBtu/h	17.200	MM Btu/hr per RICE	Test C1-C 2018 + 20% Chpt 2, SCR, Cost Control Manual, 2016, Eqn 2.1a-b for NO and NO <sub>2</sub> <sup>1</sup>
ASR	1.5	Actual Stoichiometric Ratio	2018 stack test + 20% 2018 stack test + 20% EPA/452/B-02-001
$Q_{flue\ gas}$	20,800	Inlet to SCR acfm	Approx.
$q_{scfm}$	8,000	dscfm	
$CF_{plant}$	0.95	system capacity factor, $CF_{plant}$	
$\eta_{NOx}$	0.85	NOx removal efficiency	
NH <sub>3</sub> slip (ppmv)	$(ASR - \eta_{NOx}) * 60 * MW_{NH_3} / dscfm / 359.05 / 10^6$	lb/hr	
Catalyst volume	$2.81 * Q_b * \eta_{slip} * slip_{NOx} * S_{adj} * T_{adj} / \eta_{SCR}$	ft <sup>3</sup>	EPA/452/B-02-001
$N_{SCR}$ (if of SCR reactor chambers)	1		
$\eta_{slip}$	$(0.2869 + (1.058 * \eta_{NOx}))$		EPA/452/B-02-001
Slip	$(ASR - \eta_{NOx})$		EPA/452/B-02-001
$Slip_{adj}$	$1.2835 - (0.0567 * Slip)$		EPA/452/B-02-001
NO <sub>x</sub>	3.8	lb/MM Btu	2018 stack test (typical)
NO <sub>x</sub> <sub>in</sub>	$0.8524 + (0.3208 * NO_{x_i})$		EPA/452/B-02-001
S, sulfur in fuel	7.00E-06	(weight fraction)	Caterpillar
$S_{adj}$	$0.9636 + (0.0455 * S)$		EPA/452/B-02-001
SCR inlet temp	600	F°	EPA/452/B-02-001
SCR inlet temp	589	K°	
$T_{adj}$ for inlet T not = 700 F	$15.16 - (0.03937 * T) + (2.74 * 10^{-5} * T^2)$		EPA/452/B-02-001
$A_{catalyst}$	$Q_{flue\ gas} / (16 * 60)$	ft <sup>2</sup>	EPA/452/B-02-001
$\eta_{layer}$	$V_{catalyst} / (\eta_{layer} * A_{catalyst})$	3.1	assume h = 3.1
$\eta_{layer - final}$	3	round $\eta_{layer}$ to integer	EPA/452/B-02-001
$\eta_{layer}$	$V_{catalyst} / ((\eta_{layer} * A_{catalyst}) * 1)$	4.2	EPA/452/B-02-001
$\eta_{layer - total}$	$\eta_{layer - final} * 1$	4	EPA/452/B-02-001
$h_{SCR}$	$\eta_{layer - total} * ((C_1 + \eta_{layer}) + C_2)$	53.6	ft
SCR height adjustment	$\$6.12 * h_{SCR} - 187.9$	140.2	f(h <sub>SCR</sub> )
$m_{reagent}$	$(NO_{x_i} * Q_b * NSR * \eta_{NOx} * MW_{reagent}) / (MW_{NOx} * SR_i)$	30.8	lb/hr
$MW_{reagent}$	17.0	MW of ammonia	
$MW_{NOx}$	46.0	MW of NO <sub>x</sub>	
NSR	ASR/SR <sub>i</sub>	1.5	normalized stoichiometric rate
SR <sub>i</sub>	1.0	for ammonia	EPA/452/B-02-001 w/ NO <sub>2</sub> :NO adjustment
$m_{sol}$	$m_{reagent} / C_{sol}$	106.4	lb/hr
$C_{sol}$	0.29	concentration of aqueous soln	Typical solution concentration
$\rho_{sol}$	56	lb/ft <sup>3</sup>	EPA/452/B-02-001
$V_{sol}$	7.5	gal/ft <sup>3</sup>	EPA/452/B-02-001
$Q_{sol}$	$m_{sol} / \rho_{sol} * V_{sol}$	14.2	gal/hr
$t_{store}$	14.0	reagent storage for t days	assumed, EPA/452/B-02-001
Tank volume	$q_{reagent} * t$	4,774	gallons
Cost of reagent	RC	0.15	\$/lb
Cost of reagent (per hour)		\$16.16	\$/hour of ammonia
Cost of reagent (per year)		\$141,539	\$/year (8,760) of ammonia
Catalyst Cost	$CC_{replace}$	\$436.12	\$/ft <sup>3</sup>
Catalyst Cost Replacement	$\eta_{SCR} * Vol_{catalyst} * (CC_{replace} / R_{layer})$	\$22,353	\$/replacement layer/year
Pressure drop of SCR & ductwork	$\Delta P_{duct}$	2.5	inches H <sub>2</sub> O
Pressure drop for catalyst	$D_{P_{catalyst}} = 0.875 * n_{layer-final}$	2.6	inches H <sub>2</sub> O

<sup>1</sup> Stoichiometry adjusted for NO<sub>2</sub>:NO<sub>x</sub> ratio from EPA database for the 60 reporting 2SLB engines = 46% : [https://www3.epa.gov/scram001/no2\\_isr\\_database.htm](https://www3.epa.gov/scram001/no2_isr_database.htm)  
(2 molecules of ammonia required for 1 molecule of NO<sub>2</sub> reduction)  
 $2NO_2 + 4NH_3 \rightarrow 3N_2 + 6H_2O$

### Annual Costs - C-1A -SCR

Total Capital Costs for SCR		
Cost Item	Factor	Cost
<b>DIRECT COSTS</b>		
Purchased equipment costs		
Capital (5 engines)	A	\$1,140,504
Instrumentation	0.10 A	\$114,050
Sales taxes	0.05 A	\$57,025
Freight	0.05 A	\$57,025
<b>Purchased equipment cost, PEC</b>	<b>B</b>	<b>\$1,368,605</b>
Direct installation costs		
Foundations & supports	0.08 B	\$109,488
Handling & erection	0.14 B	\$191,605
Electrical	0.04 B	\$54,744
Piping	0.02 B	\$27,372
Insulation for ductwork	0.01 B	\$13,686
Painting	0.01 B	\$13,686
<b>Direct installation cost</b>	<b>0.30 B</b>	<b>\$410,582</b>
Site preparation	As required, SP	-
Buildings	As required, Bldg.	-
<b>Total Direct Cost, DC</b>	<b>1.30 B + SP + Bldg.</b>	<b>\$1,779,187</b>
<b>INDIRECT COSTS (Installation)</b>		
Engineering	0.10 B	\$136,861
Construction and field expenses	0.05 B	\$68,430
Contractor fees	0.10 B	\$136,861
Start-up	0.02 B	\$27,372
Performance test	0.01 B	\$13,686
Contingencies	0.03 B	\$41,058
<b>Total Indirect Cost, IC</b>	<b>0.31 B</b>	<b>\$424,268</b>
<b>TOTAL CAPITAL INVESTMENT (TCI) = DC + IC</b>	<b>DC + IC</b>	<b>\$2,203,454</b>

### Annual Costs - C-1A -SCR

Cost Item		Total Annual Costs for SCR		Cost
<b><u>DIRECT ANNUAL COSTS</u></b>				
<i>Operating Labor</i>				
Operator	1 hrs/shift (5 units)	30.00 \$/hr		\$32,400
Supervisor	15% of operator			\$4,860
<i>Operating Materials</i>				
Ammonia	yearly			\$141,539
Catalyst	yearly			\$22,353
<i>Maintenance</i>				
Labor	1 hrs/shift (5 units)	30.00 \$/hr		\$32,400
Material	100% of maint. labor			\$32,400
<i>Utilities</i>				
Natural Gas	0 (kft3/yr)	\$ 5.18 \$/kft3		\$0
Electricity	0 (kWh/yr)	\$0.059 \$/kWh		\$0
<b><u>INDIRECT ANNUAL COSTS, IC</u></b>				
Overhead	60% of sum of operating labor and materials and maintenance labor and materials.			\$61,236
Administrative Charges	2% of TCI			\$44,069
Property Taxes	1% of TCI			\$22,035
Insurance	1% of TCI			\$22,035
Capital Recovery Factor (15 yrs & prime rate + 3% = 8.25%)				0.1186
Annual Capital Recovery (Recovery rate * TCI)				\$261,330
<b>TOTAL ANNUAL COST</b>				<b>\$676,656</b>
Uncontrolled Emissions (tons/yr): (5 units)				94
Controlled Emission Rate (g/bhp-hr)				1
Controlled Emissions (tons/yr):				19
Tons Removed (tons/yr):				76
<b>Cost-Effectiveness (\$/ton):</b>				<b>\$8,917</b>

#### Capital Recovery Factor

[https://www.ajdesigner.com/phpdiscounrfactors/capital\\_recovery\\_equation.php#ajscroll](https://www.ajdesigner.com/phpdiscounrfactors/capital_recovery_equation.php#ajscroll)

### Annual Total Capital Costs - C-1B - SCR

Total Capital Costs for SCR		
Cost Item	Factor	Cost
<b><u>DIRECT COSTS</u></b>		
Purchased equipment costs		
Capital (5 engines)	A	\$1,140,504
Instrumentation	0.10 A	\$114,050
Sales taxes	0.05 A	\$57,025
Freight	0.05 A	\$57,025
<b>Purchased equipment cost, PEC</b>	<b>B</b>	<b>\$1,368,605</b>
Direct installation costs		
Foundations & supports	0.08 B	\$109,488
Handling & erection	0.14 B	\$191,605
Electrical	0.04 B	\$54,744
Piping	0.02 B	\$27,372
Insulation for ductwork	0.01 B	\$13,686
Painting	0.01 B	\$13,686
<b>Direct installation cost</b>	<b>0.30 B</b>	<b>\$410,582</b>
Site preparation	As required, SP	-
Buildings	As required, Bldg.	-
<b>Total Direct Cost, DC</b>	<b>1.30 B + SP + Bldg.</b>	<b>\$1,779,187</b>
<b><u>INDIRECT COSTS (Installation)</u></b>		
Engineering	0.10 B	\$136,861
Construction and field expenses	0.05 B	\$68,430
Contractor fees	0.10 B	\$136,861
Start-up	0.02 B	\$27,372
Performance test	0.01 B	\$13,686
Contingencies	0.03 B	\$41,058
<b>Total Indirect Cost, IC</b>	<b>0.31 B</b>	<b>\$424,268</b>
<b>TOTAL CAPITAL INVESTMENT (TCI) = DC + IC</b>	<b>DC + IC</b>	<b>\$2,203,454</b>

### Annual Costs - C-1B -SCR

Cost Item		Total Annual Costs for SCR		Cost
<b><u>DIRECT ANNUAL COSTS</u></b>				
<i>Operating Labor</i>				
Operator	1 hrs/shift (5 units)	30.00 \$/hr		\$32,400
Supervisor	15% of operator			\$4,860
<i>Operating Materials</i>				
Ammonia	yearly			\$141,539
Catalyst				\$22,353
<i>Maintenance</i>				
Labor	1 hrs/shift (5 units)	30.00 \$/hr		\$32,400
Material	100% of maint. labor			\$32,400
<i>Utilities</i>				
Natural Gas	0 (kft3/yr)	\$ 5.18 \$/kft3		\$0
Electricity	0 (kWh/yr)	\$0.059 \$/kWh		\$0
<b><u>INDIRECT ANNUAL COSTS, IC</u></b>				
Overhead	60% of sum of operating labor and materials and maintenance labor and materials.			\$61,236
Administrative Charges	2% of TCI			\$44,069
Property Taxes	1% of TCI			\$22,035
Insurance	1% of TCI			\$22,035
Capital Recovery Factor (15 yrs & prime rate + 3% = 8.25%)				0.1186
Annual Capital Recovery (Recovery rate * TCI)				\$261,330
<b>TOTAL ANNUAL COST</b>				<b>\$676,656</b>
Uncontrolled Emissions (tons/yr): (5 units)				157
Controlled Emission Rate (g/bhp-hr)				1
Controlled Emissions (tons/yr):				19
Tons Removed (tons/yr):				138
<b>Cost-Effectiveness (\$/ton):</b>				<b>\$4,890</b>

#### Capital Recovery Factor

[https://www.ajdesigner.com/phpdiscountfactors/capital\\_recovery\\_equation.php#ajscroll](https://www.ajdesigner.com/phpdiscountfactors/capital_recovery_equation.php#ajscroll)

### Annual Total Capital Costs - C-1C - SCR

Total Annual Costs for SCR		
Cost Item	Factor	Cost
<b><u>DIRECT COSTS</u></b>		
Purchased equipment costs		
Capital (5 engines)	A	\$1,140,504
Instrumentation	0.10 A	\$114,050
Sales taxes	0.05 A	\$57,025
Freight	0.05 A	\$57,025
<b>Purchased equipment cost, PEC</b>	<b>B</b>	<b>\$1,368,605</b>
Direct installation costs		
Foundations & supports	0.08 B	\$109,488
Handling & erection	0.14 B	\$191,605
Electrical	0.04 B	\$54,744
Piping	0.02 B	\$27,372
Insulation for ductwork	0.01 B	\$13,686
Painting	0.01 B	\$13,686
<b>Direct installation cost</b>	<b>0.30 B</b>	<b>\$410,582</b>
Site preparation	As required, SP	-
Buildings	As required, Bldg.	-
<b>Total Direct Cost, DC</b>	<b>1.30 B + SP + Bldg.</b>	<b>\$1,779,187</b>
<b><u>INDIRECT COSTS (Installation)</u></b>		
Engineering	0.10 B	\$136,861
Construction and field expenses	0.05 B	\$68,430
Contractor fees	0.10 B	\$136,861
Start-up	0.02 B	\$27,372
Performance test	0.01 B	\$13,686
Contingencies	0.03 B	\$41,058
<b>Total Indirect Cost, IC</b>	<b>0.31 B</b>	<b>\$424,268</b>
<b>TOTAL CAPITAL INVESTMENT (TCI) = DC + IC</b>	<b>DC + IC</b>	<b>\$2,203,454</b>

### Annual Costs - C-1C -SCR

Total Annual Costs for SCR			Cost
Cost Item			
<b><u>DIRECT ANNUAL COSTS</u></b>			
<i>Operating Labor</i>			
Operator	1 hrs/shift (5 units)	30.00 \$/hr	\$32,400
Supervisor	15% of operator		\$4,860
<i>Operating Materials</i>			
Ammonia	yearly		\$141,539
Catalyst			\$22,353
<i>Maintenance</i>			
Labor	1 hrs/shift (5 units)	30.00 \$/hr	\$32,400
Material	100% of maint. labor		\$32,400
<i>Utilities</i>			
Natural Gas	0 (kft3/yr)	\$ 5.18 \$/kft3	\$0
Electricity	0 (kWh/yr)	\$0.059 \$/kWh	\$0
<b><u>INDIRECT ANNUAL COSTS, IC</u></b>			
Overhead	60% of sum of operating labor and materials and maintenance labor and materials.		\$61,236
Administrative Charges	2% of TCI		\$44,069
Property Taxes	1% of TCI		\$22,035
Insurance	1% of TCI		\$22,035
Capital Recovery Factor (15 yrs & prime rate + 3% = 8.25%)			0.1186
Annual Capital Recovery (Recovery rate * TCI)			\$261,330
<b>TOTAL ANNUAL COST</b>			<b>\$676,656</b>
Uncontrolled Emissions (tons/yr): (5 units)			191
Controlled Emission Rate (g/bhp-hr)			1
Controlled Emissions (tons/yr):			19
Tons Removed (tons/yr):			173
<b>Cost-Effectiveness (\$/ton):</b>			<b>\$3,920</b>

#### Capital Recovery Factor

[https://www.ajdesigner.com/phpdiscountfactors/capital\\_recovery\\_equation.php#ajscroll](https://www.ajdesigner.com/phpdiscountfactors/capital_recovery_equation.php#ajscroll)

### Annual Total Capital Costs - C-1E - SCR

Total Capital Costs for LEC		
Cost Item	Factor	Cost
<b>DIRECT COSTS</b>		
Purchased equipment costs		
Capital (5 engines)	A	\$1,140,504
Instrumentation	0.10 A	\$114,050
Sales taxes	0.05 A	\$57,025
Freight	0.05 A	\$57,025
<b>Purchased equipment cost, PEC</b>	<b>B</b>	<b>\$1,368,605</b>
Direct installation costs		
Foundations & supports	0.08 B	\$109,488
Handling & erection	0.14 B	\$191,605
Electrical	0.04 B	\$54,744
Piping	0.02 B	\$27,372
Insulation for ductwork	0.01 B	\$13,686
Painting	0.01 B	\$13,686
<b>Direct installation cost</b>	<b>0.30 B</b>	<b>\$410,582</b>
Site preparation	As required, SP	-
Buildings	As required, Bldg.	-
<b>Total Direct Cost, DC</b>	<b>1.30 B + SP + Bldg.</b>	<b>\$1,779,187</b>
<b>INDIRECT COSTS (Installation)</b>		
Engineering	0.10 B	\$136,861
Construction and field expenses	0.05 B	\$68,430
Contractor fees	0.10 B	\$136,861
Start-up	0.02 B	\$27,372
Performance test	0.01 B	\$13,686
Contingencies	0.03 B	\$41,058
<b>Total Indirect Cost, IC</b>	<b>0.31 B</b>	<b>\$424,268</b>
<b>TOTAL CAPITAL INVESTMENT (TCI) = DC + IC</b>	<b>DC + IC</b>	<b>\$2,203,454</b>

### Annual Costs - C-1E -SCR

Cost Item		Total Annual Costs for SCR		Cost
<b><u>DIRECT ANNUAL COSTS</u></b>				
<i>Operating Labor</i>				
Operator	1 hrs/shift (5 units)	30.00 \$/hr		\$32,400
Supervisor	15% of operator			\$4,860
<i>Operating Materials</i>				
Ammonia	yearly			\$71,753
<i>Maintenance</i>				
Labor	1 hrs/shift (5 units)	30.00 \$/hr		\$32,400
Material	100% of maint. labor			\$32,400
<i>Utilities</i>				
Natural Gas	0 (kft3/yr)	\$ 5.18 \$/kft3		\$0
Electricity	0 (kWh/yr)	\$0.059 \$/kWh		\$0
<b><u>INDIRECT ANNUAL COSTS, IC</u></b>				
Overhead	60% of sum of operating labor and materials and maintenance labor and materials.			\$61,236
Administrative Charges	2% of TCI			\$44,069
Property Taxes	1% of TCI			\$22,035
Insurance	1% of TCI			\$22,035
Capital Recovery Factor (15 yrs & prime rate + 3% = 8.25%)				0.1186
Annual Capital Recovery (Recovery rate * TCI)				\$261,330
<b>TOTAL ANNUAL COST</b>				<b>\$584,517</b>
Uncontrolled Emissions (tons/yr): (5 units)				169
Controlled Emission Rate (g/bhp-hr)				1
Controlled Emissions (tons/yr):				19
Tons Removed (tons/yr):				151
<b>Cost-Effectiveness (\$/ton):</b>				<b>\$3,879</b>

#### Capital Recovery Factor

[https://www.ajdesigner.com/phpdiscountfactors/capital\\_recovery\\_equation.php#ajscroll](https://www.ajdesigner.com/phpdiscountfactors/capital_recovery_equation.php#ajscroll)

### Annual Total Capital Costs - C-1E - SCR

Total Annual Costs for SCR		
Cost Item	Factor	Cost
<b>DIRECT COSTS</b>		
Purchased equipment costs		
Capital (5 engines)	A	\$1,140,504
Instrumentation	0.10 A	\$114,050
Sales taxes	0.05 A	\$57,025
Freight	0.05 A	\$57,025
<b>Purchased equipment cost, PEC</b>	<b>B</b>	<b>\$1,368,605</b>
Direct installation costs		
Foundations & supports	0.08 B	\$109,488
Handling & erection	0.14 B	\$191,605
Electrical	0.04 B	\$54,744
Piping	0.02 B	\$27,372
Insulation for ductwork	0.01 B	\$13,686
Painting	0.01 B	\$13,686
<b>Direct installation cost</b>	<b>0.30 B</b>	<b>\$410,582</b>
Site preparation	As required, SP	-
Buildings	As required, Bldg.	-
<b>Total Direct Cost, DC</b>	<b>1.30 B + SP + Bldg.</b>	<b>\$1,779,187</b>
<b>INDIRECT COSTS (Installation)</b>		
Engineering	0.10 B	\$136,861
Construction and field expenses	0.05 B	\$68,430
Contractor fees	0.10 B	\$136,861
Start-up	0.02 B	\$27,372
Performance test	0.01 B	\$13,686
Contingencies	0.03 B	\$41,058
<b>Total Indirect Cost, IC</b>	<b>0.31 B</b>	<b>\$424,268</b>
<b>TOTAL CAPITAL INVESTMENT (TCI) = DC + IC</b>	<b>DC + IC</b>	<b>\$2,203,454</b>

### Annual Costs - C-1E -SCR

Total Annual Costs for SCR			Cost
Cost Item			
<b>DIRECT ANNUAL COSTS</b>			
<i>Operating Labor</i>			
Operator	1 hrs/shift (5 units)	30.00 \$/hr	\$32,400
Supervisor	15% of operator		\$4,860
<i>Operating Materials</i>			
Ammonia	yearly		\$141,539
Catalyst			\$22,353
<i>Maintenance</i>			
Labor	1 hrs/shift (5 units)	30.00 \$/hr	\$32,400
Material	100% of maint. labor		\$32,400
<i>Utilities</i>			
Natural Gas	0 (kft3/yr)	\$ 5.18 \$/kft3	\$0
Electricity	0 (kWh/yr)	\$0.059 \$/kWh	\$0
<b>INDIRECT ANNUAL COSTS, IC</b>			
Overhead	60% of sum of operating labor and materials and maintenance labor and materials.		\$61,236
Administrative Charges	2% of TCI		\$44,069
Property Taxes	1% of TCI		\$22,035
Insurance	1% of TCI		\$22,035
Capital Recovery Factor (15 yrs & prime rate + 3% = 8.25%)			0.1186
Annual Capital Recovery (Recovery rate * TCI)			\$261,330
<b>TOTAL ANNUAL COST</b>			<b>\$676,656</b>
Uncontrolled Emissions (tons/yr): (5 units)			169
Controlled Emission Rate (g/bhp-hr)			1
Controlled Emissions (tons/yr):			19
Tons Removed (tons/yr):			151
<b>Cost-Effectiveness (\$/ton):</b>			<b>\$4,491</b>

### Capital Recovery Factor

[https://www.ajdesigner.com/phpdiscountfactors/capital\\_recovery\\_equation.php#ajscroll](https://www.ajdesigner.com/phpdiscountfactors/capital_recovery_equation.php#ajscroll)



**Stroh, David E.**

---

**From:** St Clair, Tony <tstclair@hess.com>  
**Sent:** Wednesday, March 13, 2019 3:21 PM  
**To:** Stroh, David E.; O'Clair, Terry L.  
**Cc:** Hal Robbins; Brian Murphy; Epperson, Brian; Sund, Vicky; Schmidt, David D.; Bugbee, Curtis; Lohnes, Brent  
**Subject:** Hess Response to Regional Haze Second Planning Period Request  
**Attachments:** 4-Factor Hess Tioga March 2019 Report.pdf

**Follow Up Flag:** Follow up  
**Due By:** Monday, May 20, 2019 8:00 AM  
**Flag Status:** Flagged

**Categories:** RH Facility

<b>CAUTION:</b> This email originated from an outside source. Do not click links or open attachments unless you know they are safe.
---

David,

In response to the Department's request for a four-factor analysis concerning emissions of sulfur dioxide (SO<sub>2</sub>) and nitrogen oxides (NO<sub>x</sub>) at Hess's Tioga Gas Plant (letter request dated May 18, 2018), please find attached our report, which has been prepared in consultation with Bison Engineering Inc and guidance from the Department.

Should you have any questions after your review of our submittal, please do not hesitate to contact me for additional clarification or information.

Regards,

**Tony St. Clair, P.E., BCEE, QEP, REM**  
*Advisor, EHS - Environmental & Regulatory*

**HESS CORPORATION**

1501 McKinney Street, Office 21.104  
Houston, Texas 77010  
Office: (713) 496-5031  
Cell: (832) 570-6741  
Email: [tstclair@hess.com](mailto:tstclair@hess.com)

# **Regional Haze 4-Factor Analysis**

## **Tioga Gas Plant Facility Hess Corporation**

**Prepared for:**

**North Dakota Department of Health  
Environmental Health Section  
Gold Seal Center, 918 E. Divide Ave.  
Bismarck, ND 58501-1947**

**Prepared by:**

**Bison Engineering Inc.  
1400 11<sup>th</sup> Ave.  
Helena, MT 59601**

**Prepared on behalf of:**



**Hess Corporation  
1501 McKinney Street  
Office 21.104  
Houston, Texas 77010**

**March 15, 2019**

## **EXECUTIVE SUMMARY**

---

Bison Engineering, Inc. was retained by Hess Corporation to prepare a 4-Factor analysis for specific units located at their Tioga Gas Plant located at Tioga, ND. The 4-Factor analysis was requested by North Dakota's Environmental Health Section, Division of Air Quality in a letter dated May 18, 2018.

The analysis itself relates to "Round 2" of development of a State Implementation Plan (SIP) to address Regional Haze. Regional haze requirements and goals are found in Section 169A of the Federal Clean Air Act and codified in 40 CFR 51.308. The purpose of the 4-Factor analysis is, to determine if there are control options at Hess to reduce emissions that could be used to attain "reasonable progress" toward the state's visibility goals.

The 4-Factor analysis was conducted on three source groups at the Hess facility: amine sweetening unit, compressor engines and flares. The results of the analysis have indicated that additional controls on these units are not necessary to make reasonable progress due to costs and other considerations. It is concluded that these sources do not qualify for additional emission controls or limitations based on the 4-Factor analysis.

## **TABLE OF CONTENTS**

EXECUTIVE SUMMARY.....	ii
1.0 INTRODUCTION .....	1
2.0 APPROACH AND METHODOLOGY .....	3
3.0 4-FACTOR ANALYSIS .....	4
3.1 Factor 1: Cost of Compliance .....	16
3.1.1. Amine Gas Sweetening Unit.....	18
3.1.2. Compressor Engines .....	19
3.2 Factor 2: Time Necessary for Compliance .....	21
3.3 Factor 3: Energy and Non-Air Quality Environmental Impacts of Compliance .....	23
3.3.1. Amine Gas Sweetening Unit.....	23
3.3.2. Compressor Engines .....	24
3.4 Factor 4: Remaining Useful Life .....	26
4.0 CONCLUSIONS AND RECOMMENDED SELECTION.....	27

## **LIST OF TABLES**

Table 1: Additional Control Options by Source Group.....	5
Table 2: Est. Costs of Control Options for Hess Tioga Gas Plant Sources .....	17

## **LIST OF APPENDICES**

APPENDIX A: COST ANALYSIS	
APPENDIX B: BASELINE EMISSIONS	

## 1.0 INTRODUCTION

---

With the 1977 amendments to the Federal Clean Air Act (42 USC 7401 *et. seq.*) Congress declared as a national goal “... *the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory class I Federal areas which impairment results from manmade air pollution.*” [42 USC 7491(a)(1)]. With that goal, plans and requirements were eventually codified in the Code of Federal Regulations primarily in 40 CFR 51.308. (The entire visibility program is found in 40 CFR 51.300 → 309). Individual states are required to establish “reasonable progress goals” [40 CFR 51.308(d)(1)] in order to “attain natural visibility conditions” by the year 2064 [§308(d)(1)(i)(B)].

The state of North Dakota has met the first round of those obligations with the establishment of Best Available Retrofit Technologies (BART) for various sources. A second round of obligations is now under development. The Regional Haze Rule (RHR) requires an additional step toward ‘reasonable progress’ in meeting the national goal.<sup>1</sup> The RHR identifies four factors which should be considered in evaluating potential emission control measures to make reasonable progress toward the visibility goal. These are as follows:

- Factor 1. Cost of compliance
- Factor 2. Time necessary for compliance
- Factor 3. Energy and non-air quality environmental impacts of compliance
- Factor 4. Remaining useful life of any existing source subject to such requirements

These four factors are collectively known as the 4-Factor analysis.

To implement the requirement, the North Dakota Department of Health (NDDH) submitted a letter to Hess dated May 18, 2018. The letter noted that NDDH needed to address 80% of the visibility impairment caused by ND sources.<sup>2</sup> According to NDDH, visibility data from the IMPROVE ambient monitoring sites at Theodore Roosevelt National Park (TRNP) and Lostwood Wilderness Areas indicate that sulfates and nitrates (via SO<sub>2</sub> and NO<sub>x</sub>; respectively) are the largest contributors to visibility impairment.<sup>3</sup>

In order to determine which ‘nearby’ sources should be subject to a 4-Factor analysis, NDDH conducted a Q/d (emissions/distance) analysis of SO<sub>2</sub> and NO<sub>x</sub> for industrial

---

<sup>1</sup> The national goal is to attain natural visibility conditions in mandatory Class I areas by the year 2064 [40 CFR 51.308(d)(1)(i)(B)].

<sup>2</sup> According to NDDH this value is derived from information contained in EPA’s Draft Guidance on Progress Tracking Metrics, Long Term Strategies found at: [https://www.epa.gov/sites/production/files/2016-07/documents/draft\\_regional\\_haze\\_guidance\\_July\\_2016.pdf](https://www.epa.gov/sites/production/files/2016-07/documents/draft_regional_haze_guidance_July_2016.pdf).

<sup>3</sup> Hess does not necessarily agree or disagree with this assessment at this time. Hess is providing the information in this document as requested by NDDH.

sources within the state. That analysis has indicated that there are three Hess sources (or source groups) that warrant the analysis according to NDDH. These sources are:

1. Amine Gas Sweetening Unit (Emission Unit S302)
2. Clark Compressor Engines (Emission Units CIA- CIG)
3. Flares (Emission Units S101 and S102)

Therefore, NDDH has requested HESS conduct a 4-Factor analysis for these units to assess potential reductions in SO<sub>2</sub> and NO<sub>x</sub> emissions. The May 18 letter and followup communication requested the analysis be completed no later than March 15, 2019.

Although NDDH requested an analysis of both SO<sub>2</sub> and NO<sub>x</sub> for all three source groups, subsequent analysis prompted a small change to the request. Based on correspondence between Hess and NDDH<sup>4</sup>, it was agreed no robust analysis was necessary for SO<sub>2</sub> for the Clark Compressor Engines. Since these engines are fired with pipeline quality natural gas, there are no substantive SO<sub>2</sub> emissions from this source category. A similar conclusion was reached with respect to NO<sub>x</sub> emissions from the Amine Gas Sweetening unit. At the time of the email correspondence it was believed that NO<sub>x</sub> emissions from these units are low, so there would be no real visibility benefit by attempting to add additional NO<sub>x</sub> controls. However, subsequent review found a published emission factor for these units. The published factor indicated a low emission rate, as suspected. However, since an emission rate was available, it was decided to proceed with an analysis even though the reduction in NO<sub>x</sub>, should additional controls be added, would not yield any measurable improvement in visibility.

Based on the discussion above and agreement with NDDH<sup>5</sup>, no formal SO<sub>2</sub> analysis was conducted for the compressor engines. For completeness, an NO<sub>x</sub> review was conducted for the Amine Sweetening Unit albeit with low actual emission rates.

The remainder of this document outlines the approach used to conduct the 4-Factor analyses along with a detailed analysis for each group.

---

<sup>4</sup> Email to David Stroh from Tony St Clair (9/14/18) and associated reply (9/17/18)

<sup>5</sup> Ibid.

## 2.0 APPROACH AND METHODOLOGY

---

The Tioga Gas Plant, the subject of this 4-Factor analysis, is located at 10340 68<sup>th</sup> Street NW in Tioga, North Dakota. The location is W½, NE¼ S26, T157N, R95W in Williams County. The plant is used to process natural gas from well sites for sale to customers.

Letters dated May 18, 2018 and January 16, 2019 from NDDH provided some recommendations for conducting the 4-Factor analysis. That information was supplemented based on an email from David Stroh (NDDH) to Tony St. Clair (Hess) which provided further discussion and recommendations (June 2018). The matter was again discussed in two conference phone calls between the staff of NDDH, Hess, and Bison Engineering on June 20, 2018 and January 30, 2019.

The most complicated or in-depth analysis of the four factors is Factor #1: Cost of Compliance. The NDDH email and phone conversation suggested this analysis should follow, in general terms, the methods conducted for a Best Available Control Technology (BACT) review. The agency made clear that this is not, in and of itself, a pure BACT analysis; only that the typical steps might be followed.

In addition to the direct contact with NDDH described above, EPA has provided draft guidance (EPA Draft Guidance) of its own for the entire Round 2 procedures including suggested methods for assessing the Cost of Compliance as well as the other 3 factors.<sup>6</sup> That guidance was published in July 2016 as a draft. We are not aware that the Draft Guidance has been finalized. Nonetheless, since this was the most recent EPA guideline available, that document was consulted for conducting this 4-Factor analysis.

In general, the cost analysis uses the overall approach for BACT, but is modified by the EPA Draft Guidance<sup>7</sup> and EPA's Control Cost manual<sup>8</sup>. The approach used in this analysis follows these recommendations and guidelines as much as practicable. The other 3 factors employed suggestions from the EPA Draft Guidance as much as reasonable or available data might have allowed.

---

<sup>6</sup> "Draft Guidance on Progress Tracking Metrics, Long-term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period," EPA, EPA-457/P-16-001, July 2016.

[https://www.epa.gov/sites/production/files/2016-07/documents/draft\\_regional\\_haze\\_guidance\\_july\\_2016.pdf](https://www.epa.gov/sites/production/files/2016-07/documents/draft_regional_haze_guidance_july_2016.pdf)

<sup>7</sup> Ibid.

<sup>8</sup> EPA Cost Control Manual (sixth edition): <https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution#cost%20manual>

### 3.0 4-FACTOR ANALYSIS

---

A 4-Factor analysis was completed for the three Hess sources/source groups selected by the NDDH Q/d analysis. The following outlines the analysis for each source using primarily the direction of the EPA Draft Guidance<sup>9</sup> and the WRAP 2009 4-Factor analysis<sup>10</sup>.

The initial step in the 4-Factor analyses was to identify possible additional control options for each source or source group. The options chosen include control techniques addressed in guidelines published by the EPA, emission control cost models such as AirControlNET, Best Available Retrofit Technology (BART) analyses, White Papers prepared by the Midwest Regional Planning Organization (MRPO), and National Association of Clean Air Agencies (NACAA).

The options for each source/source category are summarized in the Table 1.

---

<sup>9</sup> “Draft Guidance on Progress Tracking Metrics, Long-term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period,” EPA, EPA-457/P-16-001, July 2016.  
[https://www.epa.gov/sites/production/files/2016-07/documents/draft\\_regional\\_haze\\_guidance\\_july\\_2016.pdf](https://www.epa.gov/sites/production/files/2016-07/documents/draft_regional_haze_guidance_july_2016.pdf)

<sup>10</sup> “Supplementary Information for Four-Factor Analyses for Selected Individual Facilities in North Dakota”, Brad Nelson, William Battye, Janet Hou, EC/R Incorporated, Western Regional Air Partnership (WRAP) and Western Governors’ Association (WGA), May 18, 2009



**Table 1: Additional Control Options by Source Group**

Source	Emission Unit ID	Pollutant	Existing Controls	Control Efficiency (Existing)	Potential Additional Control Measures
Amine Gas Sweetening Unit (Sulfur Recovery Unit)	S302	SO <sub>2</sub>	2-Stage Claus + Cold Bed Adsorption (CBA) + tail gas incinerator	>98%	Oxidation or Reduction Options (Tail-Gas Scrubbing Treatment Unit, LO-CAT, Paques biological processes)
		_____		_____	Traditional Flue Gas Desulfurization (FGD)
		NO <sub>2</sub>		---	SCR
		SO <sub>2</sub>		>98%	Acid Gas Disposal via Injection Well
Clark Compressor Engines (Natural gas pipeline compressor engines)	C1A through C1G	NO <sub>2</sub>	Lean Burn Engines	---	Low Emission Combustion (LEC) - Turbocharge - Air-to-fuel - Ignition timing - Etc.
					SCR
					Electric Motor Replacement
Acid/Wet Gas Flare And High Pressure Flare	S101 and S102	SO <sub>2</sub> NO <sub>2</sub>	None	---	Flare Management Plan

### *Amine Gas Sweetening Unit (SO<sub>2</sub>)*

The amine gas sweetening unit at the Hess Tioga Gas Plant facility controls sulfur dioxide (SO<sub>2</sub>) emissions via two steps. The first is a 2-stage Claus process. This process converts hydrogen sulfide (H<sub>2</sub>S) and SO<sub>2</sub> into elemental sulfur (S) via the 'Claus' reaction. The general reaction is:  $\text{H}_2\text{S} + \text{SO}_2 \leftrightarrow \text{S} + \text{H}_2\text{O}$  (unbalanced). To drive the reaction toward completion, the facility further utilizes Cold Bed Adsorption (CBA) which allows this reversible reaction to proceed further. The CBA was installed in 1991. All-in-all the unit collectively reduces SO<sub>2</sub> emissions by 98+%.

### *Treatment Options*

The most common control measures that may be applied to a typical refinery-based Claus facility (with or without CBA) are generally categorized as Tail-Gas Scrubbing Treatment units (TGST). These units use either an oxidation or a reduction measure to continue to convert the underlying sulfur gas to elemental sulfur. Another common measure of removing sulfur dioxide from a gas stream is a traditional Flue Gas Desulfurization (FGD) unit that is more typically used at coal or oil-fired electrical generating units. The final option which could be applied is injecting the gas into a deep well for disposal.

The TGST control typically adds an additional scrubbing process to the Claus exhaust stream prior to the tail-gas incinerator. The processes classically convert the Claus exhaust to either H<sub>2</sub>S (reducing process) or SO<sub>2</sub> (oxidizing process). In either case, the 'newly created' H<sub>2</sub>S or SO<sub>2</sub> is then, in most cases, returns these gases to the Claus or CBA portion of the facility to extend the elemental sulfur recovery.

There are a number of processes that achieve this aim. Regarding the oxidation method, the exhaust stream from the CBA would oxidize the various sulfur compounds (S, H<sub>2</sub>S, COS ...) to sulfur dioxide. The sulfur dioxide is then concentrated and used in the Claus/CBA process itself. There are several varieties of processes within the oxidation method. They include the Stauffer, Wellman-Lord, and Aquaclaus. Only the Wellman-Lord process has been applied successfully in any US refinery.<sup>11</sup>

The reduction process, however, is the more typical refinery-based method of additional sulfur dioxide control. This process converts the sulfur gases from the Claus (or CBA) to H<sub>2</sub>S. The H<sub>2</sub>S is then sent to a scrubber for removal prior to a tail-gas incinerator. The H<sub>2</sub>S scrubber typically uses an amine process (similar to the amine unit itself) to capture the H<sub>2</sub>S and then recycles this captured H<sub>2</sub>S (now in a concentrated stream) back to the Claus plant.

Five common systems utilizing the reduction control method are the LO-CAT<sup>®</sup>, Beavon, Beavon MDEA, Shell Claus Off Treatment (SCOT), and ARCO. The most common among these are the LO-CAT<sup>®</sup> and SCOT units. Additional oxidation-reduction processes

---

<sup>11</sup> AP-42, Section 8.13, 1995, p 8.13-4.

for converting H<sub>2</sub>S into sulfur include Sulferox, Stretford, and Paques biological process. For the oxidation-reduction processes, LO-CAT® has been among the predominant industry choice.<sup>12</sup> LO-CAT® is a proprietary liquid redox process that converts H<sub>2</sub>S in the acid gas to solid elemental sulfur using an aqueous solution of iron as catalyst. LO-CAT® units are in service treating refinery fuel gas, off gas, sour-water-stripper gas, amine acid gas, and Claus tail gas. The acid gas stream is compressed and fed to a LO-CAT® Absorber unit where it contacts a dilute, iron chelate catalyst solution and the H<sub>2</sub>S is absorbed and oxidized to solid sulfur. Sweet gas leaves the absorber for disposal via a tail gas disposal system. The reduced catalyst solution returns to the oxidizer, where sparged air reoxidizes the catalyst solution. The catalyst solution is then returned to the absorber. Sulfur is concentrated in the bottom of the oxidizer and sent to a sulfur filter, which produces the solid sulfur filter cake.

The other oxidation-reduction processes are not included for further consideration for the following reasons:

- Shell's Sulferox is effectively a more concentrated form of the LO-CAT® solution, but with resulting operational issues that makes it less widely used.
- Stretford has significantly declined in popularity due to environmental concerns due to the heavy metal vanadium used in the process.
- The Paques Biological Process has capital intensity similar to LO-CAT®, but with much less operational history, using sodium hydroxide and a bioreactor in the process to generate sulfur cake instead of the LO-CAT® approach using aqueous iron catalyst and air.

There are other units designed for refinery-like facilities to remove additional sulfur from the CBA stream. These include the Superclaus<sup>13</sup>, Euroclaus<sup>14</sup> and others. For purposes of this analysis, however, it was decided not to attempt a specific cost analysis for each process mentioned above. It is more reasonable to pick one of the methods described above and conduct an analysis on that process.<sup>15</sup> It seems more than reasonable to presume that the cost of one of these processes is within the range of what might be expected for any single process. Additionally, cost estimates for these other processes is not readily available. For example, there is no recent published data for the SCOT, Superclaus or Euroclaus. Additionally, cost data is very vague or not available for many of the other units as well.

It was decided to use the LO-CAT® process as a surrogate for any and all of the oxidation or reduction options discussed above. Hess has received cost estimates from a proprietary vendor, Merichem, that provided some of the capital, indirect, and operation

---

<sup>12</sup> MeriChem reports 200+ installations. <http://www.merichem.com/gas/upstream/natural-gas/lo-cat>

<sup>13</sup> Information regarding the Superclaus may be found here:

[http://www.digitalrefining.com/literature/1000817,Sulphur\\_Recovery\\_SUPERCLAUS\\_\\_\\_Process.html#.W-TGFPZFzDI](http://www.digitalrefining.com/literature/1000817,Sulphur_Recovery_SUPERCLAUS___Process.html#.W-TGFPZFzDI)

<sup>14</sup> Information regarding the Euroclaus may be found here.

[http://www.digitalrefining.com/literature/1000580,Sulfur\\_recovery\\_\\_\\_EUROCLAUS\\_\\_\\_process.html#.W-TFnfZFzDI](http://www.digitalrefining.com/literature/1000580,Sulfur_recovery___EUROCLAUS___process.html#.W-TFnfZFzDI)

<sup>15</sup> This approach is discussed in the EPA Guidance. (See footnote 9).

costs associated with the installation and operation of the system specifically at the Tioga facility. The removal efficiency among all the units, including the LO-CAT®, are similar. They all range in sulfur removal from about 80 to 90% above the current operating system (98+%). Should the results of the LO-CAT® (as a representative of oxidation or reduction option) prove favorable, then a more detailed review of some of the options would have been useful.

### **Flue Gas Desulfurization (FGD)**

The second class of sulfur dioxide scrubbing for consideration is the traditional Flue Gas Desulfurization (FGD) unit. As noted earlier, this is the typical sulfur dioxide control system found in most coal and oil-fired electrical generation systems across the U.S. The FGD unit may be configured as a wet, semi-dry, or dry scrubber system. In all cases an alkaline compound (typically  $\text{CaCO}_3$  or  $\text{CaO}$ ) is used to react with  $\text{SO}_2$  (an acidic gas) to form a compound such as  $\text{CaSO}_3$ . The  $\text{CaSO}_3$  (and its related compounds) are then removed via a particulate control device such as a baghouse. EPA estimates FGD units' reduction emissions in the range of 50% to 98% where typically wet scrubbers achieve the highest control potential.<sup>16</sup>

While this may seem attractive, the FGD scrubbers have significant *a priori* disadvantages for this application. Among them include:

- (a) In order to operate an FGD system, it is necessary to have a significant amount of (solid) material handling equipment on site. This would also include a large surface area to store, move and otherwise handle the reagent and spent-reagent material. This equipment and space might typically be available and designed in an FGD installation such as a coal-fired electrical generation station which handles materials (coal, e.g.) on routine basis. For this gas processing facility, however, none of the required space nor handling equipment is readily available. This would require a significant redesign of the facility in both layout and surface disturbance.
- (b) FGD systems require a particulate control device to remove the alkaline scrubbing agent ( $\text{CaCO}_3$ ,  $\text{Ca(OH)}_2$ ,  $\text{CaO}$ , ...). In a typical power plant facility, a control device to remove particulate would be required regardless of the  $\text{SO}_2$  scrubber. For this application, however, no such device is installed nor necessary as particulate emissions from amine sweetening units (with Claus sulfur recovery) is nearly non-existent.

Thus, in order to install and operate an FGD for this facility, not only is an FGD itself necessary, but a complete particulate removal system will be required as well (typically a fabric filter). Thus, the FGD will add a new

---

<sup>16</sup> EPA Air Pollution Control Technology Fact Sheet – Flue Gas Desulfurization:  
<https://www3.epa.gov/ttn/catc1/dir1/ffdg.pdf> \*

particulate emissions source at this facility; offsetting some of the reduction achieved by the sulfur-removing FGD system.

- (c) An FGD system, regardless of the type, will require disposal of the spent reagent. Since space is limited at this site, the disposal will most likely take place at a “new” landfill. Thus, in addition to the cost necessary for the FGD, a suitable landfill site would need to be identified and a permit would need to be obtained. This would be a significant undertaking and not especially productive given other non-FGD processes are available.
- (d) The non-FGD processes described earlier are more efficient at reducing sulfur compounds from entering the atmosphere than FGD. The control efficiencies for FGD would likely peak at about 80 to 90% (due to low concentration streams). Non-FGD units are expected to be significantly better.
- (e) For wet scrubber FGD, a complete water system, including disposal, would be required. This is clearly unnecessary given other alternatives and the potential environmental consequences.
- (f) To our knowledge, no FGD system has been installed at any gas processing facility such as the Tioga plant. This fact makes it clear that an FGD system is not a viable option for consideration.
- (g) Finally, it is noted that the WRAP 2009 4-Factor analysis did not itself address nor consider FGD as an available technology. There was no discussion or cost estimates for this control technology.

For all of the reasons above, it was decided to not pursue the FGD option further and it was dropped from analyses that follow.

#### **Acid Gas Disposal (AGD) Injection Well**

Another theoretical control option is acid gas disposal (AGD) for the removal of sulfur dioxide and additional waste stream pollutants. This alternative was suggested by the agency as an item for consideration. AGD disposes of the SRU waste gas stream by compressing and injecting the acid gas into a suitable reservoir through an injection well. The control could dispose of the waste stream directly from the SRU.

The gas would be compressed through five stages (engines) of compression to achieve the appropriate pressure for injection into a reservoir. A gas dehydration unit would be required between compression stages four and five to remove water from the acid gas prior to injection. This step reduces hydrate and corrosion risks since water in the presence of high-pressure acid gas would prevent the use of normal metallic equipment and would result in significantly increased costs for the disposal of pipeline and well material. Compression would be achieved by electric drivers.

It has not been established at this early stage whether this option is technically feasible within the meaning of the 4-Factor (via BART) analysis. It is true that this technology has been used in some limited cases and thus it is 'possible' to apply. However, this technology is applied much differently than a typical pollution control technology. Typically, a particular control device is engineered, purchased and then installed on site. AGD is not that case. A key feature is to remove the gas many miles away and dispose of the gas in an unknown location. All of this assumes that it would be 'feasible' to purchase or lease land that Hess does not own and install or purchase a well for which no permit has been obtained and no location identified. Thus it is a folly to suggest this option is technically feasible at this time. It is not known if any disposal well might be appropriate or available in which multiple miles of right-of-way are required through property not yet identified or if the land owner would, in fact, provide permission and at a cost not yet determined. Nonetheless and at the request of the agency, a modest analysis as attempted. Hess does not acquiesce that this option is feasible.

AGD would require the construction of a pipeline and installation of an injection well into an effective formation. Pipeline and injection well tubing size were estimated by Hess along with associated costs for this analysis. Capital cost of compression and dehydration equipment are provided by proprietary vendor data. The project assumes that the compression system would be installed at the Tioga Gas Plant and the high-pressure acid gas would be exported via a 5-mile (initial estimate) pipeline to a new injection well. The assumed formation for injection was the Dakota formation, an aquifer currently used for water disposal from Tioga Gas Plant.

Acid gas injection has, from time to time, been used in North Dakota and has been used before to replace SRU units. However; confirmation of an acceptable injection zone and well location would require significant evaluation, no yet achieved, to understand the risks associated with the process (i.e., sufficient pressure/capacity/seal of a formation, integrity of the casing of nearby wells, and proximity of the Tioga community). In addition, the time to complete the required subsurface work and obtain the required permits for the AGD operation would make this a multi-year endeavor even if the option were feasible.<sup>17</sup>

### *Amine Gas Sweetening Unit (NOx)*

The amine gas sweetening unit at the Hess Tioga Gas Plant facility contains no NOx post-control technologies; nor are any needed. NOx emissions from these units are typically very small, negating the need for post controls. Hess had suggested to NDDH that it was not necessary to conduct a 4-Factor analysis for this pollutant/unit. It was later discovered that a published emission factor was available for this unit.<sup>18</sup> Despite a low baseline emission rate for this unit (< 50 tons/year) an NOx analysis proceeded.

---

<sup>17</sup> The vendor estimates a 3-year delivery time for the basic package.

<sup>18</sup> Emission Factor = 0.1 lb/10<sup>6</sup> BTU (AP-42, Table 8.13-2, April 2015)

A review of the literature indicates that the only practical technology that might be applied to this unit would be Selective Catalytic Reduction (SCR). SCR technology and its requirements and limitations are explained in detail below in the Compressor Engines section. For the sake of brevity, it will not be repeated here. For purposes of our analysis, however, it has been assumed that such a technology might achieve between 70% and 90% reduction in actual emissions.<sup>19</sup> (The actual NOx concentration in the steam is low, thus the anticipated percentage reduction would be modest at best).

Although a cost analysis has been conducted for this technology, it is not a foregone conclusion that such an application of SCR would be useful for Round 2. The emission reduction is small from a mass point of view. In addition, we are not aware that SCR has ever been applied at an amine unit anywhere in the US or elsewhere.

### **Compressor Engines (NOx)**

The gas-fired engines at the Tioga facility drive integral compressors that boost the inlet field gas pressure for processing. The engines are fueled by a portion of the gas stream (pipeline quality fuel gas) produced by the plant. The exhaust gases from each compressor engine are released to the atmosphere through individual stacks.

The seven Clark Engines that have been identified by NDDH are large integral engines; i.e. the engines themselves and the compression structure are constructed as a single unit. Thus, replacement of these engines would be extraordinarily expensive and difficult as both the compression and engine would need to be replaced. Regardless, there are five 1,950 horsepower (hp) engines and two 2,250 hp engines. The two 2,250 hp engines were modified in 2004 by adding turbocharging systems and other means to lower emissions. The emissions from these two engines are about 75% less than the other engines and as such were not subject to additional analyses. The remaining five engines have not been substantively updated since they were installed in the 1950's although they have been maintained in good working order.

Three control options were assessed for the five 1,950 hp Clark Engines: Low Emission Controls (LEC); Select Catalytic Reduction (SCR) and converting engines from gas to electric power.

#### **i) Low Emission Controls (LEC)**

LEC application includes various upgrades, modifications, and engine tuning improvements. These typically include a combination of turbocharging [increases air-to-fuel (AFR) ratio], intercooling, enhanced mixing (high pressure fuel injection) and an

---

<sup>19</sup> This is the range provided by the EPA Air Pollution Control Technology Fact Sheet for SCR: <https://www3.epa.gov/ttn/catc1/dir1/fscr.pdf>

increase in ignition energy.<sup>20</sup> LEC is the preferred approach to reduce lean burn engine NOx emissions when compared to alternative options such as SCR.<sup>21</sup>

LEC modifications provide additional air to a controlled engine which, as a result, reduces maximum combustion temperature and minimizes NOx formation. Excess air may hinder combustion of the air-to-fuel ratio in the cylinder, so a high energy ignition source is generally required for engines equipped with LEC. Pre-chamber combustions systems are generally used to aid in combustion, however the power operating range may decrease on two-stroke cycle engines as a result of an LEC conversion. The term “LEC” is often used broadly to describe a number of technology approaches that can be used depending on the engine and NOx emission limit. Normally, multiple LEC related technologies may be required. Therefore, LEC system modifications assessed for the 5 Hess compressor engines were assumed to be on the high end of any given range of costs.

The reduction in NOx emission rates expected from the application of LEC is roughly 70% to 90% (The same reduction may be expected for SCR). For purposes of this 4-Factor analysis and as a matter of consistency among the engines and control technologies (LEC vs SCR), it was presumed that each technology can achieve a controlled emission rate of 1 g/bhp-hr. This emission rate is about the same as a 90% reduction depending on the specific engine and technology. In addition, 1 g/bhp-hr is the emission rate applicable to most new internal combustion engines.<sup>22</sup> Since LEC would be applied to a set of older existing engines, the applied emission rate is conservatively low. The cost of compliance is assessed for LEC application to each of the five 1,950 hp Clark engines.

## ***ii) Select Catalytic Reduction (SCR)***

SCR is an exhaust control that could be applied to lean combustion engines which reduces NOx emissions by reacting NOx with ammonia or urea over a catalyst. Ammonia or urea is injected into the stream and requires a precise feed-rate based on the NOx concentration and the NO/NO<sub>2</sub> ratio of the NOx. This feed rate, coupled with a narrow temperature range, is critical. If the ammonia feed rate is too low, then the targeted reduction in NOx is not achieved; thus, failing in the agency’s intent to improve regional visibility. If the ammonia rate is too high, then free ammonia is released. The ammonia will itself react in the atmosphere to form compounds such as ammonium sulfate(s) and ammonium nitrate(s). Both compounds are the primary ‘culprit’ that has led to the already observed regional haze concern. Thus, an improper feed rate will lead to a worsening of regional haze rather than making an improvement.

---

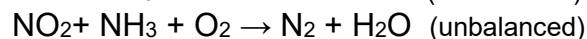
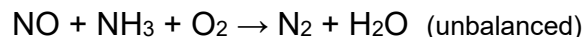
<sup>20</sup> “*Potential Impacts of the Ozone and Particulate Matter NAAQS on Retrofit NOx Control for Natural Gas Transmission and Storage Compressor Drivers*,” Interstate Natural Gas Association of America (INGAA), Report No. 2016-6, December 2017. <https://www.ingaa.org/File.aspx?id=33789>

<sup>21</sup> “*Availability and Limitations of NOx Emission Control Resources for Natural Gas-Fired Reciprocating Engine Prime Movers Used in the Interstate Natural Gas Transmission Industry*.” INGAA Foundation. July 2014. <https://www.ingaa.org/Foundation/FDNreports/NOx.aspx>

<sup>22</sup> 40 CFR 60, Subpart JJJJ, Table 1.



The process works by ammonia (the reagent) reacting with NO<sub>x</sub> on a catalyst bed to form water and N<sub>2</sub>. The reaction is characterized as follows:



While SCR has enjoyed a fairly wide applicability in power generation sources, its application to U.S. gas transmission sources has been very limited per INGAA 2014. That analysis details a number of the difficulties of applying SCR to gas transmission engines. These include:

- a) There are numerous technical concerns about SCR's application to compressor engines. Among them are exhaust temperature requirements, reagent control, and the treatment of potential variations in the reciprocating engine exhaust NO/NO<sub>2</sub> ratio.
- b) SCR has been more commonly applied to larger utility scale turbines and boilers and rarely used in compressor engines such as the Tioga facility.
- c) The use of SCR is most effective when operating in the exhaust temperature range of 480 to 800°F. The typical exhaust temperature range for some lean burn engines may present challenges because the minimum operating temperature of the catalyst is dependent on the composition of the exhaust gases and the type of catalyst materials used.
- d) Engines that have variable power loads, such as the case here, require more sophisticated controls to inject the proper amount of reagent, and it is not evident that robust control schemes have been developed for transmission applications.
- e) The installation of a continuous emissions monitor could be required to effectively control the amount of reagent necessary to achieve the desired NO<sub>x</sub> emission rate.
- f) SCR catalytic elements can be contaminated by byproducts of combustion (such as oil ash) and more importantly here; engine oil carryover. Cleaning and replacement is required on a periodic basis, and extra management is required to ensure adequate inventories of reagent are maintained.

While EPA claims that SCR is a technology applicable to compressor engines<sup>23</sup> SCR has, in fact, rarely been used in the natural gas transmission and related industry.<sup>24</sup> This does provide strong support for its use in this case.

LEC is nearly universally preferred over SCR for existing lean burn engines due to the issues described above. LEC works to prevent NO<sub>x</sub> formation while SCR acts to control already formed NO<sub>x</sub> in the exhaust stream.

---

<sup>23</sup> "Air Pollution Control Technology Fact Sheet," SCR, EPA-452/F-03-032.

<sup>24</sup> INGAA Foundation, *op. cit.*

### *iii) Electric Compressors*

The third option under (initial) consideration is replacing these natural gas-fired integral (engine + compressor as a single unit) units with an electric powered unit. This possibility has been rejected, however, because such an option does not fall within the suggested EPA Guidance for the identification of alternative controls.<sup>25</sup>

More specifically, the EPA Draft Guidance document discusses (relying on BART policies) the options that may or should be considered in identifying 4-Factor (via BART) control options. The Draft Guidance contains the following discussion (in identifying technologies outlined by BART and acceptable to the 4-Factor analysis):

*“Potentially applicable retrofit control alternatives can be categorized in three ways. Pollution prevention: use of inherently lower-emitting processes/practices, including the use of control techniques (e.g., low NOx burners) and work practices that prevent emissions and result in lower “production-specific” emissions (note that it is **not our intent to direct States to switch fuel forms, e.g., from coal to gas**), ...”* (emphasis added). EPA Draft Guidance, p 180.<sup>26</sup>

This comment alone suggests that a fuel switch is not necessarily within the realm of a 4-Factor analysis. Clearly a switch from natural gas to electricity is, in effect, a fuel switch and not the intent of the analysis. The document goes on to provide a more specific discussion:

*“We do **not consider** BART as a requirement to **redesign the source** when considering available control alternatives. For example, where the source subject to BART is a coal-fired electric generator, we do not require the BART analysis to consider building a natural gas-fired electric turbine **although** the turbine may be **inherently less polluting** on a per unit basis.”* (emphasis added). EPA Draft Guidance p. 198.<sup>27</sup>

Again, the Draft Guidance suggests that one does not need, nor should, consider what amounts to be a redefinition or fundamental change in the underlying facility/unit. If EPA rejects changing an electrical generation plant from coal-fired to a gas-fired turbine as inappropriate, the same logic applies here (gas-fired to electric).

For the reasons above, replacing these gas-fired engines with electric engines has been removed from further consideration.

---

<sup>25</sup> *Draft Guidance on Progress Tracking Metrics, Long-term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period,* EPA, EPA-457/P-16-001, July 2016.

[https://www.epa.gov/sites/production/files/2016-07/documents/draft\\_regional\\_haze\\_guidance\\_july\\_2016.pdf](https://www.epa.gov/sites/production/files/2016-07/documents/draft_regional_haze_guidance_july_2016.pdf)

<sup>26</sup> Ibid.

<sup>27</sup> Ibid.

### Flares (SO<sub>2</sub> & NO<sub>x</sub>)

The acid/wet gas flare (S-101) and high-pressure flare (S-102) operate intermittently at the Hess facility to combust off-spec gas and to address emergency/malfunction events. Both sources are to be assessed for additional NO<sub>2</sub> and SO<sub>2</sub> control. Additional control equipment systems for flare sources are not known or available for a facility whose emission rate is highly variable in both time and quantity. As a result, we are not able to identify any available control technologies for these two specific flares.

Even if a control technology were to present itself, the annual emissions from these two flares would almost certainly yield cost/ton of removal values that are not cost-effective. As evidence, the most recent 2-year average annual emissions for these two flares were:

#### SO<sub>2</sub>

S-101 = 21 t/yr @ 79 hours of operation per year  
S-102 = 40 t/yr @ 103 hours of operation per year

#### NO<sub>x</sub>

S-101 = 0.0 t/yr @ 79 hours of operation per year  
S-102 = 4.6 t/yr @ 103 hours of operation per year

The low total emissions produced by the flare sources would result in a high cost effectiveness in \$ per ton of emissions reduced since the total cost of implementation would only have the potential to control a minimal quantity of emissions. As a result, no further analyses of potential add-on controls were conducted for this source.

Nonetheless, a Flare Management Plan was also considered as a method for managing efficient operations of S-101 and S-102. The plan design could be similar to flare sources at petroleum refineries subject to 40 CFR Part 60 Subpart Ja which details the Standards of Performance for Petroleum Refineries for which Construction, Reconstruction, or Modification Commenced After May 14, 2007. A Flare Management Plan under subpart Ja requires various information such as: listing all refinery process units and systems connected to the flare; an assessment of whether discharges to the flare can be minimized; and an evaluation of the baseline flow to the flare. However, Hess, in agreement with NDDH, determined a Flare Management Plan would not be a necessary analysis due to the minimal operation of S-101 and S-102. Therefore, no additional analysis of a Flare Management Plan was conducted for these sources and is not included in Section 3.1 Cost of Compliance.

### 3.1 Factor 1: Cost of Compliance

The cost of compliance estimates the capital cost of purchasing and installing new control equipment along with the annual operation and maintenance (O&M) cost as generally outlined in EPA Draft Guidance. The 2009 WRAP analysis also delineated these cost parameters into the following categories: direct capital cost, indirect capital cost, labor cost, contingency cost, and annual cost. Methodologies given in the EPA Air Pollution Control Cost Manual (Control Cost Manual) are the indicated reference for determining the cost of compliance as directed by the EPA Draft Guidance.<sup>28</sup>

Costs were expressed in terms of cost-effectiveness in a standardized unit of dollars per ton of actual emissions reduced by the proposed control option. Baseline emissions for the Clark engines and SRU were evaluated to provide emission rates that are representative of the current operations' impact on actual observed visibility (haze) observations at Theodore Roosevelt National Park and the Lostwood Wilderness areas.<sup>29</sup> Appendix B contains a brief discussion and rationale for the specific baseline emissions chosen for the analyses in this document.

The capital recovery factor was applied to the control options based on a 20-year equipment life expectancy (25 years for SCR & LEC) applying the prime interest rate (5.5% as of December 19, 2018)<sup>30</sup>. The cost of compliance is analyzed by source/source group within Table 2 and the following sections.

---

<sup>28</sup> EPA Cost Control Manual (sixth edition): <https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution#cost%20manual>

<sup>29</sup> These are the two closest Mandatory Class I areas that are the subject of a regional haze analysis and form the basis for the need for any potential reduction in emissions from sources in and around North Dakota.

<sup>30</sup> <http://www.fedprimerate.com/>

**Table 2: Estimated Costs of Control Options for Hess Tioga Gas Plant Sources**

Source	Potential Control Option	Pollutant	Estimated Control Efficiency (%)	Potential Emission Reduction (tons/year)	Estimated Capital Cost (\$1000)	Estimated Annual Cost (\$1000/year)	Cost Effectiveness (\$/ton)
Amine Gas Sweetening Unit (SRU)	LO-CAT (or equivalent)	SO <sub>2</sub>	90%	545	32,193	7,199	\$13,217
	SCR	NO <sub>2</sub>	80% ↔ 90%	37	435	273	\$7,414
	Acid Gas Disposal via Injection Well	SO <sub>2</sub>	99%	599	17,788	2,288	\$3,821
Compressor Engines (Mean among 5 engines)	LEC	NO <sub>2</sub>	1 g/bhp-hr <sup>a</sup>	139	9,095	1,205	\$9,589 <sup>b</sup>
	SCR	NO <sub>2</sub>	1 g/bhp-hr <sup>a</sup>	139	745	892	\$7,098 <sup>c</sup>
Flares (2)	N/A	SO <sub>2</sub>	--	--	--	--	--
	N/A	NO <sub>2</sub>	--	--	--	--	--

<sup>a</sup> Emission reduction is assumed to achieve approximately 1 gram/bhp-hour.

<sup>b</sup> Cost effectiveness per engine ranged from \$16,567 to \$6,890. Individual values are found in Appendix A.

<sup>c</sup> Cost effectiveness per engine ranged from \$12,275 to \$5,103. Individual values are found in Appendix A.

<sup>d</sup> Capital cost does not include complete analyses in determining appropriate formation and injection scheme. Base-level research costs are accounted for however these costs could greatly vary in scale depending upon suitable geology, formation availability, and well and pipeline feasibility. While annual cost effectiveness appears favorable due to the 99% emissions reduction, the total capital cost is substantial and could likely exceed these early estimates.

### 3.1.1. Amine Gas Sweetening Unit

#### **LO-CAT® (SO<sub>2</sub>)**

The cost estimate of a LO-CAT® unit includes the capital cost of constructing the system which comprises the absorber, oxidizer, and filtrate systems. Additionally, the system will require an enclosure because the sulfur forms a solid filter cake that is moist. This creates freezing risks in the winter that necessitates a predominately indoor operation. Capital costs were provided as proprietary information from the vendor; Merichem.<sup>31</sup> Direct and indirect costs are evaluated using the EPA Control Cost Manual. Indirect costs include engineering design, permitting, construction and field expenses, contractor fees, start-up, performance testing, and contingencies. Operational costs are evaluated primarily from vendor data and other standard techniques. Operating chemical consumption costs are based on system requirements using Merichem proprietary chemicals and utilities. Estimated costs are detailed in Appendix A. Design, construction, and operation of a LO-CAT® system is projected to cost approximately \$13,217 per ton of SO<sub>2</sub> removed.

#### **SCR (NO<sub>x</sub>)**

To complete the analysis, a cost-effectiveness investigation was conducted for NO<sub>x</sub>. As noted earlier, the emission rate at this source is small and has, no doubt, an insignificant impact on regional haze. Regardless, a cost analysis was completed for SCR. Using the capital cost estimates found in EPA's Air Pollution Control Technology Fact Sheet, SCR, EPA-452/F-03-032,<sup>32</sup> Table 1a, the cost effectiveness for controlling NO<sub>x</sub> was estimated at \$7,414 per ton removed.<sup>33</sup> This value is outside the normal cost effectiveness range and thus is removed from further consideration.

#### **Acid Gas Disposal (SO<sub>2</sub>)**

The cost estimate of an AGD system includes the capital cost of constructing a 5-stage compression and acid gas dehydration system, a pipeline to export waste gas, and an injection well into a qualifying reservoir. Indirect costs are substantive due to the overall development of an AGD system which include engineering design of the compression and dehydration system, pipeline, well, and stormwater management system; soil site characterization; geological surveying for reservoir characterization; environmental, cultural, and wetland delineation for an environmental assessment; site surveying; field inspections; industrial commission permitting; and contractor and equipment transportation fees. Capital costs for the compression and dehydration equipment are derived from proprietary vendor data that does not include EXW cost such as loading, freight, installation, etc. Direct and indirect costs for freight, engineering, construction, etc. are calculated using guidance and factors provided in the EPA Air Pollution Control Cost Manual. Installation and equipment cost of the pipeline and injection well are estimated by Hess as these activities directly involve their product/business lines. Pipeline

---

<sup>31</sup> General information regarding Merichem and LO-CAT may be found: <http://www.merichem.com/gas>. The specific costs provided are considered Business Confidential by the vendor and are thus not provided in this document.

<sup>32</sup> <https://www3.epa.gov/ttnatcat1/dir1/fscr.pdf>

<sup>33</sup> Details of the calculation are found in Appendix A.

installation is calculated based on \$125,000 per foot-diameter mile of pipeline and the installation well cost is estimated at 10,000 ft true vertical depth with 2-7/8" tubing.

The total capital investment of an AGD system is estimated at approximately \$17,800,000 not including operating expenses or many other factors for which there is not enough information at this early stage. Based on this incomplete data, the cost effectiveness was estimated as \$3,821 per ton removed (SO<sub>2</sub>). If a more detailed analysis is warranted, the cost will, no doubt, rise substantially. This control option will require significant further evaluation to understand surface and subsurface risks (i.e., formation pressure-volume-seal, integrity of casing of nearby wells, proximity of the Tioga community, etc.) that are difficult to estimate at this early juncture. As a result, the cost of compliance is expected to be larger than this early estimate. Cost calculations for AGD are detailed in Appendix A.

### 3.1.2. Compressor Engines

The Clark Engines analysis included estimated costs for updating each of the five 1,950 hp with either LEC or SCR.

#### LEC (NO<sub>x</sub>)

The LEC analysis is based on various upgrades and changes to the 5 engines. At Hess' request, and unrelated to this 4-Factor project, Siemens<sup>34</sup> provided a cost estimate for a LEC upgrade to a Clark engines. The scope of work and cost estimate is Siemens proprietary information. An upgrade to LEC consists of the following per Siemens:

- Hardware and engineering costs for replacing the existing cooling systems with water pump systems to eliminate boil-off cooling.
- Field service, repairs, and parts replacement for zero-hour overhaul.
- Hardware, installation, and commissioning of a HPfi fuel injection upgrade that needs to include:
  - A single "Balance of Plant" engineering and hardware support for multiple engine revamps.
  - Hardware, installation, and start-up of the HPfi equipment.

Using this information, LEC direct capital costs are approximately \$4 million per engine. This cost coupled with the various emission rates for each of the five engines yielded a cost effectiveness ranging from \$16,567 to \$6,890 per ton of NO<sub>x</sub> removed. This equates to an average cost effectiveness among the 5 engines of \$7,577.

It is theoretically possible to apply LEC to a subset of engines (e.g., 2 of the 5 engines). Doing so would yield a slightly lower cost effectiveness because one of the capital expenditures quoted by the vendor (balance of plant) need only be done a single time regardless of how many engines are retrofitted at the instant in time. This cost savings

---

<sup>34</sup> <https://new.siemens.com/us/en.html>

assumes, of course, that all the retrofitted engines would be completed at the same time. That might prove problematic for plant operations as it is always imperative to have the necessary compression in the plant.

Regardless, it was instructive to briefly review the cost effectiveness of a retrofit for 2 (as an example) of the engines. Choosing the 2 lowest cost engines (\$/ton) would result as follows:

Engine C-1C:		
Stand Alone = \$6,890/ton	With 2 Engines = \$6,235	
Engine C-1E:		
Stand Alone = \$7,050/ton	With 2 Engine = \$6,296	

While a savings would be recognized, the degree of improvement is not notable nor would likely change a final 4-Factor conclusion (assuming there is any perceptible improvement in regional haze impact from any of the control options).

### **SCR (NO<sub>x</sub>)**

The capital costs for SCR, if one were to assume this was an 'achievable technology' for this application, are varied. There are a number of published cost estimates for typical coal- oil- and gas-fired medium to large sized boilers. The same cannot be said for a retrofit of a natural gas-fired compressor engine/compressor.

In addition, the cost of retrofit SCR is much higher than an original installation which would apply to this analysis. SCR systems used to retrofit an existing unit increase costs up to about 30%.<sup>35</sup> O&M costs may also be substantially dependent on reagent usage, catalyst replacement, and increased electrical usage. The average (all 5 engines) cost effectiveness of SCR was \$7,098 per ton removed. Individual engines ranged from \$12,275 to \$5,103. This cost effectiveness range coupled with multiple technical difficulties and its non-use in this general application does not make it an attractive Round 2 candidate.

The derivation of the capital cost figures, emission rates and other general information may be found in the appropriate tables in Appendix A.

---

<sup>35</sup> EPA Air Pollution Control Technology Fact Sheet – SCR: <https://www3.epa.gov/ttnatc1/dir1/fscr.pdf>



### 3.2 Factor 2: Time Necessary for Compliance

Per the EPA Draft Guidance, the provisions for this factor within the BART guidelines should be utilized to estimate time necessary for compliance. Additionally, the best guide to determine time necessary for compliance is prior experience with the planning and installation of new emission controls. Source-specific factors should be considered as well.

EPA has estimated that it takes approximately 30 months to design, permit, build, and install a typical SO<sub>2</sub> scrubbing control unit for a single source. No specific data was located as it regards the LO-CAT unit (or its equivalent). Using the EPA estimate as a guide, their analysis also determined that 12-months is additionally required for a project including the installation of control equipment on multiple sources. Another 12 months may be required for staging the installation process across the multiple sources. Finally, it is generally recognized that facilities may require a 1 year (or more) for the procurement of project funding.

As a result, the time necessary for compliance for the LO-CAT unit is estimated at between four and five years. This time period accounts for about one year of capital acquisition; two to three years for designing, permitting, constructing, and installing the control equipment; and one year for shakedown and commissioning.

A longer timeline would also be expected for the LEC conversion for the five engines discussed in this report. The installation, tuning and integration would need to be executed in a sequential fashion in order to keep the facility in operation during this time. This will stretch the 'time necessary for compliance.' No specific time-line is offered at the time of this report. However, it would be reasonable to suggest that the time needed would be 5 years (one per year) as a minimum and perhaps as long as 7 depending on commissioning and plant operations.

Although no specific data was found, it would be reasonable to assume that a five-year period would also be appropriate for the installation of SCR in lieu of LEC being required. Finally, it was further reasoned that this five-year period serves as an estimate for the time necessary for installation of an SCR unit on the Amine Sweetening Unit, although its (and others) installation is not justified for cost effectiveness reasons.

It is likely that an even longer timeframe would be required for AGD installation. To begin, a likely vendor/supplier of the compressor engines and acid gas dehydration equipment estimated a 3-year delivery for that equipment alone. Additionally, AGD requires initial land surveying and additional permitting. Substantial surveying would be required to determine the appropriate location for an injection well for both surface and subsurface purposes. Land acquisition could be required for the location of the injection well which would require surface title research to determine a database of landowners whom would allow AGD injection within their property. Subsurface research would also be required to verify mineral title requirements and geotechnical evaluations that ensure the proposed

formation has appropriate pressure limitations, volume, and seal. Additionally, a pipeline would need to be designed and permitted to connect the Tioga Gas Plant to a proposed injection well location posing additional challenges. These evaluations and logistics could add considerable time and unforeseen expense to an AGD project.

### 3.3 Factor 3: Energy and Non-Air Quality Environmental Impacts of Compliance

The provisions of the BART Guidelines are recommended for assessing both energy and non-environmental impacts. The EPA Draft Guidance states that an energy impacts assessment should be considered in terms of kilowatt-hours or mass of fuels used accounting for direct energy consumption cause by control implementation. Indirect energy inputs to produce the raw materials for construction of equipment should be excluded from the analysis. The Control Cost Manual is the preferred reference and provides advice on estimating energy requirements. Non-air environmental may include the cost associated with solid waste disposal, wastewater discharge, acid or nitrogen deposition, and climate impacts.

#### 3.3.1. Amine Gas Sweetening Unit

##### LO-CAT® or Equivalent.

Per Merichem (proprietary), a LO-CAT system does not use any toxic chemicals and does not produce any hazardous waste byproducts. It requires a reasonable amount of catalyst however it is continuously regenerated in the process. Spent catalyst may require disposal though the implications of disposal of this waste stream has not been analyzed at this time since the cost effectiveness does not make its use a practical alternative.

There is also an energy cost associated with this added level of emission controls. It has been estimated that this level of technology would require about 610 kW-hr of use.<sup>36</sup>

##### AGD Injection Well.

A new waste stream from compression and dehydrator unit will be generated from this control method. AGD via an injection well is the disposal of pipeline and well tubulars in the event of water entering the system due to dehydrator breakdown/failure. Acid gas in the presence of water creates hydrate and corrosion risk which significantly increases the proper disposal of pipeline and well material. Additional environmental risks from the construction of the pipeline and injection well will need to be mitigated through various permitting and Environmental Assessment processes.

There is also a substantial electrical input required to operate the 5-stages of compression. The compression units are estimated to require approximately 950 kW-hr of energy.<sup>37</sup>

---

<sup>36</sup> Proprietary information provided by Merichem.

<sup>37</sup> Proprietary information provided by compression and dehydration vendor.

### 3.3.2. Compressor Engines

#### SCR.

SCR control systems require the use of aqueous ammonia, anhydrous ammonia, or urea-to-ammonia reagents for the reduction reaction. Systems that use urea produce aqueous ammonia onsite. Anhydrous ammonia is nearly pure ammonia gas and must be transported and stored under pressure. Anhydrous ammonia is classified as a hazardous material which often requires special permits as well as additional procedures for transportation, handling and storage. Systems using aqueous ammonia transport and store the reagent concentration in water, generally  $\approx 28\%$  ammonia to water.<sup>38</sup> While aqueous ammonia can be safer to transport and store, the diluted ammonia concentration requires more storage capacity than anhydrous ammonia and requires shipping costs for the water solvent in the solution. Hess would be required to account for additional chemical storage, protection, and permitting with the additional reagent solution stored on site.

Additionally, SCR systems utilize catalysts to aid in NO<sub>x</sub> control. The catalysts are generally composed of active metals or ceramics with a highly porous structure. Activated sites are located within the pores of the catalyst and these sites have an acid group on the end of the compound structure where the catalytic reduction reaction occurs. The catalyst material reactivates via rehydration or oxidation after the reduction reaction occurs. This is a limited process, however, and over time the catalyst activity decreases, requiring replacement, washing/cleaning, rejuvenation, or regeneration of the catalyst. Catalyst storage, transport, and disposal must then be accounted for in the SCR control viability analysis.

An estimate was made of the aqueous ammonia feed rate necessary for the facility. It is estimated that with all 5 engines in operation, a feed rate of about 15 gallons per hour per engine would be necessary.<sup>39</sup> To handle this much material would require a large storage tank ( $\approx 18,000$  gallons for all engines) to have a 10-day supply. The storage or use of this quantity triggers the requirements of the accidental release program found in 40 CFR 68.<sup>40</sup> Depending upon specifics, a detailed amendment to the risk management plan (RMP) must be developed and implemented under this program. This only adds another layer of regulatory reporting along with an unnecessary risk by itself. The fact that such a plan would be required dampens its attractiveness for consideration.

---

<sup>38</sup> EPA Cost Control Manual (sixth edition): <https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution#cost%20manual>

<sup>39</sup> See general calculations and data found in Appendix A (from EPA Cost Control Manual).

<sup>40</sup> The program is triggered for aqueous ammonia use or storage greater than 20,000 pounds. The quantities described exceed this value.

LEC.

The LEC technology does not require the handling or storage of hazardous materials as is the case for SCR. The LEC technology does not require, on its face, changes in pressure drop across any system that could create an energy demand penalty.

### 3.4 Factor 4: Remaining Useful Life

The Hess Tioga Gas Plant remaining useful/service life is not specific at this time. As discussed in the 2009 WRAP Analysis, the service life of these emission sources at industrial facilities are difficult to estimate.

The startup dates for these units were:

Amine Sweetening Unit:	1991
Compressor Engines (5):	1954
Flares:	n/a

Regardless of the ability to select a particular time, the service life of the analyzed control technologies was estimated to be 20 years (25 years for LEC & SCR). The 20-year figure was used to amortize the capital costs of the add-on and modified (LEC and SCR for the compressor engines) emission controls at the recommendation of NDDH. Given the historical perspective, it is reasonable to conclude that the remaining life of the facility (Sweetening Unit and Engines) itself is expected to exceed the life of the control equipment.

The capital cost of the control equipment would need to be amortized over a shorter period if the remaining life of an emission source is less than the projected life of the new control equipment. Since this was not the case, the remaining equipment life of the facility is expected to equal or exceed the life of the analyzed technology options.

## 4.0 CONCLUSIONS AND RECOMMENDED SELECTION

---

A 4-Factor analysis has been conducted for the Hess Tioga facility. The analysis was conducted to meet the requirements of “Round 2” to develop of a State Implementation Plan (SIP) to address Regional Haze. Regional haze requirements and goals are found in Section 169A of the Federal Clean Air Act and codified in 40 CFR 51.308(d)(1). To implement the requirement, the North Dakota Department of Health (NDDH) submitted a letter to Hess dated May 18, 2018, seeking such an analysis.

The 4 factors to be analyzed based on the NDDH letter and the regional haze rule were:

- Factor 1. Cost of compliance
- Factor 2. Time necessary for compliance
- Factor 3. Energy and non-air quality environmental impacts of compliance
- Factor 4. Remaining useful life of any existing source subject to such requirements

NDDH then requested a 4-Factor analysis for SO<sub>2</sub> and NO<sub>x</sub> for the following source groups:

- 1. Amine Gas Sweetening Unit (S-302)
- 2. Clark Compressor Engines (C1A – C1G)
- 3. Flares (S-101 and S-102)

The emitting units were analyzed for these factors in general accordance with EPA's Draft Guidance.<sup>41</sup> The details of those results were presented in prior sections of this report.

---

<sup>41</sup> *Draft Guidance on Progress Tracking Metrics, Long-term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period*,” EPA, EPA-457/P-16-001, July 2016.  
[https://www.epa.gov/sites/production/files/2016-07/documents/draft\\_regional\\_haze\\_guidance\\_july\\_2016.pdf](https://www.epa.gov/sites/production/files/2016-07/documents/draft_regional_haze_guidance_july_2016.pdf)

## Amine Gas Sweetening Units.

### SO<sub>2</sub>

Three control technologies were considered for this unit-pollutant combination: Oxidation or Reduction Control (LO-CAT), Flue-gas desulfurization (FGD), and Acid gas disposal (AGD) via injection well. The LO-CAT technology (or its equivalent) essentially converts H<sub>2</sub>S in the acid gas to solid elemental sulfur using an aqueous solution of iron as catalyst. The FGD system, typically found in a coal-fired power plant, treats exhaust gas with an alkaline reagent (usually CaO or CaCO<sub>3</sub>) to remove SO<sub>2</sub>. The spent reagent (CaSO<sub>3</sub> or CaSO<sub>4</sub>) is then collected in a fabric filter unit in which the collected dust must be treated in a licensed landfill. AGD requires substantial design and preliminary surveying to determine the appropriate geological formation to install an injection well, pipeline, and compression-dehydration system.

It is concluded that the FGD system is not practical nor appropriate for this application. Those reasons include (but not limited to):

- A new emitting source (particulate) would be added to the plant offsetting some of the benefits of a reduction in SO<sub>2</sub>;
- A new disposal system would be required to treat the spent reagent,
- FGD has never, to our knowledge, been used in treating SO<sub>2</sub> emissions from any gas processing facility; and
- The prior (2009) 4-Factor analysis for this facility did not identify nor consider FGD as a viable technology.

The LO-CAT® technology (or its equivalent) was analyzed. While the technology may be applied to a facility like the Tioga plant, it was rejected due to its high cost effectiveness (≈ \$13,217/ton).

AGD is also not practical nor appropriate due to the unknown costs associated with determining surface and subsurface risks prior to the development of the pipeline and injection well. Additionally, the energy and environmental impacts add to the impracticality of this control option due to the additional electricity required to drive compression (nearly 1 megawatt).

### NO<sub>x</sub>

Although the emission rate of NO<sub>x</sub> from the unit is very low, an analysis for this unit was conducted for thoroughness. The technology identified most probable for this unit is Selective Catalytic Reduction (SCR). SCR was rejected as inappropriate for numerous reasons including its rare use in integral engine-compressors and even more notably SCR's high cost (≈ \$7,414/ton). Therefore, SCR is not a candidate for Round 2 emission reductions.



## Compressor Engines.

### NO<sub>x</sub>

There were two control technologies identified for reducing NO<sub>x</sub> from these units: SCR and Low Emission Control (LEC).

LEC is a system of upgrades, modifications and tuning of the engines to achieve a lower emission rate. LEC could, theoretically, be applied to each of the 5 compressor engines subject to this analysis.

The cost effectiveness of this technology was excessive. The average cost effectiveness was \$9,589/ton for each of the 5 engines. The engine-by-engine cost effectiveness ranged from roughly \$6,890 to as high as \$16,567 depending on the engine. Since these values are considered excessive, LEC has been removed from consideration for Round 2.

SCR was also analyzed as a potential control technology. However, SCR is rarely, if ever, used for this type of application. Evidence of that stems from several reports. One recent study (2014) makes the following comment: *“To date, SCR application to U.S. gas transmission sources has been very limited, and SCR has not been applied to **an existing integral engine** (emphasis added).”*<sup>42</sup> The 5 engines at the Tioga facility are existing integral engines as described in the report. In addition, an even more recent report failed to consider SCR a noteworthy technology for reducing NO<sub>x</sub> emissions from transmission and storage compressors as a means of achieving the ambient NO<sub>x</sub> standards.<sup>43</sup>

Additionally, SCR carries the burden of handling and storing either anhydrous ammonia (NH<sub>3</sub>) or aqueous ammonia (NH<sub>4</sub>OH). This would require new equipment in which to transport and handle this material. In both cases, the storage quantities necessary will trigger the need for a Risk Management Plan (RMP) required by the Accidental Release program (40 CFR 68) in order to address the potential of a spill or release that could have public health implications. The addition of this equipment constitutes an unnecessary risk for the purpose of regional haze.

In addition to the burdens described, the efficacy of the control technology is at issue. For SCR to work effectively, a precise ammonia feed rate

---

<sup>42</sup> “Availability and Limitations of NO<sub>x</sub> Emission Control Resources for Natural Gas-Fired Reciprocating Engine Prime Movers Used in the Interstate Natural Gas Transmission Industry.” INGAA Foundation. July 2014, Page 9. <https://www.ingaa.org/Foundation/FDNreports/NOx.aspx>

<sup>43</sup> “Potential Impacts of the Ozone and Particulate Matter NAAQS on Retrofit NO<sub>x</sub> Control for Natural Gas Transmission and Storage Compressor Drivers,” Interstate Natural Gas Association of America (INGAA), Report No. 2016-6, December 2017. <https://www.ingaa.org/File.aspx?id=33789>

coupled with a narrow temperature range are necessary. Both conditions would be difficult to maintain due to varying loads on the compressor engines themselves.

Finally, the cost effectiveness of SCR is, overall, excessive. The average cost effectiveness was \$7,098 for all 5 engines. The engine-by-engine effectiveness ranged from roughly \$5,103 up to \$12,275. Due to these costs, the technical concerns, the need to handle hazardous materials and the nearly universal lack of use of SCR for legacy compressor engines, SCR is rejected for Round 2 purposes.

## **Flares.**

### **NO<sub>x</sub> and SO<sub>2</sub>**

A review of the literature does not yield any 'available' control technology to control either NO<sub>x</sub> or SO<sub>2</sub> emissions from these highly intermittent sources such as the Tioga flares. The flares primarily serve emergency and other upset conditions. For example, each flare operated 0.1% of the time in the past 2 years. Clearly, any control technology, even if it were available, would not have a measurable impact on the regional haze long-term goals. Because no reasonable technology is available, and no measurable regional haze benefit would be realized, it is concluded that there are no technology options available for these sources.

A Flare Management Plan similar to flare sources at petroleum refineries subject to 40 CFR Part 60 Subpart Ja would also not be appropriate due to the minimal flaring events at S-101 and S-102. Therefore, no additional analysis of a Flare Management Plan was conducted for this source.

Following a careful review of the information it is concluded that additional emission controls and limitations for these sources are not necessary to make reasonable progress based on the 4-Factor analysis.

## APPENDIX A: COST CALCULATIONS

---

**Amine Sweetening Unit (S-302)**

**Sulfur Dioxide**

**LO-CAT (or equivalent) Control Technology**

*Hess Corporation*  
*4-Factor Cost Analysis*  
*Tioga Facility*  
*SRU*

**Total Capital Costs - Lo-Cat**

Total Capital Costs for LO-CAT		
Cost Item	Factor	Cost
<b>DIRECT COSTS</b>		
Purchased equipment costs		
LO-CAT Capital	A	\$21,000,000
Instrumentation	0.10 A	(included)
Sales taxes	0.05 A	(included)
Freight	0.05 A	\$1,050,000
<b>Purchased equipment cost, PEC</b>	<b>B = 1.15 A</b>	<b>\$22,050,000</b>
Direct installation costs		
Foundations & supports	0.08 B	\$1,764,000
Handling & erection	0.14 B	\$3,087,000
Electrical	0.04 B	\$882,000
Piping	0.02 B	\$441,000
Insulation for ductwork	0.01 B	\$220,500
Painting	0.01 B	\$220,500
<b>Direct installation cost</b>	<b>0.30 B</b>	<b>\$6,615,000</b>
Site preparation	As required, SP	-
Buildings	As required, Bldg.	-
<b>Total Direct Cost, DC</b>	<b>1.30 B + SP + Bldg.</b>	<b>\$28,665,000</b>
<b>INDIRECT COSTS (Installation)</b>		
Engineering	0.10 B	\$2,205,000
Construction and field expenses	0.05 B	\$1,102,500
Contractor fees	0.10 B	(included)
Start-up	0.02 B	(included)
Performance test	0.01 B	\$220,500
Contingencies	0.03 B	(included)
<b>Total Indirect Cost, IC</b>	<b>0.31 B</b>	<b>\$3,528,000</b>
<b>TOTAL CAPITAL INVESTMENT (TCI) = DC + IC</b>	<b>1.61 B + SP + Bldg.</b>	<b>\$32,193,000</b>

Note:

Capital costs are from vendor (Merichem) and do not include freight, direct installation and (some) indirect installation

Operating materials are Merichem proprietary chemicals. Costs of those materials (Merichem-510, 520 & 530) were provided by Americhem

<sup>1</sup> EPA/452/B-02-001; 7th Edition; Sec. 2.5 and 2.6; (2012 dollars)

**Annual Costs - Lo-Cat**

Total Annual Costs for LO-CAT		
Cost Item		Cost
<b>DIRECT ANNUAL COSTS</b>		
<i>Hess and other estimates</i>		
Operator	1 hrs/shift	60.00 \$/hr <sup>1</sup>
Supervisor	15% of operator	\$65,700
<b>Operating Materials</b>		
		(2 train system)
Merichem - 510	365 gal/day	\$3,345 \$/day/train
Merichem - 520	12 gal/day	\$655 \$/day/train
Merichem - 530	20 gal/day	\$215 \$/day/train
KOH	460 lb/day	\$58 \$/day/train
<b>Maintenance</b>		
Labor	0.5 hrs/shift	60.00 \$/hr <sup>1</sup>
Material	100% of maint. labor	\$32,850
<b>Utilities</b>		
Natural Gas	0 (kft3/yr)	\$ 5.18 \$/kft3
Electricity	0 (kWh/yr)	\$0.059 \$/kWh
<b>INDIRECT ANNUAL COSTS, IC</b>		
Overhead	60% of sum of operating labor and materials and maintenance labor and materials.	
Administrative Charges	2% of TCI	\$643,860
Property Taxes	1% of TCI	\$321,930
Insurance	1% of TCI	\$321,930
Capital Recovery Rate Factor	(20 years at Prime (5.5%))	0.0837
Annualized Capital Recovery		\$2,693,889
<b>TOTAL ANNUAL COST</b>		<b>\$7,199,084</b>

(11-yr Average; w/o min and max)	Uncontrolled Emissions (tons/yr):	605
	Control Efficiency (additional):	90%
	Controlled Emissions (tons/yr):	60.5
	Tons Removed (tons/yr):	544.7
	<b>Cost-Effectiveness (\$/ton):</b>	<b>\$13,217</b>

**Capital Recovery Factor**  $CR = \frac{i(1+i)^n}{-1 + (1+i)^n}$

n = 20 years  
i = 5.5% interest rate  
CR = 0.0837

**Amine Sweetening Unit (S-302)**

**Nitrogen Oxides**

**SCR Control Technology**

# Amine Sweetening Unit (S-302)

SRU Claus Plant Tail Gas Incineration

Parameter	Year				Units	Reference
	2014	2015	2016	2017		
Fuel burned	773	821	1,100	1,131	10 <sup>6</sup> ft <sup>3</sup>	Annual emissions inventory
Heating Value	980	980	950	950	btu/ft <sup>3</sup>	Assumed
Heat input	7.57E+05	8.04E+05	1.05E+06	1.07E+06	mmbtu/year	Calculated
Heat input	86	92	119	123	mmbtu/hour	Calculated
Emission Factor	0.1	0.1	0.1	0.1	#/10 <sup>6</sup> BTU	AP-42, Table 8.13-2, April 2015
Emissions	38	40	52	54	tons/year	Calculated

Emission Factor Reference:  
AP-42, Section 8.13, Table 8.13-2, April 2015

Heat input	105	(average)	mmbtu/hour
Emissions	46		tons/year

## SCR - Input Calculations and Reference Information

Reference: EPA/452/B-02-001 Section 4.2 in Chapter 2

Parameter / Variable	Value	Units	Reference
Removal Efficiency	80	%	EPA-CICA Fact Sheet EPA-452/F-03-032 - Mean value is chosen
Actual Emissions	46	Tons/yr (actual)	Mean emissions: 2014→ 2017. AP-42, Table 8.13-2, April 2015 (0.1 ;
Q <sub>B</sub> =Max. Heat Input at HHV, MMBtu/h	107	Max MM Btu/hr	Max annual value from annual EI report - most recent 4 years
ASR (or SRF)	1.050	Actual Stoichiometric Ratio	EPA/452/B-02-001; p 2-55; May 2016
Q <sub>flue gas</sub>	27,309	Inlet to SCR ft <sup>3</sup> /min <sub>dry</sub>	2017 RATA
qscfm	11,844	ft <sup>3</sup> /min <sub>dry</sub> -std temperature & pressure	2017 RATA
CF <sub>plant</sub>	0.95	system capacity factor, CF <sub>plant</sub>	EPA/452/B-02-001
η <sub>NOx</sub>	0.8	NOx removal efficiency	Assumes mean reported EPA Fact Sheet value - see 1st reference at
NH <sub>3</sub> slip	(ASR-η <sub>NOx</sub> )*60*MW <sub>NH3</sub> *dscfm/359.05/10 <sup>6</sup>	lb/hr	Conversion to lb/hour
Catalyst volume (V <sub>catalyst</sub> )	2.81*Q <sub>B</sub> *η <sub>NOx</sub> *slip <sub>adj</sub> *N <sub>ox</sub> *S <sub>adj</sub> *T <sub>adj</sub> /N <sub>SCR</sub>	ft <sup>3</sup>	EPA/452/B-02-001: eqn. 2.22
N <sub>SCR</sub> (# of SCR reactor chambers)	1		
η <sub>adj</sub>	(0.2869+(1.058*η <sub>NOx</sub> ))	NOx efficiency adjustment factor	EPA/452/B-02-001; eqn. 2.23
Slip	(ASR-η <sub>NOx</sub> )	Ammonia slip factor	EPA/452/B-02-001; eqn. 2.24
Slip <sub>adj</sub>	1.2835-(0.0567*Slip)		EPA/452/B-02-001; eqn. 2.26
NO <sub>x</sub> <sub>i</sub>	0.1	lb/MM Btu	AP-42, Section 8.13, Table 8.13-2; April, 2015
NO <sub>x</sub> <sub>adj</sub>	0.8524+((0.3208*NO <sub>x</sub> <sub>i</sub> ))		EPA/452/B-02-001; eqn. 2.25
S <sub>i</sub> sulfur in fuel	1.8E-05	(weight fraction)	<a href="https://www.pge.com/pipeline/operations/sulfur/sulfur_info/index.page">https://www.pge.com/pipeline/operations/sulfur/sulfur_info/index.page</a>
S <sub>adj</sub>	0.9636+((0.0455*S <sub>i</sub> ))		EPA/452/B-02-001
SCR inlet temp	600	F°	Presumed (req'd for SCR)
SCR inlet temp	589	K°	Calculated (from F°)
T <sub>adj</sub> for inlet T not = 700 F	15.16-((0.03937*T)+(2.74*10 <sup>-5</sup> *T <sup>2</sup> ))		EPA/452/B-02-001; 7th Edition; Eqn. 2.27
A <sub>catalyst</sub>	Q <sub>flue gas</sub> /(16*60)	ft <sup>2</sup>	EPA/452/B-02-001; 7th Edition; Eqn. 2.28
η <sub>layer</sub>	V <sub>catalyst</sub> /(η <sub>layer</sub> *A <sub>catalyst</sub> )	ft <sup>3</sup> (use nominal h = 3.1 feet)	EPA/452/B-02-001; 7th Edition; Eqn. 2.31
η <sub>layer - final</sub>	6	# of layers (rounded to integer)	Calculated
η <sub>layer</sub>	V <sub>catalyst</sub> /(η <sub>layer - final</sub> *A <sub>catalyst</sub> )+1	ft	EPA/452/B-02-001; 7th Edition; Eqn. 2.32
η <sub>layer - total</sub>	η <sub>layer - final</sub> +1		EPA/452/B-02-001; 7th Edition; Eqn. 2.33
η <sub>SCR</sub>	η <sub>layer - total</sub> *(C <sub>1</sub> +η <sub>layer</sub> )+C <sub>2</sub>	ft : C <sub>1</sub> =7, C <sub>2</sub> =9 per eqn. 2.34	EPA/452/B-02-001; 7th Edition; Eqn. 2.34
m <sub>reagent</sub>	(NO <sub>x</sub> <sub>i</sub> *Q <sub>B</sub> *NSR*η <sub>NOx</sub> *MW <sub>reagent</sub> )/(MW <sub>NOx</sub> *SR <sub>i</sub> )	lb/hr	EPA/452/B-02-001; 7th Edition; Eqn. 2.35
MW <sub>reagent</sub>	17.0	MW of ammonia	<a href="https://pubchem.ncbi.nlm.nih.gov/compound/ammonia">https://pubchem.ncbi.nlm.nih.gov/compound/ammonia</a>
MW <sub>NOx</sub>	46.0	MW of NO <sub>2</sub>	<a href="https://pubchem.ncbi.nlm.nih.gov/compound/nitrogen%20dioxide">https://pubchem.ncbi.nlm.nih.gov/compound/nitrogen%20dioxide</a>
NSR	ASR/SR <sub>i</sub>	normalized stoichiometric rate	EPA/452/B-02-001; Section 2.5
SR <sub>i</sub>	1.0	for ammonia	EPA/452/B-02-001
C <sub>sol</sub>	0.29	concentration of aqueous soln	Typical aqueous soln
m <sub>sol</sub>	m <sub>reagent</sub> /C <sub>sol</sub>	lb/hr	EPA/452/B-02-001; 7th Edition; Eqn. 2.36
ρ <sub>sol</sub>	56	lb/ft <sup>3</sup> (solution density)	<a href="https://www.sigmaaldrich.com/catalog/product/aldrich/380539?lang=en&amp;region=US">https://www.sigmaaldrich.com/catalog/product/aldrich/380539?lang=en&amp;region=US</a>
V <sub>sol</sub>	7.5	gal/ft <sup>3</sup> (volume conversion)	<a href="https://en.wikipedia.org/wiki/Cubic_foot">https://en.wikipedia.org/wiki/Cubic_foot</a>
Q <sub>sol</sub>	m <sub>sol</sub> /ρ <sub>sol</sub> *V <sub>sol</sub>	gal/hr (reagent feed rate)	EPA/452/B-02-001; 7th Edition; Eqn. 2.37
t <sub>store</sub>	14.0	reagent storage for t days	Assumed minimum required storage period
Tank volume	q <sub>sol</sub> *t	gallons	Calculated
Cost of reagent	RC	\$/lb	EPA/452/B-02-001; 7th Edition; Sec. 2.5 and 2.6; (2012 dollars)
Cost of reagent (per hour)	\$5.45	\$/hour of ammonia	Calculated
Cost of reagent (per year)	\$47,740	\$/year of ammonia	Calculated
Catalyst Cost	CC <sub>replace</sub>	\$/ft <sup>3</sup>	EPA/452/B-02-001; 7th Edition; Sec. 2.5 and 2.6; (2012 dollars)
Catalyst Cost Replacement	η <sub>SCR</sub> * V <sub>ol</sub> <sub>catalyst</sub> * (CC <sub>replace</sub> /R <sub>layer</sub> )	\$/one replacement layer/year	EPA/452/B-02-001, Eqn 2.50

[https://www.epa.gov/sites/production/files/2017-12/documents/srccostmanualchapter7thedition\\_2016revisions2017.pdf](https://www.epa.gov/sites/production/files/2017-12/documents/srccostmanualchapter7thedition_2016revisions2017.pdf)

## ***Hess Corporation***

### ***4-Factor Cost Analysis***

#### ***Tioga Facility***

#### ***SRU Claus Plant Tail Gas Incineration***

#### ***NO<sub>x</sub>***

#### ***SCR Control***

### **Capital Cost Derivation**

#### **Primary Reference:**

**Air Pollution Control Technology Fact Sheet, SCR, EPA-452/F-03-032**

<https://www3.epa.gov/ttn/catc1/dir1/fscr.pdf>

Value	Units	Reference
\$2,500	\$/mmBtu	Table 1a : small/large turbines : 1,500 ↔ 3,500 \$/mmbtu : 1999 Dollars (assumed a mid-range value)
105.0	mmBtu/hr	Annual emissions report to NDDH (= 4 year mean: 2014 → 2017)
167	CPI 1999	<a href="https://www.bls.gov/cpi/tables/historical-cpi-u-201709.pdf">https://www.bls.gov/cpi/tables/historical-cpi-u-201709.pdf</a> Price Index Ratio
240	CPI 2017	
1.44	CPI2017/CPI1999	
\$378,314	\$	Adjusted Capital for 2017 - \$/mmBtu
<b>\$435,061</b>	15%	EPA suggests retrofit costs is up to 30% premium addition. A mid-range of 15% was used as a reasonable estimate.



### Annual Costs - SCR - Amine Sweetening Unit

Total Capital Costs for SCR		
Cost Item	Factor	Cost
<b>DIRECT COSTS</b>		
Purchased equipment costs		
Capital	A	\$435,061
Instrumentation	0.10 A	(included)
Sales taxes	0.05 A	(included)
Freight	0.05 A	(included)
<b>Purchased equipment cost, PEC</b>	<b>B</b>	<b>\$435,061</b>
Direct installation costs		
Foundations & supports	0.08 B	(included)
Handling & erection	0.14 B	(included)
Electrical	0.04 B	(included)
Piping	0.02 B	(included)
Insulation for ductwork	0.01 B	(included)
Painting	0.01 B	(included)
<b>Direct installation cost</b>	<b>0.30 B</b>	<b>\$0</b>
Site preparation	As required, SP	-
Buildings	As required, Bldg.	-
<b>Total Direct Cost, DC</b>	<b>1.30 B + SP + Bldg.</b>	<b>\$435,061</b>
<b>INDIRECT COSTS (Installation)</b>		
Engineering	0.10 B	(included)
Construction and field expenses	0.05 B	(included)
Contractor fees	0.10 B	(included)
Start-up	0.02 B	(included)
Performance test	0.01 B	(included)
Contingencies	0.03 B	(included)
<b>Total Indirect Cost, IC</b>	<b>0.31 B</b>	<b>\$0</b>
<b>TOTAL CAPITAL INVESTMENT (TCI) = DC + IC</b>	<b>DC + IC</b>	<b>\$435,061</b>

### Annual Costs - SCR - Amine Sweetening Unit

Total Annual Costs for SCR				Cost
Cost Item				Cost
<b>DIRECT ANNUAL COSTS</b>				
<i>Operating Labor</i>				
Operator	0.5 hrs/shift	60.00 \$/hr <sup>2</sup>		\$32,400
Supervisor	15% of operator			\$4,860
<i>Operating Materials</i>				
Ammonia consumption				\$47,740
Catalyst replacement (4 layers: 1 layer/year)				\$12,038
<i>Maintenance</i>				
Labor	0.5 hrs/shift	60.00 \$/hr <sup>2</sup>		\$32,400
Material	100% of maint. labor			\$32,400
<i>Utilities</i>				
Natural Gas	0 (kft3/yr)	\$ 5.18 \$/kft3		\$0
Electricity	0 (kWh/yr)	\$0.059 \$/kWh		\$0
<b>INDIRECT ANNUAL COSTS, IC</b>				
Overhead	60% of sum of operating labor and materials and maintenance labor and materials.			\$61,236
Administrative Charges	2% of TCI			\$8,701
Property Taxes	1% of TCI			\$4,351
Insurance	1% of TCI			\$4,351
Capital Recovery Factor (25 yrs & prime rate = 5.5%)				0.0745
Annual Capital Recovery (Recovery rate * TCI)				\$32,434
<b>TOTAL ANNUAL COST</b>				<b>\$272,910</b>
Uncontrolled Emissions (tons/yr): <sup>1</sup>				46
Emission reduction (%) <sup>3</sup>				80%
Controlled Emissions (tons/yr):				9
Tons Removed (tons/yr):				37
<b>Cost-Effectiveness (\$/ton):</b>				<b>\$7,414</b>

<sup>1</sup> Mean emissions for last 4 reporting years

<sup>2</sup> EPA/452/B-02-001; 7th Edition; Sec. 2.5 and 2.6; (2012 dollars)

<sup>3</sup> EPA-452/F-03-32; Efficiency range = 70% ↔ 90%; a lower range is expected since the inlet concentration is very low (0.1 #/mmmbtu). A mid value of 80% was chosen.

$$\text{Capital Recovery Factor } CR = \frac{i(1+i)^n}{-1 + (1+i)^n}$$

n = 25 years  
i = 5.50% interest rate  
CR = 0.0745

**Amine Sweetening Unit (S-302)**

**Sulfur Dioxide and NOx**

**Acid Gas Injection Well**

## Total Capital Costs - Acid Gas Injection Well

Total Capital Costs for Acid Gas Injection		
Cost Item	Factor	Cost
<b><u>DIRECT COSTS - Compression and Dehydration System</u></b>		
Purchased equipment costs		
Compressor Engine Package (vendor data at EXW)	A	\$3,500,000
Acid Gas Dehy. package (vendor data at EXW)	A	\$1,750,000
Instrumentation	0.10 A	\$525,000
Sales taxes	0.05 A	\$262,500
Freight	0.05 A	\$262,500
<b>Purchased equipment cost, PEC</b>	<b>B = 1.15 A</b>	<b>\$6,300,000</b>
Direct installation costs		
Foundations & supports	0.08 B	\$504,000
Handling & erection	0.14 B	\$882,000
Electrical	0.04 B	\$252,000
Piping	0.02 B	\$126,000
Insulation for ductwork	0.01 B	\$63,000
Painting	0.01 B	\$63,000
<b>Direct installation cost</b>	<b>0.30 B</b>	<b>\$1,890,000</b>
<b>Total Direct Cost, DC (Compression/Dehydration)</b>	<b>1.30 B</b>	<b>\$8,190,000</b>
<b><u>INDIRECT COSTS - Compression and Dehydration System</u></b>		
Engineering		
Construction and field expenses	0.10 B	\$630,000
Contractor fees	0.05 B	\$315,000
Start-up	0.10 B	\$630,000
Performance test/Site inspections	0.02 B	\$126,000
Contingencies	0.01 B	\$63,000
	0.03 B	\$189,000
<b>Total Indirect Cost, IC (Compression/Dehydration)</b>	<b>0.31 B</b>	<b>\$1,953,000</b>
<b><u>DIRECT &amp; INDIRECT COSTS - Pipeline and Injection Well</u></b>		
Pipeline Installation (Hess provided cost)		
(5 miles; 4", Sch. 80; \$125,000/diameter mile)		\$2,500,000
Install Disposal Well (Hess provided cost)		
(10,000 ft., TVD, 2-7/8" tubing)		\$5,000,000
Land Acquisition		
Permitting	Stand alone value	\$20,000
	Stand alone value	\$125,000
<b>Total DC &amp; IC (Pipeline and Disposal Well)</b>		<b>\$7,645,000</b>
<b>TOTAL CAPITAL INVESTMENT (TCI) = DC + IC</b>	<b>1.61 B + Pipe + Well</b>	<b>\$17,788,000</b>

## Annual Costs - Acid Gas Injection Well

Total Annual Costs for Acid Gas Injection	
Cost Item	Cost
<b><u>DIRECT ANNUAL COSTS</u></b>	
<i>Hess and other estimates</i>	
<b>Annual Operating Expense</b>	
Compression electricity	\$800,000
Gas dehydration	
Compressor maintenance	
<b><u>INDIRECT ANNUAL COSTS, IC</u></b>	
Overhead	60% of sum of operating labor and materials and maintenance labor and materials.
Administrative Charges	2% of TCI
Property Taxes	1% of TCI
Insurance	1% of TCI
Capital Recovery Factor (Annualized Capital Cost, 20 yrs at 5.5%)	0.0837
Capital Recovery Factor	$CR = \frac{i(1+i)^n}{-1 + (1+i)^n}$
n =	20 years
i =	5.50% interest rate
CR =	0.0837
<b>Capital Recovery Cost (Capital Recovery Factor x TCI):</b>	
	\$1,488,488
<b>TOTAL ANNUAL COST (Capital Recovery Cost + Annual Operating Expense)</b>	<b>\$2,288,488</b>
Uncontrolled Emissions (tons/yr) [11 yr mean w/o min and max]:	
Control Efficiency (additional) [assumes near zero emissions]:	605
Controlled Emissions (tons/yr):	99%
Tons Removed (tons/yr):	6.1
<b>Cost-Effectiveness (\$/ton):</b>	<b>\$3,821</b>

**Compressor Engines  
(C-1A, C-1B, C-1C, C-1E, C1-G)**

**Nitrogen Oxides**

**LEC Control Technology**

## Input Variables and Derivation

### Nitrogen Oxides – LEC

#### Capital Cost Derivation - NOx - LEC

**Primary Reference:**

Siemen's Budgetary Proposal

Hess Tioga Facility: Estimate to Revamp/Upgrade Unit 5 (Serial 54040) : C1-E

September, 2018

Item #	Cost	Basis	Discussion
1	\$345,000	Per Engine	Replace existing cooling system to eliminate boil-off and replace water pump system. This includes hardware and engineering only.
2	\$2.5 million	Per Engine	Complete "zero-hour" overhaul. Includes field service, repairs and necessary parts replacement.
3	\$3.7 ↔ \$4.2 million	Per Engine	Provide high pressure fuel injection (HPFI) upgrade implementation. Includes hardware, installation and commissioning.
4	\$2.0 ↔ \$2.5 million	One-time cost	One-time "balance of plant" engineering and hardware to support multiple engine retrofits. Cost is the same regardless of 1 or all 5 engines.

#### Emissions Inventory: Actual (Average of past 5 years with min & max years removed from the calculation)

Engine	Tons/Year (5-yr mean with min & max removed)
C-1A	91
C-1B	160
C-1C	193
C-1E	189
C-1G	153

Mean: All 5 Engines

158

**Single Engine Only**

**Total Capital Cost - C-1A - LEC**

Total Capital Costs for LEC			
Cost Item	Factor	Cost	
<b>DIRECT COSTS</b>			
Purchased equipment costs			
High pressure fuel injection upgrade, including hardware installation and commissioning	(cost per engine)	\$4,000,000	
<b>Subtotal:</b>		<b>\$4,000,000</b>	
Direct installation costs			
Zero-Hour overhaul (+ field services, repairs etc.)	(mean cost per engine)	\$2,500,000	
Replace cooling system (hardware & engineering only)	(per engine)	\$345,000	
Electrical	(included)		
Piping	(included)		
Insulation for ductwork	(included)		
Painting	(included)		
<b>Subtotal:</b>		<b>\$2,845,000</b>	
Site preparation	As required, SP	-	
Buildings	As required, Bldg.	-	
<b>Total Direct Cost, DC</b>	<b>1.30 B + SP + Bldg.</b>	<b>\$6,845,000</b>	
<b>INDIRECT COSTS (Installation)</b>			
Balance of Plant Engineering + Hardware	(mean cost for one engine)	\$2,250,000	
Construction and field expenses	(included)		
Contractor fees	(included)		
Start-up	(included)		
Performance test	(included)		
Contingencies			
<b>Total Indirect Cost, IC</b>		<b>\$2,250,000</b>	
<b>TOTAL CAPITAL INVESTMENT (TCI) = DC + IC</b>	<b>DC + IC</b>	<b>\$9,095,000</b>	

**Annual Costs - C-1A - LEC**

Total Annual Costs for LEC		
Cost Item	Cost	
<b><u>DIRECT ANNUAL COSTS</u></b>		
<i>Operating Labor</i>		
Operator	0.5 hrs/shift (5 units)	60.00 \$/hr <sup>1</sup>
Supervisor	15% of operator	
<i>Operating Materials</i>		
<i>Maintenance</i>		
Labor	0.5 hrs/shift (5 units)	60.00 \$/hr <sup>1</sup>
Material	100% of maint. labor	
<i>Utilities</i>		
Natural Gas	0 (kft3/yr)	\$ 5.18 \$/kft3
Electricity	0 (kWh/yr)	\$0.059 \$/kWh
<b><u>INDIRECT ANNUAL COSTS, IC</u></b>		
Overhead	60% of sum of operating labor and materials and maintenance labor and materials.	
Administrative Charges	2% of TCI	
Property Taxes	1% of TCI	
Insurance	1% of TCI	
Capital Recovery Factor (20 yrs @ prime rate 5.25%)		
Annual Capital Recovery (Recovery rate * TCI)		
<b>TOTAL ANNUAL COST</b>		<b>\$1,205,122</b>
Uncontrolled Emissions (tons/yr):		91
Controlled Emission Rate (g/bhp-hr)		1
Controlled Emissions (tons/yr):		19
Tons Removed (tons/yr):		73
<b>Cost-Effectiveness (\$/ton):</b>		<b>\$16,567</b>

<sup>1</sup> EPA/452/B-02-001; 7th Edition; Sec. 2.5 and 2.6; (2012 dollars)

**Capital Recovery Factor**  $CR = \frac{i(1+i)^n}{-1 + (1+i)^n}$

n = 25 years  
i = 5.50% interest rate  
CR = 0.0745

**Single Engine Only**

**Total Capital Cost - C-1B - LEC**

Total Capital Costs for LEC		
Cost Item	Factor	Cost
<b>DIRECT COSTS</b>		
Purchased equipment costs		
High pressure fuel injection upgrade, including hardware installation and commissioning	(cost per engine)	\$4,000,000
<b>Subtotal:</b>		<b>\$4,000,000</b>
Direct installation costs		
Zero-Hour overhaul (+ field services, repairs etc.)	(mean cost per engine)	\$2,500,000
Replace cooling system (hardware & engineering)	(per engine)	\$345,000
Electrical	(included)	
Piping	(included)	
Insulation for ductwork	(included)	
Painting	(included)	
<b>Subtotal:</b>		<b>\$2,845,000</b>
Site preparation	As required, SP	-
Buildings	As required, Bldg.	-
<b>Total Direct Cost, DC</b>	1.30 B + SP + Bldg.	<b>\$6,845,000</b>
<b>INDIRECT COSTS (Installation)</b>		
Balance of Plant Engineering + Hardware	(mean cost for one engine)	\$2,250,000
Construction and field expenses	(included)	
Contractor fees	(included)	
Start-up	(included)	
Performance test	(included)	
Contingencies		
<b>Total Indirect Cost, IC</b>		<b>\$2,250,000</b>
<b>TOTAL CAPITAL INVESTMENT (TCI) = DC + IC</b>	<b>DC + IC</b>	<b>\$9,095,000</b>

**Annual Costs - C-1B - LEC**

Total Annual Costs for LEC			
Cost Item			Cost
<b>DIRECT ANNUAL COSTS</b>			
<i>Operating Labor</i>			
Operator	0.5 hrs/shift (5 units)	60.00 \$/hr <sup>1</sup>	\$32,400
Supervisor	15% of operator		\$4,860
<i>Operating Materials</i>			
			-
<i>Maintenance</i>			
Labor	0.5 hrs/shift (5 units)	60.00 \$/hr <sup>1</sup>	\$32,400
Material	100% of maint. labor		\$32,400
<i>Utilities</i>			
Natural Gas	0 (kft3/yr)	\$ 5.18 \$/kft3	\$0
Electricity	0 (kWh/yr)	\$0.059 \$/kWh	\$0
<b>INDIRECT ANNUAL COSTS, IC</b>			
Overhead	60% of sum of operating labor and materials and maintenance labor and materials.		\$61,236
Administrative Charges	2% of TCI		\$181,900
Property Taxes	1% of TCI		\$90,950
Insurance	1% of TCI		\$90,950
Capital Recovery Factor (20 yrs @ prime rate 5.25%)			0.0745
Annual Capital Recovery (Recovery rate * TCI)			\$678,026
<b>TOTAL ANNUAL COST</b>			<b>\$1,205,122</b>
Uncontrolled Emissions (tons/yr):			160
Controlled Emission Rate (g/bhp-hr)			1
Controlled Emissions (tons/yr):			19
Tons Removed (tons/yr):			142
<b>Cost-Effectiveness (\$/ton):</b>			<b>\$8,503</b>

**Capital Recovery Factor**  $CR = \frac{i(1+i)^n}{-1 + (1+i)^n}$

n = 25 years  
i = 5.50% interest rate  
CR = 0.0745

<sup>1</sup> EPA/452/B-02-001; 7th Edition; Sec. 2.5 and 2.6; (2012 dollars)

**Single Engine Only**

**Total Capital Cost - C-1C - LEC**

Total Capital Costs for LEC		
Cost Item	Factor	Cost
<b><u>DIRECT COSTS</u></b>		
Purchased equipment costs		
High pressure fuel injection upgrade, including hardware installation and commissioning	(cost per engine)	\$4,000,000
<b>Subtotal:</b>		<b>\$4,000,000</b>
Direct installation costs		
Zero-Hour overhaul (+ field services, repairs etc.)	(mean cost per engine)	\$2,500,000
Replace cooling system (hardware & engineering)	(per engine)	\$345,000
Electrical	(included)	
Piping	(included)	
Insulation for ductwork	(included)	
Painting	(included)	
<b>Subtotal:</b>		<b>\$2,845,000</b>
Site preparation	As required, SP	-
Buildings	As required, Bldg.	-
<b>Total Direct Cost, DC</b>	<b>1.30 B + SP + Bldg.</b>	<b>\$6,845,000</b>
<b><u>INDIRECT COSTS (Installation)</u></b>		
Balance of Plant Engineering + Hardware	(mean cost for one engine)	\$2,250,000
Construction and field expenses	(included)	
Contractor fees	(included)	
Start-up	(included)	
Performance test	(included)	
Contingencies		
<b>Total Indirect Cost, IC</b>		<b>\$2,250,000</b>
<b>TOTAL CAPITAL INVESTMENT (TCI) = DC + IC</b>	<b>DC + IC</b>	<b>\$9,095,000</b>

**Annual Costs - C-1 - LEC**

Total Annual Costs for LEC			
Cost Item			Cost
<b><u>DIRECT ANNUAL COSTS</u></b>			
<b>Operating Labor</b>			
Operator	0.5 hrs/shift (5 units)	60.00 \$/hr <sup>1</sup>	\$32,400
Supervisor	15% of operator		\$4,860
<b>Operating Materials</b>			
			-
<b>Maintenance</b>			
Labor	0.5 hrs/shift (5 units)	60.00 \$/hr <sup>1</sup>	\$32,400
Material	100% of maint. labor		\$32,400
<b>Utilities</b>			
Natural Gas	0 (kft3/yr)	\$ 5.18 \$/kft3	\$0
Electricity	0 (kWh/yr)	\$0.059 \$/kWh	\$0
<b><u>INDIRECT ANNUAL COSTS, IC</u></b>			
Overhead	60% of sum of operating labor and materials and maintenance labor and materials.		\$61,236
Administrative Charges	2% of TCI		\$181,900
Property Taxes	1% of TCI		\$90,950
Insurance	1% of TCI		\$90,950
Capital Recovery Factor (20 yrs @ prime rate 5.25%)			0.0745
Annual Capital Recovery (Recovery rate * TCI)			\$678,026
<b>TOTAL ANNUAL COST</b>			<b>\$1,205,122</b>
Uncontrolled Emissions (tons/yr):			193
Controlled Emission Rate (g/bhp-hr)			1
Controlled Emissions (tons/yr):			19
Tons Removed (tons/yr):			175
<b>Cost-Effectiveness (\$/ton):</b>			<b>\$6,890</b>

<sup>1</sup> EPA/452/B-02-001; 7th Edition; Sec. 2.5 and 2.6; (2012 dollars)

**Capital Recovery Factor**  $CR = \frac{i(1+i)^n}{-1 + (1+i)^n}$

n = 25 years  
i = 5.50% interest rate  
CR = 0.0745



**Single Engine Only**

**Total Capital Cost - C-1E - LEC**

Total Capital Costs for LEC		
Cost Item	Factor	Cost
<b>DIRECT COSTS</b>		
Purchased equipment costs		
High pressure fuel injection upgrade, including hardware installation and commissioning	(cost per engine)	\$4,000,000
<b>Subtotal:</b>		<b>\$4,000,000</b>
Direct installation costs		
Zero-Hour overhaul (+ field services, repairs etc.)	(mean cost per engine)	\$2,500,000
Replace cooling system (hardware & engineering)	(per engine)	\$345,000
Electrical	(included)	
Piping	(included)	
Insulation for ductwork	(included)	
Painting	(included)	
<b>Subtotal:</b>		<b>\$2,845,000</b>
Site preparation	As required, SP	-
Buildings	As required, Bldg.	-
<b>Total Direct Cost, DC</b>	<b>1.30 B + SP + Bldg.</b>	<b>\$6,845,000</b>
<b>INDIRECT COSTS (Installation)</b>		
Balance of Plajnt Engineering + Hardware	(mean cost for one engine)	\$2,250,000
Construction and field expenses	(included)	
Contractor fees	(included)	
Start-up	(included)	
Performance test	(included)	
Contingencies	(included)	
<b>Total Indirect Cost, IC</b>		<b>\$2,250,000</b>
<b>TOTAL CAPITAL INVESTMENT (TCI) = DC + IC</b>	<b>DC + IC</b>	<b>\$9,095,000</b>

**Annual Costs - C-1E - LEC**

Total Annual Costs for LEC			
Cost Item			Cost
<b>DIRECT ANNUAL COSTS</b>			
<i>Operating Labor</i>			
Operator	0.5 hrs/shift (5 units)	60.00 \$/hr <sup>1</sup>	\$32,400
Supervisor	15% of operator		\$4,860
<i>Operating Materials</i>			
			-
<i>Maintenance</i>			
Labor	0.5 hrs/shift (5 units)	60.00 \$/hr <sup>1</sup>	\$32,400
Material	100% of maint. labor		\$32,400
<i>Utilities</i>			
Natural Gas	0 (kft3/yr)	\$ 5.18 \$/kft3	\$0
Electricity	0 (kWh/yr)	\$0.059 \$/kWh	\$0
<b>INDIRECT ANNUAL COSTS, IC</b>			
Overhead	60% of sum of operating labor and materials and maintenance labor and materials.		\$61,236
Administrative Charges	2% of TCI		\$181,900
Property Taxes	1% of TCI		\$90,950
Insurance	1% of TCI		\$90,950
Capital Recovery Factor (20 yrs @ prime rate 5.25%)			0.0745
Annual Capital Recovery (Recovery rate * TCI)			\$678,026

**TOTAL ANNUAL COST**

**\$1,205,122**

Uncontrolled Emissions (tons/yr):	189
Controlled Emission Rate (g/bhp-hr)	1
Controlled Emissions (tons/yr):	19
Tons Removed (tons/yr):	171
<b>Cost-Effectiveness (\$/ton):</b>	<b>\$7,050</b>

**Capital Recovery Factor**  $CR = \frac{i(1+i)^n}{-1 + (1+i)^n}$

n = 25 years  
i = 5.50% interest rate  
CR = 0.0745

<sup>1</sup> EPA/452/B-02-001; 7th Edition; Sec. 2.5 and 2.6; (2012 dollars)

**Single Engine Only**

**Total Capital Cost - C-1G - LEC**

Total Capital Costs for LEC		
Cost Item	Factor	Cost
<b>DIRECT COSTS</b>		
Purchased equipment costs		
High pressure fuel injection upgrade, including hardware installation and commissioning	(cost per engine)	\$4,000,000
<b>Subtotal:</b>		<b>\$4,000,000</b>
Direct installation costs		
Zero-Hour overhaul (+ field services, repairs etc.)	(mean cost per engine)	\$2,500,000
Replace cooling system (hardware & engineering)	(per engine)	\$345,000
Electrical	(included)	
Piping	(included)	
Insulation for ductwork	(included)	
Painting	(included)	
<b>Subtotal:</b>		<b>\$2,845,000</b>
Site preparation	As required, SP	-
Buildings	As required, Bldg.	-
<b>Total Direct Cost, DC</b>	<b>1.30 B + SP + Bldg.</b>	<b>\$6,845,000</b>
<b>INDIRECT COSTS (Installation)</b>		
Balance of Plajnt Engineering + Hardware	(mean cost for one engine)	\$2,250,000
Construction and field expenses	(included)	
Contractor fees	(included)	
Start-up	(included)	
Performance test	(included)	
Contingencies		
<b>Total Indirect Cost, IC</b>		<b>\$2,250,000</b>
<b>TOTAL CAPITAL INVESTMENT (TCI) = DC + IC</b>	<b>DC + IC</b>	<b>\$9,095,000</b>

**Annual Costs - C-1G - LEC**

Total Annual Costs for LEC			
Cost Item			Cost
<b>DIRECT ANNUAL COSTS</b>			
<i>Operating Labor</i>			
Operator	0.5 hrs/shift (5 units)	60.00 \$/hr <sup>1</sup>	\$32,400
Supervisor	15% of operator		\$4,860
<i>Operating Materials</i>			
			-
<i>Maintenance</i>			
Labor	0.5 hrs/shift (5 units)	60.00 \$/hr <sup>1</sup>	\$32,400
Material	100% of maint. labor		\$32,400
<i>Utilities</i>			
Natural Gas	0 (kft3/yr)	\$ 5.18 \$/kft3	\$0
Electricity	0 (kWh/yr)	\$0.059 \$/kWh	\$0
<b>INDIRECT ANNUAL COSTS, IC</b>			
Overhead	60% of sum of operating labor and materials and maintenance labor and materials.		\$61,236
Administrative Charges	2% of TCI		\$181,900
Property Taxes	1% of TCI		\$90,950
Insurance	1% of TCI		\$90,950
Capital Recovery Factor (20 yrs @ prime rate 5.25%)			0.0745
Annual Capital Recovery (Recovery rate * TCI)			\$678,026
<b>TOTAL ANNUAL COST</b>			<b>\$1,205,122</b>
Uncontrolled Emissions (tons/yr):			153
Controlled Emission Rate (g/bhp-hr)			1
Controlled Emissions (tons/yr):			19
Tons Removed (tons/yr):			135
<b>Cost-Effectiveness (\$/ton):</b>			<b>\$8,933</b>

**Capital Recovery Factor**

$$CR = \frac{i(1+i)^n}{-1 + (1+i)^n}$$

n = 25 years  
i = 5.50% interest rate  
CR = 0.0745

<sup>1</sup> EPA/452/B-02-001; 7th Edition; Sec. 2.5 and 2.6; (2012 dollars)

**Compressor Engines  
(C-1A, C-1B, C-1C, C-1E, C1-G)**

**Nitrogen Oxides**

**SCR Control Technology**

## Capital Cost Derivation - SCR for Clark Engines

### Primary Reference:

Air Pollution Control Technology Fact Sheet, SCR, EPA-452/F-03-032

Value	Units	
See formula	\$/Hp	NESCAUM report; December 2000 (1994 Dollars) Page III-30 Above report is referenced in the following document: EPA/452/B-02-001; 7th Edition; Table 2.1b; Endnote 15 (p. 2-97)  Total Capital Cost = \$310,000 + \$72.7*Hp
1,920	Hp	Clark Engine
\$449,584	1994 \$	Capital Cost = \$310,000 + \$72.70/Hp
147	CPI 1994	<a href="https://www.bls.gov/cpi/tables/historical-cpi-u-201709.pdf">https://www.bls.gov/cpi/tables/historical-cpi-u-201709.pdf</a>  Escalation adjustment
244	CPI 2017	
1.66	CPI2017/CPI1994	
<b>\$745,466</b>	<b>\$/Engine</b>	

147 CPI for Calendar 1994
244 CPI for Calendar 2017
1.66 CPI Adjustment: 2017:2000

### Report below is referenced in:

EPA/452/B-02-001; 7th Edition; Table 2.1b; Endnote 15 (p. 2-97)

NESCAUM report; December 2000 (1994 Dollars) Page III-30			
<b>Total Capital Cost</b>			
Lean Burn	TCC =	\$310,000	+ \$72.70 * HP
Diesel	TCC =	\$187,000	+ \$98.00 * HP
 <u>Clark Engine:</u>			
1920 hp		<u>TCC (1994)</u>	\$449,584

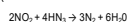
### SCR - Input Calculations and Reference Information

Data is on a per engine basis unless otherwise noted

Reference: EPA/452/B-02-001 Section 4.2 in Chapter 2

Parameter / Variable		Value	Units	Reference
Selective Catalytic Reduction (% Control);		85.0	percent	Approx = 1g/bhp-hr
Uncontrolled emissions each RICE		158	Tons/yr (actual) per Engine	Baseline Emissions (mean of last 5 yrs sans min and max)
$Q_b$ =Max. Heat Input at HHV, MMBtu/h		17.2	MM Btu/hr per RICE	Test C1-C 2018 + 20% to reach Max
ASR (or SRF)		1.5	Actual Stoichiometric Ratio	EPA/452/B-02-001; 7th Edition; May 2016; Eqn. 2.1a & 2.1b <sup>1</sup>
$q_{fuel\ gas}$		20,800	Inlet to SCR acfm	2018 stack test
$q_{scfm}$		8,000	dscfm	2018 stack test
$CF_{plant}$		0.9	system capacity factor, $CF_{plant}$	EPA/452/B-02-001
$\eta_{NOx}$		0.85	NOx removal efficiency	Approx. to reach = 1 gr/hp-hr
NH3 slip (ppmv)	$(ASR - \eta_{NOx}) * MW_{NH3} * dscfm / 359.05 / 10^5$	0.015	lb/hr	
Catalyst volume	$2.81 * Q_b * \eta_{adj} * slip_{adj} * NO_{xadj} * S_{adj} * T_{adj} / NS_{SCR}$	213	ft <sup>3</sup>	EPA/452/B-02-001: eqn. 2.22
$NS_{SCR}$ (# of SCR reactor chambers)		1		
$\eta_{adj}$	$(0.2869 + (1.058 * \eta_{NOx}))$	1.19	NOx efficiency adjustment factor	EPA/452/B-02-001; eqn. 2.23
Slip	$(ASR - \eta_{NOx})$	0.05	Ammonia slip factor	EPA/452/B-02-001; eqn. 2.24
$Slip_{adj}$	$1.2835 - (0.0567 * Slip)$	1.28		EPA/452/B-02-001; eqn. 2.26
$NO_{x_n}$		4.0	lb/MM Btu	Most recent 5-year mean sans min and max
$NO_{xadj}$	$0.8524 + (0.3208 * NO_{x_n})$	2.143		EPA/452/B-02-001; eqn. 2.25
S, sulfur in fuel		1.8E-05	(weight fraction - total S)	<a href="https://www.pge.com/pipeline/operations/sulfur/sulfur_info/index.page">https://www.pge.com/pipeline/operations/sulfur/sulfur_info/index.page</a>
$S_{adj}$	$0.9636 + (0.0455 * S)$	0.964		EPA/452/B-02-001
SCR inlet temp		600	F°	Presumed (req'd for SCR)
SCR inlet temp		589	K°	Calculated (from F°)
$T_{adj}$ for inlet T not = 700 F	$15.16 - (0.03937 * T) + (2.74 * 10^{-5} * T^2)$	1.40		EPA/452/B-02-001; 7th Edition; p. 2-82
$A_{catalyst}$	$q_{fuel\ gas} / (16 * 60)$	21.7	ft <sup>2</sup>	EPA/452/B-02-001; eqn. 2.27
$\eta_{layer}$	$V_{catalyst} / (\eta_{layer} * A_{catalyst})$	3.2	ft <sup>3</sup> (use nominal h = 3.1 feet)	EPA/452/B-02-001; eqn. 2.31 and discussion
$\eta_{layer - final}$		3	round $\eta_{layer}$ to integer	Calculated
$\eta_{layer}$	$V_{catalyst} / (\eta_{layer} * A_{catalyst}) + 1$	4.1		EPA/452/B-02-001; eqn. 2.32
$\eta_{layer - total}$	$\eta_{layer - final} + 1$	4		EPA/452/B-02-001; eqn. 2.33
$h_{SCR}$	$\eta_{layer - total} * (C_1 + \eta_{layer}) + C_2$	55.5	ft	EPA/452/B-02-001; eqn. 2.34
$m_{reagent}$	$(NO_{x_n} * Q_b * NSR * \eta_{NOx} * MW_{reagent}) / (MW_{NOx} * SR_T)$	32.9	lb/hr	EPA/452/B-02-001; eqn. 2.35
$MW_{reagent}$		17.0	MW of ammonia	<a href="https://pubchem.ncbi.nlm.nih.gov/compound/ammonia">https://pubchem.ncbi.nlm.nih.gov/compound/ammonia</a>
$MW_{NOx}$		46.0	MW of NO <sub>2</sub>	<a href="https://pubchem.ncbi.nlm.nih.gov/compound/nitrogen%20dioxide">https://pubchem.ncbi.nlm.nih.gov/compound/nitrogen%20dioxide</a>
NSR	$ASR / SR_T$	1.5	normalized stoichiometric rate	EPA/452/B-02-001 w/ NO <sub>2</sub> :NO adjustment <sup>1</sup>
$SR_T$		1.0	for ammonia	EPA/452/B-02-001
$C_{sol}$		0.29	concentration of aqueous soln	Typical solution concentration
$m_{sol}$	$m_{reagent} / C_{sol}$	113.4	lb/hr	EPA/452/B-02-001; 7th Edition; Eqn. 2.36
$\rho_{sol}$		56	lb/ft <sup>3</sup> (solution density)	<a href="https://www.sigmaaldrich.com/catalog/product/aldrich/380539?lang=en&amp;region=US">https://www.sigmaaldrich.com/catalog/product/aldrich/380539?lang=en&amp;region=US</a>
$V_{sol}$		7.5	gal/ft <sup>3</sup> (volume conversion)	<a href="https://en.wikipedia.org/wiki/Cubic_foot">https://en.wikipedia.org/wiki/Cubic_foot</a>
$Q_{sol}$	$m_{sol} / \rho_{sol} * V_{sol}$	15.1	gal/hr (reagent feed rate)	EPA/452/B-02-001; 7th Edition; Eqn. 2.37
$t_{store}$		14.0	reagent storage for t days	Assumed minimum required storage period
Tank volume	$Q_{sol} * t$	5,088	gallons	Calculated
Cost of reagent	RC	0.48	\$/lb	EPA/452/B-02-001; 7th Edition; Sec. 2.5 and 2.6; (2012 dollars)
Cost of reagent (per hour)		\$53.85	\$/hour of ammonia	Calculated
Cost of reagent (per year)		\$471,761	\$/year of ammonia	Calculated
Catalyst Cost	$CC_{replace}$	\$160.00	\$/ft <sup>3</sup>	EPA/452/B-02-001; 7th Edition; Sec. 2.5 and 2.6; (2012 dollars)
Catalyst Cost Replacement	$\eta_{SCR} * Vol_{catalyst} * (CC_{replace} / R_{layer})$	\$8,098	\$/replacement layer/year	EPA/452/B-02-001, Eqn 2.50

<sup>1</sup> Stoichiometry adjusted for NO<sub>2</sub>:NOx ratio from EPA database for the 60 reporting 2SLB engines = 46% : [https://www3.epa.gov/scram001/no2\\_isr\\_database.htm](https://www3.epa.gov/scram001/no2_isr_database.htm)  
(2 molecules of ammonia required for 1 molecule of NO<sub>2</sub> reduction)



**Clark Engine Cost Effectiveness**

**Annual Costs - C-1A -SCR**

Total Capital Costs for SCR		
Cost Item	Factor	Cost
<b>DIRECT COSTS</b>		
Purchased equipment costs		
Capital (5 engines)	A	\$745,466
Instrumentation	0.10 A	(included)
Sales taxes	0.05 A	(included)
Freight	0.05 A	(included)
<b>Purchased equipment cost, PEC</b>	<b>B</b>	<b>\$745,466</b>
Direct installation costs		
Foundations & supports	0.08 B	(included)
Handling & erection	0.14 B	(included)
Electrical	0.04 B	(included)
Piping	0.02 B	(included)
Insulation for ductwork	0.01 B	(included)
Painting	0.01 B	(included)
<b>Direct installation cost</b>	<b>0.30 B</b>	<b>\$0</b>
Site preparation	As required, SP	-
Buildings	As required, Bldg.	-
<b>Total Direct Cost, DC</b>	<b>1.30 B + SP + Bldg.</b>	<b>\$745,466</b>
<b>INDIRECT COSTS (Installation)</b>		
Engineering	0.10 B	(included)
Construction and field expenses	0.05 B	(included)
Contractor fees	0.10 B	(included)
Start-up	0.02 B	(included)
Performance test	0.01 B	(included)
Contingencies	0.03 B	(included)
<b>Total Indirect Cost, IC</b>	<b>0.31 B</b>	<b>\$0</b>
<b>TOTAL CAPITAL INVESTMENT (TCI) = DC + IC</b>	<b>DC + IC</b>	<b>\$745,466</b>

**Annual Costs - C-1A -SCR**

Cost Item			Total Annual Costs for SCR		Cost
<u>DIRECT ANNUAL COSTS</u>					
<i>Operating Labor</i>					
	Operator	1 hrs/shift	60.00 \$/hr <sup>1</sup>		\$64,800
	Supervisor	15% of operator			\$9,720
<i>Operating Materials</i>					
	Ammonia	yearly			\$471,761
	Catalyst	yearly			\$8,098
<i>Maintenance</i>					
	Labor	1 hrs/shift	60.00 \$/hr <sup>1</sup>		\$64,800
	Material	100% of maint. labor			\$64,800
<i>Utilities</i>					
	Natural Gas	0 (kft3/yr)	\$ 5.18 \$/kft3		\$0
	Electricity	0 (kWh/yr)	\$0.059 \$/kWh		\$0
<u>INDIRECT ANNUAL COSTS, IC</u>					
	Overhead	60% of sum of operating labor and materials and maintenance labor and materials.			\$122,472
	Administrative Charges	2% of TCI			\$14,909
	Property Taxes	1% of TCI			\$7,455
	Insurance	1% of TCI			\$7,455
	Capital Recovery Factor (20 yrs & prime rate = 5.5%)				0.0745
	Annual Capital Recovery (Recovery rate * TCI)				\$55,574
<b>TOTAL ANNUAL COST</b>					<b>\$891,844</b>
Uncontrolled Emissions (tons/yr): (5 units)					91
Controlled Emission Rate (g/bhp-hr)					1
Controlled Emissions (tons/yr):					19
Tons Removed (tons/yr):					73
<b>Cost-Effectiveness (\$/ton):</b>					<b>\$12,275</b>

**Capital Recovery Factor**

$$\text{Capital Recovery Factor} \quad CR = \frac{i(1+i)^n}{-1 + (1+i)^n}$$

n = 25 years  
 i = 5.5% interest rate  
 CR = 0.0745

<sup>1</sup> EPA/452/B-02-001; 7th Edition; Sec. 2.5 and 2.6; (2012 dollars)

**Clark Engine Cost Effectiveness**

**Annual Total Capital Costs - C-1B - SCR**

Total Capital Costs for SCR		
Cost Item	Factor	Cost
<b>DIRECT COSTS</b>		
Purchased equipment costs		
Capital (5 engines)	A	\$745,466
Instrumentation	0.10 A	(included)
Sales taxes	0.05 A	(included)
Freight	0.05 A	(included)
<b>Purchased equipment cost, PEC</b>	<b>B</b>	<b>\$745,466</b>
Direct installation costs		
Foundations & supports	0.08 B	(included)
Handling & erection	0.14 B	(included)
Electrical	0.04 B	(included)
Piping	0.02 B	(included)
Insulation for ductwork	0.01 B	(included)
Painting	0.01 B	(included)
<b>Direct installation cost</b>	<b>0.30 B</b>	<b>\$0</b>
Site preparation	As required, SP	-
Buildings	As required, Bldg.	-
<b>Total Direct Cost, DC</b>	<b>1.30 B + SP + Bldg.</b>	<b>\$745,466</b>
<b>INDIRECT COSTS (Installation)</b>		
Engineering	0.10 B	(included)
Construction and field expenses	0.05 B	(included)
Contractor fees	0.10 B	(included)
Start-up	0.02 B	(included)
Performance test	0.01 B	(included)
Contingencies	0.03 B	(included)
<b>Total Indirect Cost, IC</b>	<b>0.31 B</b>	<b>\$0</b>
<b>TOTAL CAPITAL INVESTMENT (TCI) = DC + IC</b>	<b>DC + IC</b>	<b>\$745,466</b>

**Annual Costs - C-1B -SCR**

Total Annual Costs for SCR				Cost
Cost Item				
<b>DIRECT ANNUAL COSTS</b>				
<i>Operating Labor</i>				
Operator	1 hrs/shift	60.00 \$/hr <sup>1</sup>		\$64,800
Supervisor	15% of operator			\$9,720
<i>Operating Materials</i>				
Ammonia	yearly			\$471,761
Catalyst				\$8,098
<i>Maintenance</i>				
Labor	1 hrs/shift	60.00 \$/hr <sup>1</sup>		\$64,800
Material	100% of maint. labor			\$64,800
<i>Utilities</i>				
Natural Gas	0 (kft3/yr)	\$ 5.18 \$/kft3		\$0
Electricity	0 (kWh/yr)	\$0.059 \$/kWh		\$0
<b>INDIRECT ANNUAL COSTS, IC</b>				
Overhead	60% of sum of operating labor and materials and maintenance labor and materials.			\$122,472
Administrative Charges	2% of TCI			\$14,909
Property Taxes	1% of TCI			\$7,455
Insurance	1% of TCI			\$7,455
				0.0745
Annual Capital Recovery (Recovery rate * TCI)				\$55,574
<b>TOTAL ANNUAL COST</b>				<b>\$891,844</b>
Uncontrolled Emissions (tons/yr): (5 units)				160
Controlled Emission Rate (g/bhp-hr)				1
Controlled Emissions (tons/yr):				19
Tons Removed (tons/yr):				142
<b>Cost-Effectiveness (\$/ton):</b>				<b>\$6,289</b>

<sup>1</sup> EPA/452/B-02-001; 7th Edition; Sec. 2.5 and 2.6; (2012 dollars)

**Capital Recovery Factor**

$$CR = \frac{i(1+i)^n}{-1 + (1+i)^n}$$

n = 25 years  
i = 5.50% interest rate  
CR = 0.0745

# Clark Engine Cost Effectiveness

## Total Capital Costs - C-1C - SCR

Total Annual Costs for SCR		
Cost Item	Factor	Cost
<b>OSTS</b>		
sed equipment costs		
Capital	A	\$745,466
Instrumentation	0.10 A	(included)
Sales taxes	0.05 A	(included)
Freight	0.05 A	(included)
<b>Purchased equipment cost, PEC</b>	B	<b>\$745,466</b>
Installation costs		
Foundations & supports	0.08 B	(included)
Handling & erection	0.14 B	(included)
Electrical	0.04 B	(included)
Piping	0.02 B	(included)
Insulation for ductwork	0.01 B	(included)
Painting	0.01 B	(included)
<b>Direct installation cost</b>	0.30 B	<b>\$0</b>
Site preparation	As required, SP	-
Buildings	As required, Bldg.	-
<b>Total Direct Cost, DC</b>	1.30 B + SP + Bldg.	<b>\$745,466</b>
<b>COSTS (Installation)</b>		
Engineering	0.10 B	(included)
Construction and field expenses	0.05 B	(included)
Contractor fees	0.10 B	(included)
Start-up	0.02 B	(included)
Performance test	0.01 B	(included)
Contingencies	0.03 B	(included)
<b>Total Indirect Cost, IC</b>	0.31 B	<b>\$0</b>
<b>CAPITAL INVESTMENT (TCI) = DC + IC</b>	DC + IC	<b>\$745,466</b>

## Annual Costs - C-1C -SCR

Total Annual Costs for SCR			
Cost Item			Cost
<b>DIRECT ANNUAL COSTS</b>			
<i>Operating Labor</i>			
Operator	1 hrs/shift	60.00 \$/hr <sup>1</sup>	\$64,800
Supervisor	15% of operator		\$9,720
<i>Operating Materials</i>			
Ammonia	yearly		\$471,761
Catalyst			\$8,098
<i>Maintenance</i>			
Labor	1 hrs/shift	60.00 \$/hr <sup>1</sup>	\$64,800
Material	100% of maint. labor		\$64,800
<i>Utilities</i>			
Natural Gas	0 (kft3/yr)	\$ 5.18 \$/kft3	\$0
Electricity	0 (kWh/yr)	\$0.059 \$/kWh	\$0
<b>INDIRECT ANNUAL COSTS, IC</b>			
Overhead	60% of sum of operating labor and materials and maintenance labor and materials.		\$122,472
Administrative Charges	2% of TCI		\$14,909
Property Taxes	1% of TCI		\$7,455
Insurance	1% of TCI		\$7,455
Capital Recovery Factor (20 yrs & prime rate = 5.5%)			0.0745
Annual Capital Recovery (Recovery rate * TCI)			\$55,574
<b>TOTAL ANNUAL COST</b>			<b>\$891,844</b>
Uncontrolled Emissions (tons/yr):			
Controlled Emission Rate (g/bhp-hr)			1
Controlled Emissions (tons/yr):			19
Tons Removed (tons/yr):			175
<b>Cost-Effectiveness (\$/ton):</b>			<b>\$5,103</b>

Capital Recovery Factor

$$CR = \frac{i(1+i)^n}{-1 + (1+i)^n}$$

n = 25 years  
i = 5.50% interest rate  
CR = 0.0745

<sup>1</sup> EPA/452/B-02-001; 7th Edition; Sec. 2.5 and 2.6; (2012 dollars)



**Clark Engine Cost Effectiveness**

**Annual Total Capital Costs - C-1E - SCR**

Total Annual Costs for SCR		
Cost Item	Factor	Cost
<b>DIRECT COSTS</b>		
Purchased equipment costs		
Capital (5 engines)	A	\$745,466
Instrumentation	0.10 A	(included)
Sales taxes	0.05 A	(included)
Freight	0.05 A	(included)
<b>Purchased equipment cost, PEC</b>	<b>B</b>	<b>\$745,466</b>
Direct installation costs		
Foundations & supports	0.08 B	(included)
Handling & erection	0.14 B	(included)
Electrical	0.04 B	(included)
Piping	0.02 B	(included)
Insulation for ductwork	0.01 B	(included)
Painting	0.01 B	(included)
<b>Direct installation cost</b>	<b>0.30 B</b>	<b>\$0</b>
Site preparation	As required, SP	-
Buildings	As required, Bldg.	-
<b>Total Direct Cost, DC</b>	<b>1.30 B + SP + Bldg.</b>	<b>\$745,466</b>
<b>INDIRECT COSTS (Installation)</b>		
Engineering	0.10 B	(included)
Construction and field expenses	0.05 B	(included)
Contractor fees	0.10 B	(included)
Start-up	0.02 B	(included)
Performance test	0.01 B	(included)
Contingencies	0.03 B	(included)
<b>Total Indirect Cost, IC</b>	<b>0.31 B</b>	<b>\$0</b>
<b>TOTAL CAPITAL INVESTMENT (TCI) = DC + IC</b>	<b>DC + IC</b>	<b>\$745,466</b>

**Annual Costs - C-1E -SCR**

Total Annual Costs for SCR			Cost
Cost Item			
<b>DIRECT ANNUAL COSTS</b>			
<b>Operating Labor</b>			
Operator	1 hrs/shift	60.00 \$/hr <sup>1</sup>	\$64,800
Supervisor	15% of operator		\$9,720
<b>Operating Materials</b>			
Ammonia	yearly		\$471,761
Catalyst			\$8,098
<b>Maintenance</b>			
Labor	1 hrs/shift	60.00 \$/hr <sup>1</sup>	\$64,800
Material	100% of maint. labor		\$64,800
<b>Utilities</b>			
Natural Gas	0 (kft3/yr)	\$ 5.18 \$/kft3	\$0
Electricity	0 (kWh/yr)	\$0.059 \$/kWh	\$0
<b>INDIRECT ANNUAL COSTS, IC</b>			
Overhead	60% of sum of operating labor and materials and maintenance labor and materials.		\$122,472
Administrative Charges	2% of TCI		\$14,909
Property Taxes	1% of TCI		\$7,455
Insurance	1% of TCI		\$7,455
Capital Recovery Factor (20 yrs & prime rate = 5.5%)			0.0745
Annual Capital Recovery (Recovery rate * TCI)			\$55,574
<b>TOTAL ANNUAL COST</b>			<b>\$891,844</b>
Uncontrolled Emissions (tons/yr): (5 units)			190
Controlled Emission Rate (g/bhp-hr)			1
Controlled Emissions (tons/yr):			19
Tons Removed (tons/yr):			171
<b>Cost-Effectiveness (\$/ton):</b>			<b>\$5,213</b>

**Capital Recovery Factor**

$$\text{Capital Recovery Factor} \quad CR = \frac{i(1+i)^n}{-1 + (1+i)^n}$$

n = 25 years  
 i = 5.50% interest rate  
 CR = 0.0745

<sup>1</sup> EPA/452/B-02-001; 7th Edition; Sec. 2.5 and 2.6; (2012 dollars)

**Clark Engine Cost Effectiveness**

**Annual Total Capital Costs - C-1G - SCR**

Total Capital Costs for SCR		
Cost Item	Factor	Cost
<b>DIRECT COSTS</b>		
Purchased equipment costs		
Capital (5 engines)	A	\$745,466
Instrumentation	0.10 A	(included)
Sales taxes	0.05 A	(included)
Freight	0.05 A	(included)
<b>Purchased equipment cost, PEC</b>	<b>B</b>	<b>\$745,466</b>
Direct installation costs		
Foundations & supports	0.08 B	(included)
Handling & erection	0.14 B	(included)
Electrical	0.04 B	(included)
Piping	0.02 B	(included)
Insulation for ductwork	0.01 B	(included)
Painting	0.01 B	(included)
<b>Direct installation cost</b>	<b>0.30 B</b>	<b>\$0</b>
Site preparation	As required, SP	-
Buildings	As required, Bldg.	-
<b>Total Direct Cost, DC</b>	<b>1.30 B + SP + Bldg.</b>	<b>\$745,466</b>
<b>INDIRECT COSTS (Installation)</b>		
Engineering	0.10 B	(included)
Construction and field expenses	0.05 B	(included)
Contractor fees	0.10 B	(included)
Start-up	0.02 B	(included)
Performance test	0.01 B	(included)
Contingencies	0.03 B	(included)
<b>Total Indirect Cost, IC</b>	<b>0.31 B</b>	<b>\$0</b>
<b>TOTAL CAPITAL INVESTMENT (TCI) = DC + IC</b>	<b>DC + IC</b>	<b>\$745,466</b>

**Annual Costs - C-1G -SCR**

Total Annual Costs for SCR				Cost
Cost Item				
<b>DIRECT ANNUAL COSTS</b>				
<i>Operating Labor</i>				
Operator	1 hrs/shift	60.00 \$/hr <sup>1</sup>		\$64,800
Supervisor	15% of operator			\$9,720
<i>Operating Materials</i>				
Ammonia	yearly			\$471,761
Catalyst				\$8,098
<i>Maintenance</i>				
Labor	1 hrs/shift	60.00 \$/hr <sup>1</sup>		\$64,800
Material	100% of maint. labor			\$64,800
<i>Utilities</i>				
Natural Gas	0 (kft3/yr)	\$ 5.18 \$/kft3		\$0
Electricity	0 (kWh/yr)	\$0.059 \$/kWh		\$0
<b>INDIRECT ANNUAL COSTS, IC</b>				
Overhead	60% of sum of operating labor and materials and maintenance labor and materials.			\$122,472
Administrative Charges	2% of TCI			\$14,909
Property Taxes	1% of TCI			\$7,455
Insurance	1% of TCI			\$7,455
Capital Recovery Factor (20 yrs & prime rate = 5.5%)				0.0745
Annual Capital Recovery (Recovery rate * TCI)				\$55,574
<b>TOTAL ANNUAL COST</b>				<b>\$891,844</b>
Uncontrolled Emissions (tons/yr): (5 units)				153
Controlled Emission Rate (g/bhp-hr)				1
Controlled Emissions (tons/yr):				19
Tons Removed (tons/yr):				135
<b>Cost-Effectiveness (\$/ton):</b>				<b>\$6,612</b>

<sup>1</sup> EPA/452/B-02-001; 7th Edition; Sec. 2.5 and 2.6; (2012 dollars)

**Capital Recovery Factor**

$$CR = \frac{i(1+i)^n}{-1 + (1+i)^n}$$

n = 25 years  
i = 5.50% interest rate  
CR = 0.0745

## **APPENDIX B: BASELINE EMISSION RATES**

---

---

This appendix contains a brief summary of the derivation of emission rates used to define the “Baseline” emissions for this analysis. The 4-Factor analysis requires that a “cost effectiveness” be determined for each (or combination) control option identified as practical or available.

## Clark Engines - NOx

The 5 Clark engines, subject to this analysis, are expected to be used less in the future. Part of the reason relates to the nature of the gas field(s) processed and part of the reason is that Hess expects it will slowly switch from the current gas-fired units to electric driven compressor engines. Regardless, baseline emissions for the existing Clark engines were evaluated using the most recent 5 years of data (2014 → 2018). It did not seem necessary to go further back in time since it would be less and less likely to represent a current (or near current) emission rate.

A review of historical data shows that there is a modest degree of variability in emission rates both within and among the engines. There is roughly a 30% difference in NOx emission results (emission factor) for the same engine over several years. The same is true when comparing the 5 engines across a specific testing period. As a result, the baseline emission rate should be established not so much by a particular rate based on NOx itself but on the underlying function of the engines (to avoid setting a value based on random testing variability).

To evaluate the baseline emissions, it is necessary to understand and review the hours of operation for these devices. Recall that the purpose of these engines is to compress gas and move it from one point to the other. Given each of the 5 engines is the same size, each hour of operation represents, more or less, a known or set quantity of compression. Therefore, to determine baseline emissions, it is necessary to establish the baseline hours. From the baseline of hours, one can then determine the NOx emissions rate that is most representative of recent and expected operation (i.e. compression).

The table below provides a summary of the hours of operation for each engine.

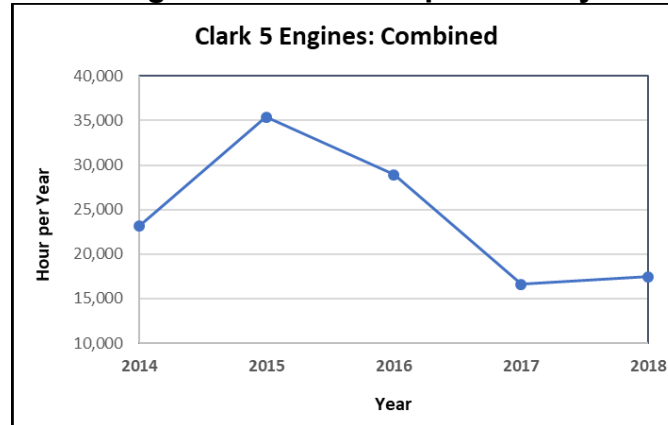
**Clark Engines: Hours of Operation by Year**

Year	C-1A	C-1B	C-1C	C-1E	C-1G	C-1D*	C-1F*	All
2014	2400	4814	5012	5594	5312	7220	4820	35172
2015	6520	7749	5818	7437	7885	10276	10487	56072
2016	3720	6417	6965	6600	5217	8623	9745	47287
2017	528	3506	4258	2070	6240	9994	8210	34806
2018	3136	4437	4647	0	5253	4489	6518	28482

\* Note the hours on these units were normalized (upward) to account for the fact that these units have a higher horse power rating and thus compress more gas than the 5 engines of interest.

For interest the same information is shown in the graphic below for the 5 Clark engines.

**Clark Engines: Hours of Operation by Year**



The data suggests that there may be a downward trend. The  $R^2$  value is 0.36 which roughly indicates that about 36% of the observed data fits the linear model (as a linear least-squares correlation) well. This fits our contention that the engines are used less and less.

A review of the data does not lead to an obvious baseline value. It was hypothesized that perhaps the best non-biased method to use would be to use an average of the results (per engine). On the other hand, the variability of the data is quite large. It ranges from roughly 35,000 hours per year to 16,000; a factor of 2 difference. Upon reflection, a better approach would be to remove the minimum and maximum values from the data set to remove some of the variability. This was the approach taken to determine hours of operation per engine which then leads to the baseline NOx emission rate.

The data above, thusly, indicates that years 2014, 2016 and 2017 were selected. From that information, the following baseline emissions data emerges.

**NOx Emissions (tons) – Baseline Years**

Year	C-1A	C-1B	C-1C	C-1E	C-1G
2014	85	167	198	230	155
2016	171	215	255	257	150
2017	18	99	127	81	155
<b>Baseline</b>	91	160	193	190	153

Interestingly these values, taken as a whole and as a representation of total gas compression, are quite similar to using the simple average from the 5 years. This confirms that the choice of baseline data is reasonable.

## Sulfur Recovery Unit (Amine Sweetening Unit): SO<sub>2</sub> & NO<sub>x</sub>

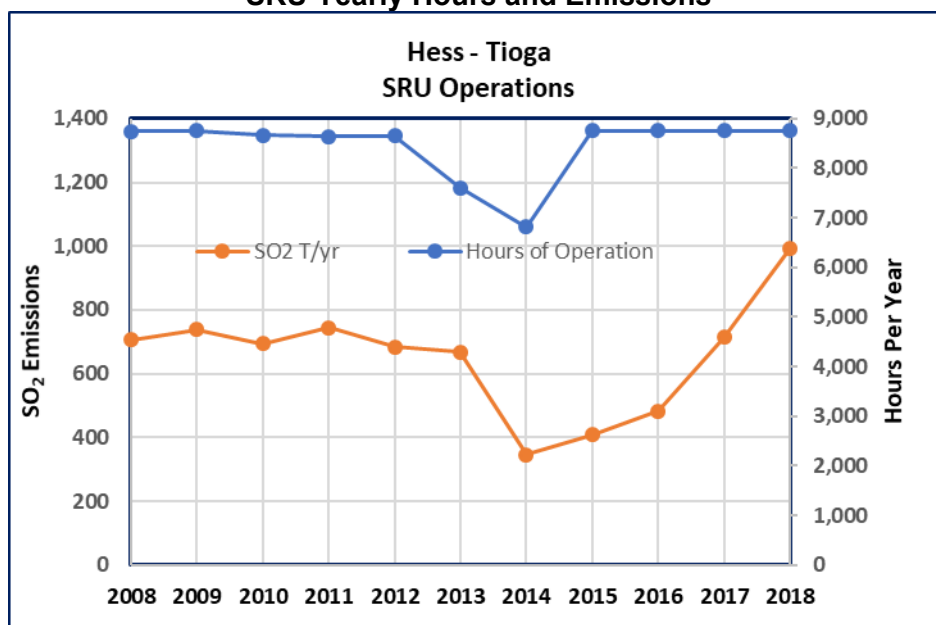
The selection of the baseline year(s) data for the SRU is a simpler task than the Clark engines. A historical review of the hours of operation of this unit reveals a relatively straight flat line as time progresses. Both the year hours and emissions from this unit are shown in the table below covering an 11-year period.

**SRU Yearly Hours and Emissions**

Year	Hours	Tons SO <sub>2</sub>
2008	8,750	707
2009	8,759	739
2010	8,665	694
2011	8,638	745
2012	8,649	683
2013	7,604	668
2014	6,816	345
2015	8,760	408
2016	8,760	482
2017	8,760	715
2018	8,760	994

The same information is shown in the figure below.

**SRU Yearly Hours and Emissions**



The table and figure show a very consistent operation from this unit. Nearly every year annual operation approaches 100% utilization with a few minor exceptions. Those years most at odds with the typical year coincide with various operational changes occurring at the unit at that time.

One item of note is an apparent increase in SO<sub>2</sub> from 2014 forward. It should be noted that this increase is not particularly relevant as an indication of a future trend. The reason for the increase relates to the operation of the Claus plant; not the amount of gas processed. For example; below is the amount of produced gas at the plant from 2014:

**Gas Processing**  
(billion ft<sup>3</sup>)

Year	Received (wet)	Produced	SO <sub>2</sub> (tons)
2014	39	20	345
2015	71	36	408
2016	62	36	482
2017	64	39	715

Clearly the amount of gas processed at the plant has no distinct correlation with the SO<sub>2</sub> emissions. The reason for the increase in SO<sub>2</sub> during this time period relates to proper operation of the Claus plant itself. The changes in the concentration of H<sub>2</sub>S in received gas along with other operational parameters has led Hess to conduct a study of the Claus operation and possible remedies to bring it back to its achievable efficiency. It was this analysis that led to obtaining vendor quote for alternatives such as the LO-CAT® and acid gas injection well.

As was the case with the Clark engines, it was deemed appropriate to remove the maximum and minimum year data from the data set. This results in a 9-year average value which seems reasonable for this 4-Factor analysis. The annual baseline emissions for the SRU are 605 tons/year.<sup>44</sup>

For NO<sub>x</sub> emissions, the baseline emissions were calculated using AP-42 values (AP-42, Section 8.13, Table 8.13-2, April 2015). As a matter of convenience only the past 4 years of available data were reviewed since they are based on fuel burned at the unit; not emissions testing. The NO<sub>x</sub> emissions from the SRU were calculated as follows:

**SRU Yearly Hours and Emissions**

Year	Hours	Tons NO <sub>x</sub>
2014	6,816	38
2015	8,760	40
2016	8,760	52
2017	8,760	54

Given the smaller sample size, it was decided to include the values from all 4 years yielding a baseline emission rate of 46 tons per year.

---

<sup>44</sup> As a side note, the annual emission value is only slightly different with or without removing the min and max year's data.

## B.8.c – Communications





January 16, 2019

**FILE**

Mr. Tony St. Clair  
EHS Advisor  
Hess Corporation  
1501 McKinney Street  
Office 11.012B  
Houston, TX 77010

Re: Regional Haze 4-Factors Analysis  
Hess Tioga Gas Plant

Dear Mr. St. Clair:

The North Dakota Department of Health (Department) has conducted an initial review of your four-factors analysis for the Hess Corporation (Hess) – Tioga Gas Plant (TGP) in North Dakota. With respect to the analysis we have the following comments:

1. The expected life of the control equipment selected appears too low: tail-gas scrubbing treatment (SCOT), low-emission combustion (LEC), and selective catalytic reduction (SCR) are each listed in the economic analysis with an expected life of 10 to 15 years.
  - a. A more appropriate life of a SCOT is 20 years.
  - b. A more appropriate life of a LEC is, at a minimum, 20 years. It has already been ~17 years since upgrades were performed on C1D and C1F at the TGP.
  - c. A more appropriate life of a SCR for a natural gas-fired unit is 20-30 years (see EPA's Control Cost Manual, Section 4.2, Chapter 2, p 2-78).

The analysis must be redone using an appropriate expected life. At a minimum, justification of why each value was chosen needs to be included.

2. The 10% interest rate for the Amine/SCOT (Appendix A-3) and the 8.25% interest rate for the Engines (Appendix A-10 through A-21) used in the economic analysis appear to be too high. EPA's Control Cost Manual (Manual) states "When performing cost analysis, it is important to ensure that the correct interest rate is being used. Because this Manual is concerned with estimating private costs, **the correct interest rate to use is the nominal interest rate, which is the rate firms actually face** [emphasis added]". The Manual further states "For input to analysis of rulemakings, assessments of private cost should be prepared using firm-specific nominal interest rates if possible, or the bank prime rate if firm-specific interest rates cannot be estimated or verified." The current bank prime rate is 5.25%. The Department believes an interest rate no higher than 5.25% should be used. Attached to this letter is an email we received from EPA regarding this matter.

The economic analysis must be redone using an appropriate interest rate. At a minimum, justification of why each value was chosen needs to be included.

3. The baseline emission rates for Emission Units C1A, C1B, C1C, C1E, and C1G appear to be too low. While the most recent 2-years of data (2016-2017) were used, this doesn't appear to be representative of past operations or future expected operations. Average utilization was low in 2016-2017 (mainly due to 2017 operations). See tables below for the data the Department has on file regarding recent emissions and utilization, which were derived from hours of operation.

2-year averages Emissions	C1A	C1B	C1C	C1E	C1G	C1D	C1F
2014-15	161.6	230.2	203.4	291.6	181.1	21.9	24.4
2015-16	204.9	254.0	232.4	305.3	178.6	27.2	32.4
2016-17	94.4	156.9	191.2	169.2	152.7	25.1	29.6

Utilization	C1A	C1B	C1C	C1E	C1G	C1D	C1F
2014-15	51%	72%	62%	74%	75%	81%	71%
2015-16	58%	81%	73%	80%	75%	88%	94%
2016-17	24%	57%	64%	49%	65%	87%	84%

Avg. Engine Utilization	A/B/C/E/G	D/F	All engines
2014	53%	56%	54%
2015	81%	96%	85%
2016	66%	85%	71%
2017	38%	85%	51%

Years 2015 and 2016 appear to be more representative of baseline numbers. Justification of the baseline years selected needs to be provided, especially when the baseline is not easily determined.

4. Are there any limitations to refurbishing, rebuilding, or retrofitting two to three of the engines, which have not already been modified (C1A, C1B, C1C, C1E, C1G) and operating them at an increased utilization? This is more consistent with C1D and C1F utilization.
  - a. Future operations could utilize the LEC modified engines first with the non-LEC modified as backup in the event of SSM (i.e. C1A, C1B, C1C, C1D, and C1F would have priority and C1E and C1G would operate as backup). Based on past plant data, this looks like the plant would still have enough inlet capacity to handle daily operations.
5. Documentation must be provided for the cost estimates. Any references, other than EPA's Control Cost Manual, must either be submitted with the analysis or a website address must be provided where the documents can be downloaded. Documentation must also be provided for any scaling done to obtain the cost estimates.
6. The capital cost derivation for a LEC was estimated at \$4 million. The referenced paper used for the cost estimate indicates a **total cost** of \$ 2-4 million. It is indicated the upper

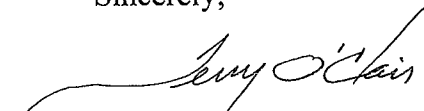
one-third was used to account for older engines. The upper one-third would be \$3.33 million. Also, additional costs for equipment, installation and indirect costs were added. The Department's interpretation is that the referenced **total cost** (\$ 2-4 million) is the "total capital investment" (TCI). Justification for the additional capital costs is required.

7. Acid gas injection must be considered for SO<sub>2</sub> reductions at the SRU.
8. The preparation and implementation of a flare management plan to control emissions from flares must be addressed and included in the analysis.
9. The cost estimate for the SCOT tail gas clean-up system references WRAP's 4-factors analysis for North Dakota from 2009. The \$15 million estimated capital cost in WRAP's report includes purchased equipment, installation costs and indirect capital costs (i.e. Total Capital Investment (TCI) – see page 2-1 of the WRAP report). Hess's SCOT estimate adds additional capital costs, installation and indirect capital costs which are already included in the \$15 million capital cost. The additional capital costs must be eliminated.
10. Note: Historic emissions from S302 appear to be incorrect and overreported from 2008-2015. The Department did not look back farther than 2008 during this review. Emissions data for 2016 and 2017 appear to be correct.

Year	SO <sub>2</sub> Emissions tpy (reported)	Tail Gas Incinerated MMcf/y	Average H <sub>2</sub> S mole%	Operating Time hours	SO <sub>2</sub> Emissions tpy (calculated from inputs)	Reported minus Calculated (per equation in AEIR form)	These are significantly different
2008	1049	2095.48	0.40	8750	707	343	
2009	1102	1825.8	0.48	8759	739	363	
2010	1045	1469.73	0.56	8665	694	351	
2011	1126	1522.95	0.58	8638	745	382	
2012	1022	1350.31	0.60	8649	683	339	
2013	1022	1056.08	0.75	7604	668	354	
2014	515	772.64	0.53	6816	345	170	
2015	614	820.56	0.59	8760	408	206	
2016	481	1100.14	0.52	8760	482	-1	
2017	719	1130.73	0.75	8760	715	4	

The revised analysis should be submitted as soon as possible. If you have any questions, please contact David Stroh or Tom Bachman of my staff at (701) 328-5188.

Sincerely,



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

TLO/AS:saj

B.9 – Northern Boarder CS4

B.9.a – Department Request



May 18, 2018

**FILE**

Ms. Ruth Jensen  
Northern Border Pipeline  
13710 FNB Parkway, Ste 300  
Omaha, NE 68154

Re: Regional Haze  
Second Planning Period

Dear Ms. Jensen:

The Department of Health (Department) has begun work on the second planning period (Round 2) State Implementation Plan (SIP) for regional haze. In Round 1 of the regional planning process, the emphasis was on Best Available Retrofit Technology (BART) and making reasonable progress towards the national visibility goal. In Round 2, there are no BART requirements; therefore, we will focus on making reasonable progress. The reasonable progress analysis will be made using the four factors in Section 169A(g)(1) of the Clean Air Act:

The four factors are:

1. The cost of compliance
2. The time necessary to achieve compliance
3. The energy and non-air quality environmental impact of compliance; and
4. The remaining useful life of any existing source subject to such requirements

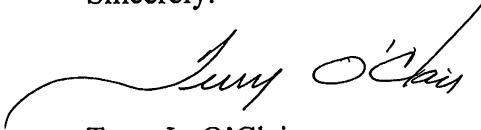
Guidance provided by the U.S. Environmental Protection Agency (Draft Guidance on Progress Tracking Metrics, Long Term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period at [https://www.epa.gov/sites/production/files/2016-07/documents/draft\\_regional\\_haze\\_guidance\\_july\\_2016.pdf](https://www.epa.gov/sites/production/files/2016-07/documents/draft_regional_haze_guidance_july_2016.pdf)) indicates the Department must address 80% of the visibility impairment caused by in-state sources. Data from the IMPROVE monitoring sites at Theodore Roosevelt National Park (TRNP) and Lostwood Wilderness Area (LWA) indicate that sulfates and nitrates continue to be the largest contributors to visibility impairment in these areas. The primary precursors of sulfates and nitrates are emissions of sulfur dioxide (SO<sub>2</sub>) and nitrogen oxides (NO<sub>x</sub>).

Northern Border Pipeline's Compress Station No.4 is a significant source of NO<sub>x</sub> and is located very close to a Class I area. Therefore, the Department requests that you prepare a "four factors" analysis for the turbine (Emission Unit CE1) at this station. The analysis should be prepared using the draft EPA guidance noted above.

Preparation of the Round 2 Regional Haze SIP will require extensive planning and review of emission sources in North Dakota. The Department will be working with the Western Regional Air Partnership (WRAP) to prepare the Round 2 SIP. WRAP will be conducting air quality modeling of potential regional emissions reductions in early 2019. The Department asks that your "four factors" analysis be submitted by January 31, 2019.

If you have any questions, please contact David Stroh of my staff at (701)328-5188.

Sincerely,

A handwritten signature in cursive script, reading "Terry O'Clair".

Terry L. O'Clair  
Director  
Division of Air Quality

TLO/TB:saj

## B.9.b – Facility Response



December 10, 2018

FedEx No. 8136 7919 7968

Mr. Terry L. O'Clair, P.E.  
Director, Division of Air Quality  
North Dakota Department of Environmental Quality  
Gold Seal Center  
918 E. Divide Ave.  
Bismarck, ND 58501-1947



Re: Regional Haze Second Planning Period and Request for "Four Factor" Analysis for the Northern Border Pipeline Company Compressor Station No. 4

Dear Mr. O'Clair:

This letter has been prepared in response to a request by the North Dakota Department of Environmental Quality (NDDEQ) to complete a "four factors" analysis<sup>1</sup> by January 31, 2019 for Northern Border Pipeline Company's (NBPL) Compressor Station No. 4 (CS4). The main intent of this letter is to provide the four factor analysis requested for the facility turbine. However, our review of related material raised several questions, and the attached four factor analysis includes supplementary information. The attachment includes:

- The four-factor analysis considering NOx control of the facility turbine;
- A request for feedback from NDDEQ to clarify the screening or selection criteria that concludes a four-factor analysis is warranted;
- Questions regarding Western Regional Air Partnership emission inventory parameters, such as exhaust temperature, that are relevant for dispersion modeling; and
- Compressor Station #4 location and turbine stack parameters.

As discussed in the attachment, NBPL believes the NOx control cost effectiveness for two available add-on control technologies exceed a reasonable cost threshold. Please contact me if there are any questions or comments at 402-492-7465. Thank you for your review and consideration of this submittal.

Sincerely,

Ruth Jensen  
Air Quality Specialist

Attachments: Attachment 1: Compressor Station No. 4 – Four Factor Analysis and Related Questions and Comments

cc. David Stroh, NDDEQ

<sup>1</sup> Section 16 A(g)(l) of the Clean Air Act  
13710 FNB Parkway, Suite 300



## **Attachment 1:**

### **Compressor Station No. 4 – Four Factor Analysis and Related Questions and Comments**

This attachment includes the four factor analysis for Compressor Station No. 4, as well as a request for feedback on the NDDEQ screening and selection process that concluded the analysis is warranted, and comments regarding potential air quality modeling and source characteristics.

#### **Four-Factor Analysis for Compressor Station No. 4**

Northern Border Pipeline Company's Compressor Station No. 4 is located in McKenzie County, North Dakota and operates under NDDEQ permit number T5-O84001. NDDEQ has requested a four factors analysis associated with its regional haze second planning period (Round 2) State Implementation Plan (SIP). As discussed below, Northern Border would appreciate additional insight into the screening and selection criteria that determined this analysis is needed. The four factor analysis considers application of NO<sub>x</sub> control on the facility combustion turbine, and the analysis follows EPA's draft guidance document<sup>2</sup> and standard methodologies from the EPA Control Cost Manual that are recommended in section 7 of the EPA guidance document.

CS4 includes a 20,000 horsepower (hp) simple cycle natural gas-fired combustion turbine that drives a natural gas compressor. The facility also includes a small emergency generator. Control cost effectiveness is not reviewed for the emergency generator in the four factor analysis because of its very limited run time. The turbine is a Rolls Royce Avon unit with a diffusion flame combustor.

The manufacturer does not offer a burner retrofit option for "lean premixed" combustion, which would decrease NO<sub>x</sub> emissions, so other control options are considered. Despite the lack of retrofit burner technology, turbines with standard burners are still relatively low emitting combustion sources (i.e., emissions are relatively low in comparison to other combustion devices such as boilers or engines and other fuel types).

#### **Factor #1 – NO<sub>x</sub> Emissions Controls and Control Cost**

The pollutant of concern for a natural gas-fired turbine is nitrogen oxides (NO<sub>x</sub>). As noted above, the Avon turbine does not offer a low NO<sub>x</sub> combustor (lean premixed combustion) as a retrofit option. The EPA guidance document indicates that both retrofit and replacement should be considered. However, replacement costs for a 20,000 hp unit would be exorbitant and more than an order of magnitude higher than the two add-on control options discussed below. The achieved emissions level for replacement would be similar to the controlled NO<sub>x</sub> emissions discussed below, thus NO<sub>x</sub> cost effectiveness would be more than an order of magnitude higher and exceed \$100,000 per ton. Replacement is not discussed further in this analysis.

Since combustion control is also not an option, the remaining add-on control technologies applicable to a combustion turbine are selective catalytic reduction (SCR) or water/steam injection. Consistent with the EPA guidance document, methodologies from the EPA Control Cost Manual are used to evaluate the NO<sub>x</sub> control cost effectiveness for these two technologies.

---

<sup>2</sup> Draft Guidance on Progress Tracking Metrics, Long-term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period, EPA document number EPA-457/P-16-001 (July 2016).

### *SCR control cost analysis*

SCR has had limited application as a retrofit control option for natural gas-fired compressor drivers. In addition to Control Cost Manual methods, costs for the analysis are based on several sources, including:

- A Department of Energy (DOE) Report, “Cost Analysis of NO<sub>x</sub> Control Alternatives for Stationary Gas Turbines.”<sup>3</sup>
- Analysis conducted by the Pennsylvania Department of Environmental Protection (PADEP)<sup>4</sup> associated with NO<sub>x</sub> control requirements for a general permit program, which included SCR and associated reagent costs (as “Total Capital Investment”) for turbines.
- Actual design and installation costs from a recent pipeline installation that were presented to PADEP during recent revisions to the general permit program.
- Capital cost comparison to EPA’s Control Strategy Tool (CoST) software, which is cited in the EPA guidance document.

Table 1 presents the cost details and the source for specific itemized cost elements. Primary assumptions for the analysis include:

- A capital cost of \$720,000 to achieve 80% reduction in NO<sub>x</sub>. This control efficiency would achieve 37 tons per year (TPY) of NO<sub>x</sub> reductions with 74% annual utilization (i.e., 6500 operating hours).
  - This cost is conservative, and may be very low based on available references. Costs from the PA DEP analysis are higher and the CoST software estimate would be more than double.
- Uncontrolled emissions are based on the 1997 performance test, and these actual emissions (approximately 100 ppmv) from testing at full load are nominally higher than the results from numerous portable analyzer tests conducted in the last fifteen years. The turbine frequently runs at marginally lower load and NO<sub>x</sub> emissions decrease at lower load.
- Utilization was reviewed for five years, and the analysis presented in the tables below is based on 6,500 annual operating hours (74% utilization) which is marginally higher than the 5-year average of approximately 6,000 annual operating hours.
- Installation costs based on the real-world example for SCR installed on a smaller unit were *not* scaled based on the unit size. *Direct installation* costs from the real world example are higher than the generic assumptions in the EPA Control Cost Manual, but these are conservative assumptions because some costs (e.g., site preparation, foundation and supports) would likely be higher for the larger unit at CS4. Some *indirect installation* costs are lower than the generic assumptions in the EPA Control Cost Manual, but the “real world” costs are used in this analysis. The default Cost Manual assumptions (i.e., “multipliers” that were not used in the analysis) are shown in Table 1 with ~~striketrough~~ text.
- Reagent costs are from the PA DEP analysis and usage / cost is scaled based on the relative mass emissions of NO<sub>x</sub>.

---

<sup>3</sup> “Cost Analysis of NO<sub>x</sub> Control Alternatives for Stationary Gas Turbines,” Department of Energy, Prepared by ONSITE SYCOM Energy Corporation under Contract No. DE-FC02-97CHIO877 (November 1999).

<sup>4</sup> “Technical Support Document, General Permit GP-5” Pennsylvania Department of Environmental Protection (January 2013).

- EPA Control Cost Manual factors and assumptions from similar EPA analysis are used for other cost elements.

Using a conservative approach to determine cost-effectiveness the resulting NOx control cost is estimated to be \$14,435 per ton. Even using this approach, this is above a reasonable cost threshold. If NDDEQ disagrees, NBPL requests an opportunity to further confirm and/or adjust the conservatively low estimates included for several assumptions, especially for the equipment capital cost.

#### *Water injection control cost analysis*

Water injection control is a technology that was applied to turbines over two decades ago, but has had very limited use in recent years, as combustion controls or SCR have been employed. A key concern with water injection is significant increases in emissions of products of incomplete combustion such as carbon monoxide (CO). The manufacturer estimates a five to eight fold increase in CO, which may necessitate installation of an oxidation catalyst, with a cost similar to the NOx technology. Thus, environmental and economic implications are broader than reflected in the NOx control cost effectiveness.

The basis for water injection costs and other assumptions include:

- A capital cost of \$2.25 million to achieve 25 ppmv NOx (i.e., approximately 75% reduction from uncontrolled emissions). This control efficiency would achieve 35 tons per year of NOx reductions with 65% annual utilization.
- Assumptions for utilization and uncontrolled emissions as discussed above for SCR.
- The technology life of fifteen years is based on the DOE Report.
- EPA Control Cost Manual factors and assumptions from similar EPA analysis are used for most other cost elements.
- Costs are not considered for add-on control to mitigate increases in CO and other emissions.

Table 2 presents the cost details and the resulting NOx cost effectiveness is \$20,160 per ton. This would appear to be above a reasonable cost threshold.

#### Factor #2 – Time Necessary for Compliance

Both NOx control technologies would require a timeline of 18 months to two years. This time is required for engineering design, permitting, site preparation, installation, commissioning, and startup. A longer schedule could be required because previous retrofit installations of SCR on natural gas transmission compressor drivers are very limited, and have resulted in extended commissioning periods to address performance issues with the reagent control system (e.g., ability of the reagent flow control to adequately respond to emissions changes as pipeline demand changes turbine load and NOx emissions). The schedule would also need to consider the timing of facility outage to ensure that natural gas demand is not affected by the lost compression capacity.

### Factor #3 – Energy and Non-Air Environmental Impacts

As briefly noted above, both NO<sub>x</sub> control technologies result in a fuel penalty and require use of electricity to drive pumps, etc. The penalty is more severe for water injection, and the DOE report estimates a 3.5% performance loss. Performance loss and electrical usage would increase greenhouse gas (GHG) emissions from the facility. Both technologies introduce other air impacts – e.g., ammonia emissions (which are a particulate precursor) from SCR and relatively large increases in CO and other “products of incomplete” (“PICs”, such as aldehyde emissions) from water injection.

The turbine manufacturer estimates a 5 to 8 fold increase in CO emissions, which may result in the need for an oxidation catalyst retrofit installation that incurs costs similar in magnitude to the NO<sub>x</sub> control technology cost, with ultimate emissions of post-control PICs similar to the previous uncontrolled level (i.e., 80% reduction after a five-fold increase). Water injection would consume that resource from the local water supply. SCR technology requires use of ammonia or urea as a reagent, and catalysts must be periodically cleaned and replaced (typically 10 year life is anticipated).

### Factor #4 – Remaining Useful Life of the Source

As noted in the EPA guidance document, control technology life will likely be shorter than the expected life of the stationary source. That is the case for a combustion turbine. The cost analysis assumes control technology life of ten years for SCR and fifteen years for water injection. These lifetimes are typical for emission control analysis presented in the DOE report and control technology analysis in EPA regulations and regulations from other states. The turbine life is much longer and not limited if standard maintenance requirements are followed.

### Summary

In summary, the four factor analysis indicates a NO<sub>x</sub> cost effectiveness of \$14,435 per ton or higher. If less conservative assumptions are used (e.g., for SCR cost) the cost per ton would increase. There are deleterious impacts on energy (e.g., efficiency loss), the environment (e.g., ammonia, CO emissions), and other factors (e.g., water use, catalyst disposal, reagent use and transport). NBPL recommends no further control requirements for Compressor Station No. 4.

**Table 1. Rolls Royce Avon Turbine Selective Catalytic Reduction NOx Control Cost Effectiveness.**

<b>Emission Controls Cost Effectiveness Estimate</b>				
Engine Manufacturer	Cooper-Rolls			
Model No.	Avon			
Engine Type				
Fuel Used	Natural Gas			
Emissions Control	SCR			
Combustion Control Purpose	NOx			
Target Reduction	80%			
<div> <div>Color Legend</div> <div>User Data / Information Input Cell</div> <div>"Cumulative" Cost Cell for Primary Categories</div> <div>Cost Effectiveness (\$ / ton)</div> </div>				
<b>1 Engine Design Conditions</b>				
Power Output	20000	(hp)		
Engine Exhaust Temperature		(F)	optional input	
Engine Exhaust Rate		(lb/hr)	optional input	
Gas Volume		(dscfm)	optional input	
<b>2 Full Load Engine Exhaust Composition:</b>				
Oxygen (O <sub>2</sub> )		(vol. %)	optional input	
Carbon Dioxide (CO <sub>2</sub> )		(vol. %)	optional input	
Oxides of Nitrogen (NOx)		(ppmvd)	optional input	
NOx	14.32 lb/hr	0.325 (lb/MMBtu)	full load NOx emissions from test (0.325 lb/MMBtu)	
<b>3 Engine Parameters</b>				
Total Operating Hours per Season	6500	(hrs)	74% utilization	
<b>4 Final Exhaust Gas Composition</b>				
Oxides of Nitrogen (NOx)	2.86	0.07 (lb/MMBtu)	Assume 80% reduction	
<b>5 Economic Parameters</b>				
Source of Cost Data	see Comments			
<b>Direct Costs</b>				
Combustion Control Equipment and Auxiliary Equipment	\$725,000	(A)	Based on DOE report (and lower than estimate from EPA Control Strategy Tool (CoST) and recent PA DEP analysis)	
Instrumentation	\$0	included	included in equipment cost	
Sales Taxes	\$21,750	(0.03*A)	3% Sales Tax in this example	
Freight	\$36,250	(0.05*A)	Calculated Cost using EPA Control Cost Manual	
<b>Purchased Equipment Cost (PEC)</b>	<b>\$783,000</b>	PEC		
<b>6 Direct Installation Costs</b>				
Foundations and Supports	\$250,000	(0.08*PEC)	Approximate actual costs from recent SCR installation	
Handling and Erection	\$220,000	(0.14*PEC)	Approximate actual costs from recent SCR installation	
Electrical	\$100,000	(0.04*PEC)	Approximate actual costs from recent SCR installation	
Piping	\$0	(0.02*PEC)	included above	
Insulation for ductwork	\$0	(0.01*PEC)	included above	
Painting	\$0	(0.01*PEC)	included above	
Site Preparation	\$120,000	SP	Approximate actual costs from recent SCR installation	
Buildings	\$0	Bldg	As required	
<b>Total Installation Cost (TIC)</b>	<b>\$690,000</b>			
<b>Total Direct Costs (PEC+TIC)</b>	<b>\$1,473,000</b>			

**Table 1 (continued).**

7 Indirect Costs			Cost Formula	Comments
Engineering	\$50,000		$(0.10 \cdot \text{PEC})$	Approximate actual costs from recent SCR installation
Construction and field expenses	\$64,000		$(0.05 \cdot \text{PEC})$	Approximate actual costs from recent SCR installation
Contractor fees	\$10,000		$(0.10 \cdot \text{PEC})$	Approximate actual costs from recent SCR installation
Start-up	\$21,000		$(0.02 \cdot \text{PEC})$	Approximate actual costs from recent SCR installation
Performance test	\$7,830		$(0.01 \cdot \text{PEC})$	Calculated Cost using EPA Control Cost Manual
Contingencies	\$23,490		$(0.03 \cdot \text{PEC})$	Calculated Cost using EPA Control Cost Manual
<b>Total Indirect Costs (IC)</b>	<b>\$176,320</b>		$(0.31 \cdot \text{PEC})$	
8 Capital Cost Summary				Comments
Total Direct Capital Costs (DC)	\$1,473,000			
Total Indirect Capital Costs (IC)	\$176,320			
<b>Total Capital Investment (TCI)</b>	<b>\$1,649,320</b>			
9 Direct Annual Costs			Cost Formula	Comments
Operator Labor	\$12,500		nominal cost	0.5 hr/shift; example from similar EPA analysis
Supervisor Labor	\$1,875			15% of operator
Operating Materials - SCR reagent	\$73,000			estimate of materials - annual reagent cost scaled from PADEP quote
Maintenance - Labor	\$12,500		nominal cost	0.5 hr/shift; rate example from EPA
Maintenance - Materials	\$5,000		nominal cost	Engineering Estimate
Catalyst replacement / maintenance	\$72,500			Engineering Estimate (10% of Cap Cost; similar to DOE report)
Testing and QA/QC	\$20,000			Engineering estimate - Annual test; reagent controller QA/QC
Electricity	\$20,000			(Approximate, scale from PADEP and DOE references)
<b>Total Direct Annual Costs</b>	<b>\$217,375</b>			
10 Indirect Annual Costs			Cost Formula    Capital Recovery Factor	Comments
Overhead	\$19,125		$(0.6 \cdot (\text{OL} + \text{SL} + \text{ML} + \text{MM}))$	
Administrative Charges	\$32,986		$(0.02 \cdot \text{TCI})$	Engine ACT Document
Property Taxes	\$16,493		$(0.01 \cdot \text{TCI})$	Engine ACT Document
Insurance	\$16,493		$(0.01 \cdot \text{TCI})$	
Capital Recovery	\$234,863		$\text{CRF}[\text{TCI}]$	CRF 0.1424
<b>Total Indirect Annual Costs</b>	<b>\$319,961</b>			Factor for costs annualized over 10 years at 7% interest.
				$\text{CRF} = i \cdot (1+i)^n / [(1+i)^n - 1]$ (i expressed as a decimal - e.g., 10% = 0.1)
11 Summary				Comments
Total Direct Annual Operating Costs	\$217,375			
Total Indirect Annual Operating Costs	\$319,961			
Total Annual Costs	\$537,336		\$27 \$ per hp	
Incremental Annual Costs Over Baseline	\$537,336			
12 Annual Emissions Reduction Over Baseline				Comments
Oxides of Nitrogen (NOx)	37.22 (Tons)			
Cost Effectiveness (\$/Ton)				Comments
Oxides of Nitrogen (NOx)	\$14,435			



**Table 2. Rolls Royce Avon Turbine Water Injection NOx Control Cost Effectiveness.**

<b>Emission Controls Cost Effectiveness Estimate</b>			
Engine Manufacturer	Cooper-Rolls		
Model No.	Avon		
Engine Type			
Fuel Used	Natural Gas		
Emissions Control	Water injection		
Combustion Control Purpose	NOx		
Target Reduction			
<div> <div>Color Legend</div> <div>User Data / Information Input Cell</div> <div>"Cumulative" Cost Cell for Primary Categories</div> <div>Cost Effectiveness (\$ / ton)</div> </div>			
<b>1 Engine Design Conditions</b>			
Power Output	20000	(hp)	
Engine Exhaust Temperature		(F)	optional input
Engine Exhaust Rate		(lb/hr)	optional input
Gas Volume		(dscfm)	optional input
<b>2 Full Load Engine Exhaust Composition:</b>			
Oxygen (O <sub>2</sub> )		(vol. %)	optional input
Carbon Dioxide (CO <sub>2</sub> )		(vol. %)	optional input
Oxides of Nitrogen (NOx)		(ppmvd)	optional input
NOx	14.32 lb/hr	0.325 (lb/MMBtu)	NOx emissions from test (0.325 lb/MMBtu)
<b>3 Engine Parameters</b>			
Total Operating Hours per Season	6500	(hrs)	74% utilization
<b>4 Final Exhaust Gas Composition</b>			
Oxides of Nitrogen (NOx)	3.58	0.08 (lb/MMBtu)	Assume 75% reduction based on manufacturer quote
<b>5 Economic Parameters</b>			
Source of Cost Data	see Comments	Based on PA DEP capital and ammonia costs; EPA Control Cost Manual	
<b>Direct Costs</b>			
Combustion Control Equipment and Auxiliary Equipment	\$2,250,000	(A)	Estimate from Turbine Manufacturer, includes required burner upgrades
Instrumentation	\$225,000	(0.1*A - default example from EPA Manual)	EPA Control Cost Manual Example
Sales Taxes	\$74,250	(0.03*A)	3% Sales Tax in this example
Freight	\$112,500	(0.05*A)	Calculated Cost using EPA Control Cost Manual
<b>Purchased Equipment Cost (PEC)</b>	<b>\$2,661,750</b>	PEC	
<b>6 Direct Installation Costs</b>			
Foundations and Supports	\$212,940	(0.08*PEC)	Calculated Cost using EPA Control Cost Manual
Handling and Erection	\$372,650	(0.14*PEC)	Calculated Cost using EPA Control Cost Manual
Electrical	\$106,470	(0.04*PEC)	Calculated Cost using EPA Control Cost Manual
Piping	\$53,240	(0.02*PEC)	Calculated Cost using EPA Control Cost Manual
Insulation for ductwork	\$26,620	(0.01*PEC)	Calculated Cost using EPA Control Cost Manual
Painting	\$26,620	(0.01*PEC)	Calculated Cost using EPA Control Cost Manual
Site Preparation	\$0	SP	As required
Buildings	\$0	Bldg	As required
<b>Total Installation Cost (TIC)</b>	<b>\$798,540</b>		
<b>Total Direct Costs (PEC+TIC)</b>	<b>\$3,460,290</b>		

Table 2 (continued).

7 Indirect Costs			Cost Formula	Comments
Engineering	\$266,175	(0.10*PEC)	[ ZERO in this analysis]	Calculated Cost using EPA Control Cost Manual
Construction and field expenses	\$133,088	(0.05*PEC)		Calculated Cost using EPA Control Cost Manual
Contractor fees	\$0	(0.10*PEC)		Calculated Cost using EPA Control Cost Manual
Start-up	\$53,235	(0.02*PEC)		Calculated Cost using EPA Control Cost Manual
Performance test	\$26,618	(0.01*PEC)		Calculated Cost using EPA Control Cost Manual
Contingencies	\$79,853	(0.03*PEC)		Calculated Cost using EPA Control Cost Manual
<b>Total Indirect Costs (IC)</b>	<b>\$558,968</b>	<b>(0.31*PEC)</b>		
8 Capital Cost Summary				Comments
Total Direct Capital Costs (DC)	\$3,460,290			
Total Indirect Capital Costs (IC)	\$558,968			
<b>Total Capital Investment (TCI)</b>	<b>\$4,019,258</b>			
9 Direct Annual Costs			Cost Formula	Comments
Operator Labor	\$12,500	nominal cost		0.5 hr/shift; example from similar EPA analysis
Supervisor Labor	\$1,875			15% of operator
Operating Materials	\$8,512			estimate of materials - annual ammonia at \$600 per ton
Maintenance - Labor	\$12,500	nominal cost		0.5 hr/shift; rate example from EPA
Maintenance - Materials	\$5,000	nominal cost		Engineering Estimate
Maintenance / water treatment	\$25,000			Approximate based on DOE Report
Testing and QA/QC	\$15,000			Engineering estimate - Annual test
Electricity	\$2,000			Approximate based on DOE Report
<b>Total Direct Annual Costs</b>	<b>\$82,387</b>			
10 Indirect Annual Costs			Cost Formula    Capital Recovery Factor	Comments
Overhead	\$19,125	(0.6*(OL+SL+ML+MM))		
Administrative Charges	\$80,385	(0.02*TCI)		Engine ACT Document
Property Taxes	\$40,193	(0.01*TCI)		Engine ACT Document
Insurance	\$40,193	(0.01*TCI)	CRF	
Capital Recovery	\$441,314	CRF[TCI]	0.1098	Costs annualized over 15 years (per DOE report) at 7% interest.
<b>Total Indirect Annual Costs</b>	<b>\$621,210</b>			CRF = $i * (1+i)^n / [(1+i)^n - 1]$ (i expressed as a decimal - e.g., 10% = 0.1)
11 Summary				Comments
Total Direct Annual Operating Costs	\$82,387			
Total Indirect Annual Operating Costs	\$621,210			
Total Annual Costs	\$703,597		\$35 \$ per hp	
Incremental Annual Costs Over Baseline	\$703,597			
12 Annual Emissions Reduction Over Baseline				Comments
Oxides of Nitrogen (NOx)	34.90 (Tons)			
Cost Effectiveness (\$/Ton)				Comments
Oxides of Nitrogen (NOx)	\$20,161			



### **Source Selection Criteria for Inclusion in Four-Factor Analysis**

Section 6.3 of the EPA draft regional haze guidance<sup>5</sup> addresses how a state may select sources for four-factor analysis based on visibility impacts. While Northern Border Pipeline Company acknowledges that the 2016 guidance requires states to address 80% of the visibility impairment caused by in-state sources, the screening analysis and/or selection criteria have not been provided.

It is unclear how the Northern Border Pipeline Company Compressor Station No. 4 (CS4) has been selected for inclusion in the second planning period (Round 2) NDDEQ regional haze reasonable progress analysis. We would appreciate additional insight into that decision. The February 24, 2010 North Dakota regional haze SIP noted a lower emitting turbine replacement in 2005 resulting in elimination of CS4 from further consideration based on actual emissions from the source and the distance of CS4 to the Theodore Roosevelt National Park (TRNP) (nearest Class I Federal area).

“The Northern Border Pipeline Company Compressor Station No. 4 is powered by a natural gas turbine. In 2005, Northern Border replaced this turbine with a lower emitting turbine. From 2006-2008, the average nitrogen oxides plus sulfur dioxide emissions were 118 tons per year for a Q/D of 6.6. Because of the installation of the lower emitting turbine, this facility was eliminated from consideration of additional controls during this planning period.”<sup>6</sup>

Please note that this quote includes an error, because the lower emitting unit was installed in the early 1990s and not 2005. However, the lower emission levels noted were appropriately used in the 2006-2008 analysis and supported the conclusion that added controls were not needed. We would appreciate insight into recent screening or other analysis conducted that concludes additional analysis is warranted for CS4.

### **Western Regional Air Partnership (WRAP) Inventory for Modeling**

A review of the CS4 2014 base case emission inventory spreadsheet<sup>7</sup> appears to contain incorrect stack parameters for facility equipment (e.g., stack temperature of 500). Assuming that the engineering units are Fahrenheit, the significant difference from actual, higher exhaust temperature would result in increased buoyancy plume rise and dispersion from the turbine. The column headings in the WRAP inventory spreadsheet should state the units for each stack parameter. The parameters should be reviewed and cross checked with individual permits or source test data to ensure proper model inputs. For example, information recently provided to NDDEQ indicated an exhaust temperature of 805 °F, and we assume this parameter will be updated in the modeling file.

---

<sup>5</sup> EPA Office of Air Quality Planning and Standards Air Quality Policy Division, Draft Guidance on Progress Tracking Metrics, Long-term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period, EPA-457/P-16-001, July 2016

<sup>6</sup> North Dakota State Implementation Plan for Regional Haze, February 24, 2010; page 199

<sup>7</sup> [https://deq.nd.gov/publications/aq/planning/regionalHaze/RegHazDocuments/Main\\_SIP\\_Sections\\_1-12.pdf](https://deq.nd.gov/publications/aq/planning/regionalHaze/RegHazDocuments/Main_SIP_Sections_1-12.pdf)

<sup>7</sup> [https://www.wrapair2.org/pdf/WESTAR\\_OGWG\\_Emissions\\_Inventory\\_2014\\_Webdistribution\\_081018.xlsx](https://www.wrapair2.org/pdf/WESTAR_OGWG_Emissions_Inventory_2014_Webdistribution_081018.xlsx)

Further, care must be taken when including emergency generators to accurately reflect the low utilization rate for this source group. Conservatively dividing the annual actual emissions by 8,760 to develop a commensurate hourly emission rate does not accurately reflect impacts from this source group. Including these as continuous lower emitting sources for 8,760 hours does not accurately pair the emission events with the meteorological condition during the few hours of operation over the year.

In summary, it is unclear how NDDEQ established a visibility impact level and/or screened the source inventory to serve as a threshold below which no further analysis of additional control measures will be undertaken – and therefore exclude a “four factors” analysis.

**Northern Border Pipeline Company Compressor Station #4 Location:**

SE¼, NE¼, Sec. 32, T100N, R100W  
2461 - 136th Avenue NW, Arnegard  
McKenzie County, North Dakota



**Stack Parameters**

Description	Cooper-Rolls Model Coberra 2648S Avon GG/RT 48 power natural gas-fired turbine	
Nominal rating	20,000	hp
latitude	47°46'10.30"N	
longitude	103°29'58.98"W	
Stack Height:	40	feet
	12.2	meters
Effective Stack Cross Sectional Area:	38.5	square feet
	3.6	square meters
Exhaust Volume:	357,400	acfm
Exit Temperature:	805	F
	429.4	C
	702.6	K
Stack Exit Velocity:	155	ft/sec
	47.2	m/sec





March 1, 2019

FedEx No.8136 7919 8302

Mr. Terry L. O'Clair, P.E.  
Director, Division of Air Quality  
North Dakota Department of Health  
Gold Seal Center  
918 E. Divide Ave.  
Bismarck, ND 58501-1947

Re: Regional Haze Second Planning Period and Request for "Four Factor" Analysis for the Northern  
Border Pipeline Company Compressor Station No. 4 – Revision 1

---

Dear Mr. O'Clair:

This letter has been prepared in response to a request by the North Dakota Department of Health (NDDH) to complete a "four factors" analysis<sup>1</sup> for Northern Border Pipeline Company's (NBPL) Compressor Station No. 4 (CS4). The main intent of this letter is to provide the four factor analysis requested for the facility turbine and update a December letter from NBPL. This letter responds to NDDH comments and discussion in a recent conference call. The attachment includes the four-factor analysis considering NOx control of the facility turbine, and addresses NDDH comments.

As discussed in the attachment, NBPL believes the NOx control cost effectiveness for SCR exceeds a reasonable cost threshold and water injection is not technologically feasible. Please contact me if there are any questions or comments at 402-492-7465. Thank you for your review and consideration of this submittal.

Sincerely,

Ruth Jensen  
Air Quality Specialist

Attachments: Attachment 1: Compressor Station No. 4 – Four Factor Analysis (Revision 1)

cc. David Stroh, NDDH

---

<sup>1</sup> Section 16 A(g)(l) of the Clean Air Act  
13710 FNB Parkway, Suite 300

## **Attachment 1:**

### **Compressor Station No. 4 – Four Factor Analysis (February 2019 Revision)**

This attachment includes the updated four factor analysis for Compressor Station No. 4.

#### **Four-Factor Analysis for Compressor Station No. 4**

Northern Border Pipeline Company's Compressor Station No. 4 is located in McKenzie County, North Dakota and operates under NDDH permit number T5-O84001. NDDH has requested a four factors analysis associated with its regional haze second planning period (Round 2) State Implementation Plan (SIP). Northern Border provided a letter submittal in December 2018. NDDH responded in January and NDDH comments were discussed in a conference call. This document updates the four factor analysis based on the comments and discussion. The four factor analysis considers application of NO<sub>x</sub> control on the facility combustion turbine, and the analysis follows EPA's draft guidance document<sup>1</sup> and standard methodologies from the EPA Control Cost Manual that are recommended in section 7 of the EPA guidance document.

CS4 includes a 20,000 horsepower (hp) simple cycle natural gas-fired combustion turbine that drives a natural gas compressor. The facility also includes a small emergency generator. Control cost effectiveness is not reviewed for the emergency generator in the four factor analysis because of its very limited run time. The turbine is a Rolls Royce Avon unit with a diffusion flame combustor.

The manufacturer does not offer a burner retrofit option for "lean premixed" combustion, which would decrease NO<sub>x</sub> emissions, so other control options are considered. Despite the lack of retrofit burner technology, turbines with standard burners are still relatively low emitting combustion sources (i.e., emissions are relatively low in comparison to other combustion devices such as boilers or engines and other fuel types).

#### **Factor #1 – NO<sub>x</sub> Emissions Controls and Control Cost**

The pollutant of concern for a natural gas-fired turbine is nitrogen oxides (NO<sub>x</sub>). As noted above, the Avon turbine does not offer a low NO<sub>x</sub> combustor (lean premixed combustion) as a retrofit option. The EPA guidance document indicates that both retrofit and replacement should be considered. However, replacement costs for a 20,000 hp unit would be exorbitant and more than an order of magnitude higher than the two add-on control options discussed below. The achieved emissions level for replacement would be similar to the controlled NO<sub>x</sub> emissions discussed below, thus NO<sub>x</sub> cost effectiveness would be more than an order of magnitude higher and exceed \$100,000 per ton. Replacement is not discussed further in this analysis.

Since combustion control is also not an option, the remaining add-on control technologies applicable to a combustion turbine are selective catalytic reduction (SCR) or water/steam injection. As discussed below, the latter is not technologically feasible for a turbine driving a natural gas compressor. Consistent with the EPA guidance document, methodologies from the EPA Control Cost Manual are used to evaluate the NO<sub>x</sub> control cost effectiveness for SCR.

---

<sup>1</sup> Draft Guidance on Progress Tracking Metrics, Long-term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period, EPA document number EPA-457/P-16-001 (July 2016).



Analysis was not conducted for water injection due to its very limited application to industrial turbines. Additional discussion on water injection technical feasibility is provided below and cost effectiveness could be evaluated if desired.

#### *SCR control cost analysis*

SCR has had limited application as a retrofit control option for natural gas-fired compressor drivers. The initial analysis presented in the December letter included several sources, such as a Department of Energy report and information on design, engineering, and installation from a compressor station application in the northeast U.S. Based on NDDH comments and the conference call discussion, the analysis was revisited to primarily rely on Control Cost Manual methods. A key input for the analysis is the capital cost, and a 2016 Control Cost Manual supplementary document that updated the SCR chapter<sup>2</sup> was used to estimate the capital cost.

Table 1 presents the cost details and the source for specific itemized cost elements. In addition to the SCR capital cost, an important assumption for the analysis is the estimate of *actual* NOx emissions. The current and anticipated ongoing operation of the turbine at CS4 is lower than full load. Thus, actual emissions should be based on the best estimate of ongoing operation and associated NOx emissions. Primary assumptions for the analysis include:

- A capital cost of \$3,740,000 to achieve 80% reduction in NOx; based on Chapter 2 of the Control Cost Manual with the cost adjusted to 2018 using the consumer price index (CPI).
- Uncontrolled emissions are based on a best estimate of actual emissions. The average value from 26 portable analyzer tests conducted from 2004 through 2017 is 0.264 lb/MMBtu, and the average operating load for these tests was about 70% load. This is consistent with average annual load in recent years and anticipated future operation.
  - The annual fuel rate and natural gas heating value, averaged for five year (from 2014 through 2018) is used in conjunction with the emission rate to calculate the average hourly emission rate of 38.2 lb/hr shown in Table 1.
- Capital cost recovery is based on a twenty year life and interest rate of 5.25% (consistent with the current prime rate). Longer life is not appropriate for catalytic systems which typically have a warranty of no longer than five years.
- Utilization was reviewed for five years, and the analysis is based on 6,500 annual operating hours (74% utilization) which is marginally higher than the 5-year average of approximately 5,740 annual operating hours. The marginally higher utilization assumed is expected to be a conservative estimate of ongoing annual operation.
  - The resulting uncontrolled annual NOx emissions are approximately 124 tons and the annual reduction at 80% control is 99 tons.
- Most other costs (direct and indirect installation costs, etc.) are based on the Control Cost Manual.
- Reagent costs are from a current cost quote for an SCR installation with usage / cost scaled based on the relative mass emissions of NOx.

---

<sup>2</sup> “Chapter 2, Selective Catalytic Reduction,” EPA update to Control Cost Manual, Table 2.1b (May 2016).

The resulting NOx control cost is estimated to be \$13,280 per ton. NBPL believes this is well above a reasonable cost threshold. If NDDH disagrees, NBPL requests an opportunity to further review several assumptions to further refine the analysis.

#### *Water injection control analysis*

Water injection control is a technology that was applied to turbines over two decades ago, but has had very limited use in recent years, as combustion controls or SCR have been employed. A key concern with water injection is significant increases in emissions of products of incomplete combustion such as carbon monoxide (CO). NOx reductions would be lower than for the SCR analysis discussed above. For example, vendors may estimate a NOx reduction of 75% at full load, but at the reduced operation that will occur at CS4, lower uncontrolled NOx emissions and less reduction would be anticipated. Manufacturers estimate a five to eight fold increase in CO. This may necessitate installation of an oxidation catalyst, with a cost similar to the NOx technology costs. In addition, a larger increase in CO emissions will occur at the reduced load operation typical for the CS4 turbine.

Performance could also be worse due to operational challenges, because this technology has not been demonstrated for natural gas transmission facilities, at least not in recent years. This technology was supplanted by low emissions combustion, which is not available for the Avon turbine at CS4. For water injection, NBPL believes that environmental and technological issues result in a conclusion that water/steam injection is not technologically feasible. A cost effectiveness analysis is not presented, but could be completed if desired. Costs would be incurred beyond base costs for NOx control, including: (1) addressing emissions of CO and other products of incomplete combustion, and (2) contingencies associated with implementing a technology with very limited historical application and no installations at compressor stations in recent years.

#### Factor #2 – Time Necessary for Compliance

Both NOx control technologies would require a timeline of three years or more. This time is required for engineering design, permitting, site preparation, installation, commissioning, and startup. A schedule up to five years could be required because previous retrofit installations of SCR on natural gas transmission compressor drivers are very limited, and have resulted in extended commissioning periods to address performance issues with the reagent control system (e.g., ability of the reagent flow control to adequately respond to emissions changes as pipeline demand changes turbine load and NOx emissions). The schedule would also need to consider the timing of facility outage to ensure that natural gas demand is not affected by the lost compression capacity.

#### Factor #3 – Energy and Non-Air Environmental Impacts

As briefly noted above, both NOx control technologies result in a fuel penalty and require use of electricity to drive pumps, etc. The penalty is more severe for water injection, and the DOE report estimates a 3.5% performance loss. Performance loss and electrical usage would increase greenhouse gas (GHG) emissions from the facility. Both technologies introduce other air impacts – e.g., ammonia emissions (which are a particulate precursor) from SCR and relatively



large increases in CO and other “products of incomplete combustion” (“PICs”, such as aldehyde emissions) from water injection.

The turbine manufacturer estimates a 5 to 8 fold increase in CO emissions, which may result in the need for an oxidation catalyst retrofit installation that incurs costs similar in magnitude to the NOx control technology cost, with ultimate emissions of post-control PICs similar to the previous uncontrolled level (i.e., 80% reduction after a five-fold increase). The emission levels would be further increased (with implications for catalyst design and cost) due to reduced load operation for the turbine. Water injection would consume that resource from the local water supply. SCR technology requires use of ammonia or urea as a reagent, and catalysts must be periodically cleaned and replaced.

#### Factor #4 – Remaining Useful Life of the Source

As noted in the EPA guidance document, control technology life will likely be shorter than the expected life of the stationary source. That is the case for a combustion turbine. The cost analysis assumes control technology life of twenty years for SCR. A twenty year lifetime exceeds typical estimates for emission control analysis presented in the DOE report and control technology analysis in EPA regulations and regulations from other states, and greatly exceeds the technology warranty. The turbine life is much longer and not limited if standard maintenance requirements are followed.

#### Summary

In summary, the four factor analysis indicates a NOx cost effectiveness of over \$13,000 per ton for SCR. Water/steam injection is not technologically feasible. There are deleterious impacts on energy (e.g., efficiency loss), the environment (e.g., ammonia, CO emissions), and other factors (e.g., water use, catalyst disposal, reagent use and transport). NBPL recommends no further control requirements for Compressor Station No. 4.



Table 1. Rolls Royce Avon Turbine Selective Catalytic Reduction NOx Control Cost Effectiveness.

NOx Control Cost Effectiveness Estimate									
Engine Manufacturer		Cooper-Rolls							
Model No.		Cobrierra 2648S Avon							
Engine Type		Natural Gas							
Fuel Used		SCR							
Emissions Control		NOx							
Combustion Control Purpose									
Target Reduction									
Color Legend									
User Data / Information Input Cell									
"Cumulative" Cost Cell for Primary Categories									
Cost Effectiveness (\$ / ton)									
Comments									
optional input									
optional input									
optional input									
Comments									
optional input									
optional input									
optional input									
optional input									
optional input									
NOx emissions - average from portables tests									
Comments									
124.0668									
74% utilization									
Comments									
Assume 80% reduction from uncontrolled									
Comments									
Analysis primarily relying on EPA Cost Manual									
Comments									
Based on EPA control cost manual (\$167/kw; adjust to 2018\$)									
Default is 0.1*A; use lower value from example (improved flow control)									
3% Sales Tax in this example									
Calculated Cost using EPA Control Cost Manual									
Comments									
Calculated Cost using EPA Control Cost Manual									
Calculated Cost using EPA Control Cost Manual									
Calculated Cost using EPA Control Cost Manual									
Calculated Cost using EPA Control Cost Manual									
Calculated Cost using EPA Control Cost Manual									
As required									
As required									
Comments									
Calculated Cost using EPA Control Cost Manual									
Calculated Cost using EPA Control Cost Manual									
Calculated Cost using EPA Control Cost Manual									
Calculated Cost using EPA Control Cost Manual									
Calculated Cost using EPA Control Cost Manual									
SP									
Bldg									
\$0									
\$0									
\$1,238,040									
\$5,364,790									

Table 1 (continued).

7 Indirect Costs		Cost Formula	Comments
Engineering	\$412,675	(0.10*PEC)	Calculated Cost using EPA Control Cost Manual
Construction and field expenses	\$206,338	(0.05*PEC)	Calculated Cost using EPA Control Cost Manual
Contractor fees	\$412,675	(0.10*PEC)	Calculated Cost using EPA Control Cost Manual
Start-up	\$82,535	(0.02*PEC)	Calculated Cost using EPA Control Cost Manual
Performance test	\$41,268	(0.01*PEC)	Calculated Cost using EPA Control Cost Manual
Contingencies	\$123,803	(0.03*PEC)	Calculated Cost using EPA Control Cost Manual
<b>Total Indirect Costs (IC)</b>	<b>\$1,279,293</b>	<b>(0.31*PEC)</b>	
8 Capital Cost Summary			Comments
Total Direct Capital Costs (DC)	\$5,364,790		
Total Indirect Capital Costs (IC)	\$1,279,293		
<b>Total Capital Investment (TCI)</b>	<b>\$6,644,083</b>		
9 Direct Annual Costs		Cost Formula	Comments
Operator Labor	\$12,500	nominal cost	0.5 hr/shift; example from similar EPA analysis
Supervisor Labor	\$1,875		15% of operator
Operating Materials - ammonia	\$57,500		estimate of materials - annual ammonia at \$600 per ton
Maintenance - Labor	\$12,500	nominal cost	0.5 hr/shift; rate example from EPA
Maintenance - Materials	\$5,000	nominal cost	Engineering Estimate
Catalyst maintenance / replacement	\$374,000		Engineering Estimate (10% of Cap Cost)
Testing and QA/QC	\$20,000		Engineering estimate - Annual test; reagent controller QA
Electricity	\$5,000		from PA DEP TSD
<b>Total Direct Annual Costs</b>	<b>\$488,375</b>		
10 Indirect Annual Costs		Cost Formula	Capital Recovery Factor
Overhead	\$19,125	(0.6*(OL+SL+ML+MM))	
Administrative Charges	\$132,882	(0.02*TCI)	
Property Taxes	\$66,441	(0.01*TCI)	Engine ACT Document
Insurance	\$66,441	(0.01*TCI)	Engine ACT Document
Capital Recovery	\$544,815	CRF[TCI]	CRF
<b>Total Indirect Annual Costs</b>	<b>\$829,703</b>		Factor for costs annualized over 20 years at 5.25% interest. CRF = $i * (1+i)^n / [(1+i)^n - 1]$ (i expressed as a decimal - e.g., 10% = 0.1)
11 Summary			Comments
Total Direct Annual Operating Costs	\$488,375		
Total Indirect Annual Operating Costs	\$829,703		
Total Annual Costs	\$1,318,078		\$66 \$ per hp
Incremental Annual Costs Over Baseline	\$1,318,078		
12 Annual Emissions Reduction Over Baseline			Comments
Oxides of Nitrogen (NOx)	99.25 (Tons)		
Cost Effectiveness (\$/Ton)			Comments
Oxides of Nitrogen (NOx)	\$13,280		

## B.9.c – Communications





December 28, 2018

FILE

Ms. Ruth Jensen  
Air Quality Specialist  
Northern Border Pipeline Company  
13710 FNB Parkway, Ste 300  
Omaha, NE 68154-5200

Re: Regional Haze 4-Factors Analysis  
Compressor Station No. 4

Dear Ms. Jensen:

The North Dakota Department of Health (Department) has conducted an initial review of your four-factors analysis for Northern Border Pipeline Company (NBPL) – Compressor Station No. 4 (CS4) in North Dakota. With respect to the analysis we have the following comments:

1. The expected life of the selective catalytic reduction (SCR) system listed in the economic analysis is 10 years. We believe a more appropriate life of an SCR for a natural gas-fired unit is 20-30 years (see EPA's Control Cost Manual, Section 4.2, Chapter 2, p 2-78). The economic analysis must be redone using an appropriate expected life of the SCR and water injection control system.
2. The 7% interest rate used in the economic analysis appears to be too high. EPA's Control Cost Manual states "When performing cost analysis, it is important to ensure that the correct interest rate is being used. Because this Manual is concerned with estimating private costs, **the correct interest rate to use is the nominal interest rate, which is the rate firms actually face** [emphasis added]". The manual further states "For input to analysis of rulemakings, assessments of private cost should be prepared using firm-specific nominal interest rates if possible, or the bank prime rate if firm-specific interest rates cannot be estimated or verified." The current bank prime rate is 5.25%. We believe an interest rate no higher than 5.25% should be used. Attached to this letter is an email we received from EPA regarding this matter. The economic analysis must be redone using an appropriate interest rate.
3. The baseline emission rate for the unit appears to be too low. The baseline emission rate should represent a realistic depiction of anticipated future annual emissions for the source. In general, estimates of anticipated emissions are based upon actual emissions from the baseline period (two-year period) that are representative of expected future emissions. Although no baseline emission rate is stated in the analysis, a back-calculation indicates a

baseline emission rate of 46.5 tons of NO<sub>x</sub> per year (i.e. 37.22 tons reduction divided by 80% reduction for SCR). The 2016 and 2017 Annual Emission Inventory Reports submitted by Northern Border Pipeline Co. indicated an average of 171 tons of NO<sub>x</sub> per year based on 1997 emissions testing results. Based on more recent testing at this unit, we believe the emission rate is even higher. The economic analysis must be redone using an appropriate baseline emission rate. Proper documentation should be provided explaining why the baseline selected for the facility is required in cases where the baseline emissions are not easily understood. As an example of our concern for the baseline emission rate of 46.5 tons of NO<sub>x</sub> per year and our expected thoroughness of calculations, please see the attached calculation summary.

4. Documentation must be provided for the cost estimates. Any references, other than the Control Cost Manual, must either be submitted with the analysis or a website address provided where the documents can be downloaded. Documentation must also be provided for any scaling that was done to obtain the cost estimates.

The Department's response to questions posed by NBPL in the four-factor analysis are:

5. NBPL CS4 was selected as a source to perform a four-factor analysis based on the 2012-2016 average combined NO<sub>x</sub> and SO<sub>2</sub> emissions of 157 tons per year, with a distance to the North Unit of Theodore Roosevelt National Park of 18 km. This results in a Q/d (tons/km) of 9, which is in line with the other sources selected for analysis and the 2016 draft guidance. Q/d was a metric used during Regional Haze Round 1 to identify sources for evaluation. Similarly, Q/d is also being used for initial source selection for analysis in Regional Haze Round 2.

Using the average emissions from 2012-2016 was beneficial (looking at Q/d) for NBPL CS4, since operating hours in 2014 and 2015 indicate 44% utilization, compared to a utilization average of 88% in 2012, 2013, 2016 and 2017. If only the last two years of NO<sub>x</sub> emissions data (2016 and 2017) provided to the Department are utilized, the Q/d becomes 11.3 (*note: NO<sub>x</sub> appears to have been underreported by NBPL CS4 based on test results submitted to the Department; see Number 3*). Using corrected data that has not been underreported, Q/d would become 14.1 (again only using NO<sub>x</sub>); therefore, NBPL CS4 was identified as a source to conduct a four-factor analysis.

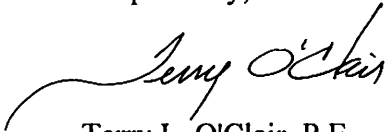
Through the four-factor analysis, North Dakota is addressing approximately 80% of the visibility impairment (nitrates and sulfates) as determined by the IMPROVE monitoring network in North Dakota (<http://vista.cira.colostate.edu/Improve/aqrv-summaries/>). Sending four factor letters to the ten highest Q/d facilities in North Dakota addresses 94% of the 2012-2016 emissions from stationary sources included in the 2014 National Emissions Inventory (NEI), which is being used for the 2014 baseline modeling performed by the Western Regional Air Partnership (WRAP). Q/d for the sources selected in North Dakota ranged from 7 to 164.

See attachment containing detailed emissions information and distance to Class 1 areas used to select the sources for a four-factor analysis.

6. The Department will ensure that the information used in the 2014 Baseline Modeling, completed by WRAP, will be consistent with the information provided by Northern Border Pipeline Co. for Compressor Station No. 4. Thank you for providing the correct stack parameters for the facility equipment.

The revised analysis should be submitted as soon as possible. If you have any questions, please contact David Stroh or Tom Bachman of my staff at (701) 328-5188.

Respectfully,

A handwritten signature in black ink, appearing to read "Terry O'Clair", with a long, sweeping horizontal line extending to the left.

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

TLO/TB:saj

**Bachman, Tom A.**

---

**From:** Worstell, Aaron <Worstell.Aaron@epa.gov>  
**Sent:** Tuesday, December 18, 2018 11:55 AM  
**To:** Bachman, Tom A.; Dobrahner, Jaslyn  
**Cc:** Sorrels, Larry  
**Subject:** RE: Regional Haze Economic Analyses

**CAUTION:** This email originated from an outside source. Do not click links or open attachments unless you know they are safe.

Hi Tom-

The interest rate recommended by EPA can vary by firm or industry, but the bank prime rate is a default rate that can be used for annualization of capital costs. The most recent bank prime rate (currently ~5.25%) can be found on the Federal Reserve website here:

<https://www.federalreserve.gov/releases/h15/>

Also, consult the somewhat recently revised Cost Estimation chapter of EPA's Control Cost Manual. See discussion of the bank prime rate in Section 2.5.2, Interest Rates:

[https://www.epa.gov/sites/production/files/2017-12/documents/epaccmcostestimationmethodchapter\\_7thedition\\_2017.pdf](https://www.epa.gov/sites/production/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf)

I hope that is helpful.

Happy Holidays!

Aaron

**From:** Bachman, Tom A. <tbachman@nd.gov>  
**Sent:** Tuesday, December 18, 2018 9:48 AM  
**To:** Worstell, Aaron <Worstell.Aaron@epa.gov>; Dobrahner, Jaslyn <Dobrahner.Jaslyn@epa.gov>  
**Subject:** Regional Haze Economic Analyses

Aaron/Jaslyn:

Now that our sources are working on four-factor analyses (and GRE is contemplating a revised BART analysis for Coal Creek Station), a question regarding the analysis has come up. That is – what is the appropriate interest rate to be used in the economic analysis to determine annualized costs? In the past we have generally used 7%; however some analyses used a lower value. Given current low interest rates, is 7% still valid?

Any information you can provide will be appreciated!

Tom Bachman, P.E.  
ND Dept. of Health  
(701) 328-5188

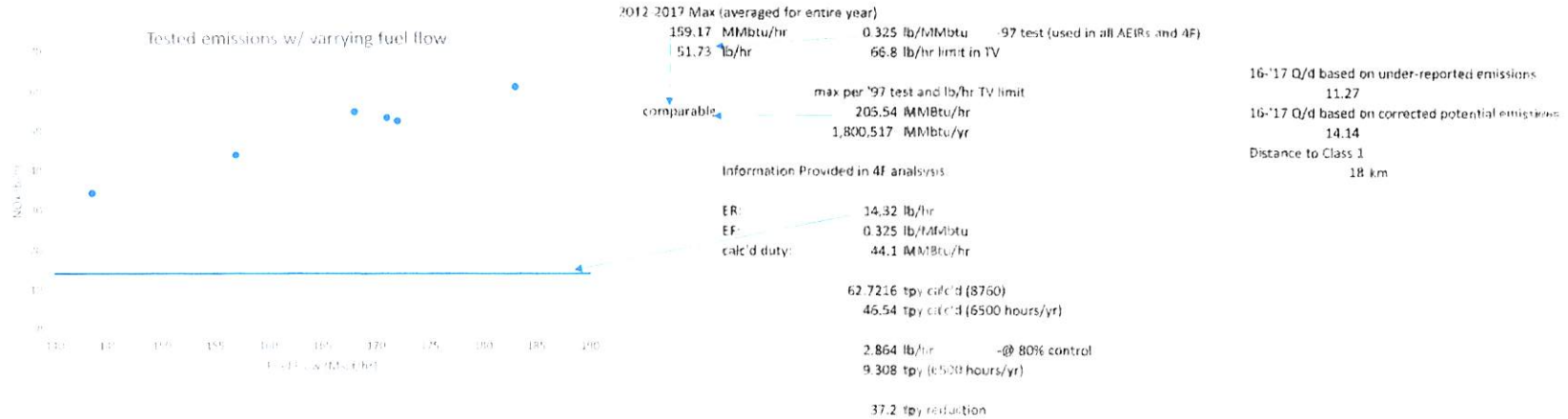


15. (b) (5) - (b) (5) (i) MMBtu/hr

157  
172  
144  
171  
168  
183

Year	Tested lb/hr	MMScf/yr	btu/scf	MMBtu/yr	hr/yr	lbs/year	tpy (calc'd)	tpy (reported)	lb/MMBtu (calc'd)	PTE tpy (testing)	Utilization
2012	44	1,332.698	1024.16	1,252,479.98	8493.5	373,714.00	186.86	205.20	0.296	192.72	97%
2013	52.7	1,287.322	1032	1,328,526.30	8346.4	439,859.28	219.93	215.90	0.331	230.826	95%
2014	34.4	566.703	1048.5	594,188.10	4115.75	141,581.80	70.79	96.60	0.238	150.672	47%
2015	53.5	472.156	1057.95	499,517.44	3712.5	198,618.75	99.31	81.20	0.398	234.33	42%
2016	54.9	994.458	1058.79	1,052,922.19	7161.43	393,162.51	196.58	171.10	0.373	240.462	82%
2017	61.3	987.398	1061.67	1,048,290.83	6821.5	418,157.95	209.08	170.40	0.399	268.494	78%

74% 2012-2017  
45% 2014-2015  
88% 2012-2013, 2016-2017



Permittee	Plant	2012-2016 Average SO <sub>2</sub> + NO <sub>x</sub> (tons)	Nearest Class I Area	Distance to Nearest Class I Area (km)	Nearest Q/D (tons/km) (2012-2016)	Notes	% 2012-2016 Emissions	% 2012-2016 Q/D
BASIN ELECTRIC POWER COOP.	AVS 1	10,592	TRNP/NU	117	91			
BASIN ELECTRIC POWER COOP.	AVS 2	12,188	TRNP/NU	117	104			
BASIN ELECTRIC POWER COOP.	LELAND OLDS 1	6,650	TRNP/NU	157	42			
BASIN ELECTRIC POWER COOP.	LELAND OLDS 2	9,967	TRNP/NU	157	63			
MINNKOTA POWER COOP.	M.R. YOUNG 1	3,877	TRNP/SU	161	24			
MINNKOTA POWER COOP.	M.R. YOUNG 2	6,863	TRNP/SU	161	43			
OTTERTAIL POWER CO.	COYOTE	21,096	TRNP/NU	129	164			
MONTANA DAKOTA UTILITIES	HESKETT 1	1,269	TRNP/SU	185	7			
MONTANA DAKOTA UTILITIES	HESKETT 2	2,941	TRNP/SU	185	16			
GREAT RIVER ENERGY	STANTON 1	3,218	TRNP/NU	156	21	shutdown		
GREAT RIVER ENERGY	STANTON 10	701	TRNP/NU	156	4	shutdown		
GREAT RIVER ENERGY	COAL CREEK 1	12,675	TRNP/NU	168	75			
GREAT RIVER ENERGY	COAL CREEK 2	10,631	TRNP/NU	168	63			
GREAT RIVER ENERGY	SPIRITWOOD	142	TRNP/SU	366	0	No 4F		
Subtotal (EGUs)		102,809			718	EGU's only	86.1%	78.2%
Dakota Gasification Co.	Great Plains Synfuels	6,550	TRNP/NU	107	61			
Hess Corporation	Tioga Gas Plant	1,920	Lostwood	35	55			
Petro-Hunt	Little Knife Gas Plant	475	TRNP/NU	39	12			
Northern Border Pipeline	Comp. Station No. 4	157	TRNP/NU	18	9			
Subtotal (gas sources)		9,102				All	93.7%	93.1%
Subtotal of remaining tracked sources		7,496				Total	119,407	918.2

**Stroh, David E.**

---

**From:** Ruth Jensen <ruth\_jensen@transcanada.com>  
**Sent:** Friday, March 1, 2019 1:06 PM  
**To:** Stroh, David E.  
**Subject:** FW: [EXTERNAL] CS4 NOx - table  
**Attachments:** CS4 NOx data\_2004-2017.xlsx

**CAUTION:** This email originated from an outside source. Do not click links or open attachments unless you know they are safe.

Here's the additional information you requested. I will send the letter by FedEx.

Ruth Jensen  
Air Quality Specialist  
TransCanada  
Phone: 402-492-7465  
Cell: 402-639-2785

---

**From:** Jim McCarthy [mailto:jamesmccarthy@comcast.net]  
**Sent:** Friday, March 1, 2019 12:09 PM  
**To:** Ruth Jensen <ruth\_jensen@transcanada.com>  
**Cc:** 'Panek Jeffrey A.' <japanek@ameritech.net>  
**Subject:** [EXTERNAL] CS4 NOx - table

The attached file is data you provided. Average for all is 0.264 lb/MMBtu which is the NOx emission rate used in the cost analysis XLS included in the submittal.

Let me know if you have additional questions.

Thanks.

We respect your right to choose which electronic messages you receive. To stop receiving this message and similar communications from TransCanada PipeLines Limited please reply to this message with the subject "UNSUBSCRIBE". This electronic message and any attached documents are intended only for the named addressee(s). This communication from TransCanada may contain information that is privileged, confidential or otherwise protected from disclosure and it must not be disclosed, copied, forwarded or distributed without authorization. If you have received this message in error, please notify the sender immediately and delete the original message. Thank you. Nous respectons votre droit de choisir quels messages électroniques vous désirez recevoir. Pour ne plus recevoir ce message et les communications similaires, de la part de TransCanada PipeLines Limited, veuillez répondre à ce message en inscrivant dans l'objet « SE DÉSINSCRIRE ». Ce message électronique et tous les documents joints sont destinés exclusivement au(x) destinataire(s) mentionné(s). Cette communication de TransCanada peut contenir des renseignements privilégiés, confidentiels ou par ailleurs protégés contre la divulgation; ils ne doivent pas être divulgués, copiés, communiqués ou distribués sans autorisation. Si vous avez reçu ce message par erreur, veuillez en avvertir immédiatement l'expéditeur et détruire le message original. Merci

Date	Lb NOx/MMBtu	NOx ppm @ 15% O2	Ambient Temp F	HP	% load
5/19/2004	0.2548	69.7	62.8	11503	57.5%
10/4/2004	0.2657	72.7	52.5	14483	72.4%
5/10/2005	0.2425	66.3	61.1	10402	52.0%
11/7/2005	0.2665	79.6	44.2	11198	56.0%
6/13/2006	0.2377	65.0	55.1	11591	58.0%
10/9/2006	0.1938	53.0	15.5	9196	46.0%
6/6/2007	0.2232	61.0	68.3	14598	73.0%
10/31/2007	0.2878	78.7	50.6	7967	39.8%
5/5/2008	0.2996	81.8	64.3	13132	65.7%
10/21/2008	0.2933	80.3	41.9	15433	77.2%
5/18/2009	0.2395	65.5	70.2	9470	47.4%
12/9/2009	0.2807	76.7	-0.4	19435	97.2%
4/20/2010	0.2510	68.7	62.5	10864	54.3%
10/6/2010	0.3148	86.1	67.1	14159	70.8%
5/11/2011	0.2655	72.6	49.5	13414	67.1%
10/11/2011	0.2739	75.0	64.6	12164	60.8%
5/18/2012	0.2334	63.8	64.1	11546	57.7%
6/18/2012	0.2743	75.0	57.0	15641	78.2%
11/5/2012	0.2793	76.4	60.7	15842	79.2%
5/24/2013	0.2293	62.7	61.4	13836	69.2%
9/20/2013	0.2830	77.3	51.1	17860	89.3%
6/10/2014	0.2121	58.0	68.2	NA	NA
11/17/2014	0.2250	61.5	14.4	14386	71.9%
10/28/2015	0.2966	81.1	33.3	18264	91.3%
10/21/2016	0.3063	83.7	57.5	16896	84.5%
10/26/2017	0.3284	89.8	34.7	19062	95.3%

**average 0.264**

-

B.10 – Basin DGC

B.10.a – Department Request



May 18, 2018

FILE

Mr. Daniel Whitley  
Dakota Gasification Company  
420 County Road 26  
Beulah, ND 58523

Re: Regional Haze  
Second Planning Period

Dear Mr. Whitley:

The Department of Health (Department) has begun work on the second planning period (Round 2) State Implementation Plan (SIP) for regional haze. In Round 1 of the regional planning process, the emphasis was on Best Available Retrofit Technology (BART) and making reasonable progress towards the national visibility goal. In Round 2, there are no BART requirements; therefore, we will focus on making reasonable progress. The reasonable progress analysis will be made using the four factors in Section 169A(g)(1) of the Clean Air Act:

The four factors are:

1. The cost of compliance
2. The time necessary to achieve compliance
3. The energy and non-air quality environmental impact of compliance; and
4. The remaining useful life of any existing source subject to such requirements

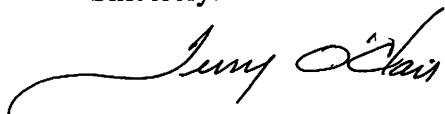
Guidance provided by the U.S. Environmental Protection Agency (Draft Guidance on Progress Tracking Metrics, Long Term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period at [https://www.epa.gov/sites/production/files/2016-07/documents/draft\\_regional\\_haze\\_guidance\\_july\\_2016.pdf](https://www.epa.gov/sites/production/files/2016-07/documents/draft_regional_haze_guidance_july_2016.pdf)) indicates the Department must address 80% of the visibility impairment caused by in-state sources. Data from the IMPROVE monitoring sites at Theodore Roosevelt National Park (TRNP) and Lostwood Wilderness Area (LWA) indicate that sulfates and nitrates continue to be the largest contributors to visibility impairment in these areas. The primary precursors of sulfates and nitrates are emissions of sulfur dioxide (SO<sub>2</sub>) and nitrogen oxides (NO<sub>x</sub>).

The Great Plains Synfuels Plant has been identified as a significant source of SO<sub>2</sub> and NO<sub>x</sub> emissions. Therefore, the Department requests that you prepare a "four factors" analysis for your facility. The analysis should be prepared using the draft EPA guidance noted above. The analysis should include all source units that emit through the main stack as well as the flares at the facility.

Preparation of the Round 2 Regional Haze SIP will require extensive planning and review of emission sources in North Dakota. The Department will be working with the Western Regional Air Partnership (WRAP) to prepare the Round 2 SIP. WRAP will be conducting air quality modeling of potential regional emissions reductions in early 2019. The Department asks that your "four factors" analysis be submitted by January 31, 2019.

If you have any questions, please contact David Stroh of my staff at (701)328-5188.

Sincerely,

A handwritten signature in black ink, appearing to read "Terry O'Clair", with a long, sweeping horizontal line extending to the left.

Terry L. O'Clair  
Director  
Division of Air Quality

TLO/TB:saj

## B.10.b – Facility Response





January 31, 2019

Mr. Terry L. O'Clair, Director  
Division of Air Quality  
North Dakota State Department of Health  
918 E. Divide Ave.  
Bismarck, ND 58501-1947

RE: Great Plains Synfuels Plant Regional Haze Second Planning Period Reasonable Progress  
Four Factor Analysis

Dear Mr. O'Clair:

At the request of the North Dakota Department of Health (NDDH), Dakota Gasification Company (DGC) has prepared a four factor analysis for the NDDH's Regional Haze Second Planning Period Reasonable Progress analysis. As part of this analysis NO<sub>x</sub> and SO<sub>2</sub> emissions were evaluated at the Great Plains Synfuels Plant (GPSP). The four factor analysis is attached to this letter.

In addition to the four factor analysis, the NDDH requested DGC to provide hourly NO<sub>x</sub> and SO<sub>2</sub> emissions rates to be included as part of the Western Regional Air Partnership (WRAP) visibility modeling. The rates provided for the GPSP facility represent actual maximum rolling 24-hour average emission rates in lb/hr and should not be construed to represent actual long-term average baseline emissions rates or proposed permit emission limits. The following three sources were identified by the NDDH to be included in the modeling effort.

Emission Source	NO <sub>x</sub> Emission Rate lb/hr	SO <sub>2</sub> Emission Rate lb/hr
Main Stack <sup>(Note 1)</sup>	944	1,681
Main Flare	224	1,598
Startup Flare	171	334

Note 1. Main Stack emission rates include emissions from three (3) Riley Boilers and two (2) Superheaters.

Based on the results of the four factor analysis, there are no additional reductions expected from current baseline emission rates either due to the technical infeasibility of installing additional emissions controls, or the control options having excessive costs and, therefore, not being cost effective.

DGC looks forward to working with the NDDH in establishing the state's reasonable progress goals. Should you or your staff have any questions regarding the GPSP four factor analysis or



January 31, 2019

Page 2

inputs to the WRAP modeling, please do not hesitate to contact me at (701) 873-6619 or by email at [dwhitley@bepc.com](mailto:dwhitley@bepc.com).

Sincerely,

A handwritten signature in dark ink, appearing to read "D. Whitley", written over a horizontal line.

Daniel Whitley  
Environmental Engineering Supervisor

dmw/dew/tlm  
ENCLOSURE

c: David Stroh, NDDH  
Nicole Rivinius, NDDH  
9850-DMW-19-005



GREAT PLAINS SYNFUELS PLANT

## NORTH DAKOTA REGIONAL HAZE SECOND PLANNING PERIOD FOUR-FACTOR ANALYSIS

SL-014820  
Final

January 31, 2019  
Project No. 13772-003



55 East Monroe Street • Chicago, IL 60603 USA • 312-269-2000  
[www.sargentlundy.com](http://www.sargentlundy.com)

## CONTENTS

<b>EXECUTIVE SUMMARY .....</b>	<b>ES-1</b>
<b>1. INTRODUCTION .....</b>	<b>1-1</b>
<b>2. FACILITY DESCRIPTION.....</b>	<b>2-1</b>
<b>3. FOUR-FACTOR ANALYSIS REQUIREMENTS .....</b>	<b>3-1</b>
3.1 REGIONAL HAZE RULE BACKGROUND .....	3-1
3.1.1 First Implementation Period.....	3-3
3.1.2 Second Implementation Period .....	3-4
3.2 DESCRIPTIONS OF THE FOUR STATUTORY FACTORS .....	3-6
3.2.1 Costs of Compliance .....	3-6
3.2.2 Time Necessary for Compliance .....	3-8
3.2.3 Energy and Non-Air Quality Environmental Impacts.....	3-9
3.2.4 Remaining Useful Life .....	3-10
3.2.5 Four Factor Analysis Approach .....	3-10
<b>4. BASELINE SO<sub>2</sub> AND NO<sub>x</sub> EMISSIONS .....</b>	<b>4-1</b>
<b>5. RILEY BOILER CONTROL MEASURES .....</b>	<b>5-1</b>
5.1 SO <sub>2</sub> EMISSIONS CONTROLS .....	5-1
5.2 NO <sub>x</sub> EMISSIONS CONTROLS .....	5-1
5.2.1 Identify Available NO <sub>x</sub> Control Options .....	5-2
5.2.2 Technical Feasibility of Available NO <sub>x</sub> Control Options .....	5-2
5.2.3 Effectiveness of NO <sub>x</sub> Control Options.....	5-12
<b>6. SUPERHEATER CONTROL MEASURES .....</b>	<b>6-1</b>
6.1 SO <sub>2</sub> EMISSIONS CONTROLS .....	6-1
6.2 NO <sub>x</sub> EMISSIONS CONTROLS .....	6-2
6.2.1 Identify Available NO <sub>x</sub> Control Options .....	6-2
6.2.2 Technical Feasibility of Available NO <sub>x</sub> Control Options .....	6-2
6.2.3 Effectiveness of NO <sub>x</sub> Control Options.....	6-5

<b>7. PACKAGE BOILER CONTROL MEASURES .....</b>	<b>7-1</b>
<b>8. FLARE CONTROL MEASURES .....</b>	<b>8-1</b>
<b>9. COSTS OF COMPLIANCE (STATUTORY FACTOR ONE).....</b>	<b>9-1</b>
9.1 ECONOMIC EVALUATION – SO <sub>2</sub> CONTROLS .....	9-2
9.2 ECONOMIC EVALUATION – NO <sub>x</sub> CONTROLS .....	9-3
<b>10. TIME NECESSARY FOR COMPLIANCE (STATUTORY FACTOR TWO) .....</b>	<b>10-1</b>
<b>11. ENERGY AND NON-AIR QUALITY ENVIRONMENTAL IMPACTS (STATUTORY FACTOR THREE) ....</b>	<b>11-1</b>
11.1 ENVIRONMENTAL IMPACTS .....	11-1
11.2 ENERGY IMPACTS .....	11-2
11.3 ENVIRONMENTAL / ENERGY IMPACTS SUMMARY .....	11-2
<b>12. REMAINING USEFUL LIFE (STATUTORY FACTOR FOUR) .....</b>	<b>12-1</b>
<b>13. FOUR-FACTOR ANALYSIS SUMMARY .....</b>	<b>13-1</b>

## FIGURES/TABLES

Figure 3-1. Federal Class I Areas .....	3-1
Figure 3-2. Regional Planning Organization Map.....	3-2
Table ES-1. NO <sub>x</sub> Control Options for GPSP Riley Boilers .....	ES-2
Table ES-2. NO <sub>x</sub> Control Options for GPSP Superheaters .....	ES-2
Table ES-3. NO <sub>x</sub> Emissions Control System Cost Effectiveness (\$2018).....	ES-3
Table ES-4. NO <sub>x</sub> Emissions Control System Implementation Schedule .....	ES-4
Table ES-5. Summary of Energy and Non-Air Quality Environmental Impacts .....	ES-4
Table 3-1. Key Steps in Developing Regional Haze SIPs for Second Planning Period .....	3-5
Table 4-1. Baseline Emissions .....	4-3
Table 5-1. Available NO <sub>x</sub> Control Options.....	5-2
Table 5-2. Summary of Technically Feasible NO <sub>x</sub> Control Options – Riley Boilers .....	5-11
Table 5-3. Effectiveness of NO <sub>x</sub> Control Options – Riley Boilers .....	5-12
Table 6-1. Comparison of Baseline SO <sub>2</sub> Emissions .....	6-1
Table 6-2. Available NO <sub>x</sub> Control Options.....	6-2
Table 6-3. Summary of Technically Feasible NO <sub>x</sub> Control Options – Superheaters.....	6-5

Table 6-4. Effectiveness of NO <sub>x</sub> Control Options – Superheaters .....	6-6
Table 9-1. NO <sub>x</sub> Control Cost Summary (\$2018) .....	9-3
Table 9-2. NO <sub>x</sub> Emissions Control System Cost Effectiveness (\$2018) .....	9-4
Table 10-1. NO <sub>x</sub> Emissions Control System Implementation Schedule .....	10-1
Table 11-1. Summary of Energy and Non-Air Quality Environmental Impacts .....	11-3

## **APPENDICES**

- A. North Dakota Department of Health Letter
- B. GPSP Baseline Emissions
- C. NO<sub>x</sub> Control Cost Effectiveness Estimates

## ABBREVIATIONS/ACRONYMS

Abbreviation/Acronym	Explanation
ABS	ammonium bisulfate
AUS	Applied Utility System Inc.
AVS	Antelope Valley Station
BACT	Best Available Control Technology
BART	Best Available Retrofit Technology
BTU	British Thermal Unit
Ca	calcium
CAA	Clean Air Act
CATC	Clean Air Technology Center
CaSO <sub>4</sub>	calcium sulfate
CERMS	continuous emission rate monitoring system
CFR	Code of Federal Regulations
CRF	capital recovery factor
CO	carbon monoxide
CO <sub>2</sub>	carbon dioxide
DCS	distributed control system
DGC	Dakota Gasification Company
EPA	Environmental Protection Agency
FGD	flue gas desulfurization
FGR	flue gas recirculation
G&A	general and administration
gpm	gallons per minute
GPSP	Great Plains Synfuels Plant
GHG	greenhouse gas
H <sub>2</sub>	hydrogen
H <sub>2</sub> O	water
H <sub>2</sub> S	hydrogen sulfide
ID	induced draft

Abbreviation/Acronym	Explanation
K	potassium
LNB	Low-NO <sub>x</sub> burner
LTS	Long-term strategy
Mg	magnesium
MMBtu	million British thermal units
Na	sodium
N <sub>2</sub>	nitrogen
ND	North Dakota
NDDH	North Dakota Department of Health
NH <sub>3</sub>	ammonia
(NH <sub>2</sub> ) <sub>2</sub> CO	urea
(NH <sub>4</sub> ) <sub>2</sub> SO <sub>4</sub>	ammonium sulfate
NH <sub>4</sub> HSO <sub>4</sub>	ammonium bisulfate
NO	nitric oxide
NO <sub>2</sub>	nitrogen dioxide
NO <sub>x</sub>	nitrogen oxides
N/P	naphtha / phenol
NSPS	New Source Performance Standard
NSR	New Source Review
NSR	normalized stoichiometric ratio
OEM	original equipment manufacturer
OFA	overfire air
O&M	operations and maintenance
PM	particulate matter
ppm	parts per million
RBLC	RACT/BACT/LAER Clearinghouse
RPG	Reasonable Progress Goals
RPO	Regional Planning Organization
S&L	Sargent & Lundy, L.L.C.
SCR	selective catalytic reduction



Abbreviation/Acronym	Explanation
SIP	State Implementation Plan
SNCR	selective non-catalytic reduction
SNG	synthetic natural gas
SO <sub>2</sub>	sulfur dioxide
SO <sub>3</sub>	sulfur trioxide
TAC	total annual cost
TCI	total capital investment
TE-SCR	tail-end SCR
tpy	tons per year
URP	uniform rate of progress
ULNB	ultra-low NOx burners
US	United States
VOC	volatile organic compound
WESP	wet electrostatic precipitator
WFGD	wet flue gas desulfurization
WRAP	Western Region Air Partnership

## EXECUTIVE SUMMARY

The Great Plain Synfuels Plant (GPSP), located near Mercer County, ND, commenced operation in 1984. The facility is owned and operated by Basin Electric Power Cooperative (Basin Electric) through its for-profit subsidiary, Dakota Gasification Company (DGC), which acquired the facility in 1988. The facility uses lignite coal to produce synthetic natural gas (SNG), fertilizers, and other products utilizing coal gasification process and is the only facility of its kind in the U.S. Lignite is delivered from the nearby Freedom mine.

On July 1, 1999, the U.S. Environmental Protection Agency (EPA) published regulations implementing Section 169A of the Clean Air Act (CAA), establishing a comprehensive visibility protection program for Federal Class I areas (the Regional Haze Rule).<sup>1</sup> The Regional Haze Rule requires each state to develop, and submit for approval by EPA, a state implementation plan (SIP) detailing the state's plan to protect visibility in Class I areas. The Regional Haze Rule established a schedule setting forth deadlines by which the States must submit their initial regional haze SIPs and subsequent revisions to the SIPs. Regional Haze SIPs for the initial planning period were due in 2007, with subsequent SIP updates due in 2018 and every 10 years thereafter.<sup>2</sup> Second planning period Regional Haze SIPs must be submitted to EPA for review by July 31, 2021.

At the request of the North Dakota Department of Health (NDDH), a Four Factor Analysis was prepared for GPSP. The analysis identified sulfur dioxide (SO<sub>2</sub>) and nitrogen oxides (NO<sub>x</sub>) control options for the three Riley Boilers, two Superheaters, auxiliary Package Boiler, Main Flare, and Startup Flare, and evaluated each of the control measures for the following four statutory factors:

1. The estimated cost of compliance;
2. The time necessary for compliance;
3. The energy and non-air quality environmental impacts of compliance; and
4. The remaining useful life of any potentially affected anthropogenic source of visibility impairment.

---

<sup>1</sup> 64 FR 35713

<sup>2</sup> On January 10, 2017, EPA made a one-time adjustment to the due date for the second implementation period SIPs (2018 – 2028) by extending the deadline from July 31, 2018 to July 31, 2021 (82 FR 3078).

The technical feasibility evaluation concluded that there are no technically feasible options for further SO<sub>2</sub> control on the individual sources, including the Riley Boilers, Superheaters, Package Boiler, Main Flare, and Startup Flare. Furthermore, the evaluation concluded that there are no technically feasible options for further NO<sub>x</sub> control on the Package Boiler, Main Flare, and Startup Flare. NO<sub>x</sub> control strategy options that are evaluated as part of the Four Factor Analysis for the Riley Boilers and Superheaters are included in Table ES-1 and Table ES-2. The tables also show baseline emission rates and estimated emission reductions for each control option.

**Table ES-1. NO<sub>x</sub> Control Options for GPSP Riley Boilers**

Control Technology	NO <sub>x</sub> Emission Rate <sup>(Note 1)</sup> lb/hr	% Reduction from Baseline Emission Rate
Selective Catalytic Reduction (tail-end) <sup>(Note 2)</sup>	103	80%
Baseline (Combustion Optimization / OFA / LNB)	517	--

Note 1. Emission rates shown represent average emission rates that the control options would be expected to achieve on an ongoing long-term basis under normal operating conditions for GPSP Riley Boilers. Emission rates are provided for comparative purposes, and should not be construed to represent proposed emission limits. Corresponding permit limits must be evaluated on an emission source type and control system-specific basis.

Note 2. TE-SCR has not been installed on a North Dakota lignite-fired unit or lignite-derived-fuel unit, and extended trials would be needed to better understand the design and operation of TE-SCR on the GPSP Riley Boilers. Nevertheless, during the initial planning period, NDDH evaluated the costs and cost-effectiveness of the control system on the Riley Boilers. TE-SCR will therefore be carried forward to the Four Factor Analysis to present hypothetical costs since the Department included it in the reasonable progress analysis for GPSP during the first planning period; however, technical feasibility has never actually been demonstrated for TE-SCR for lignite-based fuels.

**Table ES-2. NO<sub>x</sub> Control Options for GPSP Superheaters**

Control Technology	NO <sub>x</sub> Emission Rate <sup>(Note 1)</sup> lb/hr	% Reduction from Baseline Emission Rate
Combustion Optimization	42	5%
Baseline (Combustion Optimization / FGR / LNB)	44	--

Note 1. Emission rates shown represent average emission rates that the control options would be expected to achieve on an ongoing long-term basis under normal operating conditions for GPSP Superheaters. Emission rates are provided for comparative purposes, and should not be construed to represent proposed emission limits. Corresponding permit limits must be evaluated on a source-specific and control system-specific basis.

*Costs of Compliance (Statutory Factor One)*

Capital and operating and maintenance (O&M) cost estimates were developed for each of the NO<sub>x</sub> control options. The GPSP cost estimates are conceptual in nature; thus, S&L did not procure equipment quotes specifically for the control system upgrades.

Table ES-3 includes estimated costs for NO<sub>x</sub> control options for the Riley Boilers combined and the two Superheaters combined. The table provides the estimated annualized capital and O&M costs, estimated emissions reductions, and average annual cost effectiveness.

**Table ES-3. NO<sub>x</sub> Emissions Control System Cost Effectiveness (\$2018)**

<b>Unit</b> <small>(Note 1)</small>	<b>NO<sub>x</sub> Control Option</b>	<b>Total Annual Cost</b> \$/yr	<b>Expected Emission Reduction</b> tons NO <sub>x</sub> /yr	<b>Average Annual Cost Effectiveness</b> <small>(Note 2)</small> \$/ton NO <sub>x</sub> removed
Riley Boilers	TE-SCR	\$69,854,000	1,808	\$38,639
Superheaters	Combustion Optimization	\$229,000	10	\$23,596

Note 1. Costs are provided for the combination of the three Riley Boilers or two Superheaters.

Note 2. Average cost effectiveness for each control option is the total annual cost divided by the expected emission reduction.

*Time Necessary for Compliance (Statutory Factor Two)*

Table ES-4 provides estimated timeframes needed to implement each of the evaluated control options. Notably, the estimated timeframes do not account for time needed for North Dakota to develop and implement the regulations; nor the amount of time needed for EPA to take proposed and final action to approve North Dakota's SIP.

**Table ES-4. NO<sub>x</sub> Emissions Control System Implementation Schedule**

NO <sub>x</sub> Control Option	Design / Specification / Procurement (months)	Detail Design / Fabrication (months)	Construction / Commissioning / Startup (months)	Total (months after SIP approval)
TE-SCR on Riley Boilers	10	18	24	Up to 60 months
Combustion Optimization on Superheaters	2	4	4	Up to 60 months

*Energy and Non-Air Quality Environmental Impacts (Statutory Factor Three)*

An evaluation of energy impacts indicates that certain control options (e.g., TE-SCR) will increase electrical power requirements due to increased pressure drop. Use of a combustion optimization system for NO<sub>x</sub> control may also result in reduced boiler efficiency, which would increase the amount of fuels fired to maintain steam generation. Collateral environmental impacts with regard to TE-SCR include an increase in solid waste generation due to sorbent injection; increases in other stack emission such as CO, VOC and ammonia slip; as well as additional power consumption. A summary of the environmental and energy impact analysis is provided in Table ES-5.

**Table ES-5. Summary of Energy and Non-Air Quality Environmental Impacts**

Control Option	Collateral Environmental & Energy Impacts
<b>Baseline</b>	<p>GPSP Riley Boilers are currently equipped with WFGD / WESP control systems for SO<sub>2</sub> control. The Riley Boilers and Superheaters are equipped with a combination of LNB, FGR, and OFA for NO<sub>x</sub> control. Existing collateral environmental and energy impacts include:</p> <ul style="list-style-type: none"> <li>➤ Solid WFGD by-product management or disposal</li> <li>➤ Increased water consumption</li> <li>➤ Increased electrical power requirements</li> </ul>
<b>NO<sub>x</sub> Control Options</b>	
Selective Catalytic Reduction (SCR) - Tail End Configuration (Riley Boilers)	<ul style="list-style-type: none"> <li>➤ Increased electrical power requirements</li> <li>➤ Increased ammonia slip emissions and potential for ABS emissions</li> <li>➤ Potential increase in SO<sub>3</sub> emissions</li> <li>➤ Additional solid waste disposal</li> <li>➤ Additional NO<sub>x</sub>, CO, and VOC emissions from duct firing</li> </ul>
Combustion Optimization (Superheaters)	<ul style="list-style-type: none"> <li>➤ Potential decrease in boiler efficiency to reduce NO<sub>x</sub> emissions</li> <li>➤ Potential increase in CO emissions</li> </ul>

*Remaining Useful Life (Statutory Factor Four)*

Regarding remaining useful life, the GPSP owners do not have an enforceable or suggested remaining useful life that is less than 20 years. However, implementation of control technologies that eliminate any profitability for the facility may have an effect on the remaining life. Nevertheless, a 20 year remaining useful life is evaluated.

## 1. INTRODUCTION

Sargent & Lundy, L.L.C. (S&L) was hired by Basin Electric's Dakota Gasification Company (DGC) to prepare a reasonable progress four-factor analysis for the control of nitrogen oxides (NO<sub>x</sub>) and sulfur dioxide (SO<sub>2</sub>) emissions from the Great Plains Synfuels Plant (GPSP). The evaluation is in response to the North Dakota Department of Health's (NDDH) formal letter dated May 18, 2018, attached in Appendix A. The evaluation includes an assessment of potentially available emission reduction measures for the four statutory factors listed in 40 CFR 51.308(f)(2), and takes into consideration U.S. Environmental Protection Agency's (EPA's) *Draft Guidance on Progress Tracking Metrics, Long Term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period* (the "Draft EPA Guidance").<sup>3</sup> Technically feasible NO<sub>x</sub> and SO<sub>2</sub> emission reduction measures are evaluated for the following four statutory factors:

- Factor 1: The cost of compliance
- Factor 2: The time necessary to achieve compliance
- Factor 3: The energy and non-air quality environmental impact of compliance
- Factor 4: The remaining useful life of any existing source subject to such requirements

The reasonable progress four factor analysis for the Great Plains Synfuels Plant (the "Four Factor Analysis") is presented in the following sections:

- Section 2: Facility Description** contains information describing the facility, site location, and existing equipment.
- Section 3: Four-Factor Analysis Requirements** provides a brief description of the Regional Haze Program requirements set forth in 40 CFR 51.308.
- Section 4: Baseline SO<sub>2</sub> and NO<sub>x</sub> Emissions** establishes representative baseline SO<sub>2</sub> and NO<sub>x</sub> emissions for the period 2013 to present.

<sup>3</sup> On September 11, 2018, EPA released a "*Regional Haze Reform Roadmap*" announcing its plan to "release a series of implementation tools and guidance documents that will help focus states' efforts and reduce and streamline the time and resources needed to meet the statutory and regulatory requirements for reducing regional haze in National Parks, wildlife refuges, and wilderness areas." EPA stated that it plans to issue a new guidance document on Regional Haze SIP Development by Spring, 2019. Dakota Gasification Company reserves the right to update and modify this four-factor analysis, as needed, to be consistent with any new guidance issued by the agency.

**Sections 5-8: NO<sub>x</sub> and SO<sub>2</sub> Control Measures** identifies potentially available emission control technologies, and evaluates each control option for technical feasibility and effectiveness for each of the Riley Boilers and Superheaters, the Package Boiler, the Main Flare and the Startup Flare.

**Section 9: Costs of Compliance (Statutory Factor One)** evaluates the cost and cost-effectiveness of each technically feasible control option.

**Section 10: Time Necessary for Compliance (Statutory Factor Two)** provides typical timelines required to design, engineer, procure, and install the technically feasible control options.

**Section 11: Energy and Non-Air Quality Environmental Impacts (Statutory Factor Three)** identifies the energy and non-air quality environmental impacts associated with each technically feasible control option.

**Section 12: Remaining Useful Life (Statutory Factor Four)** includes a discussion of the planned remaining useful life of GPSP, including an evaluation of how remaining useful life affects the cost-effectiveness of each technically feasible control option.

**Section 13: Summary**

**Appendix A: North Dakota Department of Health Letter**

**Appendix B: GPSP Baseline Emissions**

**Appendix C: NO<sub>x</sub> Control Cost Effectiveness Estimates**



## **2. FACILITY DESCRIPTION**

The GPSP, located near Mercer County, ND, commenced operation in 1984. The facility is owned and operated by Basin Electric Power Cooperative (Basin Electric) through its for-profit subsidiary, DGC, which acquired the facility in 1988. The facility uses lignite coal to produce synthetic natural gas (SNG), fertilizers, and other products utilizing coal gasification process and is the only facility of its kind in the U.S. Lignite is delivered from the nearby Freedom mine.

The plant consists of various emission sources, including, but not limited to, the following main sources: three (3) Riley Boilers, two (2) Coen heat transfer superheaters (a.k.a. “Superheaters”), a Main Flare, a Startup Flare, a Backup Flare, and a Rentech Auxiliary Boiler (a.k.a “Package Boiler”). There are additional emission sources at the GPSP; however, the NDDH has confirmed that the emissions from these other sources are not expected to significantly contribute to visibility impairment. As such, only the main sources identified above will be included in this Four Factor Analysis.

The Riley Boilers and Superheaters generate steam required for the gasification process, and for other uses at the facility. Each Riley Boiler fires up to 763 million British thermal units per hour (MMBtu/hr) of fuels and is designed to burn a combination of gasification products, including liquid and gaseous fuels consisting of waste gas, stink gas, tar oil, naphtha/phenol (N/P) blend, lock gas, medium BTU purge gas, and SNG. The Riley Boilers complete regular combustion tuning and are equipped with low NO<sub>x</sub> burners (LNB) and a pseudo-overfire air (OFA) system for NO<sub>x</sub> control.<sup>4</sup> The Riley Boilers are also equipped with a single wet flue gas desulfurization (WFGD) system for SO<sub>2</sub> and particulate matter (PM) control, and a wet electrostatic precipitator (WESP) system for acid gas and PM control.

Each Superheater fires up to 169 MMBtu/hr of fuels and is designed to fire SNG and tar oil in combination or up to 100% of either fuel. The Superheaters complete regular combustion tuning and are equipped with LNB and partial

---

<sup>4</sup> The GPSP Riley Boilers were upgraded with windbox partitions that provide staging of combustion air to the upper burner compartment similar to overfire air systems, and subsequently provides NO<sub>x</sub> reduction.

flue gas recirculation (FGR) for NO<sub>x</sub> control. Hot exhaust flue gas from the Superheaters is combined with the WFGD outlet from the Riley Boilers to reheat the flue gas prior to exiting to atmosphere in a common stack.

Due to the nature of the gasification process and various backend components, the facility is equipped with five process gas flares: the Main Flare, Startup Flare, Ammonia Plant Flare, Ammonia Storage Tank Flare, and Backup Flare. Based on discussion with NDDH, only the Main Flare and Startup Flare are evaluated in this Four Factor Analysis; the other flares operate intermittently and/or are not expected to significantly contribute to visibility impairment. The Main Flare and Startup Flares are typically used in times of startup, shutdown, or malfunction to fire numerous process gases purged along different points of the gasification process. The flares are used as an emission control device to combust midstream components prior to emitting to the atmosphere. The Main Flare is where process relief discharges from safety or pressure control vents. The Main Flare has the ability to inject steam at the flare tip for smokeless operation. The Startup Flare is primarily used during the startup of the gasifiers when the raw gas is not of sufficient composition for additional processing. There are currently no NO<sub>x</sub> or SO<sub>2</sub> controls on the flares.

The Package Boiler was installed in 2017. It is designed to fire SNG at a rate of 318 MMBtu/hr and provides process steam primarily to the GPSP urea production facility. The Package Boiler is equipped with ultra-low NO<sub>x</sub> burners (ULNB) for NO<sub>x</sub> control. DGC fires low-to-no sulfur SNG fuel exclusively in the Package Boiler.

### 3. FOUR-FACTOR ANALYSIS REQUIREMENTS

### 3.1 REGIONAL HAZE RULE BACKGROUND

Section 169A of the 1977 Amendments to the Clean Air Act (CAA) sets forth a program for protecting visibility in Federal Class I areas which calls for the “prevention of any future, and the remedying of any existing, impairment of visibility in mandatory Federal Class I areas which impairment results from manmade air pollution.” Federal Class I areas include national parks, memorial parks, and wilderness areas over a certain size. Figure 3-1. shows the locations of the 156 federally mandated Class I areas. Federal Class I areas located within North Dakota include the Theodore Roosevelt National Park and the Lostwood National Wildlife Refuge.

### Figure 3-1. Federal Class I Areas



On July 1, 1999, the U.S. EPA published regulations implementing Section 169A of the CAA, establishing a comprehensive visibility protection program for Federal Class I areas (the Regional Haze Rule).<sup>5</sup> The Regional Haze Rule requires each state to develop, and submit for approval by EPA, a state implementation plan (SIP) detailing the state's plan to protect visibility in Class I areas. Regional Haze SIPs must contain such emission limits, schedules of compliance, and other measures as may be necessary to make reasonable progress toward meeting the national visibility goal of achieving visibility in Class 1 areas which reflects natural conditions by 2064.

To address the combined visibility effects of various pollution sources over a wide geographic region, EPA designated five Regional Planning Organizations (RPOs) to assist with the coordination and cooperation needed to address the visibility issue. The five RPOs are shown in Figure 3-2. . North Dakota is a member of the Western Regional Air Partnership (WRAP), which serves as the RPO for visibility protection at 118 Class I areas in the 15 western states.

**Figure 3-2. Regional Planning Organization Map**



<sup>5</sup> 64 FR 35713

### **3.1.1 First Implementation Period**

The Regional Haze Rule established a schedule setting forth deadlines by which the States must submit their initial regional haze SIPs and subsequent revisions to the SIPs. Regional Haze SIPs for the initial planning period were due in 2007, with subsequent SIP updates due in 2018 and every 10 years thereafter.<sup>6</sup>

Regional Haze SIP requirements for the first planning period required that states incorporate into their plans the core program requirements in 40 CFR 51.308(d), including: (1) establishing reasonable progress goals (RPGs) for each Class I area within the state that provide for measurable progress towards achieving natural visibility conditions; (2) developing a long-term strategy (LTS) including enforceable emissions limitations and compliance schedules to achieve the RPGs; and (3) developing plans to monitor and assess the effectiveness of the LTS to achieve the RPGs over the prior implementation period and affirmation of or revision to the RPGs.

The Regional Haze Rule requires that states determine the consistent rate of progress over time needed to attain natural visibility conditions on the 20 percent most impaired days by the year 2064. This “glidepath” is referred to as the uniform rate of progress (URP) line. States must consider the URP, and the emission reduction measures needed to achieve this level of improvement, when developing their RPGs and LTS. Regulations at 40 CFR 51.308(g) require each state to submit progress reports, in the form of SIP revisions, every 5 years following the submission of the initial SIP. These progress reports must evaluate the progress made towards the RPGs for Class I areas located within the state as well as those Class I areas located outside the state that may be affected by emissions from within the state.

#### **3.1.1.1 Best Available Retrofit Technology**

As a one-time requirement during the first implementation period, potential best available retrofit technology (BART) controls had to be evaluated for certain large stationary sources. States were required to conduct BART determinations for “BART-eligible” sources anticipated to cause or contribute to any visibility impairment in one or more Class I area. BART-eligible sources are stationary sources that were put in place between August 7, 1962 and August 7, 1977, and whose operations fall within one or more of the 26 listed source categories, including fossil-

---

<sup>6</sup> On January 10, 2017, EPA made a one-time adjustment to the due date for the second implementation period SIPs (2018 – 2028) by extending the deadline from July 31, 2018 to July 31, 2021 (82 FR 3078).

fuel fired boilers of more than 250 MMBtu/hr heat input.<sup>7</sup> The Riley Boilers fall within the 26 listed source categories, but were not in operation prior to August 7, 1977. In its determination of BART, states were required to take into consideration the costs of compliance, the energy and non-air quality environmental impacts of compliance, any existing pollution control technology in use at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.<sup>8</sup> As an alternative to requiring source-specific BART controls, states also had the flexibility to adopt an emissions trading program or other alternative program as long as the alternative provided greater reasonable progress towards improving visibility than BART.

#### **3.1.1.2 Reasonable Progress Control Requirements for GPSP during First Planning Period**

GPSP commenced operation in 1984, and was not classified as a BART-eligible source or subject to the BART requirements. Nevertheless, during the initial planning period, the NDDH evaluated emissions from the three GPSP Riley Boilers as reasonable progress sources. The reasonable progress analysis prepared by NDDH did not include the Superheaters, flares, or auxiliary combustion sources. The NDDH concluded that no additional controls would be required on the Riley Boilers during the initial planning period and suggested that SNCR or SCR may not be technically feasible NO<sub>x</sub> control options.

#### **3.1.2 Second Implementation Period**

Second planning period Regional Haze SIPs must be submitted to EPA for review by July 31, 2021. Among other requirements, second planning period SIPs are required to include an assessment of the state's RPGs and LTS. To support states in their efforts to develop the second planning period SIPs, in July 2016 EPA released a draft guidance document titled "*Draft Guidance on Progress Tracking Metrics, Long-term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period*" ("Draft EPA Guidance").<sup>9</sup> The Draft EPA Guidance document describes key steps states

<sup>7</sup> The term "fossil fuel" is generally defined to include natural gas, petroleum, coal, or any form of solid, liquid, or gaseous fuel derived from such material for the purpose of creating useful heat.

<sup>8</sup> CAA Section 169A(g)(2).

<sup>9</sup> See, EPA-457/P-16-001. On September 11, 2018, EPA released a "*Regional Haze Reform Roadmap*" announcing its plan to "release a series of implementation tools and guidance documents that will help focus states' efforts and reduce and streamline the time and resources needed to meet the statutory and regulatory requirements for reducing regional haze in National Parks, wildlife refuges, and wilderness areas." EPA stated



should implement when developing their RPGs and LTS for the second implementation period. Key steps identified in the Draft EPA Guidance are listed in Table 3-1.

**Table 3-1. Key Steps in Developing Regional Haze SIPs for Second Planning Period**

1. *Ambient data analysis* – Quantify baseline, current and natural conditions and the uniform rate of progress that would achieve natural conditions in 2064. (40 CFR 51.308(f)(1))
2. *Screening of sources* – Identify the pollutants and emission sources for which a full reasonable progress analysis will be completed and explain why it is appropriate to limit the full analysis to only these sources. (40 CFR 51.308(f)(2))
3. *Source and emission control measure analysis* – Identify potential emission control measures for sources selected in the screening step and develop data on the four statutory factors and visibility benefits if they will be considered. (40 CFR 51.308(f)(2))
4. *Decisions on the content of the LTS* – Consider applicable factors and decide on new emission controls for incorporation into the LTS. (40 CFR 51.308(f)(2))
5. *Regional scale modeling* – Model the emissions reductions that will result from implementation of the LTS and other enforceable measures that will reduce visibility impairment to set the RPGs for 2028. (40 CFR 51.308(f)(3))
6. *Progress, degradation and glidepath checks* – Demonstrate that there will be an improvement on the 20 percent most impaired days. Demonstrate that there is no degradation on the 20 percent clearest days. Compare the 2028 RPG for the 20 percent most impaired days to the 2028 point on the URP line (the glidepath) and, if required, provide additional justification for the reasonableness of the RPG. Revise the LTS if additional measures are identified as necessary to make reasonable progress. (40 CFR 51.308(f)(3))
7. *Additional requirements for SIPs* – Provide additional information necessary to ensure that other requirements of the Regional Haze rule are met.

The Draft EPA Guidance recommends that states evaluate all technically feasible emission control options for stationary sources and source categories identified as having the greatest potential to impact visibility at one or more Class I area. The Draft EPA Guidance recommends several options for states to consider when evaluating

that it plans to issue a new guidance document on Regional Haze SIP Development by Spring, 2019. Dakota Gasification Company reserves the right to update and modify this four-factor analysis, as needed, to be consistent with any new guidance issued by the agency.

potential emission reductions, including work practices, replacement and retrofit controls, existing control upgrades, fuel switching, year-round operation of controls, and operating restrictions.<sup>10</sup>

Emission control evaluations must consider the four statutory factors identified in 40 CFR 51.308(f)(2)(i) (discussed in Section 3.2). In addition, the Draft EPA Guidance notes that control technology assessment recommendations presented in the BART Guidelines continue to be relevant as recommendations for how a state should evaluate and select emission control measures for stationary sources.<sup>11</sup> Recommendations in the BART Guidelines that continue to be relevant to the reasonable progress Four Factor Analysis are listed in Appendix D of the Draft EPA Guidance, and include, in general, the recommended approach for evaluating the technical feasibility, effectiveness, costs, and cost-effectiveness of available emission control measures.<sup>12</sup>

## **3.2 DESCRIPTIONS OF THE FOUR STATUTORY FACTORS**

Under 40 CFR 51.308(f)(2)(i), states must consider four statutory factors when evaluating and determining emissions reduction measures from stationary sources, or groups of sources that are necessary to make reasonable progress towards achieving natural visibility conditions. The four statutory factors are:

1. The estimated cost of compliance;
2. The time necessary for compliance;
3. The energy and non-air quality environmental impacts of compliance; and
4. The remaining useful life of any potentially affected anthropogenic source of visibility impairment.

A brief description of each of the four statutory factors, and EPA's recommendations for evaluating each of the four factors (from the Draft EPA Guidance), is provided below.

### **3.2.1 Costs of Compliance**

Cost estimates should be developed for each technically feasible control option. Costs include the total capital costs to engineer, design, procure, and install the control technology, and annual operating and maintenance (O&M) costs. O&M costs include both fixed and variable O&M. Fixed O&M includes costs that are independent of

<sup>10</sup> See, Draft EPA Guidance, pgs. 85-86.

<sup>11</sup> Draft EPA Guidance, pg. 85. The BART Guidelines are published at 40 CFR Part 51 Appendix Y.

<sup>12</sup> Draft EPA Guidance, Appendix D, pgs. 186-196.



control system operation and would be incurred even if the control system were shut down. Fixed O&M includes categories such as operating and maintenance labor, administrative charges, property taxes, and insurance. Variable O&M includes the cost of consumables, including reagent (e.g., lime or limestone, ammonia, urea, etc.), by-product management, water consumption, and electric power requirements associated with operating the control system. For existing facilities, O&M cost estimates should represent the control option's incremental increase over current O&M costs.

Capital costs include all costs required to engineer, design, procure, and install equipment needed for the control system. The Draft EPA Guideline recommends that states adhere to the accounting principles described in Chapter 2 of Section 1 of EPA's Air Pollution Control Cost Manual (the "Control Cost Manual") when calculating control system costs for a four factor analysis.<sup>13</sup>

Section 2.3 of the Control Cost Manual (Section 1, Chapter 2) describes the cost categories generally used to calculate the total capital cost of a retrofit control technology. Cost categories include total capital investment (TCI), which is defined to "include all costs required to purchase equipment needed for the control systems (purchased equipment costs), the costs of labor and materials for installing that equipment (direct installation costs), costs for site preparation and buildings, and certain other costs (indirect installation costs). TCI also includes costs for land, working capital, and off-site facilities." Direct installation costs include costs for foundations and supports, erecting and handling the equipment, electrical work, piping, insulation, and painting. Indirect installation costs include costs such as engineering costs; construction and field expenses (i.e., cost for construction supervisory personnel, office personnel, rental of temporary offices, etc.); contractor fees (for construction and engineering firms involved in the project); start-up and performance test costs (to get the control system running and to verify that it meets performance guarantees); and contingencies.<sup>14</sup>

The total annual cost (TAC) of a control option includes the annualized capital recovery cost plus the total annual O&M costs. The Control Cost Manual recommends using an equivalent uniform annual cash flow method to annualize the total capital investment by multiplying the total capital investment by a capital recovery factor

<sup>13</sup> Draft EPA Guidance, pg.89.

<sup>14</sup> EPA Air Pollution Control Cost Manual, Sixth Edition, EPA/452/B-02-001, January 2002, pg. 2-5.

(CRF).<sup>15</sup> The product of the total capital investment and CRF gives a uniform end-of-year payment necessary to repay the initial capital investment in "n" years at an interest rate of "i". The CRF is calculated using the following equation:

$$CRF = \frac{i * (1 + i)^n}{(1 + i)^n - 1}$$

Where:

i = interest rate; and

n = economic life of the emission control system

The Draft EPA Guidance suggests that states may use generic cost estimates or estimating algorithms for estimating control system costs; however, source specific estimates prepared by knowledgeable engineering professionals provide more reliable information than generic cost estimates.<sup>16</sup> Source-specific cost estimates should be well documented for purposes of public comment and EPA review.<sup>17</sup>

The total annual cost of each control option (\$/yr) is divided by the total annual emissions reduction (tpy) to determine the control option's average cost-effectiveness on a \$/ton basis. Emissions reductions are calculated based on the difference between baseline annual emissions and post-control annual emissions. The Draft EPA Guidance generally recommends calculating baseline emissions based on projected 2028 emissions assuming source compliance with emission limits that have been adopted and are enforceable. As an alternative, baseline emissions may be based on representative past actual emissions, assuming there is no evident basis for using a different emissions rate.

### 3.2.2 Time Necessary for Compliance

For stationary sources, the provisions of the BART Guidelines regarding the time necessary for compliance are relevant to reasonable progress analyses. EPA recommends that prior experiences with the planning and installation of new emission controls is the best guide to how much time a particular source will reasonably need for compliance. However, source-specific factors should be considered when evaluating the time necessary to

<sup>15</sup> Ibid., at pg. 2-21.

<sup>16</sup> Draft EPA Guidance, pg. 91.

<sup>17</sup> Ibid.

engineer, procure, and install an available and technically feasible control option. Source-specific factors that affect the time necessary to install new emission controls should be identified and documented in the Four Factor Analysis.

### 3.2.3 Energy and Non-Air Quality Environmental Impacts

For stationary sources, the provisions of the BART Guidelines regarding energy impacts are relevant to reasonable progress analyses. Energy impacts of an emission control measure are a matter of engineering design and control system operation; thus, EPA recommends that prior experience at similar sources will be informative. Energy impacts may be considered in terms of kilowatt-hours or fuels used to operate the control system. The energy impact analysis should focus on direct energy consumption at the source rather than indirect energy inputs needed to produce raw materials for the construction and operation of control equipment.

For stationary sources, the provisions of the BART Guidelines regarding non-air quality environmental impacts are relevant to reasonable progress analyses. Non-air quality impacts include solid or hazardous waste generation, increased water consumption, wastewater discharge, land use impacts, and impacts to threatened and endangered species or their natural habitat. Characterizing the non-air quality environmental impacts should be done on a source-specific basis. Other guidance intended for use in assessments under the National Environmental Policy Act may be relevant to this evaluation.

Even though states are not required to consider GHG emission impacts, the Draft EPA Guidance encourages states to consider GHG impacts when developing their LTS.<sup>18</sup> As an example, some measures that would reduce emissions that contribute to visibility impairment will also reduce GHG emissions, such as measures that reduce the use of energy produced from combusting fossil fuels with relatively high GHG emissions. Conversely, control measures that require significant energy to capture visibility impairing emissions could result in increased GHG emissions. Where a measure necessary to make reasonable progress towards natural visibility conditions would increase GHG emissions, Draft EPA Guidance encourages states to work to harmonize visibility and climate change objectives.<sup>19</sup>

---

<sup>18</sup> Draft EPA Guidance, pg. 92.

<sup>19</sup> *Ibid.*

### **3.2.4 Remaining Useful Life**

For stationary sources, the provisions of the BART Guidelines regarding remaining useful life are relevant to reasonable progress analyses. In general, the remaining useful life of the source itself will be longer than the useful life of the emission control measure under consideration unless there is an enforceable requirement for the source to cease operation sooner. Thus, the useful life of the control measure will normally be used in the Four Factor Analysis to calculate emission reductions, amortized costs, and cost-effectiveness. However, if there is an enforceable requirement for the source to cease operation by a date before the end of what would otherwise be the useful life of the control measure under consideration, then the enforceable shutdown date should be used to calculate remaining useful life and evaluate control technology cost-effectiveness.

### **3.2.5 Four Factor Analysis Approach**

S&L used a top-down approach to identify and evaluate the technical feasibility and effectiveness of potentially available SO<sub>2</sub> and NO<sub>x</sub> control measures. S&L followed Steps 1 through 3 of the top-down approach described in the BART Guidelines to identify all available retrofit emission control measures, eliminate technically infeasible options, and evaluate the effectiveness of the technically feasible options. A brief description of each step is provided below.

#### ***Step 1 - Identify All Available Control Options***

Available control options are those air pollution control technologies with a practical potential for application to the emission unit and the regulated pollutant under evaluation. Air pollution control technologies can include a wide variety of available methods, systems, and techniques for control of the affected pollutant, and include not only existing controls for the source category but also take into account technology transfer of controls that have been applied to similar source categories and gas streams. Technologies which have not been applied to (or permitted for) full scale operations need not be considered as available.

In an effort to identify all potentially available emission control technologies, S&L searched a broad range of information sources including, but not necessarily limited to:

- EPA's RACT/BACT/LAER Clearinghouse (RBLC);
- EPA's New Source Review (NSR) and Clean Air Technology Center (CATC) Web sites;

- BART evaluations prepared during the initial Regional Haze planning period;
- Information from control technology vendors and engineering/environmental consultants;
- Federal and State NSR permits and Best Available Control Technology (BACT) determinations for similar sources; and
- Technical journals, reports, newsletters, and air pollution control seminars.

### ***Step 2 - Eliminate Technically Infeasible Control Options***

In Step 2, S&L evaluated the technical feasibility of the control options identified in Step 1 with respect to source-specific and unit-specific factors. Control technologies are technically feasible if either: (1) they have been installed and operated successfully for the type of source under review under similar conditions; or (2) the technology could be applied to the source under review. In order for a control option to be technically feasible, it must be “available” and “applicable” to the source under consideration. A technology is considered “available” if the source owner may obtain it through commercial channels. An available technology is “applicable” if it can reasonably be installed and operated on the source type under consideration.

Control technologies that are technically infeasible (i.e., not available or not applicable to the source under consideration) are eliminated from further evaluation. A demonstration of technical infeasibility must be based on physical, chemical, and/or engineering principals, and must show that technical difficulties would preclude the successful use of the control option on the emission unit under consideration. The economics of an option are not considered in the determination of technical feasibility/infeasibility.

### ***Step 3 - Evaluate Technically Feasible Control Technologies for Effectiveness***

Step 3 involves evaluating the control effectiveness of all the technically feasible control alternatives identified in Step 2 for the pollutant and emissions unit under review. Control effectiveness should be expressed using a metric that ensures an “apples-to-apples” comparison of emissions performance levels among options, and is generally expressed as the rate that a pollutant is emitted after installation of the control measure. Control technology evaluations for existing sources should consider ways to improve the performance of existing control devices. Special circumstances pertinent to the specific unit under review should be identified and taken into consideration when assessing the capability of the control alternative and determining control effectiveness.

For this evaluation, S&L assessed the technically feasible SO<sub>2</sub> and NO<sub>x</sub> control options for effectiveness on various sources at the GPSP facility, including the Riley Boilers, Superheaters, Package Boiler, Main Flare, and Startup Flare.

## **4. BASELINE SO<sub>2</sub> AND NO<sub>x</sub> EMISSIONS**

The first step in developing the Four Factor Analysis is to establish the baseline SO<sub>2</sub> and NO<sub>x</sub> emissions for the Riley Boilers, Superheaters, Package Boiler, Main Flare, and Startup Flare. Different averaging periods were used to determine representative emissions for each of the sources due to the variability in the nature of their operation.

To establish representative baseline emissions, S&L evaluated Riley Boiler and Superheater operating data for the period January 1, 2016 to September 30, 2018 to identify periods of normal operation (i.e., periods of operation when the boiler was not limited by infrequent or extraordinary operating restrictions). Based on review of fuels consumed, heat input, emissions control systems in place, as well as input from DGC, it was determined that this entire period was representative of normal operation for the Riley Boilers and Superheaters. The maximum 24-consecutive month annual average emission rate during the representative time period was used to establish baseline annual emissions (in terms of tons per year [tpy]) for the three Riley Boilers combined and the two Superheaters combined.

Baseline annual SO<sub>2</sub> and NO<sub>x</sub> emissions for the Riley Boilers and Superheaters were determined based on data obtained from the GPSP continuous emission rate monitoring systems (CERMS) and emissions calculations that the facility uses to report to the NDDH. While the Riley Boiler and Superheater flue gases are routed to a common stack, the NDDH has referred to them as separate emission sources. As such, the three Riley Boilers will be evaluated as a single source and the two Superheaters will be evaluated as a single source. Since the Riley Boilers and Superheaters combine to a single stack, the stack SO<sub>2</sub> CERMS and reheat duct process monitor operating data were evaluated to determine the emissions generated from the Riley Boilers and the Superheaters. Stack NO<sub>x</sub> CERMS and flue gas test reports were used to determine the emissions generated between the Riley Boilers and the Superheaters.

S&L also evaluated the GPSP Package Boiler emissions data for the baseline period of December 20, 2017 through October 11, 2018. Less than a full year of data is available since the unit only recently came into service; therefore, the total heat input was scaled to estimate the total expected annual heat input. S&L and DGC determined that the baseline operating period was representative of normal operation for the Package Boiler and encompasses operation of the ULNB system for NO<sub>x</sub> control. Since a full year of operation has not occurred at the time of this evaluation,

the maximum 30-day rolling annual average emission rate during the representative baseline period was used to establish baseline annual emissions (in tpy) for the Package Boiler.

S&L evaluated the Main Flare and Startup Flare monthly emissions data for the representative period January 1, 2015 through October 31, 2018 to determine periods of normal operation. Since the facility's flares do not have a prescribed normal operating condition, it was determined that all operation during the baseline time period was representative of typical operation. As such, to determine a realistic emission rate, the maximum annual average emission rate calculated during the representative time period was used to establish baseline annual emissions (in tpy) for the Main Flare and the Startup Flare.

Using the baseline annual average emissions and the respective baseline heat inputs described above for each source, representative emissions in terms of lb/hr were developed. Table 4-1 provides a summary of the GPSP SO<sub>2</sub> and NO<sub>x</sub> representative baseline emissions for each source. Additional details are included in Appendix B.



**Table 4-1. Baseline Emissions**

Source	Pollutant	Baseline Controls	Emissions		Heat Input	Notes
			lb/hr	tpy	MMBtu/yr	
Three (3) Riley Boilers	SO <sub>2</sub>	WFGD	671	2757	13,691,041	SO <sub>2</sub> emissions based on 24-month annual average tpy for period January 1, 2016 – December 31, 2017
	NO <sub>x</sub>	Combustion tuning, LNB & OFA	517	2260	14,265,939	NO <sub>x</sub> emissions based on 24-month annual average tpy for period August 18, 2016 – August 17, 2018
Two (2) Superheaters	SO <sub>2</sub>	Low-sulfur fuel	56	246	1,971,982	Emissions based on 24-month annual average tpy for period May 1, 2016 – April 30, 2018.
	NO <sub>x</sub>	Combustion tuning, FGR & LNB	44	194	1,971,982	
Package Boiler	SO <sub>2</sub>	Low-sulfur fuel	Non-detect	Non-detect	1,265,958	Emissions based on maximum 30-day rolling annual average for period December 20, 2017 – October 11, 2018. Annual emissions and annual heat input based on assuming similar operation for 12 months of the year to develop tpy.
	NO <sub>x</sub>	ULNB	4	19	1,265,958	
Main Flare	SO <sub>2</sub>	n/a	75	327	2,462,437	Emissions based on annual average emission rate tpy for 2018.
	NO <sub>x</sub>	n/a	24	105	3,523,823	Emissions based on annual average emission rate tpy for 2015.
Startup Flare	SO <sub>2</sub>	n/a	17	74	363,233	Emissions based on annual average emission rate tpy for 2015.
	NO <sub>x</sub>	n/a	3	12	363,233	

## 5. RILEY BOILER CONTROL MEASURES

### 5.1 SO<sub>2</sub> EMISSIONS CONTROLS

In 1996, an ammonia-based WFGD system was installed on the Riley Boilers, and has been providing SO<sub>2</sub> reduction. Outside of startup, shutdown, maintenance, or malfunction, the single WFGD system is designed to treat 100% of the flue gas from the three Riley Boilers. During normal operation, the WFGD most often operates at 97-98% SO<sub>2</sub> removal efficiency across the absorber.

As part of the first planning period for Regional Haze, the NDDH concluded that Riley Boiler WFGD system is comparable to BACT or BART for industrial boilers of similar size.<sup>20</sup> Since its installation in 1996, limited improvements in the industry have been made to provide over 98% removal efficiency on ammonia-based scrubbers, especially on inlet rates over 10 lb SO<sub>2</sub>/MMBtu. Furthermore, as indicated in the Draft EPA Guidance, operation of WFGD at 97-98% removal efficiency is similar to the levels expected from advanced FGD systems.<sup>21</sup> Since the WFGD is operating at BACT levels and is considered an advanced FGD system, SO<sub>2</sub> controls will not be evaluated further for the Riley Boilers.

### 5.2 NO<sub>x</sub> EMISSIONS CONTROLS

The Riley Boilers are regularly tuned to optimize combustion and are equipped with low-NO<sub>x</sub> burners (LNB), and a pseudo-overfire air (OFA) windbox. The Riley Boilers underwent upgrades to their firing systems and combustion air systems in 2000. Specifically, the boilers were upgraded with windbox partition plates, burner air supply dampers with pneumatic rotary actuators, air monitor probes, six staged fuel tips for synthetic natural gas (SNG) guns, six tar oil atomizers, and six tar oil meter valves. By diverting a majority of the combustion air to the windbox, the main combustion zone temperature is lowered, which lowers the thermal NO<sub>x</sub> formation in the combustion zone. The purpose of this pseudo-OFA upgrade was to optimize performance of the boilers and reduce NO<sub>x</sub> emissions. The flow measuring devices allow for consistent fuel-to-air ratios at each individual burner location within the furnace. NO<sub>x</sub> formation is optimized by monitoring and controlling fuel-to-air ratios throughout

<sup>20</sup> North Dakota Regional Haze SIP, pg. 183.

<sup>21</sup> Draft EPA Guidance, pg. 87.

combustion zones within the furnace. Finally, upgrades to the burners themselves with staged fuel tips creates a gradient of fuel-rich and fuel-lean zones within the burners, which further reduces NO<sub>x</sub> formation.

### 5.2.1 Identify Available NO<sub>x</sub> Control Options

After establishing baseline emissions for the source being evaluated, S&L reviewed the available NO<sub>x</sub> control options. Available control options are those air pollution control technologies and operational measures with a practical potential for application to the emission source and the regulated pollutant under evaluation. Based on a review of available NO<sub>x</sub> control technologies installed on existing liquid- and gas-fired boilers, as well as operational practices and equipment upgrades implemented on existing control systems, the potentially available options to control NO<sub>x</sub> emissions from the GPSP Riley Boilers are listed in Table 5-1.

**Table 5-1. Available NO<sub>x</sub> Control Options**

NO <sub>x</sub> Control Technologies
Combustion Optimization
Flue Gas Recirculation (FGR)
Selective Non-Catalytic Reduction (SNCR)
Selective Catalytic Reduction (SCR)

### 5.2.2 Technical Feasibility of Available NO<sub>x</sub> Control Options

Potentially available NO<sub>x</sub> control options identified in Table 5-1 were evaluated for technical feasibility (i.e. availability and applicability to the GPSP Riley Boilers) based on a review of physical, chemical, and engineering principals, and an assessment of commercial availability. Options deemed to be technically infeasible, or options that have no practical application to the evaluated source, were eliminated from further review. S&L evaluated the effectiveness of the control options determined to be technically feasible and established an emission performance level (i.e., controlled emission rate) for each.

#### 5.2.2.1 Combustion Optimization

Combustion optimization methods using online analyzers have been developed to improve boiler performance through implementation of artificial intelligence concepts (e.g., neural networks). These control strategies are

capable of setting target objectives, like NO<sub>x</sub> output, and adjusting multiple input variables to meet these target objectives. Neural networks have the ability to connect inputs and objectives based on continuous monitoring of plant information. These systems will automatically adjust digital control system (DCS) parameters in real time by implementing bias and trim settings on pressures, temperatures, and flows that result in the optimal boiler performance for the parameter(s) being controlled. Combustion optimization programs are meant to act as an automated real-time boiler tuning mechanism, rather than manual tuning. Depending on the complexity of the system to which it is applied and on the quality of DCS installed at a facility, the improvement in boiler efficiency can be significant. A side-effect of improved boiler efficiency is a potential improvement in NO<sub>x</sub> emissions.

Operation of the Riley Boilers is significantly more involved than typical single- or dual-fired boilers. The boilers are required to adapt to upsets and changes in product and fuel production rates, especially with gaseous fuel production since it cannot be stored. Boiler fuel sources are dictated by the gasification process conditions, requiring the boilers to adjust quickly to changes in fuel inputs. With seven different fuels injected at various elevations within the boiler, it is difficult to maintain steam production quality and quantity, as well as optimize combustion temperatures and oxygen concentrations. Furthermore, fuel quality alters as the gasification process conditions change.

Attempts to operate the Riley Boilers, and other combustion sources, in automatic mode has caused detrimental impacts to steam production rates to a complex steam system with 11 different grades of steams and multiple steam uses, which all require different flow rates and steam qualities. Operators are needed to manually adjust the steam production rates between the Riley Boilers, Superheaters, and Package Boiler to maintain the steam balance in real-time for the entire facility. As such, fine tuning of the fuel flow rates and locations within the Riley Boilers on an automatic basis is unlikely to provide consistent NO<sub>x</sub> reduction while being able to maintain fuel firing flexibility and steam production quality and quantity. Furthermore, the primary purpose of neural networks and combustion optimization systems are to improve boiler efficiency rather than reduce emissions. Neural network original equipment manufacturers (OEMs) often suggest a potential reduction in NO<sub>x</sub> emissions, but typically do not provide a guaranteed emissions reduction.

For these reasons, on-line combustion optimization is not considered a technically feasible NO<sub>x</sub> reduction technology for the Riley Boilers and will not be evaluated further.

### **5.2.2.2 Flue Gas Recirculation (FGR)**

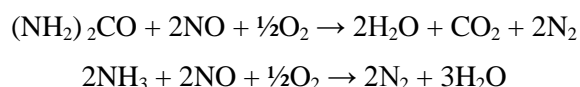
Flue Gas Recirculation (FGR) is a method of NO<sub>x</sub> control in which the flue gas produced in the boiler is directed back into the furnace via the primary combustion zone in the windbox. The flue gas is mixed with the combustion air and enters the boiler via the burners. The reused flue gas both limits the amount of oxygen at the burners and cools the combustion temperature, which reduces NO<sub>x</sub> formation. The two major challenges to implementing FGR on existing boilers are maintaining flame stability and retaining steam temperatures.

FGR is a proven technology which has been implemented in the industry over various applications, but most often in single-fuel-fired boilers (e.g., natural gas boilers). Because boiler furnaces are initially engineered for precise combustion conditions, major modifications like FGR pose challenges in implementation and troubleshooting. FGR systems also often require significant modifications in ductwork, supports, boiler tuning, and operations. There are concerns regarding the application of an FGR system at the GPSP Riley Boilers due to the use of both liquid and gaseous fuels and the variation in fuel flows and heat inputs. As the process dictates, fuels will change drastically in the firing rates as well as location of firing within the boiler, which will cause swings in combustion temperatures and boiler O<sub>2</sub>. The variation in the fuel firing rate will require precise operation of FGR to ensure the FGR ratio is maintained throughout all operating regimes.

DGC has received proposals for FGR systems on the Riley Boilers for additional NO<sub>x</sub> control. In 1999, Applied Utility Systems Inc. (AUS) proposed a retrofit of FGR technology on all three Riley Boilers. However, further investigation determined that the FGR system would not provide any additional NO<sub>x</sub> reduction since the Riley Boilers fire waste gas, which is predominantly CO<sub>2</sub>. AUS suggested that the waste gas fired at DGC, which contains a substantial amount of inert compounds, quenches the flame as it is combusted and reduces the amount of thermal NO<sub>x</sub> formation, which is typically the largest contributor to NO<sub>x</sub> emissions. The OEM suggested that as long as waste gas continues to be fired in the boilers, the potential for NO<sub>x</sub> reduction using FGR is limited and impractical. At this time, the facility already receives the benefits similar to an FGR system. Therefore, FGR is not considered a technically feasible option for additional NO<sub>x</sub> control on the Riley Boilers and will not be evaluated further.

### 5.2.2.3 Selective Non-Catalytic Reduction

Selective non-catalytic reduction (SNCR) involves the direct injection of ammonia (NH<sub>3</sub>) or urea ((NH<sub>2</sub>)<sub>2</sub>CO) at high flue gas temperatures (approximately 1,600°F – 2,100°F) in an oxidizing environment. The ammonia or urea reacts with NO<sub>x</sub> in the flue gas to produce N<sub>2</sub> and water as shown below.



Flue gas temperature at the point of reagent injection can greatly affect NO<sub>x</sub> removal efficiencies and the quantity of NH<sub>3</sub> or urea that will pass through the SNCR unreacted (referred to as NH<sub>3</sub> slip). In general, SNCR reactions are effective in the range of 1,600°F – 2,100°F. At temperatures below the desired operating range, the NO<sub>x</sub> reduction reactions diminish and unreacted NH<sub>3</sub> emissions increase. Above the desired temperature range, NH<sub>3</sub> is oxidized to NO<sub>x</sub> resulting in low NO<sub>x</sub> reduction efficiencies.

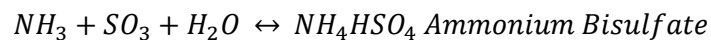
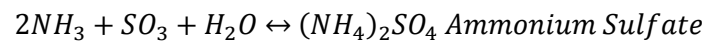
Mixing of the reactant and flue gas within the reaction zone is an important factor to SNCR performance. In large boilers, the physical distance over which reagent must be dispersed increases, and the surface area/volume ratio of the convective pass decreases. Furnace geometry, urea spray coverage, and droplet size must be considered when developing good mixing of reagent and flue gas, injecting reagent in the proper temperature window, and ensuring sufficient residence time of the reagent and flue gas in that temperature window. As the boiler cycles in load, the optimum injection region may change; thus, most facilities require multiple injection zones which are placed in and out of service as the unit ramps in load. This can include modifying the zones of injectors that are operating at different fuel inputs and temperatures.

In addition to temperature and mixing, several other factors influence the performance of an SNCR system, including residence time, reagent-to-NO<sub>x</sub> ratio, and fuel sulfur content. Increasing the normalized stoichiometric ratio (NSR) can improve NO<sub>x</sub> removal.<sup>22</sup> This can be achieved by increasing urea solution flow through the injectors or changing the concentration of urea in the solution. However, too high of reagent injection rates will

<sup>22</sup> NSR defines the amount of reagent needed to achieve the targeted NO<sub>x</sub> reduction. Based on the reaction equations in 5.2.2.2, two moles of NO<sub>x</sub> can be removed with one mole of urea or two moles of ammonia. In practice, more than the theoretical amount of reagent needs to be injected into the boiler flue gas to obtain a specific level of NO<sub>x</sub> reduction. This is due to the complexity of the actual chemical reactions involving NO<sub>x</sub> and injected reagent and mixing limitations between reagent and flue gas. Factors that influence the NSR value: (1) percent NO<sub>x</sub> reduction; (2) uncontrolled NO<sub>x</sub> concentration in the flue gas; (3) temperature and residence time available for the NO<sub>x</sub> reduction reactions; (4) extent of mixing achievable in the boiler; and (5) allowable ammonia slip.

increase the ammonia slip. Ammonia remaining in the flue gas past the reaction window will cause issues with downstream components, especially if the sulfur concentrations in the flue gas are high. For typical boilers, 10 ppm ammonia slip is the maximum recommended amount for SNCR operation, due to formation of ammonia salts, which can cause corrosion.

One significant drawback of ammonia-based NO<sub>x</sub> control systems is the undesired side-reaction of ammonium sulfate and ammonium bisulfate (ABS). The reaction mechanism is carried out as shown below:



These reactions take place when unreacted ammonia from the SNCR process comes in the presence of sulfur trioxide (SO<sub>3</sub>) compounds. The reaction carries out more readily as the temperature lowers within the process. ABS deposits out of the flue gas as a sticky liquid and will foul the inside of ductwork and within open spaces in equipment along the flue gas pathway.

While SNCR can be applied to various types of boilers, NO<sub>x</sub> reduction potential is specific to the temperature windows and residence time. Oftentimes, the reagent utilization, and subsequent ammonia slip rates, is the limiting factor for NO<sub>x</sub> reduction potential.

In September and October of 1997 DGC tested the injection of aqueous ammonia into Riley Boiler B. Ammonia solution was introduced into two separate zones of the boiler to partially simulate operation of an SNCR system. After a week of testing the ammonia system, the Riley Boiler experienced economizer leakage, high furnace pressure, and loss of outlet air flow. An investigation revealed the source of the furnace pressure buildup was due to buildup of ammonium sulfate on the Ljungström air pre-heater baskets. Results of the testing were inconclusive, as the main stack CEMS was utilized for determining impact to NO<sub>x</sub>, and four other emission sources that fire into the main stack were in operation during the testing.

During a second test run, a rental NO<sub>x</sub> analyzer was used to isolate NO<sub>x</sub> emissions reductions during ammonia injection in the Riley B Boiler. The results of this test showed 3-5% reduction in NO<sub>x</sub> emissions. D.B. Riley, the boiler and SNCR OEM, provided new spray nozzles and the average NO<sub>x</sub> reduction improved to 17%. Eventually, the boiler experienced similar issues with economizer leakage, low outlet flow, high furnace pressure, and plugging

of the air pre-heater with ammonium sulfate after a few days of testing. Ammonium sulfate generation was likely due to the high sulfur content of the fuels fired in the Riley Boilers combined with ammonia slip from the SNCR process. The operators noticed significant buildup of ammonia salts on the air heater baskets, which causes corrosion and added pressure drop. Ammonium sulfate can also deposit on boiler tubes, which will cause issues with the process steam production. The facility witnessed ammonia salt formation on the boiler tube banks during testing, which reduces heat transfer efficiency. While many utilities can still operate with reduced steam quality, at the cost of a partial derate, the reduction in steam quality at GPSP may eliminate the possibility of using the steam in all locations it is needed within the facility and limit the total production rate of the facility. Because of the consistent operational failures, the ammonia system was abandoned in place, and removed years later. The conclusion of the ammonia injection project was that high levels of SO<sub>2</sub> in the gasification facility's produced fuels were the main contributor to the formation of the ammonium salts.

The formation of ammonium sulfate and ABS salts is a problem experienced by plants with high ammonia slip, high sulfur levels, and reduced temperature windows near the air preheaters. The unique operational configuration and fuels combusted by the Riley Boilers exacerbates sulfate salt formation by introducing unpredictable variations in sulfur content to the boiler furnace over time. This can lead to significant ABS formation, and therefore air preheater plugging and boiler malfunction, which was noticed in a short SNCR trial. For these reasons, the NDDH suggested in the first planning period that SNCR is not a technically feasible NO<sub>x</sub> control technology on the Riley Boilers. At the very least, the NDDH concluded that pilot scale testing would be needed to determine the feasibility of SNCR application on a high sulfur flue gas.<sup>23</sup> Because of the site's historical issues with ammonia injection, SNCR technology is not considered a technically feasible option for the Riley Boilers and will not be evaluated further.

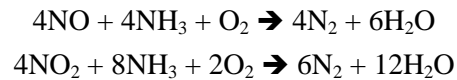
#### 5.2.2.4 Selective Catalytic Reduction

SCR is a process by which ammonia reacts with nitric oxide (NO) and nitrogen dioxide (NO<sub>2</sub>), collectively NO<sub>x</sub>, in the presence of a catalyst to reduce the NO<sub>x</sub> to nitrogen (N<sub>2</sub>) and water. SCR technology has been applied to NO<sub>x</sub>-bearing flue gases generated from solid-, liquid-, and gas-fired facilities burning various types of fuels. S&L is unaware of any instances where SCR has been implemented on a boiler that burns gasification products. However,

<sup>23</sup> North Dakota Regional Haze SIP, February 24, 2010, pg. 184.



it can be considered similar to other liquid- and gas-fired boilers when considering flue gas conditions and NO<sub>x</sub> composition, where SCR has been considered appropriate. The principal reactions resulting in NO<sub>x</sub> reduction are:



Because these reactions proceed slowly at typical boiler exit gas temperatures, a catalyst is used to increase the reaction rate between NO<sub>x</sub> and ammonia. Depending on the specific constituents in the flue gas, a typical temperature range of 550°F to 780°F is necessary to achieve normal performance of the catalyst; however, the low end of the temperature window is dependent on the sulfur concentration of the flue gas, due to the lower formation temperature with higher sulfur presence. Therefore, many facilities with high sulfur fuels require a minimum operating temperature closer to 700°F to reduce the potential of localized ammonium salt formation.

SCR catalyst deactivation occurs through two primary mechanisms: physical deactivation and chemical poisoning. Physical deactivation is caused by either exposure of the catalyst to excessive temperatures (thermal deactivation) or masking of the catalyst due to entrainment of particulate from the flue gas stream (fouling). Chemical deactivation is caused by either an irreversible reaction of the catalyst with a contaminant in the gas stream (poisoning) or a reversible absorption of a contaminant on the surface of the catalyst (inhibition). Loss of catalyst activity through thermal degradation or poisoning is permanent, and reactivity can only be restored by replacing the catalyst.

SCR catalyst poisoning is expected to result from the presence of trace elements and strong alkaline substances in flue gas, including sodium (Na), potassium (K), magnesium (Mg), and calcium (Ca). Alkaline metals can chemically attach to active catalyst pore sites and cause deactivation. Sodium and potassium are of prime concern, especially in their water-soluble forms, which are more mobile and can penetrate into the catalyst pores. Earth metals, especially calcium, can react with SO<sub>3</sub> absorbed within the catalyst to form CaSO<sub>4</sub> and blind the catalyst. The North Dakota lignite fuel gasified at GPSP contains relatively high levels of organically associated alkali and alkaline-earth elements, including Na, K, Mg, and Ca. While these components are not tracked in the fuels fired in the boiler, it is expected that the alkali metals will concentrate in the liquid fuels fired in the boiler (e.g., tar oil, N/P), analogous to the relatively high concentration of mercury measured in the liquid fuels in comparison to the feedstock lignite at the facility. It is expected that other metals, such as alkali earth metals, would follow a similar

path of volatilization in the gasifier and condensation in the water-gas-shift reaction, cooling train, and Rectisol unit.<sup>24</sup>

Traditionally, SCR application on coal-fired boilers is in a high-dust configuration, where the SCR reactor is located in the flue gas stream between the economizer outlet and the air heater inlet. This configuration locates the SCR within the inherently optimal temperature range environment for NO<sub>x</sub> reduction (i.e., 650°F to 750°F); however, the high fly ash loading at the economizer outlet can also have detrimental effects on the SCR catalyst. In a low-dust configuration, the SCR reactor vessel is located in the flue gas stream (e.g., downstream of WESP). In the case of GPSP's Riley Boilers, only gaseous and liquid fuels are fired, resulting in an inherently low-dust environment between the economizer and air preheater. The lack of fly ash particles is beneficial in reducing potential for erosion and pluggage of catalyst; however, employing this configuration is expected to expose the catalyst to potentially high levels of vapor-phase alkalis, such as sodium, which is expected to be concentrated in the tar oil produced from North Dakota lignite fuel. It is expected that the metals are concentrated in the liquid fuels (e.g., tar oil, N/P) rather than leaving the gasification system through other means (e.g., SNG, urea, etc.). The high concentration of alkalis immediately downstream of the boiler may preclude the applicability of low-dust SCR catalyst functionality. As such, both the high-dust and low-dust SCR configurations are not considered technically feasible NO<sub>x</sub> control options and will not be evaluated further.

In the tail-end configuration for the Riley Boilers, the SCR reaction vessel would be located in the flue gas stream after the FGD control system. The potential advantage of a tail-end SCR (TE-SCR) configuration at GPSP is that the flue gas from the Riley Boilers will have passed through the WFGD system prior to the SCR catalyst. As such, there is the possibility that the mass transfer mechanism that results in the capture of SO<sub>2</sub> will also capture some of the vapor-phase alkali particles, reducing the risk of catalyst poisoning and/or deactivation.

Operation of the tail-end configuration would require significant heating to raise the temperature of the flue gas to the activated temperature range of the SCR catalyst, to at least 550°F. Successful operation of the tail-end configuration would require a gas-to-gas heat exchanger to reheat the flue gas to support the SCR NO<sub>x</sub> reactions.

---

<sup>24</sup> The water-gas-shift reaction utilizes water to convert CO into CO<sub>2</sub> and H<sub>2</sub>. After the gas is shifted, it enters a cooling train, where process cooling water is used to chill the shifted gas and condense tar components. The gas then is subcooled prior to the Rectisol unit, where it is treated to further remove sulfurous compounds and CO<sub>2</sub> with a solvent. These consecutive process islands all provide mechanisms for alkalis and other metals to condense into the liquid fuels (e.g., tar oil, N/P).

Installation of the SCR downstream of the reheat duct tie-in would be advantageous due to the higher temperature flue gas; however, this option is not technically feasible due to the potential presence of alkalis, as will be discussed further in Section 6.2.2.3. Due to the presence of residual  $\text{SO}_3$  at the WFGD and WESP outlet, the formation of ABS is of concern. As such, an additional in-duct heating element should be employed to raise the SCR inlet temperature to 600°F, using SNG-fired duct burners. After the flue gas passes through the SCR (at approximately 600°F), it would pass through the hot side of the gas-to-gas heat exchanger to recover the heat and cool the flue gas prior to combining with the reheat duct upstream of the stack.

TE-SCR has not been demonstrated on a unit similar to the Riley Boilers in which solid-derived fuels are fired. There are also concerns of the remaining  $\text{SO}_2$  in the flue gas reacting with the ammonia slip from the SCR and forming ABS on the gas-to-gas heat exchanger tubes. Furthermore, a percentage of the  $\text{SO}_2$  remaining in the flue gas will oxidize to  $\text{SO}_3$  as it passes through the SCR catalyst, potentially requiring additional  $\text{SO}_3$  controls on the source upstream of the SCR. To mitigate  $\text{SO}_3$  increases, dry sorbent injection could be required. However, the introduction of a calcium or sodium sorbent upstream of the WFGD will result in additional calcium- or sodium-based sulfur byproducts in the ammonia sulfate solids. It is assumed that this combination will result in loss of sales of the ammonia sulfate fertilizer. As such, cost is included to reflect loss of sales and increased waste disposal costs. Currently, the landfill permit only allows a small amount of ammonium sulfate disposal; as such, if all of the WFGD byproduct is disposed in the landfill, the current solid waste disposal permit or landfill designation will require modification.

In general, catalyst in a TE-SCR will still be vulnerable to alkali poisoning, pore pluggage, and premature catalyst deactivation, and it is not known whether the comparatively high levels of soluble sodium and potassium in North Dakota lignite will be effectively removed by the upstream WFGD. In order to understand the applicability of installing an SCR on gasification product-fired boilers or the effect of North Dakota lignite-derived flue gas on the SCR catalyst, identify potential design solutions, and evaluate the technical feasibility and effectiveness of TE-SCR with any degree of certainty, pilot scale testing of the control configuration would be needed. Since there has not been a similar application of SCR on similar fuels or boiler configurations, extended trials would be needed to better understand the design and operation of a TE-SCR at GPSP. Because there are unresolved issues associated with catalyst poisoning, it is unlikely that DGC could obtain a viable commercial offering for TE-SCR at the GPSP facility. Furthermore, during the initial planning period, NDDH suggested there were concerns regarding technical feasibility of SCR as a  $\text{NO}_x$  control technology at GPSP and pilot scale testing would be required to determine

feasibility.<sup>25</sup> In the years following the initial planning period, during the BART analysis for other North Dakota boilers, TE-SCR was considered technically infeasible based on the lack of vendor guarantees and need for pilot testing.<sup>26</sup> However, since cost data was developed by the NDDH in the first planning period, it will be carried forward in the Four Factor Analysis to evaluate hypothetical cost effectiveness.

S&L assumed that the TE-SCR control option could achieve 80% removal efficiency on average on the Riley Boilers, for a controlled NO<sub>x</sub> emission rate of approximately 103 lb/hr.

#### 5.2.2.5 NO<sub>x</sub> Control Summary

Table 5-2 summarizes the results of the feasibility evaluation of available control options for the GPSP Riley Boilers.

**Table 5-2. Summary of Technically Feasible NO<sub>x</sub> Control Options – Riley Boilers**

NO <sub>x</sub> Control Option	Technically Feasible (Yes/No)	Technical Feasibility Summary
Combustion Optimization	No	Implementation of on-line combustion optimization is not considered a technically feasible control option for the GPSP Riley Boilers due to the unique operating requirements to maintain steam conditions and flexibility in fuel firing.
Flue Gas Recirculation	No	Flue Gas Recirculation (FGR) is not considered a technically feasible control option for the GPSP Riley Boilers due to the fuel firing profile (e.g., waste gas) which results in similar combustion flame temperature and oxygen content as traditional FGR.
Selective Non-Catalytic Reduction (SNCR)	No	SNCR is not considered a technically feasible NO <sub>x</sub> control technology for the GPSP Riley Boilers. Historic tests preclude the viability of SNCR operation on the Riley Boilers at GPSP due to significant issues with air preheater pluggage and boiler tube deposits.
Tail-end Selective Catalytic Reduction (TE-SCR)	No*	TE-SCR installation on the Riley Boilers would be a first-of-a-kind installation on a boiler firing North Dakota lignite gasification products. Further, extensive testing would be required to determine the impact of alkalis on deactivation of SCR catalyst on the North Dakota lignite-derived fuels fired at GPSP. Because there are unresolved issues associated with catalyst poisoning, it's unlikely that DGC could obtain a viable commercial offering for TE-SCR on the Riley boilers.  *TE-SCR will be carried forward to the Four Factor Analysis to present hypothetical costs since the Department included it in the reasonable progress analysis for GPSP during the first planning period.

<sup>25</sup>North Dakota SIP, pg. 184.

<sup>26</sup> Docket EPA-RO8-OAR-2010-0406. State of North Dakota November 21, 2011 comments to USEPA Region 8.

### 5.2.3 Effectiveness of NO<sub>x</sub> Control Options

The NO<sub>x</sub> control technologies that are evaluated as part of the Four Factor Analysis are listed in Table 5-3 in descending order of control efficiency. Table 5-3 also provides control option-specific NO<sub>x</sub> emission rates in terms of lb/hr. Emission rates shown in Table 5-3 represent average emission rates that the control options would be expected to achieve during normal operations on a long-term annual basis.

**Table 5-3. Effectiveness of NO<sub>x</sub> Control Options – Riley Boilers**

Control Technology	NO <sub>x</sub> Emission Rate <sup>(Note 1)</sup> lb/hr	% Reduction from Baseline Emission Rate
Selective Catalytic Reduction (tail-end) <sup>(Note 2)</sup>	103	80%
Baseline (Combustion Optimization / OFA / LNB)	517	--

Note 1. Emission rates shown represent average emission rates that the control options would be expected to achieve on an ongoing long-term basis under normal operating conditions for GPSP Riley Boilers. Emission rates are provided for comparative purposes, and should not be construed to represent proposed emission limits. Corresponding permit limits must be evaluated on an emission source type and control system-specific basis.

Note 2. TE-SCR has not been installed on a North Dakota lignite-fired unit or lignite-derived-fuel unit, and extended trials would be needed to better understand the design and operation of TE-SCR on the GPSP Riley Boilers. Nevertheless, during the initial planning period, NDDH evaluated the costs and cost-effectiveness of the control system on the Riley Boilers. TE-SCR will, therefore, be carried forward to the Four Factor Analysis to present hypothetical costs since the Department included it in the reasonable progress analysis for GPSP during the first planning period; however, technical feasibility has never actually been demonstrated for TE-SCR for lignite-based fuels.

## 6. SUPERHEATER CONTROL MEASURES

### 6.1 SO<sub>2</sub> EMISSIONS CONTROLS

The Superheaters at the GPSP currently fire a mixture of SNG and tar oil. The exhaust from Superheaters A and B are combined into a reheat duct, which heats the Riley Boiler WFGD outlet stream above the dew point prior to being routed up the main stack.

Annual SO<sub>2</sub> emissions from the Superheaters are minimized by firing a blend of SNG and tar oil, with a higher percentage of SNG being fired. The Superheaters typically fire between 80-90% SNG; repeated fuel samples of the SNG show that sulfur composition is non-detectable. The majority of sulfur is introduced into the Superheaters through the firing of tar oil.

On average, the Superheaters account for 13% of the total baseline heat input to the Main Stack. In addition, the Superheaters contribute an insignificant amount of SO<sub>2</sub> (on average less than 10%) emissions to the Main Stack SO<sub>2</sub> emissions for the same time period. Furthermore, due to the efficiency of the WFGD on the Riley Boilers and minimal SO<sub>2</sub> generated in the Superheaters, 96% of the SO<sub>2</sub> generated by the Riley Boilers and Superheaters does not reach the stack, as shown in Table 6-1.

**Table 6-1. Comparison of Baseline SO<sub>2</sub> Emissions**

	Units	Riley Boilers (Baseline)	Superheaters (Baseline)	Main Stack (Baseline)
Uncontrolled SO <sub>2</sub> Emissions	tpy	19,905	56	19,961
Stack SO <sub>2</sub> Emissions	tpy	671	56	727
SO <sub>2</sub> Removal Rate	%	97	0	96

One potential option for further SO<sub>2</sub> reduction from the Superheaters would be changing the firing profile of the tar oil and SNG so that the SNG firing is at its maximum; however, the facility needs to maintain flexibility to fire up to 100% tar oil to provide process relief during unexpected tar oil production rates or system buildup. While the Superheaters are designed to fire up to 100% tar oil, GPSP typically fires a high percentage of SNG that in turn minimizes SO<sub>2</sub> emissions. As a result, there is no additional opportunity to reduce the amount of tar oil that is fired

without removing the facility's needed flexibility. As such, there are no technically feasible options to reduce SO<sub>2</sub> emissions from the GPSP Superheaters.

## 6.2 NO<sub>x</sub> EMISSIONS CONTROLS

Superheaters A and B are equipped with LNB and FGR for NO<sub>x</sub> control. The LNBs are John Zink burners designed for axial flow combustion. Combustion air flow is evenly distributed to the burners by baffles within the windbox. The airflow is diverged into primary air, air that flows through the swirler and angularly outward from the burner centerline, and secondary air, which passes outside the periphery of the swirler and reacts with the unburned fuel to complete the combustion process. FGR technology is also implemented for the Superheaters, in which a portion of the flue gas is reintroduced to the burners to lower combustion temperatures and oxygen concentrations.

During the plant modifications in 2000, two-stage fuel tar oil atomizers were installed to provide highly efficient liquid fuel distribution to each burner within the Superheaters, resulting in reduction in overall NO<sub>x</sub> formation.

### 6.2.1 Identify Available NO<sub>x</sub> Control Options

Based on a review of available NO<sub>x</sub> control technologies installed on existing sources, as well as operational practices and equipment upgrades implemented on existing control systems, potentially available options to control NO<sub>x</sub> emissions from the GPSP Superheaters are listed in Table 6-1.

**Table 6-2. Available NO<sub>x</sub> Control Options**

NO <sub>x</sub> Control Technologies
Combustion Optimization
Selective Non-Catalytic Reduction (SNCR)
Selective Catalytic Reduction (SCR)

### 6.2.2 Technical Feasibility of Available NO<sub>x</sub> Control Options

Potentially available NO<sub>x</sub> control options identified in Table 6-1 were evaluated for technical feasibility (i.e. availability and applicability to the GPSP Superheaters) based on a review of physical, chemical, and engineering principals, and an assessment of commercial availability. Options deemed to be technically infeasible, or options that have no practical application to the evaluated source, were eliminated from further review. S&L evaluated the

effectiveness of the control options determined to be technically feasible, and established an emission performance level (i.e., controlled emission rate) for each.

#### **6.2.2.1 Combustion Optimization**

Combustion optimization methods using online analyzers have been developed to improve boiler performance through implementation of artificial intelligence concepts (e.g., neural networks). These control strategies are capable of setting target objectives like NO<sub>x</sub> output, and adjusting multiple input variables to meet these target objectives. Neural networks have the ability to connect inputs and objectives based on continuous monitoring of plant information. These systems will automatically adjust DCS parameters in real time by implementing bias and trim settings on pressures, temperatures, and flows that result in the optimal boiler performance for the parameter(s) being controlled. Combustion optimization programs are meant to act as a real-time boiler tuning mechanism, rather than an annual on-site manual tuning. Depending on the complexity of the system to which it is applied and on the quality of DCS installed at a facility, the improvement in boiler efficiency can be significant.

Based on the improvements to NO<sub>x</sub> emissions that are often realized with completion of boiler combustion tuning, NO<sub>x</sub> emissions may be achievable on a long-term annual average basis with a neural network system for constant online combustion optimization. Unlike the Riley Boilers, the Superheaters fire only two fuels. This limits the amount of burner and injector elevations as well as input parameters that need to be tuned. Furthermore, the Superheaters are only required to generate one steam source, which also reduces the amount of manual steam balancing required by operators. However, as discussed previously, combustion optimizer OEMs typically do not provide a guaranteed emissions reduction. Based on an analysis of the nominal NO<sub>x</sub> emission reductions that were achieved between Superheater combustion tuning periods, the facility may be able achieve an additional 5% NO<sub>x</sub> reduction on a long-term basis from the current annual average. However, further detailed review with the Superheater OEM as well as neural network OEMs would be required prior to determining actual emission reduction that could be achieved under various operating conditions. As such, combustion optimization is considered a technically feasible control option for the Superheaters. It is expected that the on-line combustion optimization could achieve 5% NO<sub>x</sub> reduction resulting in a long-term average NO<sub>x</sub> emission rate of 42 lb/hr.



### 6.2.2.2 Selective Non-Catalytic Reduction

As discussed in Section 5.2.2.3, SNCR is a viable technology for steam generators that combust liquid or gaseous fuels. The GPSP Superheaters have the potential to install reagent injectors in the furnace area; however, the temperature profile is unknown. Furnace temperature mapping and injection testing has not been modeled or studied in depth on the Superheaters. However, it is expected that the limiting process consideration may be the Superheater exhaust temperature. Plant personnel report that the temperature between the Superheater outlet and ID fan inlet is on average 620°F, which is within the ammonia salt formation temperature range for the sulfur levels present when high levels of tar oil are fired. At these exit temperatures, excess ammonia in the presence of sulfur will result in ammonium salt formation. ABS formation is expected to cause fouling within and downstream of the reheat duct and may impact the rear tube bundles, especially at low unit heat input or when one Superheater is offline for maintenance.

The formation of ammonium salts is a problem experienced by plants with high ammonia slip, high sulfur levels, and reduced temperature windows near the air preheaters. The unique operational configuration and fuels fired at the gasification facility exacerbates these sulfate salt formation issues by introducing unpredictable variations in sulfur content to the Superheaters over time. During periods of time when the facility is required to purge additional tar oil, it is expected that significant amounts of sulfur would be present in the Superheater flue gas and cause issues with ammonia salt formation if urea or ammonia is used for NO<sub>x</sub> control. This can lead to significant ABS formation on heat transfer surface areas and lead to boiler malfunction, similar to that experienced by the Riley Boilers during SNCR testing. Furthermore, the baseline NO<sub>x</sub> concentration (equivalent to 0.17 lb/MMBtu) is close to the emission rate achievable by SNCR systems. Due to historical issues with ammonia injection and the relatively low temperatures in the reheat duct, the SNCR technology option is not considered a technically feasible control option and will not be evaluated further.

### 6.2.2.3 Selective Catalytic Reduction

The SCR configuration that is most applicable to the Superheaters is the in-duct installation. Similar to SCR systems at combined cycle plants, the catalyst layers and ammonia injection grid would be installed downstream of the burners within the ductwork. This configuration, however, has numerous technical issues. Plant personnel have reported that the temperature between the Superheater outlet and ID fan inlet is on average 620°F. At these temperatures, there is the potential for ABS formation within the in-duct catalyst pores, limiting the NO<sub>x</sub> removal

efficiency. ABS formation is even more concerning during time periods of high SO<sub>2</sub> formation from tar oil firing. Additionally, SO<sub>2</sub> in flue gas will oxidize to SO<sub>3</sub> as it passes over the SCR catalyst, likely increasing plant-wide sulfuric acid emissions. Due to the lack of downstream particulate collection devices on the gas- and liquid-fired steam generators, dry sorbent injection prior to the catalyst is not an option.

However, the critical issue with installation of an SCR downstream of the Superheaters is the presence of vapor phase alkali metals. As discussed in Section 5.2.2.3, combustion of the liquid fuels at GPSP is expected to have a detrimental effect on the SCR catalyst due to the expected presence of alkalis in the liquid fuels (e.g., tar oil). Since there is no treatment of the Superheater gas stream to remove these alkalis prior to the catalyst, SCR is determined to be technically infeasible for the Superheaters and will not be evaluated further.

#### 6.2.2.4 NO<sub>x</sub> Control Summary

Table 6-3 summarizes the results of the feasibility evaluation of available control options for GPSP.

**Table 6-3. Summary of Technically Feasible NO<sub>x</sub> Control Options – Superheaters**

NO <sub>x</sub> Control Option	Technically Feasible (Yes/No)	Technical Feasibility Summary
Combustion Optimization	Yes	Combustion optimization is considered a technically feasible control option for the GPSP Superheaters.
Selective Non-Catalytic Reduction (SNCR)	No	SNCR is not considered a technically feasible option for the Superheaters due to low reheat duct temperatures and presence of sulfur, which will lead to significant ABS formation issues within the existing ductwork and rear steam tube banks.
Selective Catalytic Reduction (SCR)	No	SCR applied to the Superheaters would introduce alkalis to the catalyst. As such, SCR is considered technically infeasible.

#### 6.2.3 Effectiveness of NO<sub>x</sub> Control Options

The NO<sub>x</sub> control technologies that will be evaluated as part of the Four Factor Analysis are listed in Table 6-3 in descending order of control efficiency. Table 6-3 also provides control option-specific NO<sub>x</sub> emission rates in terms of lb/hr. Emission rates shown in Table 6-3 represent average emission rates that the control options would be expected to achieve during normal operations on a long-term annual basis.

**Table 6-4. Effectiveness of NO<sub>x</sub> Control Options – Superheaters**

Control Technology	NO <sub>x</sub> Emission Rate <sup>(Note 1)</sup> lb/hr	% Reduction from Baseline Emission Rate
Combustion Optimization	42	5%
Baseline (Combustion Optimization / FGR / LNB)	44	--

Note 1. Emission rates shown represent average emission rates that the control options would be expected to achieve on an ongoing long-term basis under normal operating conditions for GPSP Superheaters. Emission rates are provided for comparative purposes, and should not be construed to represent proposed emission limits. Corresponding permit limits must be evaluated on a source-specific and control system-specific basis.

## **7. PACKAGE BOILER CONTROL MEASURES**

The Package Boiler was permitted in 2014 during the Urea Project addition at GPSP. The Package Boiler subsequently commenced operation in December 2017. To minimize NO<sub>x</sub> emissions from the Package Boiler, it was determined that ULNB would be used to achieve emission rates below the new source performance standard (NSPS). While a BACT analysis was not completed for NO<sub>x</sub> control on the Package Boiler, an evaluation of the RBLC conclude that LNB is typically considered BACT for gas boilers of similar size. The Package Boiler is currently achieving a long-term average NO<sub>x</sub> rate equivalent to approximately 30 ppmvd, which is comparable to other facilities operating with LNB or ULNB. As such, no additional NO<sub>x</sub> emissions controls will be evaluated for the Package Boiler. Furthermore, the design of the Package Boiler is such that it can only fire natural gas or SNG. Based on SNG fuel analyses completed by GPSP, the sulfur content is considered non-detect. Therefore, no additional SO<sub>2</sub> emission controls will be evaluated for the Package Boiler at GPSP.

## **8. FLARE CONTROL MEASURES**

The Main Flare is the primary control device for volatile process gases throughout the process areas in the facility. Process relief streams are either discharged through safety and control valves or equipment vents. One of the components of the process gases flared is hydrogen sulfide ( $H_2S$ ). It is conservatively assumed that 100% of the  $H_2S$  vented to the flare from the process is combusted to  $SO_2$ . The Startup Flare is used during startup, shutdown, and malfunction of the facility gasifiers. During startup, the gases originating from the lignite coal are not yet of sufficient composition for further processing and are instead flared.

S&L approached various flare vendors to gather feasible options for mitigating  $NO_x$  and  $SO_2$  ( $H_2S$ ) emissions from the flared process gases. S&L provided background information on a range of flare stream compositions, maximum volumetric and mass flows, typical emission concentration values, steam injection mass flows and pressures, flare tip diameters, general arrangement drawings, and brief operations and control descriptions. S&L requested feasible control technologies that could be implemented to reduce emissions from the baseline values provided in Table 4-1.

Under typical operation,  $H_2S$  is being scrubbed from the raw gas produced from the lignite gasification process via the Rectisol unit. Depending on which segment needs to be flared during upset conditions, certain flared components would not have substantial  $H_2S$  to remove. Most process streams are vented to the Main Flare during times of emergency pressure release, or during times of process failure in the gasification process. However, the Main Flare does experience a relatively consistent stream of process “leakage” from various locations within the facility. This leakage contributes approximately 35 lb/hr of  $SO_2$ , which is significantly below the Riley Boiler WFGD outlet rates. The Startup flare is typically not flaring process gas (i.e., lock gas); instead, the majority of the flared fuel is SNG, which has non-detectable sulfur concentration. Overall, the baseline lb/hr  $SO_2$  emissions from the Main and Startup Flares combined only comprise approximately 11% of the total plant baseline  $SO_2$  emissions.

Recent technologies have emerged on the market for  $H_2S$  and volatile organic carbon (VOC) scrubbing instead of flaring to reduce emissions. However, these systems are typically applied to flare gases with very high  $H_2S$  concentrations. At GPSP, the process leakage gas going to the Main Flare has a typical  $H_2S$  concentration in the 0.05% range, which is well below the typical application of the emerging technology’s typical application, which

often deals with 5-20% ranges. Furthermore, these systems are designed for continuous operation at steady flow rates, rather than fluctuating purge conditions.

If an H<sub>2</sub>S scrubbing system was pursued, the system would be best applied to treat the relatively continuous process leakage stream. There would be design issues to the system if treatment is expected of all other process stream purges sent to the Main Flare for process pressure relief in times of plant-wide upsets. Due to the safety concerns associated with adding back pressure to a pressure relief or emergency condition, it is suggested that other process gases would need to bypass the scrubber directly.

Prior to implementing the Riley Boiler WFGD system, the GPSP facility treated the gasification products and fuels using various H<sub>2</sub>S scrubbing solutions, including Stretford® and Sulfolin®. The gaseous fuels were treated prior to combustion in the Riley Boilers; however, the facility was never able to continuously achieve the permitted limits in place at the time. During the years when the solutions were used for scrubbing, the effectiveness of the scrubbing was minimal; furthermore, the facility reported significant fugitive odors. It was concluded that the H<sub>2</sub>S scrubbing was ineffective due to chemistry issues stemming from the fuel composition, specifically the various other sulfurous compounds that can be present in the products or purged gases. It is expected that there would be similar issues with the effectiveness of H<sub>2</sub>S scrubbing of the flared gases.

Due to the limited experience with the flare scrubbing technology and low H<sub>2</sub>S inlet rates, pilot testing would have to be completed to determine the continuous effectiveness of treating the process gas without impacts to the typical emergency operation of the flare. Additionally, because of the historic issues associated with H<sub>2</sub>S scrubbing at GPSP, H<sub>2</sub>S control is not considered a technically feasible technology at this time for SO<sub>2</sub> emission reduction on either the Main Flare or Startup Flare.

Additionally, no vendors were able to provide viable solutions for NO<sub>x</sub> mitigation on the GPSP Main Flare or Startup Flare. Vendors cited numerous issues with providing solutions to this facility. One notable reason for not being able to provide additional controls was the already low baseline NO<sub>x</sub> value (equivalent to approximately 0.06 lb/MMBtu). The vendors concluded it would be difficult to obtain significant reductions beyond what is already being achieved at the facility. For comparison purposes, SCR systems achieve 0.06 lb/MMBtu and these systems are considered BACT on coal-fired units.

For these reasons, there are no technically feasible control options available to further reduce SO<sub>2</sub> or NO<sub>x</sub> emission from the Main or Startup Flares.

## 9. COSTS OF COMPLIANCE (STATUTORY FACTOR ONE)

The economic analysis performed as part of the Four Factor Analysis examines the cost-effectiveness of each control technologies identified in Table 5-3 and Table 6-4, on a dollar per ton of pollutant removed basis. Annual emissions, calculated for a particular control device, are subtracted from baseline annual emissions to calculate tons of pollutant controlled per year. For units with existing controls, the base case represents existing baseline actual emissions. Annual costs for each control option are calculated relative to the base case by adding annual operation and maintenance (O&M) costs to the annualized cost of capital and, if applicable, lost revenue due to extended outage required for installation of control equipment. Capital costs and lost revenues were annualized using a capital recovery factor based on an annual interest rate of 5.5% and equipment life of 20 years.<sup>27,28</sup> Cost effectiveness (\$/ton) of a particular control option is simply the annual cost (\$/yr) divided by the annual reduction in annual emissions (ton/yr). In addition to cost-effectiveness relative to the base case, the incremental cost-effectiveness to go from one level of control to the next, more stringent, level of control may also be calculated to evaluate the incremental cost effectiveness of the more stringent control.

Capital and O&M cost estimates were developed for each of the evaluated control options. The GPSP cost estimates are conceptual in nature; thus, S&L did not procure equipment quotes specifically for the GPSP control system upgrades. Rather, equipment costs are based on conceptual designs developed for the retrofit control systems, preliminary equipment sizing developed for the major pieces of equipment (based on GPSP-specific design parameters, including typical fuels firing profiles, fuel characteristics, and flue gas temperatures and flow rates), and recent pricing for similar equipment. S&L would characterize the cost estimates for the GPSP retrofit technologies as “concept screening” cost estimates generally based on parametric models, judgment, or analogy.

Control technology equipment costs for the retrofit options were developed by scaling cost estimates prepared by S&L for other similar projects. Major equipment costs were developed based on equipment costs recently developed for similar projects, and include the equipment, material, labor, and all other direct costs needed to

<sup>27</sup> The assumed 20-year equipment life is consistent with the control system equipment life used by NDDH in its evaluation of NO<sub>x</sub> and SO<sub>2</sub> control technologies for BART-eligible sources. (see, e.g., ND Regional Haze Final SIP, Appendix C.1, “BART Determination Study for Leland Olds Station Units 1 & 2, Basin Electric Power Cooperative, August 2006, pgs. 64 (NO<sub>x</sub> controls) and 158 (SO<sub>2</sub> controls). See also, ND Regional Haze Final SIP, Appendix C4, “NO<sub>x</sub> Best Available Control Technology Study for Milton R. Young Station Unit 1, Minnkota Power Cooperative, Inc., October 2006, pg. 3-22).

<sup>28</sup> Based on discussion with the NDDH, the state has elected to utilize the current Federal Reserve interest rate, which was 5.5% at the time of this analysis.



retrofit the units with the control technology. Sub-accounts for the capital cost estimates (e.g., mobilization and demobilization, consumables, contractor general and administration (G&A) expense, freight on materials, etc.) were developed by applying ratios from detailed cost estimates that were prepared for projects with similar scopes.

Additional costs were developed based on outage duration needed to tie-in the new control technology. Based on the location of the control technology (specifically the SCR), a special outage would be required to integrate into the flue gas path at a time when no process steam is required (i.e., when all three Riley Boilers and two Superheaters are offline). Since GPSP facility does not typically take a full facility outage on a yearly basis, a special outage is included; loss of facility profit is estimated for the outage and annualized similarly to the capital costs.

Fixed O&M costs include operating labor, maintenance labor, maintenance material, and administrative labor. Variable O&M costs include the cost of consumables, including reagent, water consumption, and electrical power requirements. Electrical power requirements reflect the additional power requirements associated with the operation of the new control technology (compared to the existing technology). All O&M costs reflect the incremental increase in O&M costs compared to the costs incurred to operate the existing control systems.

In addition to the cost effectiveness relative to the base case, the incremental cost-effectiveness to go from one level of control to the next more stringent level of control will also be calculated to evaluate the cost effectiveness of the more stringent control.

The results of the SO<sub>2</sub> and NO<sub>x</sub> control cost evaluations are included below in Sections 9.1 and Section 9.2.

## **9.1 ECONOMIC EVALUATION – SO<sub>2</sub> CONTROLS**

In the previous sections, it was determined that WFGD was established as BACT by the NDDH for the three Riley Boilers and continues to operate at approximately 97% reduction; thus no further SO<sub>2</sub> control options will be evaluated on the Riley Boilers. The two Superheaters currently generate an insignificant amount of SO<sub>2</sub> in comparison to the total SO<sub>2</sub> present at the stack. Furthermore, the WFGD is providing 96% overall SO<sub>2</sub> reduction for the combination of Superheaters and Riley Boilers, which is still within BACT levels. As such, no additional SO<sub>2</sub> control options are evaluated for the Superheaters.

The Package Boiler was recently commissioned and is only permitted to fire natural gas or SNG to limit SO<sub>2</sub> emissions. Samples taken by GPSP personnel confirm the sulfur composition of the SNG is non-detectable. Therefore, no additional SO<sub>2</sub> control options are evaluated for the Package Boiler.

Finally, there have been previous issues at GPSP with H<sub>2</sub>S scrubbing along with limited experience with operating H<sub>2</sub>S scrubbing devices on flares, especially with low H<sub>2</sub>S concentrations and those which do not operate at steady flow rates. Because of this and the safety concerns with operating backend equipment on pressure relief flare systems, no SO<sub>2</sub> control options will be evaluated for the Main Flare and Startup Flare.

## 9.2 ECONOMIC EVALUATION – NO<sub>x</sub> CONTROLS

Based on the technical feasibility analysis completed as part of the first factor, it was determined that NO<sub>x</sub> control reduction is only feasible on the Riley Boilers and Superheaters. Table 9-1 presents the capital costs and annual operating costs associated with building and operating each control system for the three combined Riley Boilers or two combined Superheaters; annual emissions and pricing is not provided on an individual unit basis. Table 9-2 shows the average annual cost effectiveness for each control system. Additional cost details are provided in Appendix C.

**Table 9-1. NO<sub>x</sub> Control Cost Summary (\$2018)**

Unit <sup>(Note 1)</sup>	NO <sub>x</sub> Control Option	Total Capital Investment \$	Annual Capital Cost \$/yr	Annualized Outage Cost \$/yr	Annual Operating Cost \$/yr	Total Annual Cost \$/yr
Riley Boilers	TE-SCR	\$178,542,000	\$14,940,000	\$3,515,000	\$51,399,000	\$69,854,000
Superheaters	Combustion Optimization	\$1,7326,000	\$144,000	\$0	\$85,000	\$229,000

Note 1. Costs are provided for the combination of the three Riley Boilers or two Superheaters.

**Table 9-2. NO<sub>x</sub> Emissions Control System Cost Effectiveness (\$2018)**

Unit <sup>(Note 1)</sup>	NO <sub>x</sub> Control Option	Total Annual Cost \$/yr	Expected Emission Reduction tons NO <sub>x</sub> /yr	Average Annual Cost Effectiveness <sup>(Note 2)</sup> \$/ton NO <sub>x</sub> removed
Riley Boilers	TE-SCR	\$69,854,000	1,808	\$38,639
Superheaters	Combustion Optimization	\$229,000	10	\$23,596

Note 1. Costs are provided for the combination of the three Riley Boilers or two Superheaters.

Note 2. Average cost effectiveness for each control option is the total annual cost divided by the expected emission reduction.

The costs indicate that the average annual cost effectiveness of the NO<sub>x</sub> control options for the facility range from \$23,596 per ton (Combustion Optimization on Superheaters) to \$38,639 per ton (TE-SCR) NO<sub>x</sub> removed.

The Combustion Optimization option is expected to achieve 5% NO<sub>x</sub> reduction from long-term average baseline levels without impact to Superheater performance. This option can be implemented on both Superheaters with additional capital and minor operating costs for a total cost effectiveness is \$23,596 per ton.

TE-SCR system costs have been included to remain consistent with the approach during the initial planning period (i.e., assuming technical feasibility and evaluating the control system for costs and cost effectiveness). Based on preliminary cost estimates, the cost effectiveness of a TE-SCR system is \$38,639 per ton to treat the NO<sub>x</sub> from the three Riley Boilers.

## 10. TIME NECESSARY FOR COMPLIANCE (STATUTORY FACTOR TWO)

The time necessary for compliance is generally defined as the time needed for full implementation of the evaluated control options identified in Table 5-3 and Table 6-4. This includes the time needed to develop and implement the regulations, as well as the time needed to install the selected control equipment. The time needed to install the control equipment includes time for equipment procurement, design, fabrication, and installation. Therefore, compliance deadlines must consider the time necessary for compliance by setting a compliance deadline that provides a reasonable amount of time for the source to implement the control measure.

Table 10-1 includes estimated timeframes needed to implement each of the control technologies. Notably, the estimated timeframes do not account for time needed for North Dakota to develop and implement the regulations; nor the amount of time needed for EPA to take proposed and final action to approve North Dakota's SIP.

**Table 10-1. NO<sub>x</sub> Emissions Control System Implementation Schedule**

NO <sub>x</sub> Control Option	Design / Specification / Procurement (months)	Detail Design / Fabrication (months)	Construction / Commissioning / Startup (months)	Total (months after SIP approval)
TE-SCR on Riley Boilers	10	18	24	Up to 60 months
Combustion Optimization on Superheaters	2	4	4	Up to 60 months

## **11. ENERGY AND NON-AIR QUALITY ENVIRONMENTAL IMPACTS (STATUTORY FACTOR THREE)**

The primary purpose of the environmental impact analysis is to assess collateral environmental impacts due to control of the regulated pollutant in question. Environmental impacts may include solid or hazardous waste generation, discharges of polluted water from a control device, visibility impacts, increased emissions of other criteria or non-criteria pollutants, increased water consumption, and land use impacts from waste disposal.

### **11.1 ENVIRONMENTAL IMPACTS**

The Riley Boilers and Superheaters are currently equipped with a combination of LNB, FGR and OFA systems for NO<sub>x</sub> control and wet ammonia scrubber technology for SO<sub>2</sub> control. The ammonia reagent used in the ammonia-based FGD system reacts with SO<sub>2</sub> in the flue gas to form ammonium sulfate and ammonium sulfite solids. The solids are either recycled to the system for reuse or removed from the system and sold as fertilizer or disposed as nonhazardous solid waste. The existing WFGD system also requires water to quench the flue gas. Based on the design of the control system, the WFGD uses approximately 640 gpm of makeup water for SO<sub>2</sub> control. Collateral environmental impacts associated with the existing control systems include water consumption and increased solid waste generation. There were no collateral impacts associated with the combustion optimization or LNB/OFA/FGR systems previously implemented.

Based on a review of potential non-air quality environmental impacts, there are potentially significant collateral environmental impacts identified for and the NO<sub>x</sub> control options. The TE-SCR catalyst oxidizes some of the SO<sub>2</sub> to SO<sub>3</sub> in addition to catalyzing the reaction between NO<sub>x</sub> and ammonia. There could be the potential for increased SO<sub>3</sub> emissions with the use of a TE-SCR. The SO<sub>3</sub> will react with the moisture in the stack to form sulfuric acid emissions and react with the ammonia slip to form ABS. If it is determined a dry sorbent injection system is required for the reduction of SO<sub>3</sub> emissions prior to the WFGD, the system will increase the solid waste generated and may affect sales of the ammonium sulfate fertilizer. If fertilizer cannot be sold, it will need to be disposed of in a solid waste landfill. There would be some ammonia slip emissions from a TE-SCR in the range of 2 ppm, and there is no means to capture the ammonia slip emissions from the TE-SCR since it would be installed downstream of the WFGD. Finally, the TE-SCR system would require combustion of SNG in a duct burner to heat the flue gas. This would result in additional NO<sub>x</sub>, CO and VOC emissions.

Impacts from the incorporation of the combustion optimization system on the Superheaters are expected to be less significant than the TE-SCR. Based on tuning the combustion for minimizing NO<sub>x</sub> formation, there would be expected increases in CO emissions, since they have an inverse relationship with respect to combustion.

## **11.2 ENERGY IMPACTS**

The facility relies on production of steam in the Riley Boilers, Superheaters, and Package Boiler as the heat energy for other processes within the gasification facility. Options that include changes to the combustion temperature for NO<sub>x</sub> control may result in sub-optimal steam production rates or quality. As such, if the combustion optimization systems may not be able to maintain the desired boiler efficiency while tuning operating conditions for minimizing NO<sub>x</sub> production, additional fuel may have to be fired to maintain steam production rate and quality. As such, the measured efficiency of the boiler may decrease, and subsequently result in higher mass emission rates due to higher fuel throughput. The TE-SCR option would increase pressure drop through the control systems, and increase the electricity consumption of the facility.

Although several of the control options have energy impacts, none of the impacts are considered significant enough as to disqualify any of the options from consideration in the Four Factor Analysis. In order to account for potential energy impacts associated with each option, the electrical power cost associated with operating the control systems have been included as an annual operating cost in the economic impact assessment.

## **11.3 ENVIRONMENTAL / ENERGY IMPACTS SUMMARY**

A summary of the Statutory Factor 3 environmental and energy impact analysis is provided in Table 11-1.

**Table 11-1. Summary of Energy and Non-Air Quality Environmental Impacts**

Control Option	Collateral Environmental & Energy Impacts
<b>Baseline</b>	<ul style="list-style-type: none"> <li>➤ GPSP Riley Boilers are currently equipped with WFGD / WESP control systems for SO<sub>2</sub> control. The Riley Boilers and Superheaters are equipped with a combination of LNB, FGR, and OFA for NOx control. Existing collateral environmental and energy impacts include:</li> <li>➤ Solid WFGD by-product management or disposal</li> <li>➤ Increased water consumption</li> <li>➤ Increased electrical power requirements</li> </ul>
<b><u>NOx Control Options</u></b>	
Selective Catalytic Reduction (SCR) - Tail End Configuration (Riley Boilers)	<ul style="list-style-type: none"> <li>➤ Increased electrical power requirements</li> <li>➤ Increased ammonia slip emissions and potential for ABS emissions</li> <li>➤ Potential increase in SO<sub>3</sub> emissions</li> <li>➤ Additional solid waste disposal</li> <li>➤ Additional NOx, CO, and VOC emissions from duct firing</li> </ul>
Combustion Optimization (Superheaters)	<ul style="list-style-type: none"> <li>➤ Potential decrease in boiler efficiency to reduce NOx emissions</li> <li>➤ Potential increase in CO emissions</li> </ul>

## **12. REMAINING USEFUL LIFE (STATUTORY FACTOR FOUR)**

The evaluation of NO<sub>x</sub> and SO<sub>2</sub> controls options should consider the source's "remaining useful life" in determining the costs of compliance. The remaining useful life is the difference between the date that controls would be put in place and the date that the facility permanently ceases operation. If the remaining useful life of the unit is shorter than the useful life of a particular control option, the remaining useful life should be used for annualizing costs. If the remaining useful life exceeds the useful life of the control options, the remaining useful life has no effect on the cost evaluation.

Under the current GPSP resource plan, the remaining useful life of the facility is expected to be greater than 20 years. Therefore, the remaining useful life has no impact on the annualized cost of control under the current regulatory framework. However, the implementation of additional controls has the potential to reduce the facility's minimal profit margin, which may adversely impact the facility's planned remaining life. In the event that occurs, GPSP would request an opportunity to reevaluate economic impacts and the facility's remaining useful life.



## **13. FOUR-FACTOR ANALYSIS SUMMARY**

At the request of NDDH, a Four Factor Analysis was prepared for GPSP. The analysis identified SO<sub>2</sub> and NO<sub>x</sub> control options for the three Riley Boilers, two Superheaters, auxiliary Package Boiler, Main Flare, and Startup Flare, and evaluated each of the control measures for the following four statutory factors:

1. The estimated cost of compliance;
2. The time necessary for compliance;
3. The energy and non-air quality environmental impacts of compliance; and
4. The remaining useful life of any potentially affected anthropogenic source of visibility impairment.

The technical feasibility evaluation concluded that there are no technically feasible options for further SO<sub>2</sub> control on the individual sources. The evaluation prepared for NO<sub>x</sub> controls options indicates that the average annual cost effectiveness for the facility ranges from \$23,596 per ton (Combustion Optimization on Superheaters) to \$38,639 per ton (TE-SCR on Riley Boilers) NO<sub>x</sub> removed.

The time necessary for compliance for the NO<sub>x</sub> control options, the time necessary for compliance ranges from 10 months (combustion optimization) to 52 months (TE-SCR); however, GPSP would expect that the state would allow up to 60 months to achieve compliance to be consistent with the first planning period.

An evaluation of energy impacts indicates that certain control options (e.g., TE-SCR) will increase electrical power requirements due to increased pressure drop. Use of a combustion optimization system for NO<sub>x</sub> control may also result in reduced boiler efficiency which would increase the amount of fuels fired to maintain steam generation. Collateral environmental impacts with regard to TE-SCR include an increase in solid waste generation due to sorbent injection; increases in other stack emission such as CO, VOC and ammonia slip; as well as additional power consumption.

Regarding remaining useful life, the GPSP owners do not have an enforceable or suggested remaining useful life that is less than 20 years. However, implementation of control technologies that eliminate any profitability for the facility may have an effect on the remaining life. Nevertheless, a 20 year remaining useful life is evaluated.

## APPENDIX A

### NORTH DAKOTA DEPARTMENT OF HEALTH LETTER



May 18, 2018



Mr. Daniel Whitley  
Dakota Gasification Company  
420 County Road 26  
Beulah, ND 58523

Re: Regional Haze  
Second Planning Period

Dear Mr. Whitley:

The Department of Health (Department) has begun work on the second planning period (Round 2) State Implementation Plan (SIP) for regional haze. In Round 1 of the regional planning process, the emphasis was on Best Available Retrofit Technology (BART) and making reasonable progress towards the national visibility goal. In Round 2, there are no BART requirements; therefore, we will focus on making reasonable progress. The reasonable progress analysis will be made using the four factors in Section 169A(g)(1) of the Clean Air Act:

The four factors are:

1. The cost of compliance
2. The time necessary to achieve compliance
3. The energy and non-air quality environmental impact of compliance; and
4. The remaining useful life of any existing source subject to such requirements

Guidance provided by the U.S. Environmental Protection Agency (Draft Guidance on Progress Tracking Metrics, Long Term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period at [https://www.epa.gov/sites/production/files/2016-07/documents/draft\\_regional\\_haze\\_guidance\\_july\\_2016.pdf](https://www.epa.gov/sites/production/files/2016-07/documents/draft_regional_haze_guidance_july_2016.pdf)) indicates the Department must address 80% of the visibility impairment caused by in-state sources. Data from the IMPROVE monitoring sites at Theodore Roosevelt National Park (TRNP) and Lostwood Wilderness Area (LWA) indicate that sulfates and nitrates continue to be the largest contributors to visibility impairment in these areas. The primary precursors of sulfates and nitrates are emissions of sulfur dioxide (SO<sub>2</sub>) and nitrogen oxides (NO<sub>x</sub>).

The Great Plains Synfuels Plant has been identified as a significant source of SO<sub>2</sub> and NO<sub>x</sub> emissions. Therefore, the Department requests that you prepare a "four factors" analysis for your facility. The analysis should be prepared using the draft EPA guidance noted above. The analysis should include all source units that emit through the main stack as well as the flares at the facility.

Preparation of the Round 2 Regional Haze SIP will require extensive planning and review of emission sources in North Dakota. The Department will be working with the Western Regional Air Partnership (WRAP) to prepare the Round 2 SIP. WRAP will be conducting air quality modeling of potential regional emissions reductions in early 2019. The Department asks that your "four factors" analysis be submitted by January 31, 2019.

If you have any questions, please contact David Stroh of my staff at (701)328-5188.

Sincerely,



Terry L. O'Clair  
Director  
Division of Air Quality

TLO/TB:saj

## APPENDIX B

### GPSP BASELINE EMISSIONS

**Great Plains Synfuels Plant**  
**Reasonable Progress Four Factor Analysis**  
**Baseline Emissions Estimates**

**Table 1. GPSP -- Baseline Emissions**

Unit No.	Pollutant	Baseline Controls	Emissions		Heat Input	Capacity Factor	Notes
			lb/hr	tons/yr	MMBtu/yr	%	
Riley Boiler A, B, and S Combined Baseline	SO <sub>2</sub>	WFGD	671	2,757	13,691,041	68%	SO <sub>2</sub> emissions based on 24-month annual average tpy for period January 1, 2016 – December 31, 2017
	NO <sub>x</sub>	Combustion tuning, LNB, OFA	517	2,260	14,265,939	71%	NO <sub>x</sub> emissions based on 24-month annual average tpy for period August 18, 2016 – August 17, 2018
Superheater A and B Combined Emissions	SO <sub>2</sub>	low-sulfur fuel	56	246	1,971,982	67%	Emissions based on 24-month annual average tpy for period May 1, 2016 – April 30, 2018.
	NO <sub>x</sub>	Combustion tuning & LNB	44	194	1,971,982	67%	
Rentech Package Boiler	SO <sub>2</sub>	low-sulfur fuel	non-detect	non-detect	1,265,958	45%	Emissions based on maximum 30-day rolling annual average for period December 20, 2017 – October 11, 2018. Annual emissions and annual heat input based on assuming similar operation for 12 months of the year to develop tpy.
	NO <sub>x</sub>	ULNB	4	19	1,265,958	45%	
Main Flare	SO <sub>2</sub>	n/a	75	327	2,462,437	n/a	Emissions based on annual average emission rate tpy for 2018.
	NO <sub>x</sub>	n/a	24	105	3,523,823	n/a	Emissions based annual average emission rate tpy for 2015.
Startup Flare	SO <sub>2</sub>	n/a	17	74	363,233	n/a	Emissions based on annual average emission rate tpy for 2015.
	NO <sub>x</sub>	n/a	3	12	363,233	n/a	

## APPENDIX C

### NO<sub>x</sub> CONTROL COST EFFECTIVENESS ESTIMATES

**Great Plains Synfuels Plant  
NO<sub>x</sub> Control Summary**

**Table 1. GPSP Operating Parameters**

Parameter	Riley Boilers (3)	Superheaters (2)	Unit
Annual Average Heat Input	14,265,939	1,971,982	MMBtu/yr
Total Maximum Hourly Heat Input	2,289	338	MMBtu/hr
Average Capacity Factor	71%	67%	%

**Table 2. Control Effectiveness**

Control Technology	Riley Boilers				Superheaters			
	Control Efficiency (%)	Expected Emissions (tons/yr)	Emission Rate (lb/hr)	Expected Emissions Reduction (tons/yr)	Control Efficiency (%)	Expected Emissions (tons/yr)	Emission Rate (lb/hr)	Expected Emissions Reduction (tons/yr)
Tail-End SCR	80.0%	452	103	1,808				
Combustion Optimization					5.0%	184	42	10
Baseline		<b>2,260</b>	517			<b>194</b>	44	



Great Plains Synfuels Plant  
NO<sub>x</sub> Control Summary

Table 3. Cost Effectiveness Riley Boilers

Control Technology	Emissions (tons/yr)	Tons of NO <sub>x</sub> Removed (tons/yr)	Total Capital Requirement (\$)	Annualized Capital Cost (\$/year)	Annualized Outage Cost (\$/year)	Total Annual Operating Costs (\$/year)	Total Annual Costs (\$)	Average Cost Effectiveness (\$/ton)
Tail-End SCR	452	1,808	\$178,542,000	\$14,940,000	\$3,515,000	\$51,399,000	\$69,854,000	\$38,639
Baseline	2,260	0	--	--	--	--	--	

Table 4. Cost Effectiveness Superheaters

Control Technology	Emissions (tons/yr)	Tons of NO <sub>x</sub> Removed (tons/yr)	Total Capital Requirement (\$)	Annualized Capital Cost (\$/year)	Annualized Outage Cost (\$/year)	Total Annual Operating Costs (\$/year)	Total Annual Costs (\$)	Average Cost Effectiveness (\$/ton)
Combustion Optimization	184	10	\$1,726,000	\$144,000	\$0	\$85,000	\$229,000	\$23,596
Baseline	194	0	--	--	--	--	--	

**GPSP Riley Boilers**  
**NO<sub>x</sub> Control Cost Evaluation**  
**Tail-End SCR**

NO <sub>x</sub> Control Option Description	Tail-End SCR
Baseline NO <sub>x</sub> Emissions, lb/hr	517
Post Upgrade NO <sub>x</sub> Emissions, lb/hr	103
Capacity Factor used of Cost Estimates (%)	71%

CAPITAL COSTS		Cost (2018\$)	Basis
<b>Direct Costs</b>			
<b>Purchased Equipment Costs (PEC)</b>			
Equipment and Materials	\$60,114,000		Based on Sargent & Lundy's conceptual cost estimating system.
Instrumentation	\$0		Included in equipment and materials cost
Sales Tax	\$3,006,000		5% of Equipment/Material Cost
Freight	\$3,006,000		5% of Equipment/Material Cost
<i>Total PEC</i>	<i>\$66,126,000</i>		
<b>Direct Installation Costs</b>			
Labor	\$43,531,000		Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding	\$1,088,000		2.5% of Labor
Mobilization / Demobilization	\$653,000		1.5% of Labor
Labor Cost Due To Overtime Inefficiency	\$2,177,000		5% of Labor
<i>Total Direct Installation Costs</i>	<i>\$47,449,000</i>		
Total Direct Costs (PEC + Direct Installation Costs)	<b>\$113,575,000</b>		
<b>Indirect Costs</b>			
Contractor's General and Administration Expense	\$11,358,000		10% of Total Direct Costs
Contractor's Profit	\$5,679,000		5% of Total Direct Costs
Engineering, Procurement, & Project Services	\$9,086,000		8% of Total Direct Costs
Construction Management/Field Engineering	\$4,543,000		4% of Total Direct Costs
S-U / Commissioning	\$1,704,000		1.5% of Total Direct Costs
Spare Parts	\$568,000		0.5% of Total Direct Costs
Owner's Cost	\$2,272,000		2% of Total Direct Costs
Total Indirect Costs	<b>\$35,210,000</b>		
Contingency	<b>\$29,757,000</b>		20% of Direct and Indirect Costs
<b>Total Capital Investment (TCI)</b>	<b>\$178,542,000</b>		sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$	0.0837		20 year life of equipment (years) @ 5.5% interest.
<b>Annualized Capital Costs (CRF x TCI)</b>	<b>\$14,940,000</b>		
<b>OUTAGE COSTS</b>			
<b>Outage Costs</b>			
Standard Outage Duration (weeks/yr)	0		
Outage Duration due to Retrofit (weeks/yr)	6		Estimate for full facility (black-plant) outage for project tie-in
<b>Lost Revenue due to Retrofit</b>	<b>\$42,000,000</b>		Based on GPSP facility net lost revenue from a black plant \$1,000,000/day
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$	0.0837		20 year life of equipment (years) @ 5.5% interest.

**GPSP Riley Boilers**  
**NO<sub>x</sub> Control Cost Evaluation**  
**Tail-End SCR**

NO <sub>x</sub> Control Option Description	Tail-End SCR
Baseline NO <sub>x</sub> Emissions, lb/hr	517
Post Upgrade NO <sub>x</sub> Emissions, lb/hr	103
Capacity Factor used of Cost Estimates (%)	71%

<b>Annualized Outage Costs (CRF x TCI)</b>		<b>\$3,515,000</b>	
<b>OPERATING COSTS</b>			
<b>Operating &amp; Maintenance Costs</b>			
<b>Variable O&amp;M Costs</b>			
Ammonia Reagent Cost	\$197,000		Based on ammonia reagent cost of \$275.18 per ton.
Hydrated Lime Cost	\$1,066,000		Based on hydrated lime cost of \$187 per ton.
Catalyst Replacement and Disposal Cost	\$2,166,000		Based on catalyst cost of \$8,000 per m3 and catalyst replacement cost of \$1,000 per m3.
SNG Cost	\$990,000		Based on an SNG sale rate of \$3.14/MMBtu.
Lost Fertilizer Revenue	\$36,010,000		Based on ammonia sulfate fertilizer sale price of \$200/ton
Additional Solid Waste Cost	\$786,000		Based on solid waste disposal cost of \$4.20/ton
Electrical Power Cost	\$881,000		Based on electricity cost of \$41.16 per MWh
<i>Total Variable O&amp;M Costs</i>	<b>\$42,096,000</b>		

**GPSP Riley Boilers**  
**NO<sub>x</sub> Control Cost Evaluation**  
**Tail-End SCR**

NO <sub>x</sub> Control Option Description	Tail-End SCR
Baseline NO <sub>x</sub> Emissions, lb/hr	517
Post Upgrade NO <sub>x</sub> Emissions, lb/hr	103
Capacity Factor used of Cost Estimates (%)	71%

<b>Fixed O&amp;M Costs</b>		
Additional Operators per Shift	1	
Operating Labor	\$398,000	Assume \$45.47/hr for each additional operator
Supervisor Labor	\$60,000	15% of Operating Labor. EPA Cost Manual Section 1, Chapter 2, page 2-31.
Maintenance Materials	\$1,704,000	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor	\$0	Included in cost for maintenance materials.
<i>Total Fixed O&amp;M Cost</i>	<i>\$2,162,000</i>	
<b>Indirect Operating Cost</b>		
Property Taxes	\$1,785,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	\$1,785,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	\$3,571,000	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
<i>Total Indirect Operating Cost</i>	<i>\$7,141,000</i>	
<b>Total Annual Operating Cost</b>	<b>\$51,399,000</b>	
<b>TOTAL ANNUAL COST</b>		
Annualized Capital Cost	\$14,940,000	
Annualized Outage Cost	\$3,515,000	
Annual Operating Cost	\$51,399,000	
<b>Total Annual Cost</b>	<b>\$69,854,000</b>	

**GPSP Superheaters**  
**NO<sub>x</sub> Control Cost Evaluation**  
**Combustion Optimization**

NO <sub>x</sub> Control Option Description	Combustion Optimization
Baseline NO <sub>x</sub> Emissions, lb/hr	44
Post Upgrade NO <sub>x</sub> Emissions, lb/hr	42
Capacity Factor used of Cost Estimates (%)	67%

CAPITAL COSTS		Cost (2018\$)	Basis
<b>Direct Costs</b>			
<b>Purchased Equipment Costs (PEC)</b>			
Equipment and Materials	\$765,000		Based on Sargent & Lundy's conceptual cost estimating system.
Instrumentation	\$0		Included in equipment and materials cost
Sales Tax	\$38,000		5% of Equipment/Material Cost
Freight	\$38,000		5% of Equipment/Material Cost
<i>Total PEC</i>	<i>\$841,000</i>		
<b>Direct Installation Costs</b>			
Labor	\$235,000		Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding	\$6,000		2.5% of Labor
Mobilization / Demobilization	\$4,000		1.5% of Labor
Labor Cost Due To Overtime Inefficiency	\$12,000		5% of Labor
<i>Total Direct Installation Costs</i>	<i>\$257,000</i>		
<b>Total Direct Costs (PEC + Direct Installation Costs)</b>		<b>\$1,098,000</b>	
<b>Indirect Costs</b>			
Contractor's General and Administration Expense	\$110,000		10% of Total Direct Costs
Contractor's Profit	\$55,000		5% of Total Direct Costs
Engineering, Procurement, & Project Services	\$88,000		8% of Total Direct Costs
Construction Management/Field Engineering	\$44,000		4% of Total Direct Costs
S-U / Commissioning	\$16,000		1.5% of Total Direct Costs
Spare Parts	\$5,000		0.5% of Total Direct Costs
Owner's Cost	\$22,000		2% of Total Direct Costs
<i>Total Indirect Costs</i>	<i>\$340,000</i>		
<b>Contingency</b>	<b>\$288,000</b>		20% of Direct and Indirect Costs
<b>Total Capital Investment (TCI)</b>	<b>\$1,726,000</b>		sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$	0.0837		20 year life of equipment (years) @ 5.5% interest.
<b>Annualized Capital Costs (CRF x TCI)</b>	<b>\$144,000</b>		
OPERATING COSTS			Basis
<b>Operating &amp; Maintenance Costs</b>			
<b>Variable O&amp;M Costs</b>			
Electrical Power Cost	\$0		Based on electricity cost of \$41.16 per MWh
<i>Total Variable O&amp;M Costs</i>	<i>\$0</i>		

**GPSP Superheaters**  
**NO<sub>x</sub> Control Cost Evaluation**  
**Combustion Optimization**

NO <sub>x</sub> Control Option Description	Combustion Optimization
Baseline NO <sub>x</sub> Emissions, lb/hr	44
Post Upgrade NO <sub>x</sub> Emissions, lb/hr	42
Capacity Factor used of Cost Estimates (%)	67%

<b>Fixed O&amp;M Costs</b>		
Additional Operators per shift	\$0	Assume no additional operators
Operating Labor	\$0	N/A
Supervisor Labor	\$0	N/A
Maintenance Materials	\$16,000	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor	\$0	Included in cost for maintenance materials.
<i>Total Fixed O&amp;M Cost</i>	<i>\$16,000</i>	
<b>Indirect Operating Cost</b>		
Property Taxes	\$17,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	\$17,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	\$35,000	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
<i>Total Indirect Operating Cost</i>	<i>\$69,000</i>	
<b>Total Annual Operating Cost</b>	<b>\$85,000</b>	
<b>TOTAL ANNUAL COST</b>		
Annualized Capital Cost	\$144,000	
Annual Operating Cost	\$85,000	
<b>Total Annual Cost</b>	<b>\$229,000</b>	